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EXELON CORP

Form 10-K

February 09, 2018

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, 2017

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) 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210
001-31403	PEPCO HOLDINGS LLC (a Delaware limited liability company) 701 Ninth Street, N.W.	52-2297449

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Washington, District of Columbia 20068
(202) 872-2000

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

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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

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	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>
Exelon Generation Company, LLC	Yes	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>
Commonwealth Edison Company	Yes	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>
PECO Energy Company	Yes	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>
Baltimore Gas and Electric Company	Yes	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>
Pepco Holdings LLC	Yes	<input checked="" type="checkbox"/>	No	<input type="checkbox"/>
Potomac Electric Power Company	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
Delmarva Power & Light Company	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
Atlantic City Electric Company	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>

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	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
Exelon Generation Company, LLC	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
Commonwealth Edison Company	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
PECO Energy Company	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
Baltimore Gas and Electric Company	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
Pepco Holdings LLC	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
Potomac Electric Power Company	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
Delmarva Power & Light Company	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>
Atlantic City Electric Company	Yes	<input type="checkbox"/>	No	<input checked="" type="checkbox"/>

Indicate by check mark whether the registrant (1) has 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) has 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

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

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

	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company	Emerging Growth Company
Exelon Corporation	<input checked="" type="checkbox"/>				
Exelon Generation Company, LLC			<input type="checkbox"/>		
Commonwealth Edison Company			<input type="checkbox"/>		
PECO Energy Company			<input type="checkbox"/>		
Baltimore Gas and Electric Company			<input type="checkbox"/>		
Pepco Holdings LLC			<input type="checkbox"/>		
Potomac Electric Power Company			<input type="checkbox"/>		
Delmarva Power & Light Company			<input type="checkbox"/>		
Atlantic City Electric Company			<input type="checkbox"/>		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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, 2017 was as follows:

Exelon Corporation Common Stock, without par value	\$34,604,071,959
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, 2018 was as follows:

Exelon Corporation Common Stock, without par value	965,029,399
Exelon Generation Company, LLC	Not applicable
Commonwealth Edison Company Common Stock, \$12.50 par value	127,021,256
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000
Pepco Holdings LLC	Not applicable
Potomac Electric Power Company Common Stock, \$0.01 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 2018 Annual Meeting of

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Shareholders and the Commonwealth Edison Company 2018 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.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
Pepco Holdings or PHI	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
Pepco	Potomac Electric Power Company
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
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, ACE, PES and PCI collectively
ACE Funding or ATF	Atlantic City Electric Transition Funding LLC
Antelope Valley	Antelope Valley Solar Ranch One
BondCo	RSB BondCo LLC
BSC	Exelon Business Services Company, LLC
CENG	Constellation Energy Nuclear Group, LLC
ConEdison Solutions	The competitive retail electricity and natural gas business of Consolidated Edison Solutions, Inc., a subsidiary of Consolidated Edison, Inc
Constellation	Constellation Energy Group, Inc.
EEDC	Exelon Energy Delivery Company, LLC
EGR IV	ExGen Renewables IV, LLC
EGTP	ExGen Texas Power, LLC
Entergy	Entergy Nuclear FitzPatrick, LLC
Exelon Corporate	Exelon in its corporate capacity as a holding company
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
FitzPatrick	James A. FitzPatrick nuclear generating station
PCI	Potomac Capital Investment Corporation and its subsidiaries
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
PHI Corporate	PHI in its corporate capacity as a holding company
PHISCO	PHI Service Company
RPG	Renewable Power Generation
SolGen	SolGen, LLC
TMI	Three Mile Island nuclear facility
UII	Unicom Investments, Inc.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and
Abbreviations

AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
AGE	Albany Green Energy Project
AMI	Advanced Metering Infrastructure
AMP	Advanced Metering Program
AOCI	Accumulated Other Comprehensive Income
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Alternative Revenue Program
CAISO	California ISO
CAP	Customer Assistance Program
CCGTs	Combined-Cycle gas turbines
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CES	Clean Energy Standard
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Conectiv	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE during the Predecessor periods
Conectiv Energy	Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries, which were sold to Calpine in July 2010
CSAPR	Cross-State Air Pollution Rule
CTA	Consolidated tax adjustment
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DCPSC	District of Columbia Public Service Commission
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
DOE	United States Department of Energy
DOJ	United States Department of Justice
DPSC	Delaware Public Service Commission
DRP	Direct Stock Purchase and Dividend Reinvestment Plan
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDF	Electricite de France SA and its subsidiaries
EE&C	Energy Efficiency and Conservation/Demand Response
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
EPSA	Electric Power Supply Association

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

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
GAAP	Generally Accepted Accounting Principles in the United States
GCR	Gas Cost Rate
GHG	Greenhouse Gas
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
Integrays	Integrays 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
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

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and
Abbreviations

MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
n.m.	not meaningful
NAAQS	National Ambient Air Quality Standards
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
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
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
NYPSC	New York Public Service Commission
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
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
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
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

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and
Abbreviations

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)
SGIG	Smart Grid Investment Grant from DOE
SILO	Sale-In, Lease-Out
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPFPA	Security, Police and Fire Professionals of America
SPP	Southwest Power Pool
TCJA	Tax Cuts and Jobs Act
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

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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.

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION

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 the Registrants include those factors discussed herein, including those factors discussed with respect to the Registrants discussed in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 23, Commitments and Contingencies; 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' website at www.exeloncorp.com. Information contained on the Registrants' website shall not be deemed incorporated into, or to be a part of, this Report.

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PART I

ITEM 1. BUSINESS

General

Corporate Structure and Business and Other Information

Exelon, incorporated in Pennsylvania in February 1999, is a utility services holding company engaged, through Generation, in the energy generation business, and through ComEd, PECO, 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.

Name of Registrant	State/Jurisdiction and Year of Incorporation	Business	Service Territories	Address of Principal Executive Offices
Exelon Generation Company, LLC	Pennsylvania (2000)	Generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity to both wholesale and retail customers. Generation also sells natural gas, renewable energy and other energy-related products and services.	Six reportable segments: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions	300 Exelon Way, Kennett Square, Pennsylvania 19348
Commonwealth Edison Company	Illinois (1913)	Purchase and regulated retail sale of electricity Transmission and distribution of electricity to retail customers	Northern Illinois, including the City of Chicago	440 South LaSalle Street, Chicago, Illinois 60605
PECO Energy Company	Pennsylvania (1929)	Purchase and regulated retail sale of electricity and natural gas Transmission and distribution of electricity and distribution of natural	Southeastern Pennsylvania, including the City of Philadelphia (electricity) Pennsylvania counties surrounding the City of	2301 Market Street, Philadelphia, Pennsylvania 19103

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		gas to retail customers	Philadelphia (natural gas)	
Baltimore Gas and Electric Company	Maryland (1906)	Purchase and regulated retail sale of electricity and natural gas	Central Maryland, including the City of Baltimore (electricity and natural gas)	110 West Fayette Street, Baltimore, Maryland 21201
		Transmission and distribution of electricity and distribution of natural gas to retail customers		
Pepco Holdings LLC	Delaware (2016)	Utility services holding company engaged, through its reportable segments Pepco, DPL and ACE	Service Territories of Pepco, DPL and ACE	701 Ninth Street, N.W., Washington, D.C. 20068
Potomac Electric Power Company	District of Columbia (1896) Virginia (1949)	Purchase and regulated retail sale of electricity	District of Columbia and Major portions of Montgomery and Prince George's Counties, Maryland	701 Ninth Street, N.W., Washington, D.C. 20068
		Transmission and distribution of electricity to retail customers		
Delmarva Power & Light Company	Delaware (1909) Virginia (1979)	Purchase and regulated retail sale of electricity and natural gas	Portions of Delaware and Maryland (electricity)	500 North Wakefield Drive, Newark, Delaware 19702
		Transmission and distribution of electricity and distribution of natural gas to retail customers	Portions of New Castle County, Delaware (natural gas)	
Atlantic City Electric Company	New Jersey (1924)	Purchase and regulated retail sale of electricity	Portions of Southern New Jersey	500 North Wakefield Drive, Newark, Delaware 19702
		Transmission and distribution of electricity to retail		

customers

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Business Services

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of corporate governance support services including corporate strategy and development, legal, human resources, information technology, finance, real estate, security, corporate communications and supply at cost. The costs of these services are directly charged or allocated to the applicable operating segments. The services are provided pursuant to service agreements. Additionally, the results of Exelon's corporate operations include interest costs and income from various investment and financing activities.

PHI Service Company (PHISCO), a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, finance, 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 PHISCO and the participating operating subsidiaries.

Operating Segments

See Note 25 — 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 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

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for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. FERC's jurisdiction over ratemaking 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.

RTOs and ISOs exist in a number of regions to provide transmission service across multiple transmission systems. FERC has approved PJM, MISO, ISO-NE and SPP as RTOs and CAISO and ISO-NY 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. 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 NERC mandatory reliability standards, which protect the nation's bulk power system against potential disruptions from cyber and physical security breaches.

Constellation Energy Nuclear Group, LLC

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 (Ginna) and Nine Mile Point. CENG's ownership share in the total capacity of these units is 4,026 MW. See ITEM 2. PROPERTIES for additional information on these sites.

Generation and EDF entered into a Put Option Agreement on April 1, 2014, pursuant to which EDF has the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. The appraisers determining fair market value of EDF's 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation's rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation's rights to other distributions. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months. In order to exercise its option, EDF must give 60-days advance written notice to Generation stating that it is exercising its option. To date, EDF has not given notice to Generation that it is exercising its option.

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. See Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for further information regarding the CENG consolidation.

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Acquisitions

James A. FitzPatrick Nuclear Generating Station

On March 31, 2017, Generation acquired the 838 MW single-unit James A. FitzPatrick nuclear generating station located in Scriba, New York from Entergy Nuclear FitzPatrick LLC (Entergy) for a total purchase price consideration of \$289 million, resulting in an after-tax bargain purchase gain of \$233 million in 2017.

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.

Dispositions

ExGen Texas Power, LLC.

On May 2, 2017, EGTP entered into a consent agreement with its lenders to permit EGTP to draw on its revolving credit facility and initiate an orderly sales process to sell the assets of its wholly owned subsidiaries, the proceeds from which will first be used to pay the administrative costs of the sale, the normal and ordinary costs of operating the plants and repayment of the secured debt of EGTP, including the revolving credit facility. As a result, Exelon and Generation classified certain EGTP assets and liabilities as held for sale at their respective fair values less costs to sell and recorded associated pre-tax impairment charges of \$460 million. On November 7, 2017, EGTP and all of its wholly owned subsidiaries filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the District of Delaware. As a result of the bankruptcy filing, EGTP's assets and liabilities were deconsolidated from Exelon and Generation's consolidated financial statements. Exelon and Generation recorded a pre-tax gain upon deconsolidation of \$213 million in the fourth quarter of 2017.

Asset Divestitures

During 2015 and 2014, 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. See Note 4 — Mergers, Acquisitions and Dispositions and Note 7 — Impairment of Long-Lived Assets and Intangibles of the Combined Notes to Consolidated Financial Statements for additional information on acquisitions and dispositions.

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Generating Resources

At December 31, 2017, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets ^{(a)(b)}	
Nuclear	20,310
Fossil (primarily natural gas and oil)	11,723
Renewable ^(c)	3,135
Owned generation assets ^(e)	35,168
Long-term power purchase contracts ^(d)	5,285
Total generating resources	40,453

(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.

Includes EGTP generating assets that were deconsolidated from Generation's consolidated financial statements. See

(e) Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

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

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 33% of capacity).

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

New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont (approximately 6% of capacity).

New York represents the operations within ISO-NY, which covers the state of New York in its entirety (approximately 6% of capacity).

ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas (approximately 16% of capacity).

Other Power Regions is an aggregate of regions not considered individually significant (approximately 5% of capacity).

See Note 25 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers and revenues net of purchased power and fuel expense for each of Generation's reportable segments.

Nuclear Facilities

Generation has ownership interests in fifteen nuclear generating stations currently in service, consisting of 25 units with an aggregate of 20,310 MW of capacity. Generation wholly owns all of its

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nuclear generating stations, except for undivided ownership interests in three jointly-owned nuclear stations: Quad Cities (75% ownership), Peach Bottom (50% ownership), and Salem (42.59% ownership), which are consolidated on Exelon's and Generation's financial statements relative to its proportionate ownership interest in each unit, and a 50.01% membership interest in CENG, which owns Calvert Cliffs, Nine Mile Point [excluding Long Island Power Authority's 18% undivided ownership interest in Nine Mile Point Unit 2] and Ginna nuclear stations. CENG is 100% consolidated on Exelon's and Generation's financial statements.

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 2017, 2016 and 2015 electric supply (in GWh) generated from the nuclear generating facilities was 69%, 67% and 68%, respectively, of Generation's total electric supply, which also includes fossil, hydroelectric and renewable generation and electric supply purchased for resale. Generation's wholesale and retail power marketing activities are, in part, supplied by the output from the nuclear generating stations. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of Generation's electric supply sources.

Nuclear Operations

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

During 2017, 2016 and 2015, the nuclear generating facilities operated by Generation achieved capacity factors of 94.1%, 94.6% and 93.7%, respectively. The capacity factors reflect ownership percentage of stations operated by Generation and include CENG. 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 power marketing 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 also 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. All nuclear generating stations operated by Generation, except for Clinton, are categorized by the NRC in the Licensee Response Column, which is the highest of five performance bands. As of February 1, 2018, the NRC categorized Clinton in the Regulatory Response Column, which is the second highest of five performance bands. 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 and/or operating costs for nuclear generating facilities.

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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 May 30, 2017, Exelon announced that Generation will permanently cease generation operations at TMI on or about September 30, 2019. On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle in October 2018. In 2010, Generation had previously agreed to permanently cease generation operations at Oyster Creek by the end of 2019. See Note 8 — Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information regarding the early retirement of TMI. See Note 28 — Subsequent Events of the Combined Notes to Consolidated Financial Statements for additional information regarding the early retirement of Oyster Creek.

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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
FitzPatrick	1	1974	2034
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
GINNA	1	1970	2029
Salem	1	1977	2036
	2	1981	2040
Three Mile Island ^(e)	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.

Generation had previously announced and notified the NRC that it will permanently cease generation operations at

(c) Oyster Creek by the end of 2019. On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle in October 2018.

(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.

(e) On May 30, 2017, Exelon announced that Generation will permanently cease generation operations at TMI on or about September 30, 2019 and has notified the NRC.

The operating license renewal process takes approximately four to five years from the commencement of the renewal process, which includes approximately two years for Generation to develop the application and approximately two years for the NRC to review the 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, TMI and Clinton. In 2017, Oyster Creek and TMI depreciation provisions were based on

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their 2019 expected shutdown dates. Beginning February 2018, Oyster Creek depreciation provisions will be based on its announced shutdown date of 2018. 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 8 — Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional detail on early retirements.

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, 2017, Generation had approximately 84,100 SNF assemblies (20,600 tons) stored on site in SNF pools or dry cask storage (this includes SNF assemblies at Zion Station, for which Generation retains ownership even though the responsibility for decommissioning Zion Station has been assumed by another party; see Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning). All currently operating Generation-owned nuclear sites have on-site dry cask storage, except for TMI, where such storage is projected to be in operation in 2021. On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at Generation's sites through the end of the license renewal periods and through decommissioning.

For a discussion of matters associated with Generation's contracts with the DOE for the disposal of SNF, see Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

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

Generation ships its Class A LLRW, which represents 93% of LLRW generated at its stations, to disposal facilities in Utah and South Carolina, which have enough storage capacity to store all Class A LLRW for the life of all stations in Generation's nuclear fleet. 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 Class 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 on-site storage and cost impacts.

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Nuclear Insurance

Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See “Nuclear Insurance” within Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for details.

For information regarding property insurance, see ITEM 2. PROPERTIES — Generation. Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for its insured losses. Such losses could have a material adverse effect on Exelon’s and Generation’s 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. 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, 2017 at fair value of approximately \$13.3 billion and have an estimated targeted annual pre-tax return of 4.8% to 6.4%, while the Nuclear AROs are recorded on Exelon’s and Generation’s Consolidated Balance Sheets at December 31, 2017 at approximately \$9.7 billion and have an estimated annual average accretion of the ARO of approximately 5% through a period of approximately 30 years after the end of the extended lives of the units. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Exelon Corporation, Executive Overview; ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates, Nuclear Decommissioning, Asset Retirement Obligations and Nuclear Decommissioning Trust Fund Investments; and Note 3 — Regulatory Matters, Note 11 — Fair Value of Financial Assets and Liabilities and Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Generation’s NDT funds and its decommissioning obligations.

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 in Zion, Illinois, and ceased operation in 1998.

On September 1, 2010, Generation and EnergySolutions completed the transactions contemplated by the ASA. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation’s transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to dispose of SNF, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. However, ZionSolutions is subject to certain restrictions on its ability to request reimbursement; specifically, if certain milestones as defined in the ASA are not met, all or a portion of requested reimbursements shall be deferred until such milestones are met. See Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station decommissioning and see Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for a discussion of variable interest entity considerations related to ZionSolutions.

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Fossil and Renewable Facilities (including Hydroelectric)

At December 31, 2017, Generation had ownership interests in 14,858 MW of capacity in generating facilities currently in service, consisting of 11,723 MW of natural gas and oil, and 3,135 MW of renewables (wind, hydroelectric and solar). Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) Wyman; (2) certain wind project entities and a biomass project entity with minority interest owners; and (3) ExGen Renewables Partners, LLC which is owned 49% by another owner. 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 and Wyman, which are operated by third parties. In 2017, 2016 and 2015, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 12%, 10% and 8%, 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, which include Generation's Conowingo Hydroelectric Project (Conowingo) and Muddy Run Pumped Storage Facility Project (Muddy Run). On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo and 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 for Conowingo was not completed prior to the expiration of the plant's license on September 1, 2014. The FERC is required to issue annual licenses for Conowingo until the new long-term license is issued. On September 10, 2014, FERC issued an annual license for Conowingo, effective as of the expiration of the previous license. The annual license renews automatically absent any further FERC action. 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 projects, but not for its fossil and hydroelectric operations unless required by contract or financing agreements. Refer to Note 13 — 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.

Long-Term Power Purchase Contracts

In addition to energy produced by owned generation assets, Generation sources electricity from plants it does not own under long-term contracts. The following tables summarize Generation's long-

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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, 2017:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic	14	2019 - 2032	237
Midwest	4	2019 - 2026	834
New England	7	2018	40
ERCOT	5	2020 - 2031	1,524
Other Power Regions	12	2018 - 2030	2,650
Total	42		5,285

	2018	2019	2020	2021	2022	Thereafter	Total
Capacity Expiring (MW)	141	644	1,020	815	298	2,367	5,285

Fuel

The following table shows sources of electric supply in GWh for 2017 and 2016:

	Source of Electric Supply	
	2017	2016
Nuclear ^(a)	182,843	176,799
Purchases — non-trading portfolio	51,595	59,987
Fossil (primarily natural gas and oil)	22,546	19,830
Renewable ^(b)	7,848	6,324
Total supply	264,832	262,940

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^(a) generation for 2017 and 2016 includes physical volumes of 34,761 GWh and 33,444 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 inventory in various forms and does not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment or fabrication services to meet the nuclear fuel requirements of its nuclear units.

Natural gas is procured through long-term and short-term contracts, as well as spot-market purchases. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

Generation uses financial instruments to mitigate price risk associated with certain commodity price exposures, using both over-the-counter and exchange-traded instruments. See ITEM 1A. RISK FACTORS, ITEM 7.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION

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AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Marketing

Generation's integrated business operations include physical delivery and marketing of power. Generation largely obtains physical power supply from its generating assets and power purchase agreements in multiple geographic regions. Power purchase agreements, including tolling arrangements, are commitments related to power generation of specific generation plants and/or dispatch similar to an owned asset depending on the type of underlying asset. The commodity risks associated with the output from generating assets and PPAs are managed using various commodity transactions including sales to customers. The main objective is to obtain low-cost energy supply to meet physical delivery obligations to both wholesale and retail customers. 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. Where necessary, Generation may also purchase transmission service to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs.

Price and 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 may also enter into transactions that are outside of this ratable sales plan.

Generation is exposed to commodity price risk in 2018 and beyond for portions of its electricity portfolio that are unhedged. As of December 31, 2017, the percentage of expected generation hedged is 85%-88%, 55%-58% and 26%-29% for 2018, 2019, and 2020, 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, 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. The 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. 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 primarily in nuclear fuel and energy generation assets. Generation's estimated capital expenditures for 2018 are approximately \$2.1 billion, which includes Generation's share of the investment in nuclear fuel for the co-owned Salem plant.

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ComEd, PECO, BGE, Pepco, DPL and ACE

Utility Operations

Service Territories and Franchise Agreements

The following table presents the size of service territories, populations of each service territory and the number of customers within each service territory for the Utility Registrants as of December 31, 2017:

	Service Territories (in square miles)			Service Territory Population (in millions)			Number of 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	4.0 ^(b)	4.0	2.4	1.6	1.6	0.5
BGE	3,250	2,300	3,050	3.1 ^(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	5,400	5,400	275	1.4 ^(e)	1.4	0.6	0.5	0.5	0.1
ACE	2,800	2,800	n/a	1.1 ^(f)	1.1	n/a	0.6	0.6	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.

The Utility Registrants have the necessary authorizations to perform their current business of providing regulated electric and natural gas distribution services in the various municipalities and territories in which they now supply such services. These authorizations include charters, franchises, permits, and certificates of public convenience issued by local and state governments and state utility commissions. ComEd's, BGE's and ACE's rights are generally non-exclusive; while PECO's, Pepco's and DPL's rights are generally exclusive. Certain authorizations are perpetual while others have varying expiration dates. The Utility Registrants anticipate working with the appropriate governmental bodies to extend or replace the authorizations prior to their expirations.

Utility Regulations

State utility commissions regulate the Utility Registrants' electric and gas distribution rates and service, issuances of certain securities, and certain other aspects of the business. The following table outlines the state commissions responsible for utility oversight.

Registrant	Commission
ComEd	ICC
PECO	PAPUC
BGE	MDPSC
Pepco	DCPSC/MDPSC
DPL	DPSC/MDPSC
ACE	NJBPU

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The Utility Registrants are public utilities under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of the utilities' business. The U.S. Department of Transportation also regulates pipeline safety and other areas of gas operations for PECO, BGE and DPL. Additionally, the Utility Registrants are subject to NERC mandatory reliability standards, which protect the nation's bulk power system against potential disruptions from cyber and physical security breaches.

Seasonality Impacts on Delivery Volumes

The Utility Registrants' electric distribution volumes 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 distribution volumes are generally higher during the winter months when cold temperatures create demand for winter heating.

ComEd, BGE, Pepco and DPL Maryland have electric distribution decoupling mechanisms and BGE has a natural gas decoupling mechanism that eliminate the favorable and unfavorable impacts of weather and customer usage patterns on electric distribution and natural gas delivery volumes. As a result, ComEd's, BGE's, Pepco's and DPL's Maryland electric distribution revenues and BGE's natural gas revenues are not materially impacted by delivery volumes. PECO's and ACE's electric distribution revenues and DPL's Delaware electric distribution and natural gas revenues are impacted by delivery volumes.

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. 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 customers that choose to purchase electric generation or natural gas from competitive suppliers, the Utility Registrants act as the billing agent and therefore do not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. Refer to ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Results of Operations for further information. For customers that choose to purchase electric generation or natural gas from a Utility Registrant, the Utility Registrants are permitted to recover the electricity and natural gas procurement costs without mark-up and therefore record equal and offsetting amounts of Operating revenues and Purchased power and fuel expense related to the electricity and/or natural gas. As a result, fluctuations in electricity or natural gas sales and procurement costs

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have no impact on the Utility Registrants' Revenues net of purchased power and fuel expense, which is a non-GAAP measure used to evaluate operational performance, or Net Income.

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. RTO spot market purchases and sales are utilized to balance the utility electric load and supply as required. 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.

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	Underground
	Natural Gas Plant Facility	Propane-Air Storage Service Agreements ^(a)
PECO	1,200	150
BGE	1,056	550
DPL	257	n/a
		18,000
		22,000
		3,800

^(a) Natural gas from underground storage represents approximately 28%, 46% and 34% of PECO's, BGE's and DPL's 2017-2018 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. The off-system gas sales are not material to PECO, BGE and DPL.

Refer to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK, Commodity Price, for further information regarding Utility Registrants' contracts to procure electric supply and natural gas.

Energy Efficiency Programs

The Utility Registrants are 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.

The Utility Registrants are allowed to earn a return on their energy efficiency costs. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

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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 2018 are as follows:

	Projected 2018 Capital Expenditure Spending			
(in millions)	Transmission	Distribution	Gas	Total
ComEd	\$375	\$ 1,750	N/A	\$2,125
PECO	125	450	\$225	800
BGE	175	425	400	1,000
Pepco	125	600	N/A	725
DPL	150	200	50	400
ACE	175	200	N/A	375

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 and smart grid in their respective service territories. ComEd expects to complete its smart meter and smart grid deployment in 2018.

Transmission Services

Under FERC's open access transmission policy, 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 approved by FERC. 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 region. The Utility Registrants 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.

On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rates and change the manner in which PECO's transmission rate is determined from a fixed rate to a formula rate. The new formula was accepted by FERC effective as of December 1, 2017, subject to refund and set for hearing and settlement judge proceedings, which are currently ongoing. See Note 3

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— Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional detail regarding the transmission formula rate.

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

Employees

As of December 31, 2017, Exelon and its subsidiaries had 34,621 employees in the following companies, of which 11,845 or 34% 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)	1,660	97	2,729	4,486	15,011
ComEd	3,515	—	—	3,515	6,280
PECO	—	1,148	—	1,148	2,534
BGE ^(d)	—	—	—	—	3,022
PHI ^(e)	—	—	322	322	1,320
Pepco ^(e)	—	—	1,151	1,151	1,582
DPL ^(e)	—	—	688	688	944
ACE ^(e)	—	—	421	421	647
Other ^(f)	65	—	49	114	3,281
Total	5,240	1,245	5,360	11,845	34,621

A separate CBA between ComEd and IBEW Local 15 covers approximately 65 employees in ComEd's System (a) Services Group and was renewed in 2016. Generation's and ComEd's separate CBAs with IBEW Local 15 will expire in 2022.

PECO craft and call center employees in the Philadelphia service territory are covered by CBAs with IBEW Local (b) 614, both expiring in 2021. Additionally, Exelon Power, an operating unit of Generation, has an agreement covering 97 employees, which was renewed in 2016 and expiring in 2019.

(c) During 2017, Generation finalized CBAs with the Security Officer unions at LaSalle, Limerick and Quad Cities, which all will expire in 2020 and Dresden expiring in 2021. Additionally, during 2017, Generation acquired and combined two CBAs at FitzPatrick into one CBA covering both craft and security employees, which will expire in 2023. 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, Generation finalized a 5-year agreement with the New England ENEH, UWUA Local 369, which will expire in 2022. 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, an agreement was negotiated with Las Vegas District Energy and IUOE Local 501, which will expire in 2018.

(d) In January 2017, an election was held at BGE which resulted in union representation for 1,394 employees at the end of the year. BGE and IBEW Local 410 are negotiating 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 CBAs with four local unions. CBAs are generally renegotiated every three to five years. All of these CBAs 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.

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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 environmental 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 Senior Vice President, Competitive Market Policy; and the Director, Safety & Sustainability, as well as senior management of Generation, ComEd, PECO, BGE, PHI, 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 Generation Oversight Committee and the Corporate Governance Committee the authority to oversee Exelon's compliance with health, environmental and safety laws and regulations and its strategies and efforts to protect and improve the quality of the environment, including Exelon's internal climate change and sustainability policies and programs, as discussed in further detail below. 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 impose restrictions on emission of particulates, sulfur dioxide (SO₂), nitrogen oxides (NO_x), mercury and other air pollutants and require permits for operation of emitting sources. Such permits have been obtained as needed by Exelon's subsidiaries. However, due to its low emitting generation fleet comprised of nuclear, natural gas, hydroelectric, wind and solar, compliance with the Federal Clean Air Act does not have a material impact on Generation's operations. 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 federal 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 Exelon's facilities discharge stormwater and 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 the Delaware River Basin Commission and the Susquehanna River Basin Commission, regional agencies that primarily regulate water usage.

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)

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are potentially most affected by recent changes to the regulations. For Generation, those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, FitzPatrick, Ginna, Gould Street, Mountain Creek, Handley, Mystic 7, Nine Mile Point Unit 1, Peach Bottom, Quad Cities, Riverside and Salem.

On October 14, 2014, the EPA's 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, such as those that would make cooling towers infeasible.

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. On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle in October 2018.

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 (i.e., the requirement most likely to support cooling towers). The R.E Ginna and Nine Mile Point Unit 1 power generation facilities received renewals of their state water discharge permits in 2014 and cooling towers were not required. These facilities are now engaged in the required analyses to enable the environmental agency to determine the best technology available in the next permit renewal cycles.

Salem

On July 28, 2016, the NJDEP issued a final permit for Salem that did not require the installation of cooling towers and allows Salem to continue to operate utilizing the existing cooling water system with certain required system modifications. However, the permit is being challenged by an environmental organization, and if successful, could result in additional costs for Clean Water Act compliance. Potential cooling water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

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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 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, Illinois, Maryland, New Jersey and Pennsylvania and the District of Columbia 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 could become in the future, parties to proceedings initiated by the EPA, state agencies and/or other responsible parties under CERCLA and RCRA with respect to a number of sites, including MGP sites, or may undertake to investigate and remediate sites for which they may be subject to enforcement actions by an agency or third-party.

See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding solid and hazardous waste regulation and legislation.

Environmental Remediation

ComEd's and PECO'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. BGE, ACE, Pepco and DPL do not have material contingent liabilities relating to MGP sites. The amount to be expended in 2018 for compliance with environmental remediation related to contamination at former MGP sites and other gas purification sites is expected to total \$48 million, consisting of \$42 million and \$6 million at ComEd and PECO respectively. The Utility Registrants also have contingent liabilities for environmental remediation of non-MGP contaminants (e.g., PCBs). As of December 31, 2017, the Utility Registrants have established appropriate contingent liabilities for environmental remediation requirements.

The Registrants' operations have in the past, and may in the future, require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws.

In addition, 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 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' environmental remediation efforts and related impacts to the Registrants' results of operations, cash flows and financial positions.

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Global Climate Change

Exelon has utility and generation assets, and customers, that are and will be further subject to the impacts of climate change. Accordingly, Exelon is engaged in a variety of initiatives to understand and mitigate these impacts, including investments in resiliency, partnering with federal, state and local governments to minimize impacts, and, importantly, advocating for public policy that reduces emissions that cause climate change. Exelon, as a producer of electricity from predominantly low- and zero-carbon generating facilities (such as nuclear, hydroelectric, natural gas, wind and solar photovoltaic), has a relatively small greenhouse gas (GHG) emission profile, or carbon footprint, compared to other domestic generators of electricity (Exelon neither owns or operates any coal-fueled generating assets). Exelon's natural gas and biomass fired generating plants produce GHG emissions, most notably, CO₂. However, Generation's owned-asset emission intensity, or rate of carbon dioxide equivalent (CO₂e) emitted per unit of electricity generated, is among the lowest in the industry. In 2017, while fossil fuel powered approximately 33 percent of Exelon's owned generating capacity, fossil fuel-fired generation represents less than 12 percent of Exelon's overall generation on a MWh basis. Other GHG emission sources at Exelon include natural gas (methane) leakage on the natural gas systems, sulfur hexafluoride (SF₆) leakage from electric transmission and distribution operations, refrigerant leakage from chilling and cooling equipment, and fossil fuel combustion in motor vehicles. Exelon facilities and operations are subject to the global impacts of climate change and Exelon believes its operations could be significantly affected by the physical risks of climate change. 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 additional climate change regulation or legislation at the federal, regional and state levels.

International Climate Change Agreements. 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, and it became effective on November 4, 2016. Under the Paris Agreement, the Parties agreed to try to limit the global average temperature increase to 2°C (3.6°F) above pre-industrial levels. In doing so, Parties developed their own national reduction commitments. The United States submitted a non-binding target of 17% below 2005 emission levels by 2020 and 26% to 28% below 2005 levels by 2025. President Trump has stated his intention to withdraw the U.S. from the Paris Agreement, but no formal action has been initiated.

Federal Climate Change Legislation and Regulation. It is highly unlikely whether federal legislation to reduce GHG emissions will be enacted in the near-term. 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. More importantly, continued inaction could negatively impact the value of Exelon's low-carbon fleet.

Under the Obama Administration, the EPA proposed and finalized regulations for fossil fuel-fired power plants, referred to as the Clean Power Plan, which are currently being litigated. However, the Trump Administration has proposed a repeal of the Clean Power Plan, and is expected to seek broad public comment on whether and how to regulate GHGs at the federal level. Details are not yet known and are likely to be further informed by the public comment process.

Given this uncertainty, Exelon and Generation cannot at this time predict the future of the Clean Power Plan, or its repeal and/or replacement, or individual state responses to Clean Power Plan developments or how developments will impact their future results of operations, cash flows and financial positions.

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Regional and State Climate Change Legislation and Regulation. A number of states in which Exelon operates have state and regional programs to reduce GHG emissions, including from the power sector. As the nation's largest generator of carbon-free electricity, our fleet supports these efforts to produce safe, reliable electricity with minimal GHGs. Notably, nine northeast and mid-Atlantic states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont) currently participate in the Regional Greenhouse Gas Initiative (RGGI), which is in the process of strengthening its requirements. The program requires most fossil fuel-fired power plants in the region to hold allowances, purchased at auction, for each ton of CO₂ emissions. Non-emitting resources do not have to purchase or hold these allowances.

Many states in which Exelon subsidiaries operate also have state-specific programs to address GHGs, including from power plants. Most notable of these, besides RGGI, are through renewable and other portfolio standards. Additionally, in response to a court decision clarifying obligations under the Global Warming Solutions Act, the Massachusetts Department of Environmental Protection in 2017 finalized regulations establishing a statewide cap on CO₂ emissions from fossil fuel power plants (Massachusetts remains in RGGI as well). The effect of this new obligation and potential for market illiquidity in the early years represent a risk to Generation's Massachusetts fossil facilities, including Medway and Mystic. At the same time, the District of Columbia is considering a plan to incorporate the cost of carbon into electricity, via consumption, as well as directly into the cost of transportation and home heating fuels. Details remain to be developed, but the specifics could have implications for Pepco's operations.

Regardless of whether GHG regulation occurs at the local, state, or federal level, Exelon remains one of the largest, lowest-carbon electric generators in the United States, relying mainly on nuclear, natural gas, hydropower, wind, and solar. The extent that the low-carbon generating fleet will continue to be a competitive advantage for Exelon depends on what, if anything, replaces the Clean Power Plan at the federal level, new or expanded state action on greenhouse gas emissions or direct support of clean energy technologies, including nuclear, as well as potential market reforms that value our fleet's emission-free attributes.

Renewable and Alternative Energy Portfolio Standards

Thirty-nine states and the District of Columbia, incorporating the vast majority of Exelon operations as well as all utility operations, have adopted some form of RPS requirement. These standards impose varying levels of mandates for procurement of renewable or clean electricity (the definition of which varies by state) and/or energy efficiency. These are generally expressed as a percentage of annual electric load, often increasing by year. Exelon's utilities comply with these various requirements through purchasing qualifying renewables, implementing efficiency programs, acquiring sufficient credits (e.g., RECs), paying an alternative compliance payment, and/or a combination of these compliance alternatives. The Utility Registrants are permitted to recover from retail customers the costs of complying with their state RPS requirements, including the procurement of RECs or other alternative energy resources. New York and Illinois adopted standards targeted at preserving the zero-carbon attributes of certain Exelon's nuclear-powered generating facilities. Generation owns multiple facilities participating in these programs within both states. Other states in which Generation and our utilities operate are considering similar programs. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on renewable portfolio standards.

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Executive Officers of the Registrants as of February 9, 2018

Exelon

Name	Age	Position	Period
Crane, Christopher M.	59	Chief Executive Officer, Exelon	2012 - Present
		Chairman, ComEd, PECO & BGE	2012 - Present
		Chairman, PHI	2016 - Present
		President, Exelon	2008 - Present
		President, Generation	2008 - 2013
Cornew, Kenneth W.	52	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
O'Brien, Denis P.	57	Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	2012 - Present
		Vice Chairman, ComEd, PECO & BGE	2012 - Present
		Vice Chairman, PHI	2016 - Present
Pramaggiore, Anne R.	59	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
Adams, Craig L.	65	President and Chief Executive Officer, PECO	2012 - Present
Butler, Calvin G.	48	Chief Executive Officer, BGE	2014 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2013 - 2014
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
David M. Velazquez	58	President and Chief Executive Officer, PHI	2016 - Present
		President and Chief Executive Officer, Pepco, DPL & ACE	2009 - Present
		Executive Vice President, Pepco Holdings, Inc.	2009 - 2016
Von Hoene Jr., William A.	64	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present
Thayer, Jonathan W.	46	Senior Executive Vice President and Chief Financial Officer, Exelon	2012 - Present
Aliabadi, Paymon	55	Executive Vice President and Chief Risk Officer, Exelon	2013 - Present
		Managing Director, Gleam Capital Management	2012 - 2013
DesParte, Duane M.	54	Senior Vice President and Corporate Controller, Exelon	2008 - Present

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Generation Name	Age	Position	Period
Cornew, Kenneth W.	52	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
Pacilio, Michael J.	57	Executive Vice President and Chief Operating Officer, Generation President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation	2015 - Present 2010 - 2015
Hanson, Bryan C	52	President and Chief Nuclear Officer, Exelon Nuclear; Senior Vice President, Generation	2015 - Present
Nigro, Joseph	53	Executive Vice President, Exelon; Chief Executive Officer, Constellation Senior Vice President, Portfolio Management and Strategy	2013 - Present 2012 - 2013
DeGregorio, Ronald	55	Senior Vice President, Generation; President, Exelon Power	2012 - Present
Wright, Bryan P.	51	Senior Vice President and Chief Financial Officer, Generation Senior Vice President, Corporate Finance, Exelon	2013 - Present 2012 - 2013
Bauer, Matthew N.	41	Vice President and Controller, Generation Vice President and Controller, BGE Vice President of Power Finance, Exelon Power	2016 - Present 2014 - 2016 2012 - 2014

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ComEd			
Name	Age	Position	Period
Pramaggiore, Anne R.	59	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
Donnelly, Terence R.	57	Executive Vice President and Chief Operating Officer, ComEd	2012 - Present
Trpik Jr., Joseph R.	48	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2009 - Present
Jensen, Val	62	Senior Vice President, Customer Operations, ComEd	2012 - Present
Gomez, Veronica	48	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	56	Senior Vice President, Governmental & External Affairs, Exelon	2012 - Present
McGuire, Timothy M.	59	Senior Vice President, Distribution Operations, ComEd	2016 - Present
		Vice President, Transmission and Substations, ComEd	2010 - 2016
Kozel, Gerald J.	45	Vice President, Controller, ComEd	2013 - Present
		Assistant Corporate Controller, Exelon	2012 - 2013

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PECO			
Name	Age	Position	Period
Adams, Craig L.	65	President and Chief Executive Officer, PECO	2012 - Present
Barnett, Phillip S.	54	Senior Vice President and Chief Financial Officer, PECO Treasurer, PECO	2007 - Present 2012 - Present
Innocenzo, Michael A.	52	Senior Vice President and Chief Operations Officer, PECO	2012 - Present
Murphy, Elizabeth A.	58	Senior Vice President, Governmental & External Affairs, PECO Vice President, Governmental & External Affairs, PECO	2016 - Present 2012 - 2016
Webster Jr., Richard G.	56	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
Jiruska, Frank J.	57	Vice President, Customer Operations, PECO	2013 - Present
Diaz Jr., Romulo L.	71	Vice President and General Counsel, PECO	2012 - Present
Bailey, Scott A.	41	Vice President and Controller, PECO	2012 - Present

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BGE			
Name	Age	Position	Period
Butler, Calvin G.	48	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.	50	President, BGE	2014 - Present
		Chief Operating Officer, BGE	2012 - Present
		Senior Vice President, BGE	2009 - 2014
Vahos, David M.	45	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
Núñez, Alexander G.	46	Senior Vice President, Regulatory and External Affairs, BGE	2016 - Present
		Vice President, Governmental & External Affairs, BGE	2013 - 2016
		Director, State Affairs, BGE	2012 - 2013
Case, Mark D.	56	Vice President, Regulatory Policy and Strategy, BGE	2012 - Present
Biagiotti, Robert D.	48	Vice President, Customer Operations, BGE	2015 - Present
		Vice President, Gas Distribution, BGE	2011 - 2015
Gahagan, Daniel P.	64	Vice President and General Counsel, BGE	2007 - Present
Andrew W. Holmes	49	Vice President and Controller, BGE	2016 - Present
		Director, Generation Accounting, Exelon	2013 - 2016
		Director, Derivatives and Technical Accounting, Exelon	2008 - 2013

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PHI, Pepco, DPL and ACE

Name	Age	Position	Period
Velazquez, David M.	58	President and Chief Executive Officer, PHI	2016 - Present
		Executive Vice President, Pepco Holdings, Inc.	2009-2016
		President and Chief Executive Officer, Pepco, DPL & ACE	2009 - Present
Anthony, J. Tyler	53	Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL & ACE	2016 - Present
		Senior Vice President, Distribution Operations, ComEd	2010 - 2016
Kinzel, Donna J.	50	Senior Vice President, Chief Financial Officer and Treasurer, PHI, Pepco, DPL & ACE	2016 - Present
		Vice President, Treasurer and Chief Risk Officer, Pepco Holdings	2012 - 2016
Bonney, Paul R.	59	Senior Vice President, Legal and Regulatory Strategy, PHI, Pepco, DPL & ACE	2016 - Present
		Senior Vice President and General Counsel, Constellation	2012 - 2016
Lavinson, Melissa A.	48	Senior Vice President, Governmental & External Affairs, PHI, Pepco, DPL & ACE	2018 - Present
		Vice President, Federal Affairs and Policy, and Chief Sustainability Officer, PG&E Corporation	2015 - 2018
		Vice President, Federal Affairs, PG&E Corporation	2012 - 2015
Stark, Wendy E.	45	Vice President and General Counsel, PHI, Pepco DPL & ACE	2016 - Present
		Deputy General Counsel, Pepco Holdings, Inc.	2012 - Present
McGowan, Kevin M.	56	Vice President, Regulatory Policy and Strategy, PHI, Pepco, DPL & ACE	2016 - Present
		Vice President, Regulatory Affairs, Pepco Holdings, Inc.	2012 - 2016
Aiken, Robert M.	51	Vice President and Controller, PHI, Pepco, DPL & ACE	2016 - Present
		Vice President and Controller, Generation	2012 - 2016

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ITEM 1A. RISK FACTORS

Each of the Registrants operates in a market and regulatory environment that poses significant risks, many of which are beyond that Registrant's control. Management of each Registrant regularly meets with the Chief Risk Officer and the Registrant's Risk Management Committee (RMC), which comprises officers of the Registrant, to identify and evaluate the most significant risks of the Registrant's business and the appropriate steps to manage and mitigate those risks. The Chief Risk Officer and senior executives of the Registrants discuss those risks with the Finance and Risk Committee and Audit Committee of the Exelon Board of Directors and the ComEd, PECO, 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, cash flows or financial positions and the market prices of their publicly traded securities. Each of the Registrants has disclosed the known material risks that affect its business at this time. However, there may be further risks and uncertainties that are not presently known or that are not currently believed by a Registrant to be material that could adversely affect its performance or financial condition in the future.

Exelon's results of operations, cash flows and financial position 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 results of operations, cash flows or financial positions 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, (4) the impacts of on-going competition in the retail channel and (5) emerging technologies.

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, tax policy, zero emission credit programs 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 (RPS), 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, secure 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, safety and security of its energy delivery systems are fundamental to Exelon's ability to achieve value-added growth for customers, communities and shareholders. Additionally, the operating costs of the Registrants and the opinions of their customers, regulators and shareholders are affected by those companies' ability to maintain the reliability, safety and efficiency of their energy delivery systems.

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Risks Related to the PHI Merger. Exelon is subject to additional risks related to the merger with PHI, which 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, cash flows or financial position (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 exposed to variability of spot and forward market prices in the markets in which it operates.

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 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 such as Exelon's nuclear 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, cash flows or financial positions and such impacts could be

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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 regulated utility growth for the benefit of customers, reduce debt and provide attractive shareholder returns. 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 positions. See Note 8 — 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 development or applications of technologies related to shale gas production, cost-effective renewable energy technologies, energy efficiency, distributed generation and energy storage devices. Such developments could affect the price of energy, levels of customer-owned generation, customer expectations and current business models and make portions of our electric system power supply and transmission and/or distribution facilities

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obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy. Each of these factors could materially affect the Registrants' results of operations, cash flows or financial positions through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Market performance and other factors could decrease the value of NDT funds and employee benefit plan assets and could increase the related employee benefit plan obligations, which then could require significant additional funding (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 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, cash flows or financial positions 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 positions could be negatively impacted.

Unstable capital and credit markets and increased volatility in commodity markets could adversely affect the Registrants' businesses in several ways, including the availability and cost of short-term funds for liquidity requirements, the Registrants' ability to meet long-term commitments, Generation's ability to hedge effectively its generation portfolio, and the competitiveness and liquidity of energy markets; each could negatively impact the Registrants' results of operations, cash flows or financial positions (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

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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, Canada and Asia. Disruptions in these markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2017, approximately 19%, or \$1.8 billion, 19%, or \$1.8 billion, and 17%, or \$1.6 billion of the Registrants' available credit facilities were with European, Canadian and Asian banks, respectively. The credit facilities include \$9.5 billion in aggregate total commitments of which \$8.3 billion was available as of December 31, 2017. As of December 31, 2017, there were no borrowings under Generation's bilateral credit facilities. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the credit facilities.

The strength and depth of competition in energy markets depend heavily on active participation by multiple trading parties, which could be adversely affected by disruptions in the capital and credit markets and legislative and regulatory initiatives that 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, cash flows or financial positions.

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 broad remedies, including rights to foreclose against the project assets and related collateral or to force the Exelon subsidiaries in the project-specific financings to enter into bankruptcy proceedings.

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

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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 remaining sources of liquidity. PJM 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-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 ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources — Credit Matters — 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, cash flows or financial position for Generation.

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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 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 as well as the risk of ineffective hedges. 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, results of operations, cash flows or financial position.

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 or effectively address the changes in the wholesale power markets.

Challenges to tax positions taken by the Registrants as well as tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions, could impact the Registrants' results of operations, cash flows or financial positions. (All Registrants).

Corporate Tax Reform

On December 22, 2017, President Trump signed into law the TCJA. See Note 14 - Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

While the Registrants' current tax accounting and future expectations are based on management's present understanding of the provisions under the TCJA, further interpretive guidance of the TCJA's provisions could result in further adjustments that could have a material impact to the Registrants' future results of operations, cash flows or financial positions.

In addition, as allowed under SEC Staff Accounting Bulletin No. 118 (SAB 118), the Registrants have recorded provisional income tax amounts as of December 31, 2017 for changes pursuant to the TCJA related to depreciation for which the impacts could not be finalized upon issuance of the Registrants' financial statements, but reasonable estimates could be determined. However, the provisional amounts may change as the Registrants finalize their analysis and computations and such changes could be material to the Registrants' future results of operations, cash flows or financial positions.

The Utility Registrants have made their best estimate regarding the probability and timing of settlements of net regulatory liabilities established pursuant to the TCJA. However, the amount and timing of the settlements may change based on decisions and actions by the rate regulators, which could

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have a material impact on the Utility Registrants' future results of operations, cash flows or financial positions.

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 appeal 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 Note 1 — Significant Accounting Policies and Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Increases in customer rates, including increases in the cost of purchased power and increases in natural gas prices for the Utility Registrants, 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, cash flows or financial positions (All Registrants).

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 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 affect the Utility Registrants' results of operations, cash flows or financial positions. 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, cash flows or financial position. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for further discussion of the Registrants' credit risk.

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 and DPL, purchased natural gas costs are charged to customers with no return or profit component. For BGE, purchased natural gas costs are charged to customers using a MBR mechanism that compares the actual cost of gas to a market index. The difference between the actual cost and the market index is shared equally between shareholders and customers. Purchased power and natural gas prices fluctuate based on their relevant supply and demand. Significantly higher rates related to purchased power and natural gas 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 adverse effect on the Registrants' results of operations, cash flows or financial positions. Also, the Utility Registrants' cash flows could be adversely affected by differences between the time period when electricity and natural gas are purchased and the ultimate recovery from customers.

The effects of weather could impact the Registrants' results of operations, cash flows or financial positions (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 PECO, DPL and ACE. Due to revenue decoupling,

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BGE, Pepco and DPL Maryland 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 Future Energy Jobs Act (FEJA), beginning in 2017, customer rates for ComEd are adjusted to eliminate the favorable and unfavorable impacts of weather and customer usage patterns on distribution revenue.

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, cash flows or financial positions. 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 64%, 51%, 70%, 79%, 84%, 77%, 82% and 79% of total assets for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE, respectively, as of December 31, 2017. In addition, Exelon and Generation have significant balances related to unamortized energy contracts, as further disclosed in Note 10 — 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, cash flows or financial positions.

As of December 31, 2017, 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.

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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 6 — Property, Plant and Equipment, Note 7 — Impairment of Long-Lived Assets and Intangibles and Note 10 — 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 results of operations, cash flows or financial position 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 assets and a Registrant could incur substantial costs to fulfill its obligations under these indemnities and such costs could adversely affect a Registrant's results of operations, cash flows or financial position.

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 adversely impact that Registrant's results of operations, cash flows or financial position. Each of the Utility Registrants has transferred its former generation business to a third party and in each case the transferee may have agreed to assume certain obligations and to indemnify the applicable Utility Registrant for such obligations. In connection with the restructurings under which ComEd, PECO and BGE transferred their generating assets to Generation, Generation assumed certain of ComEd's, PECO's and BGE's rights and obligations with respect to their former generation businesses. Further, ComEd, PECO and BGE may have entered into agreements with third parties under which the third-party agreed to indemnify ComEd, PECO or BGE 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, Generation or the transferee of Pepco's, DPL's or ACE's generation facilities experienced events that reduced its creditworthiness or the indemnity arrangement became unenforceable, the applicable Utility Registrant could be liable for any existing or future claims, which could impact that Utility Registrant's results of operations, cash flows or financial position. In addition, the Utility Registrants may have residual liability under certain laws in connection with their former generation facilities. For example, under CERCLA, former owners of property may retain certain liability for environmental claims and remediation. The third parties to whom the Utility Registrants transferred their former generation facilities may have agreed to indemnify the Utility Registrants for all or a portion

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of such liability but if such third parties fail or are unable to perform under the indemnity, the applicable Utility Registrant may be liable for certain remediation costs.

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 results of operations, cash flows or financial positions. 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, cash flows 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 results of operations, cash flows or financial positions are significantly affected by Generation's sales and purchases of commodities at market-based rates, as opposed to cost-based or other similarly regulated rates, and Exelon's and the Utility Registrants' results of operations, cash flows or financial positions are heavily dependent on the ability of the Utility Registrants to recover their costs for the retail purchase and distribution of power and natural gas 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 positions.

State and federal regulatory and legislative developments related to emissions, climate change, tax reform, capacity market mitigation, energy price information, resilience, fuel diversity and RPS could also significantly affect Exelon's and Generation's results of operations, cash flows or financial positions. Various legislative and regulatory proposals to address climate change through GHG emission reductions, if enacted, could result in increased costs to entities that generate electricity through carbon-emitting fossil fuels, which could increase the market price at which all generators in a region, including Generation, could sell their output, thereby increasing the revenue Generation could realize from its low-carbon nuclear assets. Conversely, existing or new regulations intended to reduce GHG emissions could be rolled back, allowing fossil fueled facilities which were otherwise scheduled to retire to continue to operate if economical. This could result in decreases in market prices thereby reducing Generation's revenues. 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 GHG 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.

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Legislative and regulatory efforts in Illinois and New York to preserve the environmental attributes and reliability benefits of zero-emission nuclear-powered generating facilities through zero emission credit programs are subject to legal challenges and, if overturned, could negatively impact Exelon's and Generation's results of operations, cash flows or financial positions and result in the early retirement of certain of Generation's nuclear plants.

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 61% 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 and recognize the value of zero-carbon electricity and resiliency and (2) the absence of material changes to market structures that would limit or otherwise negatively affect market competition. Generation could also be adversely affected by state laws, regulations or initiatives designed to reduce wholesale prices artificially below competitive levels or to subsidize existing or new generation.

FERC's requirements for market-based rate authority, established in Order 697 and 816 and related subsequent orders, could pose a risk that Generation may no longer satisfy 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 affects Exelon most significantly is Title VII, which is known as the Dodd-Frank Wall Street Transparency and Accountability Act (Dodd-Frank). Dodd-Frank requires 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. The primary aim of Dodd-Frank is to regulate the key intermediaries in the swaps market, which entities are swap dealers (SDs), major swap participants (MSPs), or certain other financial entities, but the law also applies to a lesser degree to end-users of swaps. The CFTC's Dodd-Frank regulations generally preserved the ability of end users in the energy industry to hedge their risks using swaps without being subject to mandatory clearing, and many of the other substantive regulations that apply to SDs, MSPs, and other financial entities. Generation manages, and expects to be able to continue to manage, its commercial activity to ensure that it does not have to register as an SD or MSP or other type of covered financial entity.

There are some rulemaking proceedings that have not yet been finalized, in particular, proposed rules on position limits that would apply to both Exchange-traded futures contracts and economically-equivalent over-the-counter swaps. It is possible that those rules will be finalized by the end of 2018. Although the company would incur some costs associated with monitoring and compliance with such rules, it does not expect the rules to have a material impact on its business operations.

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.

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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. These 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. See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

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

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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 23 — 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 prudence reviews by state regulators, whereby various portions of rates could be adjusted, subject to refund or disallowed, 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 or earn an adequate return and could have a material adverse effect on the Utility Registrants' results of operations, cash flows or financial positions. 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, cash flows or financial positions 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.

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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, 2017, 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. 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 10 — Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information regarding accounting for the effects of regulation, regulatory matters and ComEd's and PHI's goodwill, respectively.

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

Various stakeholders, including legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors, including utilities, are considering ways to address the effect of GHG emissions on climate change. 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, a Federal RPS could increase the cost of compliance by mandating the purchase or construction of more expensive supply alternatives. For more information regarding climate change, see ITEM 1. BUSINESS — Global Climate Change and Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

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

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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 23 — 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 legislative or regulatory requirements (e.g. disallowances of costs, lower ROEs). The imposition of any of the foregoing could have a material negative impact on the Registrants' business, results of operations, cash flows or 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 positions (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 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures, result in lost revenue or restrict existing business activities, any of which could have a material adverse effect on the Registrants' results of operations, cash flows or financial positions.

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, cash flows 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.

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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 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, cash flows or financial position. 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 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on the SNF obligation.

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, fires resulting from natural causes such as lightning, 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' results of operations, cash flows or financial positions and their ability to raise capital.

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The impact that potential terrorist attacks could have on the industry and on Exelon 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 or interruption of fuel or the supply chain, which could adversely affect the Registrants' results of operations, cash flows or financial positions and their 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.

In addition, Exelon maintains a level of insurance coverage consistent with industry practices against property, casualty and cybersecurity 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 and higher operating and maintenance costs.

Nuclear fuel quality

The quality of nuclear fuel utilized by Generation could affect the efficiency and costs of Generation's operations. Remediation actions could result in increased costs due to accelerated fuel amortization, increased outage costs and/or increased costs due to decreased generation capabilities.

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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 nuclear 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, cash flows 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, cash flows 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 adversely affect Generation's results of operations, cash flows or financial position.

Nuclear insurance

As required by the Price-Anderson Act, Generation carries the maximum available amount of nuclear liability insurance, \$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 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional discussion of nuclear insurance.

Decommissioning obligation and funding

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

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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.

Generation recognizes as a liability the present value of the estimated future costs to decommission its nuclear facilities. The estimated liability is based on assumptions in the approach and timing of decommissioning the nuclear facilities, estimation of decommissioning costs and Federal and state regulatory requirements. No assurance can be given that the costs of such decommissioning will not substantially exceed such liability, as facts, circumstances or our estimates may change, including changes in the approach and timing of decommissioning activities, changes in decommissioning costs, changes in Federal or state regulatory requirements on the decommissioning of such facilities, other changes in our estimates or Generation's ability to effectively execute on its planned decommissioning activities. The performance of capital markets 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, cash flows or financial positions could be significantly affected. See Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results could differ significantly from current estimates. 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 results of operations, 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 15 — 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 Statements 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

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and Comprehensive Income and the adverse impact to Exelon's and Generation's results of operations, cash flows or financial positions 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 Statements 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, cash flows and financial positions 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 on 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 renews 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, cash flows 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.

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, cash flows or financial positions 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, generation facilities 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.

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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 natural causes such as 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 positions 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 or third party 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 internal and/or external 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, cash flows or financial position.

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 (Exelon and the Utility 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 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 Registrants 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 positions.

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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 increases the potentially unfavorable impacts of such attacks. A security breach of the physical assets or information systems of the Registrants, their competitors, vendors, business partners and 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 result in the 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 the Registrants have been, and will likely continue to be, subjected to physical and cyber-attacks, to date none has directly experienced a material breach or disruption to its 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 or another Registrant 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, loss of revenues, increased costs, operations shutdown, etc., any of which could contribute to the loss of customers and have a negative impact on the business and/or results of operations, cash flows or financial positions. 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 or financial positions.

Failure to attract and retain an appropriately qualified workforce could negatively impact the Registrants' results of operations, cash flows or financial positions (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, cash flows or financial positions 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, nuclear advisory or operating services for third

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parties, 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 and utility of the future initiatives and other non-regulatory mandated 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' results of operations, cash flows or financial positions.

The Registrants may not realize or achieve the anticipated cost savings through the cost management efforts which could impact the Registrants' results of operations (All Registrants).

The Registrants' future financial performance and level of profitability is dependent, in part, on various cost reduction initiatives. The Registrants may encounter challenges in executing these cost reduction initiatives and not achieve the intended cost savings.

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 and PHI).

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 and PHI's future business, prospects, results of operations, cash flows or financial conditions.

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 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

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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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

All Registrants

None.

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ITEM 2. PROPERTIES

Generation

The following table describes Generation's interests in net electric generating capacity by station at December 31, 2017:

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	2,381	
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	51	Wind	Base-load	46	(f)(h)
Beebe	Midwest	Gratiot Co., MI	34	51	Wind	Base-load	42	(f)(h)
Michigan Wind 1	Midwest	Huron Co., MI	46	51	Wind	Base-load	35	(f)(h)
Harvest 2	Midwest	Huron Co., MI	33	51	Wind	Base-load	30	(f)(h)
Harvest	Midwest	Huron Co., MI	32	51	Wind	Base-load	27	(f)(h)
Beebe 1B	Midwest	Gratiot Co., MI	21	51	Wind	Base-load	26	(f)(h)
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)
Solar Ohio	Midwest	Toledo, OH	2		Solar	Base-load	4	
Blue Breezes	Midwest	Faribault Co., MN	2		Wind	Base-load	3	
CP Windfarm	Midwest	Faribault Co., MN	2	51	Wind	Base-load	2	(f)(h)
Southeast Chicago	Midwest	Chicago, IL	8		Gas	Peaking	296	
Clinton Battery Storage	Midwest	Blanchester, OH	1		Energy Storage	Peaking	10	
Total Midwest							11,950	
Limerick	Mid-Atlantic	Sanatoga, PA	2		Uranium	Base-load	2,317	
Peach Bottom	Mid-Atlantic	Delta, PA	2	50	Uranium	Base-load	1,303	(f)
Salem	Mid-Atlantic	Lower Alloways Creek Township, NJ	2	42.59	Uranium	Base-load	1,007	(f)
Calvert Cliffs	Mid-Atlantic	Lusby, MD	2	50.01	Uranium	Base-load	888	(f)(g)
Three Mile Island	Mid-Atlantic	Middletown, PA	1		Uranium	Base-load	837	(k)
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	51	Wind	Base-load	36	(f)(h)
Fair Wind	Mid-Atlantic	Garrett County, MD	12		Wind	Base-load	30	
Solar Maryland MC	Mid-Atlantic	Various, MD	17		Solar	Base-load	29	
Fourmile	Mid-Atlantic	Garrett County, MD	16	51	Wind	Base-load	20	(f)(h)
Solar New Jersey 1	Mid-Atlantic	Various, NJ	5		Solar	Base-load	18	
Solar New Jersey 2	Mid-Atlantic	Various, NJ	2		Solar	Base-load	11	

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Station ^(a)	Region	Location	No. of Units Owned ^(b)	Percent Owned ^(b)	Primary Fuel Type	Primary Dispatch Type ^(c)	Net Generation Capacity (MW) ^(d)	
Solar Horizons	Mid-Atlantic	Emmitsburg, MD	1	51	Solar	Base-load	8	(f)(h)
Solar Maryland	Mid-Atlantic	Various, MD	11		Solar	Base-load	8	
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	51	Solar	Base-load	1	(f)(h)
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	404	
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	
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 Township, NJ	1	42.59	Oil	Peaking	16	(f)
Pennsbury	Mid-Atlantic	Morrisville, PA	2		Landfill Gas	Peaking	6	
Total Mid-Atlantic							11,566	
Whitetail	ERCOT	Webb County, TX	57	51	Wind	Base-load	46	(f)(h)
Sendero	ERCOT	Jim Hogg and Zapata County, TX	39	51	Wind	Base-load	40	(f)(h)
Colorado Bend II	ERCOT	Wharton, TX	3		Gas	Intermediate	1,088	
Wolf Hollow II	ERCOT	Granbury, TX	3		Gas	Intermediate	1,064	
Wolf Hollow 1, 2, 3	ERCOT	Granbury, TX	3		Gas	Intermediate	705	(l)
Mountain Creek 8	ERCOT	Dallas, TX	1		Gas	Intermediate	568	(l)
Colorado Bend	ERCOT	Wharton, TX	6		Gas	Intermediate	468	(l)
Handley 3	ERCOT	Fort Worth, TX	1		Gas	Intermediate	395	(l)
Handley 4, 5	ERCOT	Fort Worth, TX	2		Gas	Peaking	870	(l)
Mountain Creek 6, 7	ERCOT	Dallas, TX	2		Gas	Peaking	240	(l)
LaPorte	ERCOT	Laporte, TX	4		Gas	Peaking	152	(l)
Total ERCOT							5,636	

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Solar Massachusetts	New England	Various, MA	10	Solar	Base-load	7
Holyoke Solar	New England	Various, MA	2	Solar	Base-load	5

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Station ^(a)	Region	Location	No. of Units	Percent Owned ^(b)	Primary Fuel Type	Primary Dispatch Type ^(c)	Net Generation Capacity (MW) ^(d)	
Solar Net Metering	New England	Uxbridge, MA	1		Solar	Base-load	2	
Solar Connecticut	New England	Various, CT	1		Solar	Base-load	1	
Mystic 8, 9	New England	Charlestown, MA	6		Gas	Intermediate	1,417	
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	Peaking	124	
Framingham	New England	Framingham, MA	3		Oil	Peaking	30	
Mystic Jet	New England	Charlestown, MA	1		Oil	Peaking	9	
Total New England							2,206	
Nine Mile Point	New York	Scriba, NY	2	50.01	Uranium	Base-load	838	(f)(g)
FitzPatrick	New York	Scriba, NY	1		Uranium	Base-load	842	
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							1,971	
AVSR	Other	Lancaster, CA	1		Solar	Base-load	242	
Bluestem	Other	Beaver County, OK	60	51	Wind	Base-load	101	(f)(h)(i)
Exelon Wind 4	Other	Gruver, TX	38		Wind	Base-load	80	
Shooting Star	Other	Kiowa County, KS	65	51	Wind	Base-load	53	(f)(h)
Albany Green Energy	Other	Albany, GA	1	99	Biomass	Base-load	46	(j)
Solar Arizona	Other	Various, AZ	127		Solar	Base-load	46	
Bluegrass Ridge	Other	King City, MO	27	51	Wind	Base-load	29	(f)(h)
California PV Energy 2	Other	Various, CA	89		Solar	Base-load	27	
Conception	Other	Barnard, MO	24	51	Wind	Base-load	26	(f)(h)
Cow Branch	Other	Rock Port, MO	24	51	Wind	Base-load	26	(f)(h)
Solar Arizona 2	Other	Various, AZ	25		Solar	Base-load	23	
California PV Energy	Other	Various, CA	53		Solar	Base-load	21	
Mountain Home	Other	Glenns Ferry, ID	20	51	Wind	Base-load	21	(f)(h)
High Mesa	Other	Elmore Co., ID	19	51	Wind	Base-load	20	(f)(h)
Echo 1	Other	Echo, OR	21	50.49	Wind	Base-load	17	(f)(h)
Sacramento PV Energy	Other	Sacramento, CA	4	51	Solar	Base-load	15	(f)(h)
Cassia	Other	Buhl, ID	14	51	Wind	Base-load	15	(f)(h)
Wildcat	Other	Lovington, NM	13	51	Wind	Base-load	14	(f)(h)
Echo 2	Other	Echo, OR	10	51	Wind	Base-load	10	(f)(h)
Exelon Wind 5	Other	Texhoma, TX	8		Wind	Base-load	10	
Exelon Wind 6	Other	Texhoma, TX	8		Wind	Base-load	10	

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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

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Station ^(a)	Region	Location	No. of Units	Percent Owned ^(b)	Primary Fuel Type	Primary Dispatch Type ^(c)	Net Generation Capacity (MW) ^(d)	
Exelon Wind 11	Other	Dumas, TX	8		Wind	Base-load	10	
High Plains	Other	Panhandle, TX	8	99.5	Wind	Base-load	10	(f)
Tuana Springs	Other	Hagerman, ID	8	51	Wind	Base-load	9	(f)(h)
Solar Georgia	Other	Various, GA	10		Solar	Base-load	8	
Solar Georgia 2	Other	Various, GA	6		Solar	Base-load	8	
Greensburg	Other	Greensburg, KS	10	51	Wind	Base-load	7	(f)(h)
Outback Solar	Other	Christmas Valley, OR	1		Solar	Base-load	6	
Echo 3	Other	Echo, OR	6	50.49	Wind	Base-load	5	(f)(h)
Three Mile Canyon	Other	Boardman, OR	6	51	Wind	Base-load	5	(f)(h)
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	51	Solar	Base-load	2	(f)(h)
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							1,839	
Total							35,168	

(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.

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 (c) 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.

Generation had previously agreed to permanently cease generation operations at Oyster Creek by the end of 2019.

(e) On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle in October 2018. See Note 28 — Subsequent Events of the Combined Notes to Consolidated Financial Statements for additional information regarding the early retirement of Oyster Creek.

(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) Reflects the sale of 49% of ExGen Renewables Partners to a third party on July 6, 2017. See Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information.

(i) ExGen Renewables Partners owns 100% of the Class A membership interests and a tax equity investor owns 100% of the Class B membership interests of the entity that owns the Bluestem generating assets.

(j) Generation directly owns a 50% interest in the Albany Green Energy station and an additional 49% through the consolidation of a Variable Interest Entity.

Generation has announced it will permanently cease generation operations at TMI on or about September 30, 2019.

(k) See Note 8 — Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information regarding the early retirement of TMI.

As a result of the EGTP bankruptcy and deconsolidation on November 7, 2017, Generation deconsolidated EGTP's assets and liabilities from Generation's consolidated financial statements. As of December 31, 2017, these assets (1) were still under Generation's ownership and included in the table. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

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

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

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nuclear insurance of generating facilities, see ITEM 1. BUSINESS — Exelon Generation Company, LLC. For its insured losses, Generation is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on Generation’s consolidated financial condition or results of operations.

ComEd

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

Transmission and Distribution

ComEd’s high voltage electric transmission lines owned and in service at December 31, 2017 were as follows:

Voltage (Volts) Circuit Miles

765,000	90
345,000	2,718
138,000	2,209

ComEd’s electric distribution system includes 35,383 circuit miles of overhead lines and 31,798 circuit miles of underground lines.

First Mortgage and Insurance

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

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

PECO

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

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Transmission and Distribution

PECO's high voltage electric transmission lines owned and in service at December 31, 2017 were as follows:

Voltage (Volts)	Circuit Miles
500,000	188(a)
230,000	548
138,000	135
69,000	181

(a) In addition, PECO has a 22.00% ownership interest in 127 miles of 500 kV lines located in Pennsylvania and a 42.55% ownership interest in 131 miles of 500 kV lines located in Delaware and New Jersey. PECO's electric distribution system includes 12,957 circuit miles of overhead lines and 9,322 circuit miles of underground lines.

Gas

The following table sets forth PECO's natural gas pipeline miles at December 31, 2017:

	Pipeline Miles
Transmission	30
Distribution	6,889
Service piping	6,328
Total	13,247

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 105 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

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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, 2017 were as follows:

Voltage (Volts) Circuit Miles

500,000	218
230,000	352
138,000	55
115,000	713

BGE's electric distribution system includes 9,169 circuit miles of overhead lines and 17,209 circuit miles of underground lines.

Gas

The following table sets forth BGE's natural gas pipeline miles at December 31, 2017:

Pipeline Miles

Transmission	161
Distribution	7,306
Service piping	6,263
Total	13,730

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.

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Transmission and Distribution

Pepco's high voltage electric transmission lines owned and in service at December 31, 2017 were as follows:

Voltage (Volts) Circuit Miles

500,000	142
230,000	767
138,000	61
115,000	38

Pepco's electric distribution system includes approximately 4,105 circuit miles of overhead lines and 6,844 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.

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, 2017 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 6,028 circuit miles of overhead lines and 6,103 circuit miles of underground lines. DPL also owns and operates a distribution system control center in New Castle, Delaware.

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Gas

The following table sets forth DPL's natural gas pipeline miles at December 31, 2017:

	Pipeline Miles
Transmission ^(a)	8
Distribution	2,061
Service piping	1,393
Total	3,462

DPL has a 10% undivided interest in approximately 8 miles of natural gas transmission mains located in Delaware (a) 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 DPL 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.

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, 2017 were as follows:

Voltage (Volts)	Circuit Miles
500,000	281
230,000	237
138,000	268
69,000	652

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ACE's electric distribution system includes approximately 7,378 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.

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

ITEM 4. MINE SAFETY DISCLOSURES

All Registrants

Not Applicable to the Registrants.

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PART II

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

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

Exelon

Exelon's common stock is listed on the New York Stock Exchange. As of January 31, 2018, there were 965,029,399 shares of common stock outstanding and approximately 104,909 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:

	2017				2016			
	Fourth	Third	Second	First	Fourth	Third	Second	First
	Quarter	Quarter	Quarter	Quarter	Quarter	Quarter	Quarter	Quarter
High price	\$42.67	\$38.78	\$37.44	\$37.19	\$36.36	\$37.70	\$36.37	\$35.95
Low price	37.55	35.37	33.30	34.47	29.82	32.86	33.18	26.26
Close	39.41	37.67	36.07	35.98	35.49	33.29	36.36	35.86
Dividends	0.328	0.328	0.328	0.328	0.318	0.318	0.318	0.310

Stock Performance Graph

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of \$100 in Exelon common stock, as compared with the S&P 500 Stock Index and the S&P Utility Index, for the period 2013 through 2017.

This performance chart assumes:

\$100 invested on December 31, 2012 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and

• All dividends are reinvested.

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Value of Investment at December 31,

	2012	2013	2014	2015	2016	2017
Exelon Corporation	\$100	\$65.11	\$88.14	\$66.01	\$84.36	\$132.16
S&P 500	\$100	\$144.74	\$161.22	\$160.05	\$175.31	\$182.82
S&P Utilities	\$100	\$107.43	\$133.52	\$122.32	\$137.24	\$147.82

Generation

As of January 31, 2018, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2018, there were 127,021,256 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, 2018, in addition to Exelon, there were 294 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

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PECO

As of January 31, 2018, 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, 2018, 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, 2018, Exelon indirectly held the entire membership interest in PHI.

Pepco

As of January 31, 2018, 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, 2018, 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, 2018, 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

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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.

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 approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

At December 31, 2017, Exelon had retained earnings of \$13,503 million, including Generation's undistributed earnings of \$4,310 million, ComEd's retained earnings of \$1,132 million consisting of retained earnings appropriated for future dividends of \$2,771 million, partially offset by \$1,639 million of unappropriated accumulated deficits, PECO's retained earnings of \$1,087 million, BGE's retained earnings of \$1,536 million, and PHI's undistributed earnings of \$(10) million.

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The following table sets forth Exelon's quarterly cash dividends per share paid during 2017 and 2016:

(per share)	2017				2016			
	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Exelon	\$0.328	\$0.328	\$0.328	\$0.328	\$0.318	\$0.318	\$0.318	\$0.310

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

(in millions)	2017				2016			
	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	\$ 165	\$ 164	\$ 166	\$ 164	\$ 755	\$ 56	\$ 56	\$ 55
ComEd	106	105	106	105	94	92	92	91
PECO	72	72	72	72	69	69	70	69
BGE	50	49	50	49	45	44	45	45
PHI	44	136	62	69	99	50	16	108
Pepco	—	75	28	30	44	37	16	39
DPL	30	28	24	30	15	1	—	38
ACE	15	31	12	10	39	13	—	11

First Quarter 2018 Dividend

On January 30, 2018, the Exelon Board of Directors declared a first quarter 2018 regular quarterly dividend of \$0.3450 per share on Exelon's common stock payable on March 9, 2018, to shareholders of record of Exelon at the end of the day on February 15, 2018.

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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.

(In millions, except per share data)	For the Years Ended December 31,				
	2017	2016 ^(a)	2015	2014 ^(b)	2013
Statement of Operations data:					
Operating revenues	\$33,531	\$31,360	\$29,447	\$27,429	\$24,888
Operating income	4,260	3,112	4,409	3,096	3,669
Net income	3,849	1,204	2,250	1,820	1,729
Net income attributable to common shareholders	3,770	1,134	2,269	1,623	1,719
Earnings per average common share (diluted):					
Net income	\$3.97	\$1.22	\$2.54	\$1.88	\$2.00
Dividends per common share	\$1.31	\$1.26	\$1.24	\$1.24	\$1.46

(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.

(In millions)	December 31,				
	2017	2016	2015	2014	2013
Balance Sheet data:					
Current assets	\$11,834	\$12,412	\$15,334	\$11,853	\$9,562
Property, plant and equipment, net	74,202	71,555	57,439	52,170	47,330
Total assets	116,700	114,904	95,384	86,416	79,243
Current liabilities	10,796	13,457	9,118	8,762	7,686
Long-term debt, including long-term debt to financing trusts	32,565	32,216	24,286	19,853	18,165
Shareholders' equity	29,857	25,837	25,793	22,608	22,732

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Generation

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

(In millions)	For the Years Ended December 31,				
	2017	2016	2015	2014 ^(a)	2013
Statement of Operations data:					
Operating revenues	\$18,466	\$17,751	\$19,135	\$17,393	\$15,360
Operating income	921	836	2,275	1,176	1,677
Net income	2,771	558	1,340	1,019	1,060

^(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.

(In millions)	December 31,				
	2017	2016	2015	2014	2013
Balance Sheet data:					
Current assets	\$6,820	\$6,528	\$6,342	\$7,311	\$5,964
Property, plant and equipment, net	24,906	25,585	25,843	23,028	20,111
Total assets	48,387	46,974	46,529	44,951	40,700
Current liabilities	4,189	5,683	4,933	4,459	3,842
Long-term debt, including long-term debt to affiliate	8,644	8,124	8,869	7,582	7,111
Member's equity	13,630	11,482	11,635	12,718	12,725

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,				
	2017	2016	2015	2014	2013
Statement of Operations data:					
Operating revenues	\$5,536	\$5,254	\$4,905	\$4,564	\$4,464
Operating income	1,323	1,205	1,017	980	954
Net income	567	378	426	408	249

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(In millions)	December 31,				
	2017	2016	2015	2014	2013
Balance Sheet data:					
Current assets	\$1,364	\$1,554	\$1,518	\$1,723	\$1,540
Property, plant and equipment, net	20,723	19,335	17,502	15,793	14,666
Total assets	29,726	28,335	26,532	25,358	24,089
Current liabilities	2,294	2,938	2,766	1,923	2,032
Long-term debt, including long-term debt to financing trusts	6,966	6,813	6,049	5,870	5,235
Shareholders' equity	9,542	8,725	8,243	7,907	7,528

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,				
	2017	2016	2015	2014	2013
Statement of Operations data:					
Operating revenues	\$2,870	\$2,994	\$3,032	\$3,094	\$3,100
Operating income	655	702	630	572	666
Net income	434	438	378	352	395

(In millions)	December 31,				
	2017	2016	2015	2014	2013
Balance Sheet data:					
Current assets	\$822	\$757	\$842	\$645	\$821
Property, plant and equipment, net	8,053	7,565	7,141	6,801	6,384
Total assets	10,170	10,831	10,367	9,860	9,521
Current liabilities	1,267	727	944	653	889
Long-term debt, including long-term debt to financing trusts	2,587	2,764	2,464	2,416	2,120
Shareholder's equity	3,577	3,415	3,236	3,121	3,065

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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,				
	2017	2016	2015	2014	2013
Statement of Operations data:					
Operating revenues	\$3,176	\$3,233	\$3,135	\$3,165	\$3,065
Operating income	614	550	558	439	449
Net income	307	294	288	211	210

(In millions)	December 31,				
	2017	2016	2015	2014	2013
Balance Sheet data:					
Current assets	\$811	\$842	\$845	\$951	\$1,009
Property, plant and equipment, net	7,602	7,040	6,597	6,204	5,864
Total assets	9,104	8,704	8,295	8,056	7,839
Current liabilities	760	707	1,134	794	800
Long-term debt, including long-term debt to financing trusts and variable interest entities	2,577	2,533	1,732	2,109	2,179
Shareholder's equity	3,141	2,848	2,687	2,563	2,365

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.

(In millions)	Successor		Predecessor		
	For the Year Ended December 31, 2017	March 24 to December 31, 2016	January 1 to March 23, 2016	For the Years Ended December 31, 2015 2014	
Statement of Operations data ^(a) :					
Operating revenues	\$4,679	\$3,643	\$1,153	\$4,935	\$4,808
Operating income	769	93	105	673	605
Net income (loss) from continuing operations	362	(61)	19	318	242
Net income (loss)	362	(61)	19	327	242

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(In millions)	Successor		Predecessor
	December 31, 2017	December 31, 2016	December 31, 2015
Balance Sheet data ^(a) :			
Current assets	\$1,551	\$ 1,838	\$ 1,474
Property, plant and equipment, net	12,498	11,598	10,864
Total assets	21,247	21,025	16,188
Current liabilities	1,931	2,284	2,327
Long-term debt	5,478	5,645	4,823
Preferred Stock	—	—	183
Member's equity/Shareholders' equity	8,825	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,			
	2017	2016	2015	2014
Statement of Operations data ^(a) :				
Operating revenues	\$2,158	\$2,186	\$2,129	\$2,055
Operating income	399	174	385	349
Net income	205	42	187	171

(In millions)	December 31,		
	2017	2016	2015
Balance Sheet data ^(a) :			
Current assets	\$710	\$684	\$726
Property, plant and equipment, net	6,001	5,571	5,162
Total assets	7,832	7,335	6,908
Current liabilities	550	596	455
Long-term debt	2,521	2,333	2,340
Shareholders' equity	2,533	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.

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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)	2017	2016	2015	2014
Statement of Operations data ^(a) :				
Operating revenues	\$ 1,300	\$ 1,277	\$ 1,302	\$ 1,282
Operating income	229	50	165	207
Net income (loss)	121	(9)	76	104
	December 31,			
(In millions)	2017	2016	2015	
Balance Sheet data ^(a) :				
Current assets	\$ 325	\$ 370	\$ 388	
Property, plant and equipment, net	3,579	3,273	3,070	
Total assets	4,357	4,153	3,969	
Current liabilities	547	381	564	
Long-term debt	1,217	1,221	1,061	
Shareholders' equity	1,335	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.

	For the Years Ended			
	December 31,			
(In millions)	2017	2016	2015	2014
Statement of Operations data ^(a) :				
Operating revenues	\$ 1,186	\$ 1,257	\$ 1,295	\$ 1,210
Operating income	157	7	134	137
Net income (loss)	77	(42)	40	46

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(In millions)	December 31,		
	2017	2016	2015
Balance Sheet data ^(a) :			
Current assets	\$258	\$399	\$546
Property, plant and equipment, net	2,706	2,521	2,322
Total assets	3,445	3,457	3,387
Current liabilities	619	320	297
Long-term debt	840	1,120	1,153
Shareholders' equity	1,043	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.

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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 25 - Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

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Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of corporate governance support services including corporate strategy and development, legal, human resources, information technology, finance, real estate, security, corporate communications and supply at cost. The costs of these services are directly charged or allocated to the applicable operating segments. The services are provided pursuant to service agreements. Additionally, the results of Exelon's corporate operations include interest costs and income from various investment and financing activities.

PHISCO, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, finance, 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 PHISCO and the participating operating subsidiaries.

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.

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Financial Results of Operations

GAAP Results of Operations

The following table sets forth Exelon's GAAP consolidated results of operations for the year ended December 31, 2017 compared to the same period in 2016. 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 Exelon ^(b)	Favorable (Unfavorable) Variance
	2017	Generation	ComEd	PECO	BGE	PHI	Other		
Operating revenues	\$18,466	\$5,536	\$2,870	\$3,176	\$4,679	\$(1,196)	\$33,531	\$31,360	\$ 2,171
Purchased power and fuel expense	9,690	1,641	969	1,133	1,716	(1,114)	14,035	12,640	(1,395)
Revenue net of purchased power and fuel expense ^(a)	8,776	3,895	1,901	2,043	2,963	(82)	19,496	18,720	776
Other operating expenses									
Operating and maintenance	6,291	1,427	806	716	1,068	(182)	10,126	10,048	(78)
Depreciation and amortization	1,457	850	286	473	675	87	3,828	3,936	108
Taxes other than income	555	296	154	240	452	34	1,731	1,576	(155)
Total other operating expenses	8,303	2,573	1,246	1,429	2,195	(61)	15,685	15,560	(125)
Gain (Loss) on sales of assets	2	1	—	—	1	(1)	3	(48)	51
Bargain purchase gain	233	—	—	—	—	—	233	—	233
Gain on deconsolidation of business	213	—	—	—	—	—	213	—	213
Operating income (loss)	921	1,323	655	614	769	(22)	4,260	3,112	1,148
Other income and (deductions)									
Interest expense, net	(440)	(361)	(126)	(105)	(245)	(283)	(1,560)	(1,536)	(24)
Other, net	948	22	9	16	54	7	1,056	413	643
Total other income and (deductions)	508	(339)	(117)	(89)	(191)	(276)	(504)	(1,123)	619
Income (loss) before income taxes	1,429	984	538	525	578	(298)	3,756	1,989	1,767
Income taxes	(1,375)	417	104	218	217	294	(125)	761	886
Equity in (losses) earnings of unconsolidated affiliates	(33)	—	—	—	1	—	(32)	(24)	(8)
Net income (loss)	2,771	567	434	307	362	(592)	3,849	1,204	2,645
Net income attributable to noncontrolling interests and preference stock dividends	77	—	—	—	—	2	79	70	(9)
Net income (loss) attributable to common shareholders	\$2,694	\$567	\$434	\$307	\$362	\$(594)	\$3,770	\$1,134	\$ 2,636

(a) The Registrants' evaluate operating performance using the measure of revenues net of purchased power and fuel expense. The Registrant's 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 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, Exelon includes the consolidated results of PHI, Pepco, DPL and ACE from March 24, 2016 through December 31, 2016.

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Exelon's Net income attributable to common shareholders was \$3,770 million for the year ended December 31, 2017 as compared to \$1,134 million for the year ended December 31, 2016, and diluted earnings per average common share were \$3.97 for the year ended December 31, 2017 as compared to \$1.22 for the year ended December 31, 2016.

Revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by \$776 million as compared to 2016. The year-over-year increase was primarily due to the following favorable factors:

- Increase of \$104 million at BGE primarily due to the impacts of the electric and natural gas distribution rate orders issued by the MDPSC in June 2016 and July 2016 and an increase in transmission formula rate revenues;

- Increase of \$99 million at ComEd primarily due to increased electric distribution and transmission formula rate revenues (reflecting the impacts of increased capital investment and higher allowed electric distribution ROE),

- partially offset by lower revenues resulting from the change to defer and recover over time energy efficiency costs pursuant to FEJA and the impact of favorable weather conditions in 2016; and

- Increase of \$767 million in Revenue net of purchased power and fuel due to the inclusion of PHI's results for the year ended December 31, 2017 compared to the period March 24, 2016 to December 31, 2016, as well as distribution rate increases effective in 2016 and 2017.

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

- Decrease of \$134 million at Generation due to mark-to-market losses of \$175 million in 2017 compared to mark-to-market losses of \$41 million in 2016;

- Decrease of \$46 million at PECO primarily due to unfavorable weather conditions; and

- Decrease of \$11 million at Generation primarily due to lower realized energy prices, the impacts of lower load volumes delivered due to mild weather in the third quarter 2017, the conclusion of the Ginna Reliability Support

- Services Agreement and the impact of declining natural gas prices on Generation's natural gas portfolio, partially offset by the impact of the New York CES, increased nuclear volumes primarily as a result of the acquisition of

- FitzPatrick, higher capacity prices, the addition of two combined-cycle gas turbines in Texas and lower nuclear fuel prices.

Operating and maintenance expense increased by \$78 million as compared to 2016. The year-over-year increase was primarily due to the following unfavorable factors:

- Increase of \$307 million at Generation due to higher asset impairment charges;

- Increase of \$127 million at Generation primarily due to Generation's decision in 2017 to early retire the TMI nuclear facility compared to the previous decision in 2016 to early retire the Clinton and Quad Cities nuclear facilities;

- Increase of \$104 million at Generation due to increased nuclear refueling outage costs;

- Increase of \$84 million at Generation due to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units in 2017 versus 2016; and

- Increase of \$253 million at PHI due to the inclusion of PHI's results for the year ended December 31, 2017 compared to the period March 24, 2016 to December 31, 2016.

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

• Decrease of \$665 million at Exelon due to merger commitment and other merger-related costs of \$73 million in 2017 compared to \$738 million in 2016;

• Decrease of \$85 million at ComEd due to the change to defer and recover over time energy efficiency costs pursuant to the Illinois Future Energy Jobs Act; and

• Decrease of \$21 million at BGE primarily due to certain disallowances contained in the June and July 2016 rate orders, partially offset by the impact of the favorable 2016 settlement of the Baltimore City conduit fee dispute.

Depreciation and amortization expense decreased by \$108 million primarily due to lower accelerated depreciation and amortization expense as a result of the 2017 decision to early retire the TMI nuclear facility compared to the previous decision in 2016 to early retire the Clinton and Quad Cities nuclear facilities, partially offset by increased depreciation expense as a result of ongoing capital expenditures across all operating companies and the inclusion of PHI's results for the year ended December 31, 2017 compared to the period March 24, 2016 to December 31, 2016.

Taxes other than income increased by \$155 million primarily due to increased real estate taxes and sales and use taxes at Generation, as well as the inclusion of PHI's results for the year ended December 31, 2017 compared to the period March 24, 2016 to December 31, 2016.

Gain (Loss) on sales of assets increased by \$51 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.

Bargain purchase gain increased by \$233 million due to the gain associated with Generation's acquisition of FitzPatrick in 2017.

Gain on deconsolidation of business increased by \$213 million due to the deconsolidation of EGTP's net liabilities, which included the previously impaired assets and related debt, as a result of the November 2017 bankruptcy filing.

Interest expense, net increased by \$24 million primarily due to the inclusion of PHI's results for the year ended December 31, 2017 compared to the period March 24, 2016 to December 31, 2016, partially offset by additional interest related to Exelon's like-kind exchange tax position recorded in 2016 compared to 2017.

Other, net increased by \$643 million primarily due to higher net unrealized and realized gains on NDT funds at Generation for the year ended December 31, 2017 as compared to the same period in 2016 and the penalty recorded in 2016 related to Exelon's like-kind exchange tax position.

Exelon's effective income tax rates for the years ended December 31, 2017 and 2016 were (3.3)% and 38.3%, respectively. Exelon's effective income tax rate for the year ended December 31, 2017 includes the impact of the Tax Cuts and Jobs Act. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the years ended December 31, 2017 and 2016, 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.

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Adjusted (non-GAAP) Operating Earnings

Exelon's Adjusted (non-GAAP) operating earnings for the year ended December 31, 2017 were \$2,471 million, or \$2.60 per diluted share, compared with Adjusted (non-GAAP) operating earnings of \$2,488 million, or \$2.68 per diluted share, for the same period in 2016. 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.

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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, 2017 as compared to 2016:

	For the years ended December 31,			
	2017	Earnings per Diluted Share	2016	Earnings per Diluted Share
(All amounts after tax; in millions, except per share amounts)				
Net Income Attributable to Common Shareholders	\$3,770	\$ 3.97	\$1,134	\$ 1.22
Mark-to-Market Impact of Economic Hedging Activities ^(a) (net of taxes of \$68 and \$18, respectively)	107	0.11	24	0.03
Unrealized Gains Related to NDT Fund Investments ^(b) (net of taxes of \$204 and \$77, respectively)	(318)	(0.34)	(118)	(0.13)
Amortization of Commodity Contract Intangibles ^(c) (net of taxes of \$22 and \$22, respectively)	34	0.04	35	0.04
Merger and Integration Costs ^(d) (net of taxes of \$25 and \$50, respectively)	40	0.04	114	0.12
Merger Commitments ^(e) (net of taxes of \$137 and \$126, respectively)	(137)	(0.14)	437	0.47
Long-Lived Asset Impairments ^(f) (net of taxes of \$204 and \$68, respectively)	321	0.34	103	0.11
Plant Retirements and Divestitures ^(g) (net of taxes of \$134 and \$273, respectively)	207	0.22	432	0.47
Reassessment of Deferred Income Taxes ^(h) (entire amount represents tax expense)	(1,299)	(1.37)	10	0.01
Cost Management Program ⁽ⁱ⁾ (net of taxes of \$21 and \$21, respectively)	34	0.04	34	0.04
Like-Kind Exchange Tax Position ^(j) (net of taxes of \$66 and \$61, respectively)	(26)	(0.03)	199	0.21
Asset Retirement Obligation ^(k) (net of taxes of \$1 and \$13, respectively)	(2)	—	(75)	(0.08)
Tax Settlements ^(l) (net of taxes of \$1 and \$0, respectively)	(5)	(0.01)	—	—
Bargain Purchase Gain ^(m) (net of taxes of \$0 and \$0, respectively)	(233)	(0.25)	—	—
Gain on Deconsolidation of Business ⁽ⁿ⁾ (net of taxes of \$83 and \$0, respectively)	(130)	(0.14)	—	—
Vacation Policy Change ^(o) (net of taxes of \$21 and \$0, respectively)	(33)	(0.03)	—	—
Curtailment of Generation Growth and Development Activities ^(p) (net of taxes of \$0 and \$35, respectively)	—	—	57	0.06
Change in Environmental Remediation Liabilities (net of taxes of \$17 and \$0, respectively)	27	0.03	—	—
Noncontrolling Interests ^(q) (net of taxes of \$24 and \$9, respectively)	114	0.12	102	0.11
Adjusted (non-GAAP) Operating Earnings	\$2,471	\$ 2.60	\$2,488	\$ 2.68

Reflects the impact of net gains and losses on Generation's economic hedging activities. See Note 12 - Derivative (a) Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

Reflects the impact of net unrealized gains on Generation's NDT fund investments for Non-Regulatory Agreement (b) Units. See Note 15 - Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

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Represents the non-cash amortization of intangible assets, net, primarily related to commodity contracts recorded at (c) fair value related to, in 2017, the ConEdison Solutions and FitzPatrick acquisitions, and in 2016, the Integrys and ConEdison Solutions acquisitions.

Primarily reflects certain costs incurred for the PHI acquisition in 2017 and 2016 and Generation's FitzPatrick acquisition in 2017, including professional fees, employee-related expenses and integration activities. See (d) Note 4 - Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail related to merger and acquisition costs.

Represents costs incurred as part of the settlement orders approving the PHI acquisition, and in 2017, a decrease in reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the (e) 2012 CEG and 2016 PHI acquisitions, and in 2016, a charge related to a 2012 CEG merger commitment. See Note 4 - Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail related to PHI Merger commitments.

Primarily reflects charges to earnings in 2017 related to impairments of EGTP assets and the PHI District of (f) Columbia sponsorship intangible asset, and in 2016, impairments of Upstream assets and certain wind projects at Generation.

Primarily reflects in 2017 accelerated depreciation and amortization expenses, increases to materials and supplies inventory reserves, construction work in progress impairments and charges for severance reserves associated with (g) Generation's decision to early retire the Three Mile Island nuclear facility. Primarily reflects in 2016 accelerated depreciation and amortization expenses through December 2016 and construction work in progress impairments associated with Generation's previous decision to early retire the Clinton and Quad Cities nuclear facilities, partially offset by a gain associated with Generation's sale of the New Boston generating site.

Reflects in 2017 one-time non-cash impacts associated with remeasurements of deferred income taxes as a result of the Tax Cuts and Jobs Act (including impacts on pension obligations), changes in the Illinois and District of (h) Columbia statutory tax rates and changes in forecasted apportionment, and in 2016, the non-cash impact of the remeasurement of deferred income taxes as a result of changes in forecasted apportionment related to the PHI acquisition.

(i) Represents severance and reorganization costs related to a cost management program.

Represents in 2017 adjustments to income tax, penalties and interest expenses as a result of the finalization of the (j) IRS tax computation related to Exelon's like-kind exchange tax position, and in 2016, the recognition of a penalty and associated interest expense as a result of a tax court decision on Exelon's like-kind exchange tax position.

(k) Reflects a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units.

(l) Reflects benefits related to the favorable settlement in 2017 of certain income tax positions related to PHI's unregulated business interests that were transferred to Generation.

(m) Represents the excess of the fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition.

(n) Represents the gain recorded upon deconsolidation of EGTP's net liabilities, which included the previously impaired assets and related debt, as a result of the November 2017 bankruptcy filing.

(o) Represents the reversal of previously accrued vacation expenses as a result of a change in Exelon's vacation vesting policy.

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

(q) Represents elimination from Generation's results of the noncontrolling interests related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.

Note:

Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net Income and Adjusted (non-GAAP) Operating Earnings is based on the marginal statutory federal and state income tax rates for each

Registrant, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. For all items except the unrealized gains and losses related to NDT fund investments, the marginal statutory income tax rates ranged from 39 percent to 41 percent. Under IRS regulations, NDT fund investment returns are taxed at differing rates for investments in qualified vs. non-qualified funds. The tax rates applied to unrealized gains and losses related to NDT Fund investments were 47.4 percent and 48.7 percent for the years ended December 31, 2017 and 2016, respectively.

Merger, Integration and Acquisition Costs

As a result of the PHI Merger that was completed on March 23, 2016, the Registrants have 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. In addition, as a result of the acquisition of the FitzPatrick nuclear generating station on March 31, 2017, Exelon and Generation incurred costs associated with evaluating, structuring and executing the transaction and integrating FitzPatrick into Exelon.

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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,						Successor
	2016						March 24,
							2016 to
							December
							31, 2016
	Exelon	Generation	Pepco	DPL	ACE	PHI	
Merger commitments ^(a)	\$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	

^(a) See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for more information.

In addition to the one-time PHI Merger charges discussed above, for the years ended December 31, 2017 and 2016, expense has been recognized for the PHI Merger and Generation's FitzPatrick acquisition as follows:

	Pre-tax Expense								
	For the Year Ended December 31, 2017								
Merger, Integration and Acquisition Expense:	Exelon	Generation ^(a)	ComEd	PECO	BGE	PHI ^(a)	Pepco ^(a)	DPL ^(a)	ACE ^(a)
Transaction ^(b)	\$6	\$ 5	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —
Other ^{(c)(d)}	67	75	1	4	4	(18)	(6)	(7)	(6)
Total	\$73	\$ 80	\$ 1	\$ 4	\$ 4	\$(18)	\$(6)	\$(7)	\$(6)
	Pre-tax Expense								
	For the Year Ended December 31, 2016								
Merger Integration and Acquisition Expense:	Exelon	Generation ^(a)	ComEd	PECO	BGE	PHI ^(a)	Pepco ^(a)	DPL ^(a)	ACE ^(a)
Transaction ^(b)	\$34	\$ 2	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —
Employee-related ^(e)	77	10	2	1	1	64	30	18	15
Other ^{(c)(d)}	52	44	(8)	4	(2)	5	(2)	2	4
Total	\$163	\$ 56	\$(6)	\$ 5	\$(1)	\$ 69	\$ 28	\$ 20	\$ 19

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

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

^(c) Costs to integrate PHI processes and systems into Exelon. For the year ended December 31, 2017, also includes costs to integrate FitzPatrick processes and systems into Exelon.

For the year ended December 31, 2017, includes deferrals of previously incurred integration costs to achieve distribution synergies related to the PHI acquisition of \$24 million, \$8 million, \$8 million, and \$8 million incurred at PHI, Pepco, DPL, and ACE, respectively, that have been recorded as a regulatory asset for anticipated recovery.

^(d) For the year ended December 31, 2016, includes deferrals of previously incurred integration costs to achieve distribution synergies related to the PHI acquisition of \$8 million, \$6 million, \$11 million, and \$4 million incurred at ComEd, BGE, Pepco, and DPL, respectively, that have been recorded as a regulatory asset for anticipated recovery. For the Successor period March 24, 2016 to December 31, 2016, includes deferrals of previously incurred integration costs to achieve distribution synergies related to the PHI acquisition of \$16 million incurred at PHI that have been recorded as a regulatory asset for anticipated recovery. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for more information.

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

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Significant 2017 Transactions and Recent Developments

Corporate Tax Reform

On December 22, 2017, President Trump signed the TCJA into law. The TCJA makes many significant changes to the Internal Revenue Code, including, but not limited to, (1) reducing the U.S. federal corporate tax rate from 35% to 21%; (2) creating a 30% limitation on deductible interest expense (not applicable to regulated utilities); (3) allowing 100% expensing for the cost of qualified property (not applicable to regulated utilities); (4) eliminating the domestic production activities deduction; (5) eliminating the corporate alternative minimum tax and changing how existing alternative minimum tax credits can be realized; and (6) changing rules related to uses and limitations of net operating loss carryforwards created in tax years beginning after December 31, 2017.

The most significant change that impacts the Registrants is the reduction of the corporate federal income tax rate from 35% to 21% beginning January 1, 2018. Adjusted non-GAAP operating earnings per share for Exelon is expected to increase by approximately \$0.10 on a run-rate basis in 2019 relative to Exelon's projections before the TCJA. For the Utility Registrants, the amount and timing of when certain income tax benefits resulting from the TCJA are provided to customers may vary from jurisdiction to jurisdiction.

Beginning in 2018, Generation will incur lower income tax expense, which will decrease its projected effective income tax rate, even with the elimination of the domestic production activities deduction, and increase its net income. Generation's operating cash inflows are also expected to increase beginning in 2018 reflecting the lower income tax rates and full expensing of capital investments. Generation's projected effective income tax rate in 2018, 2019, and 2020 is expected to be approximately 22%.

Beginning in 2018, the Utility Registrants will incur lower income tax expense, which will generally decrease their projected effective income tax rates. The TCJA is expected to lead to lower customer rates over time due to lower income tax expense recoveries and the settlement of deferred income tax net regulatory liabilities. The TCJA is expected to lead to an incremental increase in rate base of approximately \$1.7 billion by 2020 relative to previous expectations across the Utility Registrants. The increased rate base will be funded consistent with each utility jurisdiction, using a combination of third party debt financings and equity funding from Exelon generally consistent with existing capitalization ratio structures. To fund any additional equity contributions to the Utility Registrants, Exelon would have available to it its typical sources, including, but not limited to, the increased operating cash flows at Generation referenced above, which over time are expected to exceed the incremental equity needs at the Utility Registrants. The TCJA is generally expected to result in lower operating cash inflows for the Utility Registrants as a result of the elimination of bonus depreciation and lower customer rates.

Exelon Corporate expects that the interest on its debt will continue to be fully tax deductible albeit at a lower tax rate. The Utility Registrants continue to work with their state regulatory commissions to determine the amount and timing of the passing back of TCJA income tax savings benefits to customers; with filings either made, or expected to be made, at Pepco, DPL and ACE, and approved filings at ComEd and BGE. The amounts being passed back or proposed to be passed back to customers reflect the benefit of lower income tax expense beginning January 1, 2018 (Feb. 1, 2018 for DPL Delaware), and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. To date, neither the PAPUC nor FERC has yet issued guidance on how and when to reflect the impacts of the TCJA in customer rates. Refer to Note 3 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information on their filings.

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Early Nuclear Plant Retirements

On May 30, 2017, Generation announced it will permanently cease generation operations at Three Mile Island Generating Station (TMI) on or about September 30, 2019. The TMI nuclear plant did not clear in the May 2017 PJM capacity auction for the 2020-2021 planning year and will not receive capacity revenue for that period, the third consecutive year that TMI failed to clear the PJM base residual capacity auction. The plant is currently committed to operate through May 2019. In 2017, as a result of the plant retirement decision of TMI, Exelon and Generation recognized one-time charges in Operating and maintenance expense of \$77 million related to materials and supplies inventory reserve adjustments, employee-related costs and construction work-in-progress (CWIP) impairments, among other items. In addition to these one-time charges, there will be ongoing annual incremental non-cash charges to earnings stemming from shortening the expected economic useful life of TMI primarily related to accelerated depreciation of plant assets (including any asset retirement costs (ARC)), accelerated amortization of nuclear fuel, and additional asset retirement obligation (ARO) accretion expense associated with the changes in decommissioning timing and cost assumptions. During the year ended December 31, 2017, both Exelon's and Generation's results include an incremental \$262 million of pre-tax expense for these items.

The following table summarizes the estimated annual amount and timing of expected incremental non-cash expense items through 2019.

	Actual	Projected ^(a)	
	2017	2018	2019
Income statement expense (pre-tax)			
Depreciation and Amortization			
Accelerated depreciation ^(b)	\$ 250	\$ 440	\$ 330
Accelerated nuclear fuel amortization	12	20	5
Total	\$ 262	\$ 460	\$ 335

^(a) Actual results may differ based on incremental future capital additions, actual units of production for nuclear fuel amortization, future revised ARO assumptions, etc.

^(b) Reflects incremental accelerated depreciation of plant assets, including any ARC.

On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle in October 2018. In 2010, Generation announced that Oyster Creek would retire by the end of 2019 as part of an agreement with the State of New Jersey to avoid significant costs associated with the construction of cooling towers to meet the State's then new environmental regulations. Since then, like other nuclear sites, Oyster Creek has continued to face rising operating costs amid a historically low wholesale power price environment. The decision to retire Oyster Creek in 2018 at the end of its current operating cycle involved consideration of several factors, including economic and operating efficiencies, and avoids a refueling outage scheduled for the fall of 2018 that would have required advanced purchasing of fuel fabrication and materials beginning in late February 2018.

Because of the decision to retire Oyster Creek in 2018, Exelon and Generation will recognize certain one-time charges in the first quarter of 2018 ranging from an estimated \$25 million to \$35 million (pre-tax) related to a materials and supplies inventory reserve adjustment, employee-related costs, and construction work-in-progress impairment, among other items. Estimated cash expenditures related to the one-time charges primarily for employee-related costs are expected to range from \$5 million to \$10 million.

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In addition to these one-time charges, there will be financial impacts stemming from shortening the expected economic useful life of Oyster Creek primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and additional ARO accretion expense associated with the changes in decommissioning timing and cost assumptions to reflect an earlier retirement date. The following table summarizes the estimated amount of expected incremental non-cash expense items expected to be incurred in 2018 because of the early retirement decision.

	Projected ^(b) 2018
Income statement expense (pre-tax)	
Depreciation and Amortization	
Accelerated depreciation ^(a)	\$110 to \$140
Accelerated nuclear fuel amortization	\$40
Operating and Maintenance	
Increased ARO accretion	Up to \$5

(a) Includes the accelerated depreciation of plant assets including any ARC.

(b) Actual results may differ based on incremental future capital additions, actual units of production for nuclear fuel amortization, future revised ARO assumptions, etc.

EGTP Consent Agreement and Bankruptcy

On May 2, 2017, EGTP, an indirect subsidiary of Exelon and Generation, entered into a consent agreement with its lenders to permit EGTP to draw on its revolving credit facility and initiate an orderly sales process to sell the assets of its wholly owned subsidiaries. As a result, Exelon and Generation classified certain EGTP assets and liabilities as held for sale at their respective fair values less costs to sell and recorded a \$460 million pre-tax impairment loss during 2017. On November 7, 2017, EGTP and all of its wholly owned subsidiaries filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the District of Delaware. As a result, Exelon and Generation deconsolidated EGTP's assets and liabilities from their consolidated financial statements and recorded a \$213 million pre-tax gain. See Note 4 — Mergers, Acquisitions and Dispositions, Note 7 — Impairment of Long-Lived Assets and Intangibles and Note 13 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information regarding EGTP and the associated nonrecourse debt.

Acquisition of James A. FitzPatrick Nuclear Generating Station

On March 31, 2017, Generation acquired the 842 MW single-unit James A. FitzPatrick (FitzPatrick) nuclear generating station for a total purchase price of \$289 million. In accounting for the acquisition as a business combination, Exelon and Generation recorded an after-tax bargain purchase gain of \$233 million which is included within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information regarding the Generation's acquisition of FitzPatrick and related costs.

Illinois Future Energy Jobs Act

On December 7, 2016, FEJA was signed into law by the Governor of Illinois. FEJA was effective on June 1, 2017, and includes, among other provisions, (1) a Zero Emission Standard (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

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exceeds specified limits, (6) revisions to the existing net metering statute 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 8 — Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information regarding the economic challenges facing Generation's Clinton and Quad Cities nuclear plants and the expected benefits of the ZES.

Illinois ZEC Procurement

On January 25, 2018, the ICC announced that Generation's Clinton Unit 1, Quad Cities Unit 1 and Quad Cities Unit 2 nuclear plants were selected as the winning bidders through the IPA's ZEC procurement event. Generation executed the ZEC procurement contracts with Illinois utilities, including ComEd, effective January 26, 2018 and will begin recognizing revenue. Winning bidders will be entitled to compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA. In the first quarter of 2018, Generation will recognize approximately \$150 million of revenue and ComEd will record an obligation to Generation and corresponding reduction to its regulatory liability of approximately \$100 million related to ZECs generated from June 1, 2017 through December 31, 2017.

Dismissal of Litigation Challenging ZEC Programs

On July 14, 2017, the U.S. District Court for the Northern District of Illinois dismissed two lawsuits challenging the ZEC program contained in FEJA. On July 17, 2017, the plaintiffs appealed the court's decisions to the U.S. Court of Appeals for the Seventh Circuit. Briefs were fully submitted on December 12, 2017 and the Court heard oral argument on January 3, 2018. At the argument, the Court asked for supplemental briefing, which was filed on January 26, 2018. Additionally, on July 25, 2017, the U.S. District Court for the Southern District of New York dismissed a lawsuit challenging the ZEC program contained in the New York CES. On August 24, 2017, the plaintiffs appealed the decision to the Second Circuit. Briefing in the appeal was completed in December 2017, and oral argument is expected to take place in March 2018.

In addition, on November 30, 2016, a group of parties, including certain environmental groups and individuals, filed a Petition in New York State court seeking to invalidate the ZEC program. The Petition, which was amended on January 13, 2017, argued that the NYPSC did not have authority to establish the program and that it violated certain technical provisions of the State Administrative Procedures Act (SAPA) when adopting the ZEC program. On February 15, 2017, Generation and CENG filed a motion to dismiss the state court action. The NYPSC also filed a motion to dismiss the state court action. On March 24, 2017, the plaintiffs filed a memorandum of law opposing the motions to dismiss, and Generation and CENG filed a reply brief on April 28, 2017. Oral argument was held on June 19, 2017. On January 22, 2018, the court denied the motions to dismiss without commenting on the merits of the case. The case will now proceed to summary judgment upon filing of the full record.

The court decisions to date have upheld the ZEC programs which support Illinois's and New York's efforts to advance clean energy and preserve affordable and reliable energy resources for customers. See Note 3 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information regarding FEJA and the New York CES.

Merger Commitment Unrecognized Tax Benefits

Exelon established a liability for an uncertain tax position associated with the tax deductibility of certain merger commitments incurred by Exelon in connection with the acquisitions of Constellation in 2012 and PHI in 2016. In the first quarter 2017, as a part of its examination of Exelon's return, the IRS

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National Office issued guidance concurring with Exelon's position that the merger commitments were deductible. As a result, Exelon, Generation, PHI, Pepco, DPL and ACE decreased their liability for unrecognized tax benefits by \$146 million, \$19 million, \$59 million, \$21 million, \$16 million, and \$22 million, respectively, as of December 31, 2017, resulting in a benefit to Income taxes on Exelon's, Generation's, PHI's, Pepco's, DPL's and ACE's Consolidated Statements of Operations and Comprehensive Income and corresponding decreases in their effective tax rates.

Combined-Cycle Gas Turbine Projects

In June 2017, Generation commenced commercial operations of two new combined-cycle gas turbines (CCGTs) at the Colorado Bend II and Wolf Hollow II Generating Stations in Texas. The two new CCGTs have added nearly 2,200 MWs of capacity to Generation's fleet, enhancing Generation's strategy to match generation to customer load.

Generation invested approximately \$1.5 billion over the past three years to complete the new plant construction, which utilizes new General Electric technology to make them among the cleanest, most efficient CCGTs in the nation.

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.

The following tables show the Utility Registrants' completed and pending distribution rate case proceedings in 2017.

Completed Distribution Rate Case Proceedings

Company	Jurisdiction	Approved		Completion Date	Rate Effective Date
		Revenue Requirement Increase (in millions)	Approved Return on Equity		
ComEd	Illinois (Electric) ^(a)	\$ 96	^(b) 8.4 %	^(c) December 6, 2017	January 1, 2018
Pepco	District of Columbia (Electric)	\$ 37	9.5 %	July 25, 2017	August 15, 2017
Pepco	Maryland (Electric)	\$ 32	9.5 %	October 27, 2017	October 20, 2017
DPL	Maryland (Electric)	\$ 38	9.6 %	February 15, 2017	February 15, 2017
DPL	Delaware (Electric)	\$ 31.5	9.7 %	May 23, 2017	June 1, 2017
DPL	Delaware (Natural Gas)	\$ 4.9	9.7 %	June 6, 2017	July 1, 2017
ACE	New Jersey (Electric)	\$ 43	9.6 %	September 22, 2017	October 1, 2017

Pursuant to EIMA, ComEd's electric distribution rates are established through a performance-based formula through which ComEd is required to file an annual update on or before May 1, with resulting rates effective in January of the following year. ComEd's annual electric distribution formula rate update is based on prior year actual costs and current year projected capital additions (initial year revenue requirement). The update also reconciles any differences between the revenue requirement in effect for the prior year and actual costs incurred for the year (annual reconciliation).

^(a) Reflects an increase of \$78 million for the initial revenue requirement for 2017 and an increase of \$18 million related to the annual reconciliation.

^(b) ComEd's allowed ROE under its electric distribution formula rate is the annual average rate on 30-year treasury notes plus 580 basis points and is subject to reduction if ComEd does not deliver certain reliability and customer service benefits. The initial revenue requirement for 2017 reflects an allowed ROE of 8.40%, while the annual reconciliation reflects an allowed ROE of 8.34%, which is inclusive of a 6-basis-point performance penalty.

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Pending Distribution Rate Case Proceedings

Company	Jurisdiction	Requested Revenue Requirement Increase (in millions)		Requested Return on Equity	Filing Date	Expected Completion Timing
Pepco	Maryland (Electric)	\$ 11	(a)	10.1 %	January 2, 2018 (Updated February 5, 2018)	Third quarter 2018
Pepco	District of Columbia (Electric)	\$ 66	(b)	10.1 %	December 19, 2017	Fourth quarter 2018
DPL	Maryland (Electric)	\$ 19	(b)(c)	10.1 %	July 14, 2017 (Updated on November 16, 2017)	First quarter 2018
DPL	Delaware (Electric)	\$ 31	(b)	10.1 %	August 17, 2017 (Updated on October 18, 2017)	Third quarter 2018
DPL	Delaware (Natural Gas)	\$ 11	(b)	10.1 %	August 17, 2017 (Updated on November 7, 2017)	Fourth quarter 2018

On February 5, 2018, Pepco filed with the MDPSC an update to its current distribution rate case to reflect (a) approximately \$31 million in TCJA tax savings, thereby reducing the requested annual base rate increase to \$11 million.

(b) By mid-February, Pepco and DPL will update their current distribution rate cases to reflect the TCJA impacts.

On December 18, 2017, a settlement agreement was filed with the MDPSC wherein DPL will be granted a rate increase of \$13 million, and a ROE of 9.5% solely for purposes of calculating AFUDC and regulatory asset (c) carrying costs. On January 5, 2018, the MDPSC held a hearing on the settlement agreement. DPL expects a decision in the matter in the first quarter of 2018, but cannot predict whether the MDPSC will approve the settlement agreement as filed or how much of the requested increase will be approved.

Transmission Formula Rates

The following total increases/(decreases) were included in ComEd's, BGE's, Pepco's, DPL's and ACE's 2017 annual electric transmission formula rate filings:

Annual Transmission Filings ^(a)	2017				
	ComEd	BGE	Pepco	DPL	ACE
Initial revenue requirement increase	\$44	\$31	\$5	\$6	\$20
Annual reconciliation increase (decrease)	(33)	3	15	8	22
Dedicated facilities decrease ^(b)	—	(8)	—	—	—
Total revenue requirement increase	\$11	\$26	\$20	\$14	\$42
Allowed return on rate base ^(c)	8.43%	7.47%	7.92%	7.16%	8.02%
Allowed ROE ^(d)	11.5%	10.5%	10.5%	10.5%	10.5%

(a) All rates are effective June 2017.

(b) BGE's transmission revenues include a FERC approved dedicated facilities charge to recover the costs of providing transmission service to specifically designated load by BGE.

(c) Represents the weighted average debt and equity return on transmission rate bases.

(d) As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.50%, inclusive of a 50-basis-point incentive adder for being a member of a RTO, and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%. As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL and ACE, the rate of return on common equity is 10.50%, inclusive of a 50-basis-point incentive adder for being a member of a RTO.

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PECO Transmission Formula Rate. On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rates and change the manner in which PECO's transmission rate is determined from a fixed rate to a formula rate. The formula rate would be updated annually to ensure that under this rate customers pay the actual costs of providing transmission services. The formula rate filing includes a requested increase of \$22 million to PECO's annual transmission revenues and a requested rate of return on common equity of 11%, inclusive of a 50-basis-point adder for being a member of a regional transmission organization. PECO requested that the new transmission rate be effective as of July 2017. On June 27, 2017, FERC issued an Order accepting the filing and suspending the proposed rates until December 1, 2017, subject to refund, and set the matter for hearing and settlement judge procedures. PECO cannot predict the final outcome of the settlement or hearing proceedings, or the transmission formula FERC may approve.

See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further details on these regulatory proceedings.

Westinghouse Electric Company LLC Bankruptcy

On March 29, 2017, Westinghouse Electric Company LLC (Westinghouse) and its affiliated debtors filed petitions for relief under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York. In the petitions and supporting documents, Westinghouse makes clear that its requests for relief center on one business area that is losing money - the construction of nuclear power plants in Georgia and South Carolina. On January 4, 2018, Westinghouse announced its agreement to be acquired by Brookfield Business Partners. The deal, which requires bankruptcy court and regulatory approvals, is expected to close in in the third quarter of 2018. Brookfield has informally indicated to Generation that it will assume all of Exelon's contracts with Westinghouse. Generation is monitoring the bankruptcy and pending sale proceedings to ensure that its rights are protected.

ExGen Renewables Holdings, LLC Transaction

On July 6, 2017, ExGen Renewables Holdings, LLC, a wholly owned subsidiary of Generation, completed the sale of a 49% interest of ExGen Renewables Partners, LLC, a newly formed owner and operator of approximately 1,439 megawatts of Generation's operating wind and solar electric generating facilities. ExGen Renewables Holdings will be the managing member of ExGen Renewables Partners, LLC, and have day-to-day control and management over its renewable generation portfolio. The closing of the transaction was subject to certain regulatory approvals, including the Federal Energy Regulatory Commission (FERC) and the Public Utility Commission of Texas (PUCT) which were received during the second quarter of 2017. The sale price was \$400 million plus immaterial working capital and other customary post-closing adjustments. The net proceeds, after approximately \$100 million of income taxes, will be used to pay down debt and for general corporate purposes. Generation will continue to consolidate ExGen Renewables Partners, LLC and will record a noncontrolling interest on its Consolidated Balance Sheet for the investor's equity share as well as earnings attributable to the noncontrolling interest in the Consolidated Statements of Operations and Comprehensive Income each period going forward.

Hurricanes Harvey, Irma and Maria Impacts

Although Exelon subsidiaries provided substantial assistance to recovery efforts following Hurricanes Harvey and Irma, Hurricanes Harvey, Irma and Maria are not expected to have a material impact on the Registrants' businesses or financial results given the limited operations in the areas affected by the storms.

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Exelon's Strategy and Outlook for 2018 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 steadily growing earnings, which translates to a stable currency in our stock. Generation's competitive businesses provide free cash flow to invest primarily in 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, the Utility Registrants 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 energy 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 approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 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. One key issue is ensuring the ability to properly value nuclear generation assets in the market, solutions to which Exelon is actively pursuing in a variety of jurisdictions and venues. See ITEM 1A. RISK FACTORS for additional information regarding market and financial factors.

Continually optimizing the cost structure is a key component of Exelon's financial strategy. In August 2015, Exelon announced a cost management program focused on cost savings of approximately \$400 million at BSC and Generation, of which approximately 60% of run-rate savings was achieved by the

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end of 2017 with the remainder to be fully realized in 2018. At least 75% of the savings are expected to be related to Generation, with the remaining amount related to the Utility Registrants. Additionally, in November 2017, Exelon announced a new commitment for an additional \$250 million of cost savings, primarily at Generation, to be achieved by 2020. These actions are in response to the continuing economic challenges confronting all parts of Exelon's business and industry, necessitating continued focus on cost management through enhanced efficiency and productivity.

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 \$26 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 \$15 billion by the end of 2022. 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 its generation assets as well as explores wholesale and retail opportunities within the power and gas sectors. Generation's long-term growth strategy is to ensure appropriate valuation of its generation assets, in part through public policy efforts, identify and capitalize on opportunities that provide generation to load matching as a means to provide stable earnings, and identify emerging technologies where strategic investments provide the option for significant future growth or influence in market development.

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. For further detail regarding the Registrants' liquidity for the year ended December 31, 2017, see Liquidity and Capital Resources discussion below.

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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 debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other project-related borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, or restructured, 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 lives. See Note 13 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on nonrecourse debt.

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 positions. 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,

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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. On June 20, 2017, the DC Circuit denied all the appeals.

MISO Capacity Market Results

On April 14, 2015, the 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, 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, 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. 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 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. 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 prejudice 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 8 - Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on the impacts of the MISO announcement.

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 require 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 certain subsidized resources could have on capacity markets (such as the New

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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. The EPSA parties have filed motions to expedite both proceedings. 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, for Generation's facilities in NYISO and PJM expected to receive ZEC compensation (Quad Cities, Ginna, Nine Mile Point and FitzPatrick), an expanded MOPR could require exclusion of ZEC compensation when bidding into future capacity auctions such that these facilities would have an increased risk of not clearing in those auctions and thus no longer receiving capacity revenues during the respective ZEC programs. Any such mitigation of these generating resources could have a material effect on Exelon's and Generation's future cash flows and results of operations. On August 30, 2017, EPSA filed motions to lodge the district court decisions dismissing the complaints and urging FERC to act expeditiously on its requests to expand the MOPR. On September 14, 2017, Exelon filed a response in each docket noting that it does not oppose the motions to lodge but arguing that the requests to expedite a decision on the requests to expand the MOPR have no merit. The timing of FERC's decision with respect to both proceedings is currently unknown and the outcome of these matters is currently uncertain.

DOE Notice of Proposed Rulemaking

On August 23, 2017, the DOE staff released its report on the reliability of the electric grid. One aspect of the wide-ranging report is the DOE's recognition that the electricity markets do not currently value the resiliency provided by baseload generation, such as nuclear plants. On September 28, 2017, the DOE issued a Notice of Proposed Rulemaking (NOPR) that would entitle certain eligible resilient generating units (i.e., those located in organized markets, with a 90-day supply of fuel on site, not already subject to state cost of service regulation and satisfying certain other requirements) to recover fully allocated costs and earn a fair return on equity on their investment. The DOE's NOPR recommended that the FERC take comments for 45 days after publication in the Federal Register and issue a final order 60 days after such publication. On January 8, 2018, the FERC issued an order terminating the rulemaking docket that was initiated to address the proposed rule in the DOE NOPR, concluding the proposed rule did not sufficiently demonstrate there is a resiliency issue and that it proposed a remedy that did not appear to be just, reasonable and nondiscriminatory as required under the Federal Power Act. At the same time, the FERC initiated a new proceeding to consider resiliency challenges to the bulk power system and evaluate whether additional FERC action to address resiliency would be appropriate. The FERC directed each RTO and ISO to respond within 60 days to 24 specific questions about how they assess and mitigate threats to resiliency. Interested parties may submit reply comments within 30 days after the due date of the RTO/ISO responses. Exelon has been and will continue to be an active participant in these proceedings, but cannot predict the final outcome or its potential financial impact, if any, on Exelon or Generation.

Energy Demand

Modest economic growth partially offset by energy efficiency initiatives is resulting in flat to declining load growth in electricity for the utilities. There is decrease in projected load for electricity for ComEd, PECO, BGE, and DPL, and an increase in projected load for electricity for Pepco and ACE. ComEd, PECO, BGE, Pepco, DPL, and ACE are projecting load volumes to increase (decrease) by (0.5)%, (0.5)%, (0.6)%, 1.5%, (1.5)% and 1.5%, respectively, in 2018 compared to 2017.

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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, second, third and fourth quarter 2017 dividends of \$0.3275 per share each on Exelon's common stock, and the first quarter 2018 dividends declared was \$0.3450 per share. The dividends for the first, second, third and fourth quarter 2017 were paid on March 10, 2017, June 9, 2017, September 8, 2017 and December 8, 2017, respectively. The first quarter 2018 dividend is payable on March 9, 2018.

Exelon's Board of Directors approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 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 2018 and 2019. 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, 2017, the percentage of expected generation hedged is 85%-88%, 55%-58% and 26%-29% for 2018, 2019, and 2020 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

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contracted prices. Approximately 59% of Generation's uranium concentrate requirements from 2018 through 2022 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 positions.

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

Environmental Legislative and Regulatory Developments

Exelon was actively involved in the Obama Administration'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 fossil-fueled electric generating units, as set forth in the discussion below. These regulations have had a disproportionate adverse impact on coal-fired power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and have resulted in the retirement of older, marginal facilities. Due to its low emission generation portfolio, Generation has not been significantly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil fuel plants.

Through the issuance of a series of Executive Orders (EO), President Trump has initiated review of a number of EPA and other regulations issued during the Obama Administration, with the expectation that the Administration will seek repeal or significant revision of these rules. Under these EOs, each executive agency is required to evaluate existing regulations and make recommendations regarding repeal, replacement, or modification. The Administration's actions are intended to result in less stringent compliance requirements under air, water, and waste regulations. The exact nature, extent, and timing of the regulatory changes are unknown, as well as the ultimate impact on Exelon's and its subsidiaries results of operations and cash flows.

In particular, the Administration has targeted existing EPA regulations for repeal, including notably the Clean Power Plan, as well as revoking many Executive Orders, reports, and guidance issued by the Obama Administration on the topic of climate change or the regulation of greenhouse gases. The Executive Order also disbanded the Interagency Working Group that developed the social cost of carbon used in rulemakings, and withdrew all technical support documents supporting the calculation. Other regulations that have been specifically identified for review are the Clean Water Act rule relating to jurisdictional waters of the U.S., the Steam Electric Effluent Guidelines relating to waste water discharges from coal-fired power plants, and the 2015 National Ambient Air Quality Standard (NAAQS) for ozone. The review of final rules could extend over several years as formal notice and comment rulemaking process proceeds.

Air Quality

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

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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. On April 27, 2017, the D.C. Circuit granted EPA's motion to hold the litigation in abeyance, pending EPA's review of the MATS rule pursuant to President Trump's EO discussed above. Following EPA's review and determination of its course of action for the MATS rule, the parties will have 30 days to file motions on future proceedings. Notwithstanding the Court's order to hold the litigation in abeyance, 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.

Clean Power Plan. On April 28, 2017, the D.C. Circuit Court issued orders in separate litigation related to the EPA's actions under the Clean Power Plan (CPP) to amend Clean Air Act Section 111(d) regulation of existing fossil-fired electric generating units and Section 111(b) regulation of new fossil-fired electric generating units. In both cases, the Court has determined to hold the litigation in abeyance pending a determination whether the rule should be remanded to the EPA. On October 10, 2017, EPA issued a proposed rule to repeal the CPP in its entirety, based on a proposed change in the Agency's legal interpretation of Clean Air Act Section 111(d) regarding actions that the Agency can consider when establishing the Best System of Emission Reduction ("BSER") for existing power plants. Under the proposed interpretation, the Agency exceeded its authority under the Clean Air Act by regulating beyond individual sources of GHG emissions. The EPA has also indicated its intent to issue an advance notice of proposed rulemaking to solicit information on systems of emission reduction that are in accord with the Agency's proposed revised legal interpretation; namely, only by regulating emission reductions that can be implemented at and to individual sources. **2015 Ozone National Ambient Air Quality Standards (NAAQS).** On April 11, 2017, the D.C. Circuit ordered that the consolidated 2015 ozone NAAQS litigation be held in abeyance pending EPA's further review of the 2015 Rule. EPA did not meet the October 1, 2017 deadline to promulgate initial designations for areas in attainment or non-attainment of the standard. A number of states and environmental organizations have notified the EPA of their intent to file suit to compel EPA to issue the designations.

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" or "Convention"). See ITEM 1. BUSINESS, "Global Climate Change" for further discussion.

Water Quality

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 recent changes to the regulations. For Generation, those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, FitzPatrick, Ginna, Gould Street, Mountain Creek, Handley, Mystic 7, Nine Mile Point Unit 1, Peach Bottom, Quad Cities, and Salem. 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

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federal regulations. Generation has previously recorded accruals 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 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Employees

In January 2017, an election was held at BGE which resulted in union representation for approximately 1,394 employees. BGE and IBEW Local 410 are negotiating 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. In April 2017, Exelon Nuclear Security successfully ratified its CBA with the SPFPA Local 238 at Quad Cities to an extension of three years. In June 2017, Exelon Nuclear Security successfully ratified its CBA with the UGSOA Local 12 at Limerick to an extension of three years.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements. Management discusses these policies, estimates and assumptions with its Accounting and Disclosure Governance Committee on a regular basis and provides periodic updates on management decisions to the Audit Committee of the Exelon Board of Directors. Management believes that the accounting policies described below require significant judgment in their application, or 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 \$9.7 billion at December 31, 2017. 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.

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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 following methodologies and significant estimates and assumptions:

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.

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.

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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 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

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 license renewal for the Clinton unit. Clinton depreciation provisions are based on 2027 which is the last year of the Illinois Zero Emissions Standard. No prior Generation initial license extension application has been denied. Generation intends to apply for a second 20-year renewal for the Peach Bottom Units 2 and 3.

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 authoritative guidance required Generation to establish an ARO at fair value at the time of the initial adoption. 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. The ARO is not required or permitted to be re-measured for changes in the CARFR that occur in isolation. 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. If Generation's future nominal cash flows associated with the ARO were to be discounted at current prevailing CARFR, the obligation would increase from approximately \$9.7 billion to approximately \$10.3 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 2016 CARFR rather than the 2017 CARFR in performing its annual 2017 ARO update, Generation would have increased the ARO by an additional \$10 million; and ii) if the CARFR

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used in performing the annual 2017 ARO update are increased by 50 basis points or decreased by 50 basis points, the ARO would have decreased by \$170 million and increased by \$30 million, respectively, as compared to the actual decrease of \$69 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.

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, 2017
Cost escalation studies	
Uniform increase in escalation rates of 50 basis points	\$ 1,690
Probabilistic cash flow models	
Increase the estimated costs to decommission the nuclear plants by 10 percent	700
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	500
Shorten each unit's probability weighted operating life assumption by 10% ^(a)	660
Extend the estimated date for DOE acceptance of SNF to 2035	130

^(a) Timing sensitivity does not include any sites for which an early plant retirement has been announced.

For more information regarding accounting for nuclear decommissioning obligations, see Note 1 — Significant Accounting Policies, Note 8 — Early Nuclear Plant Retirements and Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements.

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

As of December 31, 2017, 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, 2017, related to its 1995 acquisition of the Conowingo Power Company. Generation also has goodwill of \$47 million as of December 31, 2017. 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 25 — 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 including regulatory and political developments, 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.

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 authoritative 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. In January 2017, the FASB issued a new standard, effective January 1, 2020 with early adoption permitted, that simplifies the accounting for goodwill impairment by removing the second step of the test and, instead, measuring goodwill impairment at the amount by which a reporting unit's carrying value exceeds its fair value (currently the first step in the test). Exelon, Generation, ComEd, PHI and DPL have not determined whether to early adopt this standard.

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,

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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.

For their 2017 annual goodwill impairment assessments, Exelon, ComEd, PHI and DPL each qualitatively determined that it was more likely than not that the fair value of their respective reporting unit exceeded their respective carrying value. Therefore, ComEd, PHI and DPL did not perform quantitative assessments. As part of their qualitative assessments, ComEd, PHI and DPL evaluated, among other things, management's best estimate of projected operating and capital cash flows for their businesses, outcomes of recent regulatory proceedings, changes in certain market conditions, including the discount rate and regulated utility peer EBITDA multiples, and the passing margin from their last quantitative assessments performed as of November 1, 2016.

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 10 — Intangible Assets and Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Purchase Accounting (Exelon, Generation and PHI)

In January 2017, the FASB issued a new standard, effective January 1, 2018 with early adoption permitted, that clarifies the definition of a business with the objective of addressing whether acquisitions/dispositions should be accounted for as acquisitions/dispositions of assets or as acquisitions/dispositions of businesses. The Registrants did not early adopt this new standard. See Note 1-Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for further information.

In accordance with authoritative 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 the purchase price exceeds the estimated net fair value or as a bargain purchase gain on the income statement if the purchase price is less than 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, could significantly impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. Authoritative guidance provides that the allocation of the purchase price may be modified up to one year after the

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acquisition date 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 and PHI)

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that Generation has acquired and the electricity 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 of the unamortized energy contract assets and liabilities is recorded through purchased power and fuel expense or operating revenues, depending on the nature of the underlying contract. Refer to Note 3 — Regulatory Matters, Note 4 — Mergers, Acquisitions and Dispositions and Note 10 — 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, an asset remaining idle for more than a short period of time, 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 and purchases 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 impact 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 long-lived assets or 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. 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.

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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. Beginning January 1, 2018, the authoritative guidance eliminates the available-for-sale and cost method classifications for equity securities and requires that all equity investments (other than those accounted for using the equity method of accounting) be measured and recorded at fair value with any changes in fair value recorded through earnings. Investments in equity securities without readily determinable fair values must be qualitatively assessed for impairment each reporting period and fair value determined if any significant impairment indicators exist. If the fair value is less than the carrying value, the impairment is recorded through earnings immediately in the period in which it is identified without regard to whether the decline in value is temporary in nature. The new authoritative guidance does not impact the classification or measurement of investments in debt securities. See Note 1-Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for further information.

See Note 7 — Impairment of Long-Lived Assets and Intangibles 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 group, composite or unitary methods of depreciation. The group approach is typically for groups of similar assets that have approximately the same useful lives and the composite approach is used for heterogeneous assets that have different lives. Under both methods, a reporting entity depreciates the assets over the average life of the assets in the group. The estimation of asset useful lives requires management judgment, supported by formal depreciation studies of historical asset retirement experience. Depreciation studies are generally 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 customer rates, unless the depreciation rates reflected in customer rates do not align with management's judgment as to an appropriate estimated useful life or have not been updated on a timely basis. Depreciation expense for ComEd, BGE, Pepco, DPL and ACE includes an estimated cost of dismantling and removing plant from service upon retirement. Actual incurred removal costs are applied against a related regulatory liability or recorded to a regulatory asset if in excess of previously collected removal costs. PECO's removal costs are capitalized to accumulated depreciation when incurred, and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method. 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 8 — Early Nuclear Plant

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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 effective 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. In addition, BGE's electric transmission depreciation rates were updated effective April 1, 2015.

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. On December 19, 2017, Pepco filed an electric distribution rate application which included revised depreciation rates. Pepco expects a decision in the fourth quarter of 2018.

Neither the DPSC nor the MDPSC mandates the frequency or timing of DPL's electric distribution or gas depreciation studies. On July 20, 2016, DPL filed revised electric depreciation rates with the MDPSC as part of the electric distribution base rate filing, resulting in new depreciation rates effective on April 20, 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, resulting in new electric depreciation rates effective June 1, 2017 and new gas depreciation rates effective July 1, 2017.

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. ACE expects to perform an electric distribution depreciation study in 2018.

While FERC does not mandate the frequency or timing of electric transmission depreciation studies, the Utility Registrants and Generation perform studies on all assets every 5 years. Pepco, DPL and ACE last performed transmission depreciation studies in 1988, 1990, and 2003, respectively, but are adopting Exelon's practice and are currently evaluating the timing of the next study.

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 current employees. See Note 16 — Retirement Benefits of the Combined Notes to

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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 16 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for information on fair value measurements of pension and other postretirement plan assets, including valuation techniques and classification under the fair value hierarchy in accordance with authoritative guidance.

Expected Rate of Return on Plan Assets

In determining the EROA, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectation regarding future long-term capital market performance, weighted by Exelon's target asset class allocations. 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. See Note 16 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for further information regarding Exelon's EROA assumptions.

Discount Rate

At December 31, 2017 and 2016, 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. See Note 16 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for further information regarding Exelon's discount rate assumptions.

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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. Authoritative 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 assumes an ultimate health care cost trend rate of 5.00% has been reached in 2017 for its other postretirement benefit 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's mortality assumption is supported by an actuarial experience study of Exelon's plan participants and utilizes the IRS's RP-2000 base table and the Scale BB 2-Dimensional improvement scale with long-term improvements of 0.75%.

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	Actual Assumption			Change in Assumption		
	Pension	OPEB	Change in Assumption	Pension	OPEB	Total
Change in 2017 cost:						
Discount rate ^(a)	4.04%	4.04%	0.5%	\$ (72)	\$ (16)	\$ (88)
	4.04%	4.04%	(0.5)%	89	19	108
EROA	7.00%	6.58%	0.5%	(85)	(12)	(97)
	7.00%	6.58%	(0.5)%	85	12	97
Health care cost trend rate	NA	5.00%	1.00%	N/A	9	9
	NA	5.00%	(1.00)%	N/A	(8)	(8)
Change in benefit obligation at December 31, 2017:						
Discount rate ^(a)	3.62%	3.61%	0.5%	(1,183)	(252)	(1,435)
	3.62%	3.61%	(0.5)%	1,371	291	1,662
Health care cost trend rate	NA	5.00%	1.00%	N/A	125	125
	NA	5.00%	(1.00)%	N/A	(113)	(113)

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 (a) extrapolated for larger increases or decreases in the discount rate. Additionally, Exelon utilizes a liability-driven investment strategy for its pension asset portfolio. The sensitivities shown above do not reflect the offsetting impact that changes in discount rates may have on pension asset returns.

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 authoritative guidance is

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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 designed to recover costs can be charged to and collected 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) revenue or gains 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, 2017, 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 authoritative 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. At December 31, 2017, the gain (loss) could have been as much as \$1.1 billion, \$5.3 billion, \$280 million, \$592 million, \$(1.1) billion, \$(59) million, \$321 million and \$(8) million (before taxes) as a result of the elimination of regulatory assets and liabilities of Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively. Further, Exelon would record a charge against OCI (before taxes) of up to \$3.8 billion, \$2.4 billion, \$544 million, \$177 million, \$407 million, \$202 million and \$92 million related to Exelon's, ComEd's, BGE's, PHI's, Pepco's, DPL's and ACE's respective portions of the deferred costs associated with Exelon's pension and other postretirement benefit plans that are recorded as regulatory assets on Exelon's Consolidated Balance Sheets. Exelon also has a net regulatory liability of \$(31) million (before taxes) related to PECO's portion of the deferred costs associated with Exelon's other postretirement benefit plans that would result in an increase in OCI if reversed. 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 ICC-approved electric distribution and energy efficiency formula rates for ComEd, and FERC transmission formula rate tariffs for ComEd, PECO, 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, cash flows and financial positions could be material.

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

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Accounting for Derivative Instruments (All Registrants)

The Registrants use derivative instruments to manage commodity price risk, foreign currency exchange risk and interest rate risk related to ongoing business operations. The Registrants' derivative activities are in accordance with Exelon's Risk Management Policy (RMP). See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments. The Registrants account for derivative financial instruments under the applicable authoritative guidance. Determining whether a contract qualifies as a derivative 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 quantities. Changes in management's assessment of contracts and the liquidity of their markets, and changes in authoritative guidance, could result in previously excluded contracts becoming in scope to new authoritative guidance. Generation has determined that contracts to purchase uranium, contracts to purchase and sell capacity in certain ISO's, certain emission products, ZECs and RECs do not meet the definition of a derivative as they do not provide for net settlement and the uranium, certain capacity, emission and ZEC and REC markets are not sufficiently liquid to conclude that physical forward contracts are readily convertible to cash. If these markets become sufficiently liquid, then Generation would be required to account for these contracts as 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 could have a material impact to Exelon's and Generation's results of operations and financial positions.

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 either 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 immediately. 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 AOCI and reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. The Registrants rarely elect hedge accounting for commodity transactions. Economic commodity hedges are recorded at fair value through earnings. In addition, for commodity derivatives executed for proprietary trading purposes, changes in the fair value of the derivatives are recognized in earnings immediately. For economic hedges that are not designated for hedge accounting for the Utility Registrants, changes in the fair value each period are generally recorded with a corresponding offsetting regulatory asset or liability given likelihood of recovering the associated costs through customer rates.

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 by Generation as normal purchases and normal sales transactions, which 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 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 that qualify for the normal purchases and normal sales exception

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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 the contract 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 the authoritative guidance, 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. Under 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 generally 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. The price quotations reflect the average of the bid-ask mid-point from markets 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. The Registrant's derivatives are traded predominately at liquid trading points. The remaining derivative contracts are valued using models that consider 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 and are categorized in Level 3.

The Registrants consider nonperformance risk, including credit risk in the valuation of derivative contracts, including both historical and current market data in its assessment of nonperformance risk, including credit risk. The impacts of nonperformance and credit 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, 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 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

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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 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 observable inputs and are primarily categorized in Level 2 in the fair value hierarchy. Certain exchange based interest rate derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 11 — Fair Value of Financial Assets and Liabilities and Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

Taxation (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.

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.

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. The Registrants have recorded the provisional income tax amounts as of December 31, 2017 for changes pursuant to the TCJA related to depreciation for which the impacts could not be finalized upon issuance of the Registrants' financial statements, but for which reasonable estimates could be determined. In accordance with SAB 118, additional remeasurement may occur based on technical corrections or other forms of guidance issued, which may result in material changes to previously finalized provisions. While the Registrants believe the resulting tax balances as of December 31, 2017 and 2016 are appropriately accounted for in accordance with the applicable authoritative guidance, the ultimate outcome of tax matters could result in favorable or unfavorable adjustments that could be material to their consolidated financial statements. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

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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 amount recorded may differ from the actual expense incurred when the uncertainty is resolved. Such difference could have a significant impact on the Registrants' 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 the Utility Registrants to determine future remediation requirements for MGP sites and estimates are adjusted accordingly. In addition, periodic reviews are performed at each of the Registrants to assess the adequacy of other environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant impact on the Registrants' results of operations, cash flows and financial positions. See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information.

Other, Including Personal Injury Claims

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

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.

The accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable authoritative guidance. The Registrants primarily use accrual, mark-to-market, and Alternative Revenue Program (ARP) accounting as discussed in more detail below. Beginning on January 1, 2018, the Registrants will begin applying the Revenue from Contracts with Customers guidance to recognize revenue. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for additional information.

Accrual Accounting

Under accrual accounting, the Registrants recognize 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,

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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.

The determination of Generation's and the Utility Registrants' 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 energy 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 customers classes in the period could be significant to the calculation of unbilled revenue. In addition, unbilled 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 also impact the measurement of unbilled revenue, however, total operating revenues would remain materially unchanged. See Note 5 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information on unbilled revenue.

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.

Alternative Revenue Program Accounting

Certain of the Utility Registrants' ratemaking mechanisms qualify as ARPs if they meet certain criteria. At each balance sheet date, the Utility Registrants with such mechanisms, including ComEd's electric distribution and energy efficiency formulas, and ComEd's, PECO's, BGE's, Pepco's, DPL's, and ACE's FERC transmission formula rates, record ARP revenues for any differences between the prior year revenue requirement in effect in rates and their best estimate of the current year revenue requirement that is probable of approval by the ICC or FERC. Estimates of the current year revenue requirement are based on actual and/or forecasted costs and investment in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. ComEd, BGE, Pepco, and DPL also have decoupling mechanisms which qualify as ARPs. The Utility Registrants recognize and record an offsetting regulatory asset or liability once the condition or event allowing for the automatic adjustment of future rates occurs.

The Utility Registrants' ARP revenues include both: (i) the recognition of "originating" ARP revenues (when the regulator-specified condition or event allowing for additional billing or refund has occurred) and (ii) an equal and offsetting reversal of the "originating" ARP revenues as those amounts are reflected in the price of utility service. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

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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, BGE, Pepco, DPL and ACE, estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by customer risk segment. Risk segments represent a group of customers with similar credit quality indicators that are comprised based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on a historical average of charge-offs as a percentage of accounts receivable in each risk segment. The Utility Registrants' customer 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 5 — 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, 2017, 2016 and 2015 set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Net Income (Loss) Attributable to Common Shareholders by Registrant

	For the Years Ended December 31,		Favorable (unfavorable) 2017 vs. 2016 variance	For the Year Ended December 31, 2015	Favorable (unfavorable) 2016 vs. 2015 variance
	2017	2016			
Exelon	\$3,770	\$1,134	\$ 2,636	\$ 2,269	\$ (1,135)
Generation	2,694	496	2,198	1,372	(876)
ComEd	567	378	189	426	(48)
PECO	434	438	(4)	378	60
BGE	307	286	21	275	11
Pepco	205	42	163	187	(145)
DPL	121	(9)	130	76	(85)
ACE	77	(42)	119	40	(82)

	Successor For the Year Ended December 31, 2017	Predecessor January 1, 2016 to March 31, 2016	For the 2016 Year Ended March 31, 2015
PHI	\$362 \$ (61)	\$ 19 \$ 327	

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Results of Operations—Generation

	2017	2016	Favorable (unfavorable) 2017 vs. 2016 variance	2015	Favorable (unfavorable) 2016 vs. 2015 variance
Operating revenues	\$18,466	\$17,751	\$ 715	\$19,135	\$ (1,384)
Purchased power and fuel expense	9,690	8,830	(860)	10,021	1,191
Revenues net of purchased power and fuel expense ^(a)	8,776	8,921	(145)	9,114	(193)
Other operating expenses					
Operating and maintenance	6,291	5,641	(650)	5,308	(333)
Depreciation and amortization	1,457	1,879	422	1,054	(825)
Taxes other than income	555	506	(49)	489	(17)
Total other operating expenses	8,303	8,026	(277)	6,851	(1,175)
Gain (Loss) on sales of assets	2	(59)	61	12	(71)
Bargain purchase gain	233	—	233	—	—
Gain on deconsolidation of business	213	—	213	—	—
Operating income	921	836	85	2,275	(1,439)
Other income and (deductions)					
Interest expense	(440)	(364)	(76)	(365)	1
Other, net	948	401	547	(60)	461
Total other income and (deductions)	508	37	471	(425)	462
Income before income taxes	1,429	873	556	1,850	(977)
Income taxes	(1,375)	290	1,665	502	212
Equity in losses of unconsolidated affiliates	(33)	(25)	(8)	(8)	(17)
Net income	2,771	558	2,213	1,340	(782)
Net income (loss) attributable to noncontrolling interests	77	62	15	(32)	94
Net income attributable to membership interest	\$2,694	\$496	\$ 2,198	\$1,372	\$ (876)

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 (a) 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.

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Net Income Attributable to Membership Interest

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. Generation's Net income attributable to membership interest increased compared to the same period in 2016, primarily due to lower Depreciation and amortization, a Bargain purchase gain in 2017, a Gain on deconsolidation of business in 2017, higher Other income and decreased Income taxes, partially offset by lower Revenues net of purchased power and fuel expense and higher Operating and maintenance expense. The decrease in Depreciation and amortization expense is primarily due to lower accelerated depreciation and amortization as a result of the 2017 decision to early retire the TMI nuclear facility compared to the previous decision in 2016 to early retire Clinton and Quad Cities nuclear facilities. The Bargain purchase gain is due to the acquisition of the FitzPatrick nuclear facility. The Gain on deconsolidation of business in 2017 is due to the deconsolidation of EGTP's net liabilities, which included the previously impaired assets and related debt, as a result of the November 2017 bankruptcy filing. The increase in Other income is primarily due to higher realized NDT fund gains. The decrease in Income taxes primarily relates to the one-time non-cash impacts associated with the Tax Cuts and Jobs Act. The decrease in Revenues net of purchased power and fuel expense primarily reflects lower realized energy prices, the impacts of lower load volumes delivered due to mild weather in the third quarter 2017, the conclusion of the Ginna Reliability Support Services Agreement and the impact of declining natural gas prices on Generation's natural gas portfolio, partially offset by the impact of the New York CES, higher capacity prices, the addition of two combined-cycle gas turbines in Texas and lower nuclear fuel prices. The increase in Operating and maintenance expense is primarily related to the impairment of EGTP in 2017.

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.

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.

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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 nuclear decommissioning; and other miscellaneous revenues. Generation evaluates the operating performance of electric business activities using the measure of Revenue net of purchased power and fuel expense, which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to 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.

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For the years ended December 31, 2017 compared to 2016 and December 31, 2016 compared to 2015, Generation's Revenue net of purchased power and fuel expense by region were as follows:

	2017	2016	2017 vs. 2016			2015	2016 vs. 2015		
			Variance	% Change			Variance	% Change	
Mid-Atlantic ^(a)	\$3,214	\$3,317	\$(103)	(3.1)	%	\$3,571	\$(254)	(7.1)	%
Midwest ^(b)	2,820	2,971	(151)	(5.1)	%	2,892	79	2.7	%
New England	514	438	76	17.4	%	461	(23)	(5.0)	%
New York ^(d)	976	742	234	31.5	%	634	108	17.0	%
ERCOT	332	281	51	18.1	%	293	(12)	(4.1)	%
Other Power Regions	305	336	(31)	(9.2)	%	250	86	34.4	%
Total electric revenues net of purchased power and fuel expense	8,161	8,085	76	0.9	%	8,101	(16)	(0.2)	%
Proprietary Trading	18	15	3	n.m.		1	14	n.m.	
Mark-to-market gains (losses)	(175)	(41)	(134)	326.8	%	257	(298)	(116.0)	%
Other ^(c)	772	862	(90)	(10.4)	%	755	107	14.2	%
Total revenue net of purchased power and fuel expense	\$8,776	\$8,921	\$(145)	(1.6)	%	\$9,114	\$(193)	(2.1)	%

Results of transactions with PECO and BGE are included in the Mid-Atlantic region. Results of transactions with (a) Pepco, DPL, and ACE are included in the Mid-Atlantic region beginning on March 24, 2016, the day after the PHI merger was completed.

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

Other represents activities not allocated to a region. See text above for a description of included activities. Includes amortization of intangible assets related to commodity contracts recorded at fair value of a \$54 million decrease to RNF, an \$57 million decrease to RNF, and an \$8 million increase to RNF for the years ended December 31, 2017, (c) 2016, and 2015, respectively, and accelerated nuclear fuel amortization associated with announced early plant retirements, as discussed in Note 8 - Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements, of \$12 million and \$60 million for the years ended December 31, 2017 and 2016, respectively.

(d) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

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Generation's supply sources by region are summarized below:

Supply Source (GWh)	2017	2016	2017 vs. 2016			2015	2016 vs. 2015		
			Variance	% Change			Variance	% Change	
Nuclear Generation^(a)									
Mid-Atlantic	64,466	63,447	1,019	1.6	%	63,283	164	0.3	%
Midwest	93,344	94,668	(1,324)	(1.4)	%	93,422	1,246	1.3	%
New York ^(c)	25,033	18,684	6,349	34.0	%	18,769	(85)	(0.5)	%
Total Nuclear Generation	182,843	176,799	6,044	3.4	%	175,474	1,325	0.8	%
Fossil and Renewables									
Mid-Atlantic	2,789	2,731	58	2.1	%	2,774	(43)	(1.6)	%
Midwest	1,482	1,488	(6)	(0.4)	%	1,547	(59)	(3.8)	%
New England	7,179	6,968	211	3.0	%	2,983	3,985	133.6	%
New York	3	3	—	—	%	3	—	—	%
ERCOT	12,072	6,785	5,287	77.9	%	5,763	1,022	17.7	%
Other Power Regions	6,869	8,179	(1,310)	(16.0)	%	7,848	331	4.2	%
Total Fossil and Renewables	30,394	26,154	4,240	16.2	%	20,918	5,236	25.0	%
Purchased Power									
Mid-Atlantic	9,801	16,874	(7,073)	(41.9)	%	8,160	8,714	106.8	%
Midwest	1,373	2,255	(882)	(39.1)	%	2,325	(70)	(3.0)	%
New England	18,517	16,632	1,885	11.3	%	24,309	(7,677)	(31.6)	%
New York	28	—	28	—	%	—	—	—	%
ERCOT	7,346	10,637	(3,291)	(30.9)	%	10,070	567	5.6	%
Other Power Regions	14,530	13,589	941	6.9	%	18,773	(5,184)	(27.6)	%
Total Purchased Power	51,595	59,987	(8,392)	(14.0)	%	63,637	(3,650)	(5.7)	%
Total Supply/Sales by Region									
Mid-Atlantic ^(b)	77,056	83,052	(5,996)	(7.2)	%	74,217	8,835	11.9	%
Midwest ^(b)	96,199	98,411	(2,212)	(2.2)	%	97,294	1,117	1.1	%
New England	25,696	23,600	2,096	8.9	%	27,292	(3,692)	(13.5)	%
New York	25,064	18,687	6,377	34.1	%	18,772	(85)	(0.5)	%
ERCOT	19,418	17,422	1,996	11.5	%	15,833	1,589	10.0	%
Other Power Regions	21,399	21,768	(369)	(1.7)	%	26,621	(4,853)	(18.2)	%
Total Supply/Sales by Region	264,832	262,940	1,892	0.7	%	260,029	2,911	1.1	%

(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) 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 beginning on March 24, 2016.

(c) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

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Mid-Atlantic

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. The \$103 million decrease in revenues net of purchased power and fuel expense in the Mid-Atlantic primarily reflects lower load volumes, lower realized energy prices and decreased capacity prices, partially offset by the absence of oil inventory write-downs in 2017 and decreased nuclear outage days.

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.

Midwest

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. The \$151 million decrease in revenues net of purchased power and fuel expense in the Midwest primarily reflects lower realized energy prices and increased nuclear outage days, partially offset by decreased fuel prices.

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.

New England

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. The \$76 million increase in revenues net of purchased power and fuel expense in New England was driven by increased capacity prices, partially offset by lower realized energy prices.

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.

New York

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. The \$234 million increase in revenues net of purchased power and fuel expense in New York was primarily due to the impact of the New York CES and the acquisition of Fitzpatrick, partially offset by the conclusion of the Ginna Reliability Support Service Agreement and lower realized energy prices.

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.

ERCOT

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. The \$51 million increase in revenues net of purchased power and fuel expense in ERCOT was primarily due to the addition of two combined-cycle gas turbines in Texas, partially offset by lower realized energy prices.

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.

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Other Power Regions

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. The \$31 million decrease in revenues net of purchased power and fuel expense in Other Power Regions was primarily due to lower realized energy prices.

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.

Proprietary Trading

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. The \$3 million increase in revenues net of purchased power and fuel expense in Proprietary trading was primarily due to congestion activity.

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.

Mark-to-market

Generation is exposed to market risks associated with changes in commodity prices and executes economic hedges to mitigate exposure to these fluctuations. See Note 11 — Fair Value of Financial Assets and Liabilities and Note 12 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. Mark-to-market losses on economic hedging activities were \$175 million in 2017 compared to losses of \$41 million in 2016.

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.

Other

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. The \$90 million decrease in other revenue net of purchased power and fuel was primarily due to the impacts of declining natural gas prices on Generation's natural gas portfolio and the decline in revenues related to the distributed generation business, partially offset by a decrease in accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 — Early Nuclear Plant Retirements of the Combined Notes to the Financial Statements.

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 8 — Early Nuclear Plant Retirements of the Combined Notes to the Financial Statements.

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Nuclear Fleet Capacity Factor

The following table presents nuclear fleet operating data for 2017, as compared to 2016 and 2015, 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 to be 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.

	2017	2016	2015
Nuclear fleet capacity factor ^(a)	94.1 %	94.6 %	93.7 %
Refueling outage days ^(a)	293	245	290
Non-refueling outage days ^(a)	53	63	82

^(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon. Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. The nuclear fleet capacity factor, which excludes Salem, decreased in 2017 compared to 2016 primarily due to increased refueling outage days, partially offset by fewer non-refueling outage days.

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.

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Operating and Maintenance Expense

The changes in operating and maintenance expense for 2017 compared to 2016, consisted of the following:

	Increase (Decrease) ^(a)
Impairment and related charges of certain generating assets ^(b)	\$ 307
Merger and integration costs	13
ARO update ^(c)	84
Pension and non-pension postretirement benefits expense	10
Corporate allocations	23
Plant retirements and divestitures ^(d)	127
Accretion expense ^(e)	35
Nuclear refueling outage costs, including the co-owned Salem plant ^(f)	104
Merger commitments ^(g)	(53)
Labor, other benefits, contracting and materials ^(h)	52
Cost management program	(2)
Curtailment of Generation growth and development activities ⁽ⁱ⁾	(24)
Vacation policy change ⁽ⁱ⁾	(40)
Allowance for uncollectible accounts	33
Change in Environmental Remediation Liabilities	44
Other	(63)
Increase in operating and maintenance expense	\$ 650

(a) The 2017 financial results include Generation's acquisition of the FitzPatrick nuclear generating station from March 31, 2017.

(b) Primarily reflects charges to earnings related to impairments as a result of the EGTP assets in 2017 and impairment of Upstream assets and certain wind projects in 2016.

(c) Primarily reflects the non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units in 2017 compared to 2016.

(d) Primarily represents the announcement of the early retirement of Generation's TMI nuclear facility in 2017 compared to the previous decision to early retire Generation's Clinton and Quad Cities nuclear facilities in 2016.

(e) Reflects the impact of increased accretion expenses primarily due to the acquisition of FitzPatrick on March 31, 2017.

(f) Primarily reflects an increase in the number of nuclear outage days during 2017 compared to 2016.

(g) Primarily represents costs incurred as part of the settlement orders approving the PHI acquisition during 2016.

(h) Reflects increased salaries, wages and contracting costs primarily related to the acquisition of the FitzPatrick nuclear facility beginning on March 31, 2017.

(i) Represents the reversal of previously accrued vacation expenses as a result of a change in Exelon's vacation vesting policy.

(j) Reflects the one-time recognition for a loss on sale of assets and 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.

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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.

Depreciation and Amortization

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. Depreciation and amortization expense decreased 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 compared to the decision to early retire the Three Mile Island nuclear facility in 2017.

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.

Taxes Other Than Income

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. The increase in taxes other than income was primarily due to increased real estate taxes and sales and use taxes.

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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.

Gain (Loss) on Sales of Assets

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. The increase in gain (loss) on sales of assets is 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.

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.

Bargain Purchase Gain

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. The increase in the Bargain purchase gain is related to the result of the gain associated with the FitzPatrick acquisition. Refer to Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information.

Gain on Deconsolidation of Business

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. The increase in the Gain on deconsolidation of business is related to the deconsolidation of EGTP's net liabilities, which included the previously impaired assets and related debt, as a result of the November 2017 bankruptcy filing. Refer to Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information.

Interest Expense

The changes in interest expense for 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Interest expense on long-term debt	\$ —	\$ 8
Interest expense on interest rate swaps	(2)	1
Interest expense on tax settlements	12	16
Other interest expense	66	(26)
(Decrease) increase in interest expense, net	\$ 76	\$ (1)

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Other, Net

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. 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 \$209 million and \$80 million for the years ended December 31, 2017 and 2016, respectively, related to the contractual elimination of income tax expense associated with the NDT fund investments of the Regulatory Agreement Units. Refer to Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT fund investments.

Year Ended December 31, 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, respectively, related to the contractual elimination of income tax expense associated with the NDT fund investments of the Regulatory Agreement Units. Refer to Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT fund investments.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for 2017, 2016 and 2015:

	2017	2016	2015
Net unrealized gains (losses) on decommissioning trust funds	\$521	\$194	\$(197)
Net realized gains on sale of decommissioning trust funds	95	35	66

Effective Income Tax Rate

Generation's effective income tax rates for the years ended December 31, 2017, 2016 and 2015 were (96.2)%, 33.2% and 27.1%, respectively. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

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Results of Operations—ComEd

	2017	2016	Favorable (unfavorable) 2017 vs. 2016 variance	2015	Favorable (unfavorable) 2016 vs. 2015 variance
Operating revenues	\$5,536	\$5,254	\$ 282	\$4,905	\$ 349
Purchased power expense	1,641	1,458	(183)	1,319	(139)
Revenues net of purchased power expense ^{(a)(b)}	3,895	3,796	99	3,586	210
Other operating expenses					
Operating and maintenance	1,427	1,530	103	1,567	37
Depreciation and amortization	850	775	(75)	707	(68)
Taxes other than income	296	293	(3)	296	3
Total other operating expenses	2,573	2,598	25	2,570	(28)
Gain on sales of assets	1	7	(6)	1	6
Operating income	1,323	1,205	118	1,017	188
Other income and (deductions)					
Interest expense, net	(361)	(461)	100	(332)	(129)
Other, net	22	(65)	87	21	(86)
Total other income and (deductions)	(339)	(526)	187	(311)	(215)
Income before income taxes	984	679	305	706	(27)
Income taxes	417	301	(116)	280	(21)
Net income	\$567	\$378	\$ 189	\$426	\$ (48)

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.

(a)

For regulatory recovery mechanisms, including ComEd's electric distribution and transmission formula rates, and (b)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, 2017 Compared to Year Ended December 31, 2016. ComEd's Net income for the year ended December 31, 2017 was higher than the same period in 2016 primarily due to the recognition of the penalty and the after-tax interest due on the asserted penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position in 2016 and increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment and higher allowed electric distribution ROE). The higher Net income was partially offset by the impact of weather conditions in 2016. See Revenue Decoupling discussion below for additional information on the impact of weather.

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 due on the asserted penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position, partially offset by increased electric

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distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment, partially offset by lower allowed electric distribution ROE) and favorable weather.

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, REC and ZEC procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity, REC and ZEC procurement costs from retail customers without mark-up. Therefore, fluctuations in these 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, 2017, 2016 and 2015, consisted of the following:

For the Years
 Ended
 December 31,
 2017 2016 2015

Electric 70% 72% 76%

Retail customers purchasing electric generation from competitive electric generation suppliers at December 31, 2017, 2016 and 2015 consisted of the following:

December 31, 2017		December 31, 2016		December 31, 2015	
Number	% of total	Number	% of total	Number	% of total
of	retail	of	retail	of	retail
customers	customers	customers	customers	customers	customers
Electric 1,371,700	34 %	1,502,900	38 %	1,655,400	42 %

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The changes in ComEd's Revenue net of purchased power expense for the year ended December 31, 2017, compared to the same period in 2016, and for the year ended December 31, 2016, compared to the same period in 2015, consisted of the following:

	Increase (Decrease)	Increase (Decrease)
	2017 vs. 2016	2016 vs. 2015
Weather ^(a)	\$ (36)	\$ 54
Volume ^(a)	(5)	(2)
Pricing and customer mix ^(a)	(18)	14
Electric distribution revenue	170	69
Transmission revenue	60	97
Energy efficiency revenue ^(b)	16	—
Regulatory required programs ^(b)	(85)	(31)
Uncollectible accounts recovery, net	(7)	(13)
Other	4	22
Total increase	\$ 99	\$ 210

For the year ended December 31, 2017, compared to the same period in 2016, the changes reflect the 2016 impacts of weather, volume and pricing and customer mix. As further described below, pursuant to the revenue decoupling (a) provision in FEJA, ComEd began recording an adjustment to revenue in the first quarter of 2017 to eliminate the favorable or unfavorable impacts associated with variations in delivery volumes associated with above or below normal weather, number of customers or usage per customer.

Beginning on June 1, 2017, ComEd is deferring energy efficiency costs as a regulatory asset that will be recovered (b) through the energy efficiency formula rate over the weighted average useful life of the related energy efficiency measures.

Revenue Decoupling. 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.

Under EIMA, ComEd's electric distribution formula rate provided for an adjustment to future billings if its earned ROE fell outside a 50-basis-point collar of its allowed ROE, which partially eliminated the impacts of weather and load on ComEd's revenue. As allowed under FEJA, ComEd will revise its electric distribution formula rate to eliminate the ROE collar beginning with the reconciliation filed in 2018 for the 2017 calendar year. Elimination of the ROE collar effectively offsets the favorable or unfavorable impacts to Operating revenues associated with variations in delivery volumes associated with above or below normal weather, numbers of customers or usage per customer. ComEd began recognizing the impacts of this change beginning in the first quarter of 2017. For the year ended December 31, 2017, ComEd recorded an increase to Electric distribution revenues of approximately \$32 million to eliminate weather and load impacts.

For the year ended December 31, 2016, favorable weather conditions increased Operating revenues net of purchased power expense when compared to the prior year.

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.

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Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in 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, 2017, 2016 and 2015 consisted of the following:

	For the Years Ended			% Change	
Heating and Cooling Degree-Days	December 31,				
	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	5,435	5,715	6,198	(4.9)%	(12.3)%
Cooling Degree-Days	991	1,157	893	(14.3)%	11.0 %
	For the Years Ended			% Change	
Heating and Cooling Degree-Days	December 31,				
	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	5,715	6,091	6,198	(6.2)%	(7.8)%
Cooling Degree-Days	1,157	806	893	43.5 %	29.6 %

Electric Distribution Revenue. EIMA and FEJA provide 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. 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. 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, 2017, electric distribution revenue increased \$170 million, primarily due to increased capital investment, increased Depreciation expense, higher allowed ROE due to an increase in treasury rates and revenue decoupling impacts (as described above). 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. 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, capital 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, 2017 and 2016, 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.

Energy Efficiency Revenue. Beginning June 1, 2017, FEJA 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 FEJA, energy efficiency 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. Beginning January 1, 2018, ComEd's

allowed ROE is subject to a maximum downward or upward adjustment of 200 basis points if ComEd's cumulative persisting annual MWh savings falls short of or exceeds specified percentage benchmarks of its annual

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incremental savings goal. See Depreciation and amortization expense discussions 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 rate riders to recover costs incurred for regulatory programs such as ComEd's purchased power administrative costs and energy efficiency and demand response through June 1, 2017 pursuant to FEJA. 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.

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)
	2017	2016	2017 vs. 2016	2016	2015	2016 vs. 2015
Operating and maintenance expense—baseline	\$1,329	\$1,347	\$ (18)	\$1,347	\$1,353	\$ (6)
Operating and maintenance expense—regulatory required programs ^(a)	98	183	(85)	183	214	(31)
Total operating and maintenance expense	\$1,427	\$1,530	\$ (103)	\$1,530	\$1,567	\$ (37)

Operating and maintenance expense for regulatory required programs are costs for various legislative and/or (a)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.

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The changes in Operating and maintenance expense for year ended December 31, 2017, compared to the same period in 2016, and for the year ended December 31, 2016, compared to the same period in 2015, consisted of the following:

	Increase (Decrease)	Increase (Decrease)
	2017 vs. 2016	2016 vs. 2015
Baseline		
Labor, other benefits, contracting and materials	\$ (41)	\$ 12)
Pension and non-pension postretirement benefits expense ^(a)	3	(24)
Storm-related costs	2	(9)
Uncollectible accounts expense—provision ^(b)	(6)	5)
Uncollectible accounts expense—recovery, net	(1)	(18)
BSC costs ^(c)	44	29
Other	(19)	(1)
	(18)	(6)
Regulatory required programs		
Energy efficiency and demand response programs ^(d)	(85)	(31)
Decrease in operating and maintenance expense	\$ (103)	\$ (37)

^(a) Primarily reflects the favorable impact of higher assumed pension and OPEB discount rates for the year ended December 31, 2016.

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 ^(b)decrease in 2017 and 2016 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.

^(c) Primarily reflects increased information technology support services from BSC in 2017 and 2016. For the year ended December 31, 2017, includes the \$8 million write-off of a regulatory asset related to Constellation merger and integration costs for which recovery is no longer expected.

^(d) Beginning on June 1, 2017 ComEd is deferring energy efficiency costs as a regulatory asset that will be recovered through the energy efficiency over the weighted average useful life of the related energy efficiency measures.

Depreciation and Amortization Expense

The increases in Depreciation and amortization expense for 2017 compared to 2016, and 2016 compared to 2015, consisted of the following:

	Increase (Decrease)	Increase (Decrease)
	2017 vs. 2016	2016 vs. 2015
Depreciation expense ^(a)	\$ 60	\$ 58
Regulatory asset amortization ^(b)	7	(5)
Other	8	15
Total increase	\$ 75	\$ 68

^(a) Primarily reflects ongoing capital expenditures for the years ended December 31, 2017 and 2016.

^(b) Beginning in June 2017, includes amortization of ComEd's energy efficiency formula rate regulatory asset.

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, 2017, compared to the same period in 2016, and for the year ended December 31, 2016, compared to the same period in

2015.

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Gain on Sale of Assets

Gain on sale of assets decreased during the year ended December 31, 2017, compared to the same period in 2016, and increased during the year ended December 31, 2016, compared to the same period in 2015, primarily due to the sale of land during March 2016.

Interest Expense, Net

The increase (decrease) in Interest expense, net, for the year ended 2017, compared to the same period in 2016, and for the year ended 2016, compared to the same period in 2015, consisted of the following:

	Increase (Decrease)	Increase (Decrease)
	2017 vs. 2016	2016 vs. 2015
Interest expense related to uncertain tax positions ^(a)	\$ (104)	\$ 109
Interest expense on debt (including financing trusts) ^(b)	6	24
Other	(2)	(4)
Increase (decrease) in interest expense, net	\$ (100)	\$ 129

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 2016. For the year ended December 31, 2017, the decrease was partially offset by additional interest recorded in 2017 related to Exelon's like-kind exchange tax position. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Primarily reflects an increase in interest expense due to the issuance of First Mortgage Bonds for the years ended December 31, 2016. See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's debt obligations.

Other, Net

The increase (decrease) in Other, net, for the year ended 2017 compared to the same period in 2016, and for the year ended 2016 compared to the same period in 2015, consisted of the following:

	Increase (Decrease)	Increase (Decrease)
	2017 vs. 2016	2016 vs. 2015
Other income and deductions, net ^(a)	\$ 88	\$ (94)
AFUDC equity	(2)	9
Other	1	(1)
Increase (decrease) in Other, net	\$ 87	\$ (86)

Primarily reflects the recognition of the penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position in 2016. See Note 13 — 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, 2017, 2016 and 2015, were 42.4%, 44.3% and 39.7%, respectively. The decrease in the effective income tax rate for the year ended December 31, 2017 compared to the same period in 2016 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 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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ComEd Electric Operating Statistics and Revenue Detail

	2017	2016	% Change 2017 vs. 2016	Weather- Normal %	2015	% Change 2016 vs. 2015	Weather- Normal %
Retail Deliveries to customers (in GWhs)							
Retail Deliveries ^(a)							
Residential	26,292	27,790	(5.4)%	(0.9)%	26,496	4.9 %	(0.6)%
Small commercial & industrial	31,332	31,975	(2.0)%	(0.7)%	31,717	0.8 %	(0.3)%
Large commercial & industrial	27,467	27,842	(1.3)%	(0.5)%	27,210	2.3 %	1.5 %
Public authorities & electric railroads	1,286	1,298	(0.9)%	(0.3)%	1,309	(0.8)%	(0.8)%
Total retail deliveries	86,377	88,905	(2.8)%	(0.7)%	86,732	2.5 %	0.2 %
	As of December 31,						
Number of Electric Customers	2017	2016	2015				
Residential	3,624,372	3,595,376	3,550,239				
Small commercial & industrial	378,345	374,644	370,932				
Large commercial & industrial	1,959	2,007	1,976				
Public authorities & electric railroads	4,775	4,750	4,820				
Total	4,009,451	3,976,777	3,927,967				
			%		%		
Electric Revenue	2017	2016	Change 2017 vs. 2016	2015	Change 2016 vs. 2015		
Retail Sales ^(a)							
Residential	\$2,746	\$2,597	5.7 %	\$2,360	10.0 %		
Small commercial & industrial	1,376	1,316	4.6 %	1,337	(1.6)%		
Large commercial & industrial	461	462	(0.2)%	443	4.3 %		
Public authorities & electric railroads	44	45	(2.2)%	42	7.1 %		
Total retail	4,627	4,420	4.7 %	4,182	5.7 %		
Other revenue ^(b)	909	834	9.0 %	723	15.4 %		
Total electric revenue ^(c)	\$5,536	\$5,254	5.4 %	\$4,905	7.1 %		

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.

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.

Includes operating revenues from affiliates totaling \$15 million, \$15 million, and \$4 million for the years ended December 31, 2017, 2016, and 2015, respectively.

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Results of Operations—PECO

	2017	2016	Favorable (unfavorable) 2017 vs. 2016 variance	2015	Favorable (unfavorable) 2016 vs. 2015 variance
Operating revenues	\$2,870	\$2,994	\$ (124)	\$3,032	\$ (38)
Purchased power and fuel expense	969	1,047	78	1,190	143
Revenues net of purchased power and fuel expense ^(a)	1,901	1,947	(46)	1,842	105
Other operating expenses					
Operating and maintenance	806	811	5	794	(17)
Depreciation and amortization	286	270	(16)	260	(10)
Taxes other than income	154	164	10	160	(4)
Total other operating expenses	1,246	1,245	(1)	1,214	(31)
Gain on sales of assets	—	—	—	2	(2)
Operating income	655	702	(47)	630	72
Other income and (deductions)					
Interest expense, net	(126)	(123)	(3)	(114)	(9)
Other, net	9	8	1	5	3
Total other income and (deductions)	(117)	(115)	(2)	(109)	(6)
Income before income taxes	538	587	(49)	521	66
Income taxes	104	149	45	143	(6)
Net income	\$434	\$438	\$ (4)	\$378	\$ 60

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

Net Income

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. PECO's net income for the year ended December 31, 2017 was lower than the same period in 2016, primarily due to a decrease in Revenues net of purchased power and fuel expense as a result of unfavorable weather in PECO's service territory, partially offset by the one-time non-cash impacts associated with the Tax Cuts and Jobs Act in 2017.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. PECO's net income for the year ended December 31, 2016 was higher than the same period in 2015, primarily due to an increase in Revenues net of purchased power and fuel expense as a result of increased electric distribution revenue pursuant to the 2015 PAPUC authorized electric distribution rate increase effective January 1, 2016.

Revenues Net of Purchased Power and Fuel Expense

Electric and natural gas revenue and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers

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are subject to adjustments as specified in the PAPUC-approved tariffs that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with PECO's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and natural gas revenues net of purchased power and fuel expense.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer Choice Program activity has no impact on electric and natural gas revenue net of purchase power and fuel expense.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mcf sales, respectively) for the years ended December 31, 2017, 2016, and 2015 consisted of the following:

	For the Years Ended December 31,		
	2017	2016	2015
Electric	71 %	70 %	70 %
Natural Gas	26 %	26 %	25 %

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at December 31, 2017, 2016, and 2015 consisted of the following:

	December 31, 2017		December 31, 2016		December 31, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	565,900	35 %	587,200	36 %	563,400	35 %
Natural Gas	83,800	16 %	81,300	16 %	81,100	16 %

The changes in PECO's Operating revenues net of purchased power and fuel expense for the years ended December 31, 2017 and December 31, 2016 compared to the same periods in 2016 and 2015, respectively, consisted of the following:

	2017 vs. 2016 Increase (Decrease)			2016 vs. 2015 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	\$(28)	\$ 4	\$(24)	\$1	\$(12)	\$(11)
Volume	(18)	3	(15)	6	4	10
Pricing	8	2	10	160	(1)	159
Regulatory required programs	(31)	—	(31)	(46)	—	(46)
Other	14	—	14	(7)	—	(7)
Total increase (decrease)	\$(55)	\$ 9	\$(46)	\$114	\$(9)	\$105

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Weather. The demand for electricity and natural gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. For the year ended December 31, 2017 compared to the same period in 2016, and the year ended December 31, 2016 compared to the same period in 2015 Operating revenues net of purchased power and fuel expense was reduced by the impact of unfavorable weather conditions in PECO’s service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO’s service territory. The changes in heating and cooling degree days in PECO’s service territory for the years ended December 31, 2017 and December 31, 2016 compared to the same periods in 2016 and 2015, respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	3,949	4,041	4,603	(2.3)%	(14.2)%
Cooling Degree-Days	1,490	1,726	1,290	(13.7)%	15.5 %

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	4,041	4,245	4,603	(4.8)%	(12.2)%
Cooling Degree-Days	1,726	1,720	1,290	0.3 %	33.8 %

Volume. The decrease in Operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2017 compared to the same period in 2016, was driven by electric and primarily reflects the impact of energy efficiency initiatives on customer usages for residential and small commercial and industrial electric classes, partially offset by solid customer growth. Additionally, the decrease represents a shift in the volume profile across classes from residential and small commercial and industrial to large commercial and industrial.

The increase in Operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016 compared to the same period in 2015, primarily reflects the impact of moderate economic and customer growth partially offset by energy efficiency initiatives on customer usages for gas and residential and small commercial and industrial electric classes. Additionally, the increase represents a shift in the volume profile across classes from large commercial and industrial classes to residential and small commercial and industrial classes for electric.

Pricing. The increase in Operating revenues net of purchased power expense as a result of pricing for the year ended December 31, 2017 compared to the same period in 2016 reflects higher overall effective rates due to decreased usage in the residential and small commercial and industrial customer classes. Operating revenues net of fuel expense as a result of pricing remained relatively consistent.

The increase in Operating revenues net of purchased power and fuel expense as a result of pricing for the year ended December 31, 2016 compared to the same period in 2015 reflects an increase in

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electric distribution rates charged to customers. The increase in electric distribution rates was effective January 1, 2016 in accordance with the 2015 PAPUC approved electric distribution rate case settlement. See Note 3 — Regulatory Matters for further information.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Income taxes. Refer to the Operating and maintenance expense discussion below for additional information on included programs.

Other. Other revenue, which can vary period to period, primarily includes wholesale transmission revenue, rental revenue, revenue related to late payment charges and assistance provided to other utilities through mutual assistance programs.

Operating and Maintenance Expense

	Year		Increase	Year		Increase
	Ended December 31,		(Decrease)	Ended December 31,		(Decrease)
	2017	2016	2017 vs. 2016	2016	2015	2016 vs. 2015
Operating and maintenance expense—baseline	\$ 746	\$ 740	\$ 6	\$ 740	\$ 685	\$ 55
Operating and maintenance expense—regulatory required programs ^(a)	60	71	(11)	71	109	(38)
Total operating and maintenance expense	\$ 806	\$ 811	\$ (5)	\$ 811	\$ 794	\$ 17

Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or (a)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.

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The changes in Operating and maintenance expense for 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015	
Baseline			
Labor, other benefits, contracting and materials	\$ 17	\$ 22	
Storm-related costs	(7)	(9)	
Pension and non-pension postretirement benefits expense	(3)	(4)	
PHI merger integration costs	—	6	
BSC costs	4	36	(a)
Uncollectible accounts expense	(5)	1	
Other	—	3	
	6	55	
Regulatory required programs			
Smart meter	—	(28)	
Energy efficiency	(10)	(7)	
GSA	—	(2)	
Other	(1)	(1)	
	(11)	(38)	
Increase (decrease) in operating and maintenance expense	\$ (5)	\$ 17	

(a) Primarily reflects increased information technology support services from BSC during 2016.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2017 compared to 2016 and 2016 compared to 2015, consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Depreciation expense	\$ 17	\$ 5
Regulatory asset amortization	(1)	5
Increase in depreciation and amortization expense	\$ 16	\$ 10

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 decreased for the year ended December 31, 2017, compared to the same period in 2016, primarily due to a decrease in gross receipts tax driven by decreases in electric revenue.

Taxes other than income increased for the year ended December 31, 2016, compared to the same period in 2015, primarily due to an increase in gross receipts tax driven by increases in electric revenue, which was impacted primarily by the new distribution rates that went into effect in January 2016.

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Interest Expense, Net

The increase in Interest expense, net for the year ended December 31, 2017, compared to the same period in 2016, primarily reflects an increase in interest expense due to the issuance of First and Refunding Mortgage Bonds in September 2017.

The increase in Interest expense, net for the year ended December 31, 2016, compared to the same period in 2015, primarily reflects an increase in interest expense due to the issuance of First and Refunding Mortgage Bonds in October 2015.

Other, Net

Other, net remained relatively consistent for the year ended December 31, 2017, compared to the same period in 2016, and the year ended December 31, 2016, compared to the same period in 2015.

Effective Income Tax Rate

PECO's effective income tax rates for the years ended December 31, 2017, 2016 and 2015 were 19.3%, 25.4% and 27.4%, respectively. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rates.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2017	2016	% Change 2017 vs. 2016	Weather- Normal % Change	2015	% Change 2016 vs. 2015	Weather- Normal % Change
Retail Deliveries ^(a)							
Residential	13,024	13,664	(4.7)%	(1.8)%	13,630	0.2 %	0.4 %
Small commercial & industrial	7,968	8,099	(1.6)%	(1.1)%	8,118	(0.2)%	0.5 %
Large commercial & industrial	15,426	15,263	1.1 %	1.4 %	15,365	(0.7)%	(1.4)%
Public authorities & electric railroads	809	890	(9.1)%	(9.1)%	881	1.0 %	1.0 %
Total electric retail deliveries	37,227	37,916	(1.8)%	(0.5)%	37,994	(0.2)%	(0.3)%
As of December 31,							
Number of Electric Customers	2017	2016	2015				
Residential	1,469,916	1,456,585	1,444,338				
Small commercial & industrial	151,552	150,142	149,200				
Large commercial & industrial	3,112	3,096	3,091				
Public authorities & electric railroads	9,569	9,823	9,805				
Total	1,634,149	1,619,646	1,606,434				

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	2017	2016	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
Electric Revenue					
Retail Sales ^(a)					
Residential	\$1,505	\$1,631	(7.7)%	\$1,599	2.0 %
Small commercial & industrial	401	430	(6.7)%	428	0.5 %
Large commercial & industrial	223	234	(4.7)%	221	5.9 %
Public authorities & electric railroads	30	32	(6.3)%	31	3.2 %
Total retail	2,159	2,327	(7.2)%	2,279	2.1 %
Other revenue ^(b)	216	204	5.9 %	207	(1.4)%
Total electric operating revenues ^(c)	\$2,375	\$2,531	(6.2)%	\$2,486	1.8 %

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

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

(c) Total electric revenue includes operating revenues from affiliates totaling \$6 million, \$7 million and \$1 million for the years ended December 31, 2017, 2016, and 2015, respectively.

PECO Gas Operating Statistics and Revenue Detail

	2017	2016	% Change 2017 vs. 2016	Weather- Normal % Change	2015	% Change 2016 vs. 2015	Weather- Normal % Change
Deliveries to customers (in mmcf)							
Retail Deliveries ^(a)							
Retail sales	58,457	56,447	3.6 %	1.2 %	59,003	(4.3)%	1.5 %
Transportation and other	26,382	27,630	(4.5)%	(2.3)%	27,879	(0.9)%	(0.1)%
Total natural gas deliveries	84,839	84,077	0.9 %	0.1 %	86,882	(3.2)%	1.0 %

As of December 31,

Number of Gas Customers	2017	2016	2015
Residential	477,213	472,606	467,263
Commercial & industrial	43,892	43,668	43,160
Total retail	521,105	516,274	510,423
Transportation	771	790	827
Total	521,876	517,064	511,250

	2017	2016	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
Gas revenue					
Retail Sales ^(a)					
Retail sales	\$462	\$430	7.4 %	\$511	(15.9)%
Transportation and other	33	33	— %	35	(5.7)%
Total natural gas operating revenues ^(b)	\$495	\$463	6.9 %	\$546	(15.2)%

Reflects delivery volumes and revenue from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.

(b) Total natural gas revenue includes operating revenues from affiliates totaling \$1 million for the years ended December 31, 2017, 2016 and 2015.

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Results of Operations—BGE

	2017	2016	Favorable (unfavorable) 2017 vs. 2016 variance	2015	Favorable (unfavorable) 2016 vs. 2015 variance
Operating revenues	\$3,176	\$3,233	\$ (57)	\$3,135	\$ 98
Purchased power and fuel expense	1,133	1,294	161	1,305	11
Revenues net of purchased power and fuel expense ^(a)	2,043	1,939	104	1,830	109
Other operating expenses					
Operating and maintenance	716	737	21	683	(54)
Depreciation and amortization	473	423	(50)	366	(57)
Taxes other than income	240	229	(11)	224	(5)
Total other operating expenses	1,429	1,389	(40)	1,273	(116)
Gain on sales of assets	—	—	—	1	(1)
Operating income	614	550	64	558	(8)
Other income and (deductions)					
Interest expense, net	(105)	(103)	(2)	(99)	(4)
Other, net	16	21	(5)	18	3
Total other income and (deductions)	(89)	(82)	(7)	(81)	(1)
Income before income taxes	525	468	57	477	(9)
Income taxes	218	174	(44)	189	15
Net income	307	294	13	288	6
Preference stock dividends	—	8	8	13	5
Net income attributable to common shareholder	\$307	\$286	\$ 21	\$275	\$ 11

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

Net Income Attributable to Common Shareholder

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. Net income attributable to common shareholder was higher primarily due to an increase in Revenues net of purchased power and fuel expense and lower Operating and maintenance expense, partially offset by higher Depreciation and amortization expense and higher income tax expense. The increase in Revenues net of purchased power and fuel expense was primarily due to the impacts of the electric and natural gas distribution rate orders issued by the MDPSC in June 2016 and July 2016 and an increase in transmission formula rate revenues. The lower Operating and maintenance expense was primarily due to the absence of cost disallowances resulting from the 2016 distribution rate orders issued by the MDPSC and

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decreased storm costs in 2017 partially offset by the favorable 2016 settlement of the Baltimore City conduit fee dispute. These items were partially offset by an increase in Depreciation and amortization expense primarily related to the initiation of cost recovery of the AMI programs under the distribution rate orders and the impacts of increased capital investment and higher income tax expense primarily resulting from higher taxable income as well as a 2016 favorable adjustment and 2017 impairment of certain transmission-related income tax regulatory assets.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. Net income attributable to common shareholder was higher primarily due to lower income tax expense and decreased preference stock dividends partially offset by slightly lower operating income. The lower income tax expense was driven by a one-time adjustment associated with transmission-related regulatory assets. The slight decrease in operating income was driven by an increase in Operating and maintenance expense as a result of cost disallowances which reduced certain regulatory assets and other long-lived assets stemming from the distribution rate orders issued by the MDPSC in June 2016 and July 2016 and increased storm costs. This increase in Operating and maintenance expense was offset by an increase in Revenues net of purchased power and fuel expense, primarily as a result of an increase in transmission formula rate revenues and higher electric and natural gas revenues as a result of the distribution rate orders issued by the MDPSC in June 2016 and July 2016.

Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to Operating revenues that are offset by their impact on Purchased power and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Operating revenues and Purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on Revenues net of purchased power and fuel expense.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in the number of customers electing to use a competitive supplier for electricity and/or natural gas. All BGE customers have the choice to purchase electricity and natural gas from competitive suppliers. The customers' choice of suppliers does not impact the volume of deliveries, but does affect revenue collected from customers related to supplied electricity and natural gas.

Retail deliveries purchased from competitive electricity and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the years ended December 31, 2017, 2016 and 2015 consisted of the following:

	For the Years		
	Ended		
	December 31,		
	2017	2016	2015
Electric	60%	59%	61%
Natural Gas	55%	57%	56%

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The number of retail customers purchasing electricity and natural gas from competitive suppliers at December 31, 2017, 2016 and 2015 consisted of the following:

	December 31, 2017		December 31, 2016		December 31, 2015	
	Number	% of total	Number	% of total	Number	% of total
	of	retail	of	retail	of	retail
	Customers	customers	Customers	customers	Customers	customers
Electric	341,000	27 %	337,000	27 %	343,000	27 %
Natural Gas	151,000	22 %	151,000	23 %	154,000	23 %

The changes in BGE's Operating revenues net of purchased power and fuel expense for the year ended December 31, 2017 compared to the same period in 2016 and for the year ended December 31, 2016 compared to the same period in 2015, respectively, consisted of the following:

	2017 vs. 2016			2016 vs. 2015		
	Increase			Increase		
	(Decrease)			(Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution rate increase	\$21	\$29	\$50	\$24	\$22	\$46
Regulatory required programs	17	3	20	10	(5)	5
Transmission revenue	18	—	18	30	—	30
Other, net	5	11	16	24	4	28
Total increase	\$61	\$43	\$104	\$88	\$21	\$109

Distribution Rate Increase. During the years ended December 31, 2017 and December 31, 2016, the increases in distribution revenues were primarily due to the impact of the electric and natural gas distribution rate changes that became effective in June 2016 in accordance with the electric and natural gas distribution rate case orders in June 2016 and July 2016. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Revenue Decoupling. The demand for electricity and natural gas is affected by weather and usage conditions. The MDPSC allows BGE to record a monthly adjustment to its electric and natural gas distribution revenue from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service natural gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and natural gas distribution volumes, thereby recovering a specified dollar amount of distribution revenue per customer, by customer class, regardless of fluctuations in actual consumption levels. This allows BGE to recognize revenue at MDPSC-approved distribution charges per customer, regardless of what BGE's actual distribution volumes were for a billing period. Therefore, while this revenue is affected by customer growth (i.e., increase in the number of customers), it will not be affected by volatility in actual weather or usage conditions (i.e., changes in consumption per customer). BGE bills or credits customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

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Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat 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 BGE's service territory. The changes in heating and cooling degree days in BGE's service territory for the year ended December 31, 2017 compared to the same period in 2016 and for the year ended December 31, 2016 compared to the same period in 2015, respectively, and normal weather consisted of the following:

	For the Year Ended December 31,			% Change	
	Normal			2017 vs. 2016	2017 vs. Normal
Heating and Cooling Degree-Days	2017	2016			
Heating Degree-Days	4,190	4,427	4,666	(5.4)%	(10.2)%
Cooling Degree-Days	940	998	875	(5.8)%	7.4 %

	For the Year Ended December 31,			% Change	
	Normal			2016 vs. 2015	2016 vs. Normal
Heating and Cooling Degree-Days	2016	2015			
Heating Degree-Days	4,427	4,666	4,684	(5.1)%	(5.5)%
Cooling Degree-Days	998	924	876	8.0 %	13.9 %

Regulatory Required Programs. Revenue from regulatory required programs are billings for the costs of various legislative and/or regulatory programs that are recoverable from customers on a full and current basis. These programs are designed to provide full cost recovery, as well as a return in certain instances. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in BGE's Consolidated Statements of Operations and Comprehensive Income.

Transmission Revenue. Under a FERC approved formula, transmission revenue varies from year to year based upon rate adjustments to reflect fluctuations in the underlying costs, capital investments being recovered and other billing determinants. During the years ended December 31, 2017 and 2016, the increase in transmission revenue was primarily due to increases in capital investment and operating and maintenance expense recoveries. See Operating and Maintenance Expense below and Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other, Net. Other net revenue, which can vary from period to period, primarily includes late payment fees and other miscellaneous revenue such as service application fees, assistance provided to other utilities through BGE's mutual assistance program and recoveries of electric supply and natural gas procurement costs.

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Operating and Maintenance Expense

	Year Ended		Increase (Decrease)	Year Ended		Increase (Decrease)
	December 31, 2017	December 31, 2016		December 31, 2016	December 31, 2015	
Operating and maintenance expense—baseline	\$ 672	\$ 701	\$ (29)	\$ 701	\$ 636	\$ 65
Operating and maintenance expense—regulatory required programs	44	36	8	36	47	(11)
Total operating and maintenance expense	\$ 716	\$ 737	\$ (21)	\$ 737	\$ 683	\$ 54

Operating and maintenance expense for regulatory required programs are costs for various legislative and/or (a) 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 the year ended December 31, 2017 compared to the same period in 2016 and the year ended December 31, 2016 compared to the same period in 2015 consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Baseline		
Impairment on long-lived assets and losses on regulatory assets ^(a)	\$ (50)	\$ 52
Labor, other benefits, contracting and materials	(11)	7
Storm-related costs	(13)	18
Uncollectible accounts expense	7	(14)
BSC costs	16	11
Conduit lease settlement ^(b)	15	(15)
Other	7	6
	\$ (29)	\$ 65
Regulatory Required Programs		
Other	8	(11)
	8	(11)
Total (decrease) increase	\$ (21)	\$ 54

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

(b) See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

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Depreciation and Amortization

The changes in Depreciation and amortization expense for the year ended December 31, 2017 compared to the same period in 2016 and December 31, 2016 compared to the same period in 2015 consisted of the following:

	Increase (Decrease)	Increase (Decrease)
	2017 vs. 2016	2016 vs. 2015
Depreciation expense ^(a)	\$ 13	\$ 10
Regulatory asset amortization ^(b)	25	31
Regulatory required programs ^(c)	12	16
Increase in depreciation and amortization expense	\$ 50	\$ 57

(a) Depreciation expense increased due to ongoing capital expenditures.

Regulatory asset amortization increased primarily due to an increase in regulatory asset amortization related to energy efficiency programs and the initiation of cost recovery of the AMI programs under the final electric and natural gas distribution rate case order issued by the MDPSC in June 2016. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full (c) and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

Taxes Other Than Income

Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income taxes increased for the year ended December 31, 2017 compared to the same period in 2016, and for the year ended December 31, 2016 compared to the same period in 2015, primarily due to an increase in property taxes.

Interest Expense, Net

Interest expense, net remained relatively consistent for the year ended December 31, 2017 compared to the same period in 2016, and for the year ended December 31, 2016 compared to the same period in 2015.

Other, Net

Other, net remained relatively consistent for the year ended December 31, 2017, compared to the same period in 2016, and the year ended December 31, 2016, compared to the same period in 2015.

Effective Income Tax Rate

BGE's effective income tax rates for the years ended December 31, 2017, 2016 and 2015 were 41.5%, 37.2% and 39.6%, respectively. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2017	2016	% Change 2017 vs. 2016	Weather- Normal % Change	2015	% Change 2016 vs. 2015	Weather- Normal % Change
Retail Deliveries ^(a)							
Residential	12,094	12,740	(5.1)%	(2.8)%	12,598	1.1 %	(3.2)%
Small commercial & industrial	2,921	3,040	(3.9)%	(4.9)%	3,119	(2.5)%	2.7 %
Large commercial & industrial	13,688	13,957	(1.9)%	(2.4)%	14,293	(2.4)%	(1.6)%
Public authorities & electric railroads	268	283	(5.3)%	(3.0)%	294	(3.7)%	(8.9)%
Total electric deliveries	28,971	30,020	(3.5)%	(2.8)%	30,304	(0.9)%	(1.9)%
As of December 31,							
Number of Electric Customers	2017	2016	2015				
Residential	1,160,783	1,150,096	1,137,934				
Small commercial & industrial	113,594	113,230	113,138				
Large commercial & industrial	12,155	12,053	11,906				
Public authorities & electric railroads	272	280	285				
Total	1,286,804	1,275,659	1,263,263				
			%		%		
Electric Revenue	2017	2016	Change 2017 vs. 2016	2015	Change 2016 vs. 2015		
Retail Sales ^(a)							
Residential	\$1,428	\$1,554	(8.1)%	\$1,449	7.2 %		
Small commercial & industrial	266	277	(4.0)%	273	1.5 %		
Large commercial & industrial	450	449	0.2 %	469	(4.3)%		
Public authorities & electric railroads	31	35	(11.4)%	32	9.4 %		
Total retail	2,175	2,315	(6.0)%	2,223	4.1 %		
Other revenue ^{(b)(c)}	314	294	6.8 %	267	10.1 %		
Total electric revenue	\$2,489	\$2,609	(4.6)%	\$2,490	4.8 %		

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

(b) Other revenue primarily includes wholesale transmission revenue and late payment charges.

(c) Includes operating revenues from affiliates totaling \$5 million, \$7 million and less than \$1 million for the years ended 2017, 2016 and 2015, respectively.

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BGE Natural Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2017	2016	% Change		Weather-Normal % Change	2015	% Change		Weather-Normal % Change
			2017 vs. 2016	2016 vs. 2015			2016 vs. 2015	2015	
Retail Deliveries ^(a)									
Retail sales	89,337	96,808	(7.7)%	(4.2)%		96,618	0.2 %	3.5 %	
Transportation and other ^(b)	3,615	5,977	(39.5)%	n/a		6,238	(4.2)%	n/a	
Total natural gas deliveries	92,952	102,785	(9.6)%	(4.2)%		102,856	(0.1)%	3.5 %	
As of December 31,									
Number of Gas Customers									
Residential	629,690	623,647	616,994						
Commercial & industrial	44,247	44,255	44,119						
Total	673,937	667,902	661,113						
Natural Gas revenue									
	2017	2016	% Change		2015	% Change			
			2017 vs. 2016	2016 vs. 2015		2016 vs. 2015			
Retail Sales ^(a)									
Retail sales	\$655	\$593	10.5 %		\$607	(2.3)%			
Transportation and other ^(b)	32	31	3.2 %		38	(18.4)%			
Total natural gas revenues ^(c)	\$687	\$624	10.1 %		\$645	(3.3)%			

Reflects delivery volumes and revenue from customers purchasing natural gas directly from BGE and customers (a) purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges.

For customers purchasing natural gas from BGE, revenue also reflects the cost of natural gas.

(b) Transportation and other natural gas revenue includes off-system revenue of 3,615 mmcfs (\$21 million), 5,977 mmcfs (\$23 million), and 6,238 mmcfs (\$35 million) for the years ended 2017, 2016 and 2015, respectively.

(c) Includes operating revenues from affiliates totaling \$11 million, \$14 million, and \$14 million for the years ended 2017, 2016 and 2015, respectively.

Results of Operations—PHI

PHI's results of operations include the results of its three reportable segments, Pepco, DPL and ACE for all periods presented below. For "Predecessor" reporting periods, PHI's results of operations also include the results of PES and PCI. See Note 25 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding PHI's reportable segments. All material intercompany accounts and transactions have been eliminated in consolidation. A separate specific discussion of the results of operations for Pepco, DPL and ACE is presented elsewhere in this report.

As a result of the PHI Merger, the following consolidated financial results present two separate reporting periods for 2016. The "Predecessor" reporting periods represent PHI's results of operations for the period of January 1, 2016 to March 23, 2016 and the year ended December 31, 2015. The "Successor" reporting periods represents PHI's results of operations for the year ended December 31, 2017 and for the period of March 24, 2016 to December 31, 2016. All amounts presented below are before the impact of income taxes, except as noted.

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	Successor		Predecessor	
	For the Year Ended December 31, 2017	March 24 to December 31, 2016	January 1 to March 23, 2016	For the Year Ended December 31, 2015
Operating revenues	\$4,679	\$ 3,643	\$1,153	\$ 4,935
Purchased power and fuel	1,716	1,447	497	2,073
Revenues net of purchased power and fuel expense ^(a)	2,963	2,196	656	2,862
Other operating expenses				
Operating and maintenance	1,068	1,233	294	1,156
Depreciation and amortization	675	515	152	624
Taxes other than income	452	354	105	455
Total other operating expenses	2,195	2,102	551	2,235
Gain (loss) on sales of assets	1	(1)	—	46
Operating income	769	93	105	673
Other income and (deductions)				
Interest expense, net	(245)	(195)	(65)	(280)
Other, net	54	44	(4)	88
Total other income and (deductions)	(191)	(151)	(69)	(192)
Income (loss) before income taxes	578	(58)	36	481
Income taxes	217	3	17	163
Equity in earnings of unconsolidated affiliates	1	—	—	—
Net income (loss) from continuing operations	362	(61)	19	318
Net income from discontinued operations	—	—	—	9
Net income (loss) attributable to membership interest/common shareholders	\$362	\$ (61)	\$19	\$ 327

PHI evaluates its operating performance using the measure of revenue net of purchased power and fuel expense for electric and natural gas sales. PHI believes revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. PHI has (a) included the analysis below as a complement to the financial information provided in accordance with GAAP.

However, Revenue net of purchased power and fuel expense 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.

Successor Year Ended December 31, 2017

PHI's Net income was \$362 million for the year ended December 31, 2017. There were no significant changes in the underlying trends affecting PHI's results of operations during the Successor year except for the impact of increases in electric distribution and natural gas rates within Revenue net of purchased power expense (Pepco electric distribution rates effective November 2016 and October 2017 in Maryland, Pepco electric distribution rates effective August 2017 in the District of Columbia, DPL electric distribution rates effective February 2017 in Maryland, DPL electric distribution and natural gas rates effective July 2016 and December 2016 in Delaware, and ACE electric distribution rates effective August 2016 and

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October 2017 in New Jersey). Operating and maintenance expense incurred included the deferral of merger-related, rate case, and customer billing system costs to regulatory assets and lower uncollectible accounts expense, partially offset by a pre-tax impairment charge of \$25 million. Income taxes expense incurred included unrecognized tax benefits of \$59 million for uncertain tax positions related to the deductibility of certain merger commitments in the first quarter of 2017, and was offset by a \$27 million December 2017 impairment of certain transmission-related income tax regulatory assets and the one-time non-cash impacts of \$35 million associated with the Tax Cuts and Jobs Act in 2017. For more information on 2017 results please refer to Results of Operations for Pepco, DPL, and ACE. PHI's effective income tax rate for the year ended December 31, 2017 was 37.5%. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of effective income tax rates.

Successor Period of March 24, 2016 to December 31, 2016

PHI's Net loss for the Successor period of March 24, 2016 to December 31, 2016 was \$61 million. There were no significant changes in the underlying trends affecting PHI's results of operations during the Successor period March 24, 2016 to December 31, 2016 except for the pre-tax recording of \$392 million of non-recurring merger-related costs including merger integration and merger commitments within Operating and maintenance expense. For more information on 2016 results please refer to Results of Operations for Pepco, DPL and ACE.

PHI's effective income tax rate for the period of March 24, 2016 to December 31, 2016 was (5.2)%. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Predecessor Period of January 1, 2016 to March 23, 2016

PHI's Net income for the Predecessor period of January 1, 2016 to March 23, 2016 was \$19 million. There were no significant changes in the underlying trends affecting PHI's results of operations during the Predecessor period of January 1, 2016 to March 23, 2016 except for the pre-tax recording of \$29 million of non-recurring merger-related costs within Operating and maintenance expense and \$18 million of preferred stock derivative expense within Other, net.

PHI's effective income tax rate for the period of January 1, 2016 to March 23, 2016 was 47.2%. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Predecessor Period Year Ended December 31, 2015

PHI's Net income was \$327 million for the year ended December 31, 2015. There were no significant changes in the underlying trends affecting PHI's results of operations during the Predecessor year except for the impact of increases in electric distribution rates within Revenue net of purchased power expense (Pepco electric distribution rates effective April 2014 in the District of Columbia, Pepco electric distribution rates effective July 2014 in Maryland, and ACE electric distribution rates effective September 2014), partially offset by Operating and maintenance costs incurred due to the implementation of a new customer information system for Pepco, DPL, and ACE in 2015. Gain (loss) on sales of assets were \$46 million, primarily due to 2015 gains recorded at Pepco associated with the sale of unimproved land, held as non-utility property.

PHI's effective income tax rate for the year ended December 31, 2015 was 33.9%. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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Results of Operations—Pepco

	2017	2016	Favorable (unfavorable) 2017 vs. 2016 variance	2015	Favorable (unfavorable) 2016 vs. 2015 variance
Operating revenues	\$2,158	\$2,186	\$ (28)	\$2,129	\$ 57
Purchased power expense	614	706	92	719	13
Revenues net of purchased power expense ^(a)	1,544	1,480	64	1,410	70
Other operating expenses					
Operating and maintenance	454	642	188	439	(203)
Depreciation and amortization	321	295	(26)	256	(39)
Taxes other than income	371	377	6	376	(1)
Total other operating expenses	1,146	1,314	168	1,071	(243)
Gain on sales of assets	1	8	(7)	46	(38)
Operating income	399	174	225	385	(211)
Other income and (deductions)					
Interest expense, net	(121)	(127)	6	(124)	(3)
Other, net	32	36	(4)	28	8
Total other income and (deductions)	(89)	(91)	2	(96)	5
Income before income taxes	310	83	227	289	(206)
Income taxes	105	41	(64)	102	61
Net income	\$205	\$42	\$ 163	\$187	\$ (145)

Pepco evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. Pepco believes revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Pepco has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. Pepco's Net income for the year ended December 31, 2017, was higher than the same period in 2016, primarily due to a decrease in Operating and maintenance expense due to merger-related costs recognized in March 2016 and an increase in Revenue net of purchased power expense as a result of the distribution rate increases approved by the MDPSC effective November 2016 and October 2017 and an electric distribution rate increase approved by the DCPSC effective August 2017, partially offset by higher depreciation expense due to increased depreciation rates in Maryland effective November 2016. Income taxes expense incurred included unrecognized tax benefits of \$21 million for uncertain tax positions related to the deductibility of certain merger commitments in the first quarter of 2017. This decrease was offset by an increase in income taxes due to the \$14 million December 2017 impairment of certain transmission-related income tax regulatory assets and the one-time non-cash impacts of \$8 million associated with the Tax Cuts and Jobs Act in 2017.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. Pepco's Net income for the year ended December 31, 2016, was lower than the same period in 2015, primarily due to an increase in Operating and maintenance expense due to merger-related costs.

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Operating Revenue Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to Pepco's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that Pepco receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All Pepco customers have the choice to purchase electricity from competitive electric generation suppliers. The customers' choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the years ended December 31, 2017, 2016 and 2015 respectively, consisted of the following:

For the Years
Ended
December 31,
2017 2016 2015

Electric 66% 65% 65%

Retail customers purchasing electric generation from competitive electric generation suppliers at December 31, 2017, 2016 and 2015 consisted of the following:

December 31, 2017		December 31, 2016		December 31, 2015	
Number	% of total	Number	% of total	Number	% of total
of	retail	of	retail	of	retail
customers	customers	customers	customers	customers	customers

Electric 179,184 21 % 176,372 21 % 173,222 21 %

Retail deliveries purchased from competitive electric generation suppliers represented 73% of Pepco's retail kWh sales to the District of Columbia customers and 60% of Pepco's retail kWh sales to Maryland customers for the year ended December 31, 2017; 73% of Pepco's retail kWh sales to the District of Columbia customers and 59% of Pepco's retail kWh sales to Maryland customers for the year ended December 31, 2016; and 71% of Pepco's retail kWh sales to the District of Columbia customers and 60% of Pepco's retail kWh sales to Maryland customers for year ended December 31, 2015.

Operating revenues include transmission enhancement credits that Pepco receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Purchased power expense consists of the cost of electricity purchased by Pepco to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders.

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The changes in Pepco's Operating revenues net of purchased power expense for the years ended December 31, 2017 and 2016 compared to the same periods in 2016 and 2015, respectively, consisted of the following:

	Increase (Decrease)	Increase (Decrease)
	2017 vs. 2016	2016 vs. 2015
Volume	\$ 16	\$ 15
Distribution rate increase	66	5
Regulatory required programs	(12)	38
Transmission revenues	9	(1)
Other	(15)	13
Total increase	\$ 64	\$ 70

Volume. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2017 compared to the same period in 2016 primarily reflects the impact of residential customer growth. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016 compared to the same period in 2015 primarily reflects the impact of moderate economic and customer growth.

Distribution Rate Increase. The increase in electric operating revenues net of purchased power expense for the year ended December 31, 2017 compared to the same period in 2016 was primarily due to the impact of the higher electric distribution rates charged to customers in Maryland that became effective in November 2016 and October 2017 and higher electric distribution rates charged to customers in the District of Columbia that became effective August 2017. The increase in distribution revenue for the year ended December 31, 2016 compared to the same period in 2015 was primarily due to the impact of the new electric distribution rates charged to customers in Maryland that became effective in November 2016. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Revenue Decoupling. Pepco's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of Pepco in Maryland and in the District of Columbia, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland and the District of Columbia to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

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Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in Pepco's service territory. The changes in heating and cooling degree days in Pepco's service territory for the years ended December 31, 2017 and December 31, 2016 compared to same periods in 2016 and 2015, respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	3,312	3,624	3,869	(8.6)%	(14.4)%
Cooling Degree-Days	1,767	1,936	1,653	(8.7)%	6.9 %

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	3,624	3,657	3,887	(0.9)%	(6.8)%
Cooling Degree-Days	1,936	1,936	1,626	— %	19.1 %

Regulatory Required Programs. This represents the change in Operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in Pepco's Consolidated Statements of Operations and Comprehensive Income. Revenue from regulatory required programs decreased for the year ended December 31, 2017 compared to the same period in 2016 primarily due to lower demand-side management program surcharge revenue due to a decrease in kWh sales and a rate decrease effective January 2017. Revenue from regulatory required programs increased for the year ended December 31, 2016 compared to the same period in 2015 primarily due to higher demand-side management program surcharge revenue due to a rate increase effective February 2016. Refer to the Operating and maintenance expense and Depreciation and amortization expense discussion below for additional information on included programs.

Transmission Revenues. Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered and other billing adjustments. Transmission revenue increased for the year ended December 31, 2017 compared to the same period in 2016 due to higher rates effective June 1, 2017 and June 1, 2016 related to increases in transmission plant investment and operating expenses. Transmission revenue decreased for the year ended December 31, 2016 compared to the same period in 2015 due to lower revenue related to the MAPP abandonment recovery period that ended in March 2016, partially offset by higher rates effective June 1, 2016 and June 1, 2015 related to increases in transmission plant investment and operating expenses.

Other. The decrease in other operating revenue net of purchased power expense for the year ended December 31, 2017 compared to the same period in 2016 is primarily due to lower pass-through revenue (which is substantially offset in Taxes other than income) primarily the result of lower sales that resulted in a decrease in utility taxes that are collected by Pepco on behalf of the jurisdiction. The increase in other operating revenue net of purchased power

expense for the year ended December 31, 2016 compared to the same period in 2015 is primarily due to higher pass-through revenue (which is substantially offset in Taxes other than income) primarily the result of higher sales that resulted in an increase in utility taxes that are collected by Pepco on behalf of the jurisdiction.

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Operating and Maintenance Expense

	Year			Year		
	Ended	Increase	(Decrease)	Ended	Increase	(Decrease)
	December	(Decrease)		December	(Decrease)	
	31,			31,		
	2017	2016	2017 vs.	2016	2015	2016 vs.
			2016			2015
Operating and maintenance expense - baseline	\$449	\$631	\$ (182)	\$631	\$427	\$ 204
Operating and maintenance expense - regulatory required programs ^(a)	5	11	(6)	11	12	(1)
Total operating and maintenance expense	\$454	\$642	\$ (188)	\$642	\$439	\$ 203

Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or (a) 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 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase	Increase
	(Decrease)	(Decrease)
	2017 vs.	2016 vs.
	2016	2015
Baseline		
Labor, other benefits, contracting and materials	\$ 16	\$ 7
Storm-related costs	(1)	6
Remeasurement of AMI-related regulatory asset ^(a)	(7)	7
Deferral of billing system transition costs to regulatory asset	—	(7)
Deferral of merger-related costs to regulatory asset	—	(11)
Uncollectible accounts expense - provision	(11)	8
BSC and PHISCO allocations ^(b)	(24)	53
Merger commitments ^(c)	(132)	126
Write-off of construction work in progress ^(d)	(14)	13
Other	(9)	2
	(182)	204
Regulatory required programs		
Purchased power administrative costs	(6)	(1)
Total (decrease) increase	\$ (188)	\$ 203

(a) Related to a remeasurement of a regulatory asset for legacy meters recognized in 2016.

(b) Primarily related to merger severance and compensation costs recognized in 2016

(c) Primarily related to merger-related commitments for customer rate credits and charitable contributions recognized in 2016.

(d) Primarily resulting from a review of capital projects during the fourth quarter of 2016.

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Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase (Decrease)	Increase (Decrease)
	2017 vs. 2016	2016 vs. 2015
Depreciation expense ^(a)	\$ 28	\$ 11
Regulatory asset amortization ^(b)	8	(11)
Regulatory required programs ^(c)	(10)	39
Total increase	\$ 26	\$ 39

(a) Depreciation expense increased primarily due to higher depreciation rates in Maryland effective November 2016 and ongoing capital expenditures.

Regulatory asset amortization increased for the year ended December 31, 2017 compared to the same period in 2016 primarily due to higher amortization of AMI-related regulatory assets, partially offset by lower amortization of MAPP abandonment costs. Regulatory asset amortization decreased for the year ended December 31, 2016 compared to the same period in 2015 primarily due to lower amortization of MAPP abandonment costs.

Regulatory required programs decreased for the year ended December 31, 2017 compared to the same period in 2016 primarily due to an EmPower Maryland surcharge rate decrease effective February 2016 and increased for the year ended December 31, 2016 compared to the same period in 2015 due to an EmPower Maryland surcharge rate increase effective February 2015. Depreciation and amortization expenses for regulatory required programs 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 and Operating and maintenance expense.

Taxes Other Than Income

Taxes other than income for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to lower utility taxes that are collected and passed through by Pepco (which is substantially offset in Operating revenues), partially offset by higher property taxes. Taxes other than income for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher utility taxes that are collected and passed through by Pepco, partially offset by lower property taxes in Maryland.

Gain on Sales of Assets

Gain on sales of assets for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to higher gains recorded in 2016 at Pepco associated with the sale of land. Gain on sale of assets for the year ended December 31, 2016 compared to the same period in 2015 decreased primarily due to higher gains recorded in 2015 at Pepco associated with the sale of land held as non-utility property.

Interest Expense, Net

Interest expense, net for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to the recording of interest expense for an uncertain tax position in 2016, partially offset by higher interest expense associated with the issuance of long term debt in May 2017. Interest expense, net for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to the recording of interest expense for an uncertain tax position in 2016, partially offset by an increase in capitalized AFUDC debt.

Other, Net

Other, net for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to the September 2016 reversal of contributions in aid of construction tax gross-

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up reserves due to the determination that there is no legal obligation to refund customers per contract term. Other, net for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher income from AFUDC equity.

Effective Income Tax Rate

Pepco's effective income tax rates for the years ended December 31, 2017, 2016, and 2015 were 33.9%, 49.4%, and 35.3%, respectively. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates. In the first quarter of 2017, Pepco decreased its liability for unrecognized tax benefits by \$21 million resulting in a benefit to Income taxes and corresponding decrease to its effective tax rate. This decrease was offset by an increase in income taxes due to the \$14 million December 2017 impairment of certain transmission-related income tax regulatory assets and the one-time non-cash impacts of \$8 million associated with the Tax Cuts and Jobs Act in 2017.

As a result of the merger, Pepco recorded an after-tax charge of \$31 million during the year ended December 31, 2016 as a result of the assessment and remeasurement of certain federal and state uncertain tax positions.

Pepco Electric Operating Statistics and Revenue Detail

			%	Weather		%	Weather
			Change	-		Change	-
Retail Deliveries to Customers (in GWhs)	2017	2016	2017 vs.	Normal	2015	2016 vs.	Normal
			2016	%		2015	%
				Change			Change
Retail Deliveries ^(a)							
Residential	7,831	8,372	(6.5)%	(2.5)%	8,452	(0.9)%	(0.3)%
Small commercial & industrial	1,303	1,459	(10.7)%	(9.0)%	1,471	(0.8)%	(0.6)%
Large commercial & industrial	14,988	15,559	(3.7)%	(2.5)%	15,351	1.4 %	1.6 %
Public authorities & electric railroads	734	724	1.4 %	1.4 %	714	1.4 %	1.7 %
Total retail deliveries	24,856	26,114	(4.8)%	(2.8)%	25,988	0.5 %	0.9 %
	As of December 31,						
Number of Electric Customers	2017	2016	2015				
Residential	792,211	780,652	767,392				
Small commercial & industrial	53,489	53,529	53,838				
Large commercial & industrial	21,732	21,391	20,976				
Public authorities & electric railroads	144	130	129				
Total	867,576	855,702	842,335				

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	2017	2016	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
Electric Revenue					
Retail Sales ^(a)					
Residential	\$956	\$1,000	(4.4)%	\$970	3.1 %
Small commercial & industrial	147	150	(2.0)%	153	(2.0)%
Large commercial & industrial	810	803	0.9 %	777	3.3 %
Public authorities & electric railroads	33	32	3.1 %	30	6.7 %
Total retail	1,946	1,985	(2.0)%	1,930	2.8 %
Other revenue ^(b)	212	201	5.5 %	199	1.0 %
Total electric revenue ^(c)	\$2,158	\$2,186	(1.3)%	\$2,129	2.7 %

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

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

(b) Includes operating revenues from affiliates totaling \$6 million for the year ended December 31, 2017 and \$5 million for the years ended December 31, 2016 and 2015, respectively.

Results of Operations—DPL

	2017	2016	Favorable (unfavorable) 2017 vs. 2016 variance	2015	Favorable (unfavorable) 2016 vs. 2015 variance
Operating revenues	\$1,300	\$1,277	\$ 23	\$1,302	\$ (25)
Purchased power and fuel expense	532	583	51	634	51
Revenues net of purchased power and fuel expense ^(a)	768	694	74	668	26
Other operating expenses					
Operating and maintenance	315	441	126	304	(137)
Depreciation and amortization	167	157	(10)	148	(9)
Taxes other than income	57	55	(2)	51	(4)
Total other operating expenses	539	653	114	503	(150)
Gain on sales of assets	—	9	(9)	—	9
Operating income	229	50	179	165	(115)
Other income and (deductions)					
Interest expense, net	(51)	(50)	(1)	(50)	—
Other, net	14	13	1	10	3
Total other income and (deductions)	(37)	(37)	—	(40)	3
Income before income taxes	192	13	179	125	(112)
Income taxes	71	22	(49)	49	27
Net income (loss)	\$121	\$(9)	\$ 130	\$76	\$ (85)

(a) DPL evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. DPL believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements because they provide information that can be used to evaluate its operational performance. DPL has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense and Revenue net of fuel

expense 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.

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Net Income (Loss)

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. The increase in Net income was driven primarily by a decrease in Operating and maintenance expense primarily due to merger-related costs recognized in March 2016 and an increase in Revenues net of purchased power and fuel expense as a result of the distribution rate increases approved by the DPSC effective July and December 2016 and a distribution rate increase approved by the MDPSC effective February 2017, partially offset by higher depreciation expense due to increased depreciation rates in Maryland effective February 2017. Income taxes expense incurred included unrecognized tax benefits of \$16 million for uncertain tax positions related to the deductibility of certain merger commitments in the first quarter of 2017. This decrease was offset by an increase in income taxes due to the \$6 million December 2017 impairment of certain transmission-related income tax regulatory assets and the one-time non-cash impacts of \$5 million associated with the Tax Cuts and Jobs Act in 2017.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The decrease in Net income was driven primarily by an increase in Operating and maintenance expense primarily due to merger-related costs.

Operating Revenue Net of Purchased Power and Fuel Expense

Operating revenues include revenue from the distribution and supply of electricity and natural gas to DPL's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that DPL receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

Electric and natural gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All DPL customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customers' choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the years ended December 31, 2017, 2016 and 2015, consisted of the following:

	For the Years		
	Ended		
	December 31,	December 31,	December 31,
	2017	2016	2015
Electric	52%	51%	51%
Natural Gas	33%	28%	31%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at December 31, 2017, 2016 and 2015 consisted of the following:

	December 31,		December 31,		December 31,	
	2017		2016		2015	
	Number	% of total	Number	% of total	Number	% of total
	of retail	customers	of retail	customers	of retail	customers
Electric	77,790	14.9 %	78,675	15.2 %	77,603	15.1 %
Natural Gas	154	0.1 %	156	0.1 %	159	0.1 %

Retail deliveries purchased from competitive electric generation suppliers represented 54% of DPL's retail kWh sales to Delaware customers and 48% of DPL retail kWh sales to Maryland customers for

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the year ended December 31, 2017; 53% of DPL's retail kWh sales to Delaware customers and 48% of DPL's retail kWh sales to Maryland customers for the year ended December 31, 2016; and 53% of DPL's retail kWh sales to Delaware customers and 47% of DPL's retail kWh sales to Maryland customers for the year ended December 31, 2015. Operating revenues include transmission enhancement credits that DPL receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Natural gas operating revenues includes sources that are subject to price regulation (Regulated Gas Revenue) and those that generally are not subject to price regulation (Other Gas Revenue). Regulated gas revenue includes the revenue DPL receives from on-system natural gas delivered sales and the transportation of natural gas for customers within its service territory at regulated rates. Other gas revenue consists of off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers. Off-system sales are made possible when low demand for natural gas by regulated customers creates excess pipeline capacity. Purchased power expense consists of the cost of electricity purchased by DPL to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders. Purchased fuel expense consists of the cost of gas purchased by DPL to fulfill its obligation to regulated gas customers and, as such, is recoverable from customers in accordance with the terms of public service commission orders. It also includes the cost of gas purchased for off-system sales.

The changes in DPL's Operating revenues net of purchased power and fuel expense for the years ended December 31, 2017 and 2016 compared to the same periods in 2016 and 2015, respectively, consisted of the following:

	2017 vs. 2016			2016 vs. 2015		
	Increase (Decrease)			Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	\$(7)	\$(13)	\$(20)	\$—	\$—	\$—
Volume	2	11	13	2	2	4
Distribution rate increase	65	4	69	2	1	3
Regulatory required programs	(3)	—	(3)	10	—	10
Transmission revenues	10	—	10	8	—	8
Other	6	(1)	5	1	—	1
Increase in revenue net of purchased power expense	\$73	\$1	\$74	\$23	\$3	\$26

Revenue Decoupling. DPL's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of DPL in Maryland, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland to fluctuate from period to period are changes

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in the number of customers and changes in the approved distribution charge per customer. A modified fixed variable rate design, which would provide for a charge not tied to a customer's volumetric consumption of electricity or natural gas, has been proposed for DPL electricity and natural gas customers in Delaware. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

Weather. The demand for electricity and natural gas in areas not subject to the BSA is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the year ended December 31, 2017 compared to the same period in 2016, operating revenues net of purchased power and fuel expenses was lower due to the impact of unfavorable weather conditions in DPL's service territory. During the year ended December 31, 2016 compared to the same period in 2015, weather was not a significant impact.

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 20-year period in DPL's electric service territory and a 30-year period in DPL's natural gas service territory. The changes in heating and cooling degree days in DPL's service territory for the years ended December 31, 2017 and December 31, 2016 compared to same periods in 2016 and 2015, respectively, and normal weather consisted of the following:

Electric Service Territory	For the Years Ended December 31,			% Change	
	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	4,077	4,319	4,519	(5.6)%	(9.8)%
Cooling Degree-Days	1,300	1,453	1,210	(10.5)%	7.4 %

Natural Gas Service Territory	For the Years Ended December 31,			% Change	
	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	4,319	4,421	4,572	(2.3)%	(5.5)%
Cooling Degree-Days	1,453	1,328	1,188	9.4 %	22.3 %

Electric Service Territory	For the Years Ended December 31,			% Change	
	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	4,203	4,454	4,739	(5.6)%	(11.3)%

% Change

For the
 Years
 Ended
 December
 31,

	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating and Cooling Degree-Days					
Heating Degree-Days	4,454	4,618	4,754	(3.6)%	(6.3)%

Volume. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2017 compared to the same period in 2016, primarily reflects the impact of customer growth. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects

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of weather, for the year ended December 31, 2016 compared to the same period in 2015, primarily reflects the impact of moderate economic and customer growth.

Distribution Rate Increase. The increase in electric operating revenues net of purchased power expense for the year ended December 31, 2017 compared to the same period in 2016 was primarily due to the impact of the higher electric distribution and natural gas rates charged to Delaware customers that became effective in July and December 2016 and the impact of higher electric distribution rates charged to Maryland customers that became effective in February 2017. The increase in electric operating revenues net of purchased power expense for the year ended December 31, 2016 compared to the same period in 2015 was primarily due to the impact of the new electric distribution rates charged to Delaware customers that became effective in July 2016. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in DPL's Consolidated Statements of Operations and Comprehensive Income. Revenue from regulatory required programs decreased for the year ended December 31, 2017 compared to the same period in 2016 primarily due to lower demand-side management program surcharge revenue due to a decrease in kWh sales and a rate decrease effective January 2017. Revenue from regulatory required programs increased for the year ended December 31, 2016 compared to the same period in 2015 primarily due to higher demand-side management program surcharge revenue due to a rate increase effective February 2016. Refer to the Operating and maintenance expense and Depreciation and amortization expense discussion below for additional information on included programs.

Transmission Revenues. Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered and other billing adjustments. Transmission revenue increased for the year ended December 31, 2017 compared to the same period in 2016 due to higher rates effective June 1, 2017 and June 1, 2016 related to increases in transmission plant investment and operating expenses. Transmission revenue increased for the year ended December 31, 2016 compared to the same period in 2015 due to higher rates effective June 1, 2016 and June 1, 2015 related to increases in transmission plant investment and operating expenses, partially offset by lower revenue related to the MAPP abandonment recovery period that ended in March 2016.

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, and recoveries of other taxes.

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Operating and Maintenance Expense

	Year Ended December 31, 2017		Increase (Decrease)	Year Ended December 31, 2016		Increase (Decrease)
	2016	2015		2016	2015	
Operating and maintenance expense - baseline	\$306	\$425	\$ (119)	\$425	\$289	\$ 136
Operating and maintenance expense - regulatory required programs ^(a)	9	16	(7)	16	15	1
Total operating and maintenance expense	\$315	\$441	\$ (126)	\$441	\$304	\$ 137

Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or (a)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 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Baseline		
Labor, other benefits, contracting and materials	\$ 4	\$ 1
Storm-related costs	4	5
Deferral of billing system transition costs to regulatory asset	2	(2)
Deferral of merger-related costs to regulatory asset	(6)	(4)
Uncollectible accounts expense - provision	(10)	3
BSC and PHISCO allocations ^(a)	(15)	34
Merger commitments ^(b)	(88)	86
Write-off of construction work in progress ^(c)	(3)	4
Other	(7)	9
	(119)	136
Regulatory required programs		
Purchased power administrative costs	(7)	1
Total (decrease) increase	\$ (126)	\$ 137

(a) Primarily related to merger severance and compensation costs recognized in 2016.

(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions recognized in 2016.

(c) Primarily resulting from a review of capital projects during the fourth quarter of 2016.

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Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase (Decrease)	Increase (Decrease)
	2017 vs. 2016	2016 vs. 2015
Depreciation expense ^(a)	\$ 14	\$ 7
Regulatory asset amortization ^(b)	—	(7)
Regulatory required programs ^(c)	(4)	9
Total increase	\$ 10	\$ 9

(a) Depreciation expense increased due to higher depreciation rates in Maryland effective February 2017 and due to ongoing capital expenditures.

(b) Regulatory asset amortization decreased for the year ended December 31, 2016 compared to the same period in 2015 primarily due to lower amortization of MAPP abandonment costs.

(c) Regulatory required programs decreased for the year ended December 31, 2017 compared to the same period in 2016 primarily due to an EmPower Maryland surcharge rate decrease effective February 2016 and increased for the year ended December 31, 2016 compared to the same period in 2015 due to an EmPower Maryland surcharge rate increase effective February 2015. Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. A partially offsetting amount has been reflected in Operating revenues and Operating and maintenance expense.

Taxes Other Than Income

Taxes other than income for the year ended December 31, 2017 compared to the same period in 2016 remained relatively constant. Taxes other than income for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher property taxes in Maryland related to higher property assessments and rate increases.

Gain on Sales of Assets

Gain on sales of assets for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to gains recorded in 2016 at DPL associated with the sale of land held as non-utility property. Gain on sales of assets for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to gains recorded in 2016 at DPL associated with the sale of land held as non-utility property.

Interest Expense, Net

Interest expense, net for the year ended December 31, 2017 compared to the same period in 2016 and for the year ended December 31, 2016 compared to the same period in 2015 remained relatively constant.

Other, Net

Other, net for the year ended December 31, 2017 compared to the same period in 2016 remained relatively constant. Other, net for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher income from AFUDC equity.

Effective Income Tax Rate

DPL's effective income tax rates for the years ended December 31, 2017, 2016 and 2015 were 37.0%, 169.2% and 39.2%, respectively. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates. In the first quarter of 2017, DPL decreased its liability for unrecognized

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tax benefits by \$16 million resulting in a benefit to Income taxes and corresponding decrease to its effective tax rate. This decrease was offset by an increase in income taxes due to the \$6 million December 2017 impairment of certain transmission-related income tax regulatory assets and the one-time non-cash impacts of \$5 million associated with the Tax Cuts and Jobs Act in 2017.

As a result of the merger, DPL recorded an after-tax charge of \$23 million during the year ended December 31, 2016 as a result of the assessment and remeasurement of certain federal and state uncertain tax positions.

DPL Electric Operating Statistics and Revenue Detail

	2017	2016	% Change 2017 vs. 2016	Weather - Normal % Change	2015	% Change 2016 vs. 2015	Weather - Normal % Change
Retail Deliveries to Customers (in GWhs)							
Retail Deliveries ^(a)							
Residential	5,010	5,181	(3.3)%	(0.3)%	5,337	(2.9)%	(2.9)%
Small commercial & industrial	2,237	2,290	(2.3)%	(0.9)%	2,311	(0.9)%	(1.3)%
Large commercial & industrial	4,585	4,623	(0.8)%	0.3 %	4,781	(3.3)%	(3.9)%
Public authorities & electric railroads	44	46	(4.3)%	(8.3)%	45	2.2 %	6.7 %
Total retail deliveries	11,876	12,140	(2.2)%	(0.2)%	12,474	(2.7)%	(2.9)%
	As of December 31,						
Number of Electric Customers	2017	2016	2015				
Residential	459,389	456,181	453,145				
Small commercial & industrial	60,697	60,173	59,714				
Large commercial & industrial	1,400	1,411	1,410				
Public authorities & electric railroads	629	643	643				
Total	522,115	518,408	514,912				
			%	%			
Electric Revenue	2017	2016	Change 2017 vs. 2016	2015	Change 2016 vs. 2015		
Retail Sales ^(a)							
Residential	\$660	\$668	(1.2)%	\$681	(1.9)%		
Small commercial & industrial	185	187	(1.1)%	192	(2.6)%		
Large commercial & industrial	102	98	4.1 %	101	(3.0)%		
Public authorities & electric railroads	14	13	7.7 %	12	8.3 %		
Total retail	961	966	(0.5)%	986	(2.0)%		
Other revenue ^(b)	178	163	9.2 %	152	7.2 %		
Total electric revenue ^(c)	\$1,139	\$1,129	0.9 %	\$1,138	(0.8)%		

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

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

(c) Includes operating revenues from affiliates totaling \$8 million, \$7 million and \$6 million for the years ended December 31, 2017, 2016 and 2015, respectively.

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DPL Gas Operating Statistics and Revenue Detail

	2017	2016	2015	% Change 2017 vs. 2016	Weather Normal %	2015	% Change 2016 vs. 2015	Weather Normal %
Retail Deliveries to Customers (in mmcf)								
Retail Deliveries								
Residential	13,107	13,341	13,816	(1.8)%	5.2 %	13,816	(3.4)%	(0.4)%
Transportation & other	6,538	6,201	6,193	5.4 %	6.9 %	6,193	0.1 %	1.4 %
Total gas deliveries	19,645	19,542	20,009	0.5 %	5.7 %	20,009	(2.3)%	0.1 %
As of December 31,								
Number of Gas Customers	2017	2016	2015					
Residential	122,347	120,951	119,771					
Commercial & industrial	9,853	9,801	9,712					
Transportation & other	154	156	159					
Total	132,354	130,908	129,642					
		%	%					
Gas Revenue	2017	2016	2015	% Change 2017 vs. 2016			% Change 2016 vs. 2015	
Retail Sales ^(a)								
Retail sales	\$136	\$127	\$143	7.1 %			(11.2)%	
Transportation & other ^(b)	25	21	21	19.0 %			— %	
Total gas revenues	\$161	\$148	\$164	8.8 %			(9.8)%	

Reflects delivery volumes and revenues from customers purchasing natural gas directly from DPL and customers (a) purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges.

For customers purchasing natural gas from DPL, revenue also reflects the cost of natural gas.

(b) Transportation and other revenue includes off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers.

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Results of Operations—ACE

	2017	2016	Favorable (unfavorable) 2017 vs. 2016 variance	2015	Favorable (unfavorable) 2016 vs. 2015 variance
Operating revenues	\$1,186	\$1,257	\$ (71)	\$1,295	\$ (38)
Purchased power expense	570	651	81	708	57
Revenues net of purchased power expense ^(a)	616	606	10	587	19
Other operating expenses					
Operating and maintenance	307	428	121	271	(157)
Depreciation and amortization	146	165	19	175	10
Taxes other than income	6	7	1	7	—
Total other operating expenses	459	600	141	453	(147)
Gain on sales of assets	—	1	(1)	—	1
Operating income	157	7	150	134	(127)
Other income and (deductions)					
Interest expense, net	(61)	(62)	1	(64)	2
Other, net	7	9	(2)	3	6
Total other income and (deductions)	(54)	(53)	(1)	(61)	8
Income (loss) before income taxes	103	(46)	149	73	(119)
Income taxes	26	(4)	(30)	33	37
Net income (loss)	\$77	\$(42)	\$ 119	\$40	\$ (82)

ACE evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. ACE believes Revenue net of purchased power expense is a useful measurement of its performance because it provides information that can be used to evaluate its operational performance. ACE has included the analysis 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.

^(a) Net Income (Loss)

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. The increase in Net income was primarily due to a decrease in Operating and maintenance expense primarily due to merger-related costs recognized in March 2016 and an increase in Revenues net of purchased power expense resulting from impact of distribution rate increases approved by the NJBPU effective August 2016 and October 2017 and an increase in transmission formula rate revenues, partially offset by lower customer usage. Income taxes expense incurred included unrecognized tax benefits of \$22 million for uncertain tax positions related to the deductibility of certain merger commitments in the first quarter of 2017. This decrease was offset by an increase in income taxes due to the December 2017 impairment of certain transmission-related income tax regulatory assets of \$7 million and the one-time non-cash impacts of \$2 million associated with the Tax Cuts and Jobs Act in 2017.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The decrease in Net income was driven primarily by an increase in Operating and maintenance expense primarily due to merger-related costs.

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Revenues Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to ACE’s customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that ACE receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All ACE customers have the choice to purchase electricity from competitive electric generation suppliers. The customer’s choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the years ended December 31, 2017, 2016 and 2015, consisted of the following:

	For the Years Ended December 31,		
	2017	2016	2015
Electric	48%	47%	45%

Retail customers purchasing electric generation from competitive electric generation suppliers at December 31, 2017, 2016 and 2015 consisted of the following:

	December 31, 2017		December 31, 2016		December 31, 2015	
	Number	% of total of retail customers	Number	% of total of retail customers	Number	% of total of retail customers
Electric	86,155	16 %	94,562	17 %	78,299	14 %

Operating revenues include revenue from Transition Bond Charges that ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds, revenue from the resale in the PJM wholesale markets for energy and capacity purchased under contracts with unaffiliated NUGs, and revenue from transmission enhancement credits.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Purchased power expense consists of the cost of electricity purchased by ACE to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders.

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The changes in ACE's Operating revenues net of purchased power expense for the years ended December 31, 2017 and 2016 compared to the same periods in 2016 and 2015, respectively, consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Weather	\$ (3)	\$ (3)
Volume	(20)	1
Distribution rate increase	40	14
Regulatory required programs	(24)	(14)
Transmission revenues	22	23
Other	(5)	(2)
Increase in revenue net of purchased power expense	\$ 10	\$ 19

Weather. The demand for electricity is affected by weather conditions. With respect to the electric business, very warm weather in summer months and very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity. Conversely, mild weather reduces demand. During the year ended December 31, 2017 compared to the same period in 2016, operating revenues net of purchased power and fuel expense was lower due to the impact of unfavorable winter weather conditions in ACE's service territory. During the year ended December 31, 2016 compared to the same period in 2015, operating revenues net of purchased power and fuel expense was lower due to the impact of unfavorable winter weather conditions in ACE's service territory.

For retail customers of ACE, distribution revenues are not decoupled for the distribution of electricity by ACE, and thus are subject to variability due to changes in customer consumption. Therefore, changes in customer usage (due to weather conditions, energy prices, energy savings programs or other reasons) from period to period have a direct impact on reported distribution revenue for customers in ACE's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in ACE's service territory. The changes in heating and cooling degree days in ACE's service territory for the years ended December 31, 2017 and December 31, 2016 compared to same periods in 2016 and 2015, respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Heating and Cooling Degree-Days	4,206	4,487	4,713	(6.3)%	(10.8)%
Heating Degree-Days	1,228	1,303	1,115	(5.8)%	10.1 %

	For the Years Ended December 31,			% Change	
	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating and Cooling Degree-Days					

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Heating Degree-Days	4,487	4,671	4,768	(3.9)%	(5.9)%
Cooling Degree-Days	1,303	1,259	1,093	3.5 %	19.2 %

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Volume. The decrease in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2017 compared to the same period in 2016, primarily reflects lower average customer usage, partially offset by the impact of customer growth. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016 compared to the same period in 2015, primarily reflects the impact of moderate economic and customer growth, partially offset by lower average customer usage.

Distribution Rate Increase. The increase in electric operating revenues net of purchased power expense for the year ended December 31, 2017 compared to the same period in 2016 was primarily due to the impact of the new electric distribution rates charged to customers that became effective in August 2016 and October 2017. The increase in electric operating revenues net of purchased power expense for the year ended December 31, 2016 compared to the same period in 2015 was primarily due to the impact of the new electric distribution rates charged to customers that became effective in August 2016. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in ACE's Consolidated Statements of Operations and Comprehensive Income. Revenue from regulatory required programs decreased for the year ended December 31, 2017 compared to the same period in 2016 due to a rate decrease effective October 2016 for the ACE Transition Bond Charge and Market Transition Charge Tax. Revenue from required regulatory programs decreased for the year ended December 31, 2016 compared to the same period in 2015 due to rate decreases effective October 2016 and October 2015 for the ACE Market Transition charge tax. Refer to the Operating and maintenance expense and Depreciation and amortization expense discussion below for additional information on included programs.

Transmission Revenues. Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered and other billing adjustments. Transmission revenue increased for the year ended December 31, 2017 compared to the same period in 2016 due to higher rates effective June 1, 2017 and June 1, 2016 related to increases in transmission plant investment and operating expenses. Transmission revenue increased for the year ended December 31, 2016 compared to the same period in 2015 due to higher rates effective June 1, 2016 and June 1, 2015 related to increases in transmission plant investment and operating expenses.

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Operating and Maintenance Expense

	Year Ended December 31, 2017			Increase (Decrease) 2017 vs. 2016	Year Ended December 31, 2016			Increase (Decrease) 2016 vs. 2015
Operating and maintenance expense - baseline	\$303	\$424	\$ (121)	\$424	\$267	\$ 157	
Operating and maintenance expense - regulatory required programs ^(a)	4	4	—		4	4	—	
Total operating and maintenance expense	\$307	\$428	\$ (121)	\$428	\$271	\$ 157	

Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or (a) 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 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Baseline		
Labor, other benefits, contracting and materials	\$ 9	\$ 6
BSC and PHISCO allocations ^(a)	(11) 26
Merger commitments ^(b)	(111) 111
Deferral of merger-related costs to regulatory asset	(9) —
Other	1	14
Total (decrease) increase	\$ (121) \$ 157

(a) Primarily related to merger severance and compensation costs recognized in 2016.

(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions recognized in 2016.

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Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase (Decrease)	Increase (Decrease)
	2017 vs. 2016	2016 vs. 2015
Depreciation expense ^(a)	\$ 6	\$ 6
Regulatory asset amortization	(2)	(4)
Required regulatory programs ^(b)	(24)	(12)
Other	1	—
Total decrease	\$ (19)	\$ (10)

(a) Depreciation expense increased due to ongoing capital expenditures.

Regulatory required programs decreased for the year ended December 31, 2017 compared to the same period in 2016 primarily as a result of lower revenue due to a rate decrease effective October 2016 for the ACE Transition Bond Charge and Market Transition Charge Tax. Required regulatory programs amortization decreased for the

(b) year ended December 31, 2016 compared to the same period in 2015 primarily as a result of lower revenue due to a rate decrease effective October 2015 for the ACE Market Transition charge tax. Depreciation and amortization expenses for regulatory required programs 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 and Operating and maintenance expense.

Taxes Other Than Income

Taxes other than income for the year ended December 31, 2017 compared to the same period in 2016, remained constant. Taxes other than income for the year ended December 31, 2016 compared to the same period in 2015, remained constant.

Interest Expense, Net

Interest expense, net remained relatively consistent for the year ended December 31, 2017, compared to the same period in 2016, and the year ended December 31, 2016, compared to the same period in 2015.

Gain on Sales of Assets

Gain on sales of assets for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to gains recorded in 2016 at ACE associated with the sale of property. Gain on sales of assets for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to gains recorded in 2016 at ACE associated with the sale of property.

Other, Net

Other, net for the year ended December 31, 2017 compared to the same period in 2016 remained relatively constant. Other, net for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher income from AFUDC equity.

Effective Income Tax Rate

ACE's effective income tax rates for the years ended December 31, 2017, 2016 and 2015 were 25.2%, 8.7%, and 45.2%, respectively. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates. In the first quarter of 2017, ACE decreased its liability for unrecognized tax benefits by \$22 million resulting in a benefit to Income taxes and corresponding decrease to its effective tax rate. This decrease was offset by an increase in income taxes due to the December 2017

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impairment of certain transmission-related income tax regulatory assets of \$7 million and the one-time non-cash impacts of \$2 million associated with the Tax Cuts and Jobs Act in 2017.

As a result of the merger, ACE recorded an after-tax charge of \$22 million during the year ended December 31, 2016 as a result of the assessment and remeasurement of certain federal and state uncertain tax positions.

ACE Electric Operating Statistics and Revenue Detail

	2017	2016	% Change 2017 vs. 2016	Weather - Normal % Change	2015	% Change 2016 vs. 2015	Weather - Normal % Change
Retail Deliveries to Customers (in GWhs)							
Retail Deliveries ^(a)							
Residential	3,853	4,153	(7.2)%	(6.2)%	4,322	(3.9)%	(2.9)%
Small commercial & industrial	1,286	1,455	(11.6)%	(11.1)%	1,288	13.0 %	13.5 %
Large commercial & industrial	3,399	3,402	(0.1)%	0.4 %	3,594	(5.3)%	(5.2)%
Public authorities & electric railroads	47	49	(4.1)%	(4.1)%	45	8.9 %	8.9 %
Total retail deliveries	8,585	9,059	(5.2)%	(4.5)%	9,249	(2.1)%	(1.4)%
	As of December 31,						
Number of Electric Customers	2017	2016	2015				
Residential	487,168	484,240	482,000				
Small commercial & industrial	61,013	61,008	60,745				
Large commercial & industrial	3,684	3,763	3,871				
Public authorities & electric railroads	636	610	529				
Total	552,501	549,621	547,145				
			% Change		% Change		
Electric Revenue	2017	2016	2017 vs. 2016	2015	2016 vs. 2015		
Retail Sales ^(a)							
Residential	\$619	\$664	(6.8)%	\$690	(3.8)%		
Small commercial & industrial	166	183	(9.3)%	175	4.6 %		
Large commercial & industrial	189	201	(6.0)%	213	(5.6)%		
Public authorities & electric railroads	13	13	— %	12	8.3 %		
Total retail	987	1,061	(7.0)%	1,090	(2.7)%		
Other revenue ^(b)	199	196	1.5 %	205	(4.4)%		
Total electric revenue ^(c)	\$1,186	\$1,257	(5.6)%	\$1,295	(2.9)%		

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

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

(c) Includes operating revenues from affiliates totaling \$2 million, \$3 million and \$4 million for the years ended December 31, 2017, 2016 and 2015, respectively.

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Liquidity and Capital Resources

Exelon activity presented below includes the activity of PHI, Pepco, DPL and ACE, from the PHI Merger effective date of March 24, 2016 through December 31, 2017. Exelon prior year activity is unadjusted for the effects of the PHI Merger. Due to the application of push-down accounting to the PHI entity, PHI's activity is presented in two separate reporting periods, the legacy PHI activity through March 23, 2016 (Predecessor), and PHI activity for the remainder of the period after the PHI merger date (Successor). For each of Pepco, DPL and ACE the activity presented below include its activity for the years ended December 31, 2017, 2016 and 2015. All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, the Registrants have access to unsecured revolving credit facilities with aggregate bank commitments of \$9 billion. In addition, Generation has \$480 million in bilateral facilities with banks which have various expirations between January 2019 and December 2019. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the "Credit Matters" section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO, BGE, Pepco, DPL and ACE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are based upon the assumption that decommissioning activities will commence after the end of the current licensed life of each unit. If a unit fails the NRC minimum funding test, then the plant's owners or parent companies would be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional cash contributions to the NDT fund to ensure sufficient funds are available. See Note 15 - Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information on the NRC minimum funding requirements.

If a nuclear plant were to early retire there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT fund investments could appreciate in value. A shortfall could require Exelon to post parental guarantees for Generation's share of the obligations. However, the amount of any required guarantees will ultimately depend on the decommissioning approach adopted at each site, the associated level of costs, and the decommissioning trust fund investment performance going forward.

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Within two years after shutting down a plant, Generation must submit a post-shutdown decommissioning activities report (PSDAR) to the NRC that includes the planned option for decommissioning the site. As discussed in Note 15 - Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements, Generation filed its biennial decommissioning funding status report with the NRC on March 31, 2017 and demonstrated adequate funding assurance for all nuclear units currently operating. As of December 31, 2017, across the four alternative decommissioning approaches available, Generation estimates a parental guarantee of up to \$90 million from Exelon could be required for TMI, dependent upon the ultimate decommissioning approach selected. For Oyster Creek, none of the alternative decommissioning approaches available would require Exelon to post a parental guarantee. In the event PSEG decides to early retire Salem, Generation estimates a parental guarantee of up to \$45 million from Exelon could be required for Salem, dependent upon the ultimate decommissioning approach selected.

Upon issuance of any required financial guarantees, each site would be able to utilize the respective NDT funds for radiological decommissioning costs, which represent the majority of the total expected decommissioning costs. However, the NRC must approve an additional exemption in order for the plant's owner(s) to utilize the NDT fund to pay for non-radiological decommissioning costs (i.e., spent fuel management and site restoration costs). If a unit does not receive this exemption, the costs would be borne by the owner(s). While the ultimate amounts may vary greatly and could be reduced by alternate decommissioning scenarios and/or reimbursement of certain costs under the United States Department of Energy reimbursement agreements or future litigation, across the four alternative decommissioning approaches available, if TMI or Oyster Creek were to fail to obtain the exemption, Generation estimates it could incur spent fuel management and site restoration costs over the next ten years of up to \$225 million and \$200 million net of taxes, respectively, dependent upon the ultimate decommissioning approach selected. In the event PSEG decides to early retire Salem and Salem were to fail to obtain the exemption, Generation estimates it could incur spent fuel management and site restoration costs over the next ten years of up to \$80 million net of taxes.

Junior Subordinated Notes

In June 2014, Exelon issued \$1.15 billion of junior subordinated notes in the form of 23 million equity units at a stated amount of \$50.00 per unit. Each equity unit represented an undivided beneficial ownership interest in Exelon's \$1.15 billion of 2.50% junior subordinated notes due in 2024 ("2024 notes") and a forward equity purchase contract. As contemplated in the June 2014 equity unit structure, in April 2017, Exelon completed the remarketing of the 2024 notes into \$1.15 billion of 3.497% junior subordinated notes due in 2022 ("Remarketing"). Exelon conducted the Remarketing on behalf of the holders of equity units and did not directly receive any proceeds therefrom. Instead, the former holders of the 2024 notes used debt remarketing proceeds towards settling the forward equity purchase contract with Exelon on June 1, 2017. Exelon issued approximately 33 million shares of common stock from treasury stock and received \$1.15 billion upon settlement of the forward equity purchase contract. When reissuing treasury stock Exelon uses the average price paid to repurchase shares to calculate a gain or loss on issuance and records gains or losses directly to retained earnings. A loss on reissuance of treasury shares of \$1.05 billion was recorded to retained earnings as of December 31, 2017. See Note 21 — Earnings Per Share of the Combined Notes to Consolidated Financial Statements for further information on the issuance of common stock.

Cash Flows from Operating ActivitiesGeneral

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

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The Utility Registrants' cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO, BGE and DPL, gas distribution services. The Utility Registrants' distribution services are provided to an established and diverse base of retail customers. The Utility Registrants' future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions. See Notes 3 — Regulatory Matters and 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation. The following table provides a summary of the major items affecting Exelon's cash flows from operations for the years ended December 31, 2017, 2016 and 2015:

	2017	2016	2017 vs. 2016 Variance	2015	2016 vs. 2015 Variance
Net income	\$3,849	\$1,204	\$2,645	2,250	\$(1,046)
Add (subtract):					
Non-cash operating activities ^(a)	5,446	7,722	(2,276)	5,630	2,092
Pension and non-pension postretirement benefit contributions	(405)	(397)	(8)	(502)	105
Income taxes	299	(674)	973	97	(771)
Changes in working capital and other noncurrent assets and liabilities ^(b)	(1,579)	(275)	(1,304)	(264)	(11)
Option premiums received (paid), net	28	(66)	94	58	(124)
Collateral received (posted), net	(158)	931	(1,089)	347	584
Net cash flows provided by operations	\$7,480	\$8,445	\$(965)	\$7,616	\$829

^(a) Represents depreciation, amortization, depletion and accretion, net fair value changes related to derivatives, deferred income taxes, provision for uncollectible accounts, pension and non-pension postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, and other non-cash charges. See Note 24 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for further detail on non-cash operating activity.

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

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The projected contributions below reflect a funding strategy of contributing the greater of (1) \$300 million (updated for the inclusion of PHI) until the qualified plans are fully funded on an ABO basis, and (2) the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions. Unlike

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the qualified pension plans, Exelon's non-qualified pension plans are not funded given that they are not subject to statutory minimum contribution requirements.

While other postretirement plans are also not subject to statutory minimum contribution requirements, Exelon does fund certain of its plans. For Exelon's funded OPEB plans, contributions generally equal accounting costs, however, Exelon's management has historically considered several factors in determining the level of contributions to its other postretirement benefit plans, including liabilities management, levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery). The amounts below include benefit payments related to unfunded plans.

The following table provides all registrants' planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to other postretirement plans in 2018:

	Qualified Pension Plans	Non-Qualified Pension Plans	Other Postretirement Benefits
Exelon	\$ 301	\$ 30	\$ 42
Generation 119		11	13
ComEd	38	2	3
PECO	17	1	—
BGE	41	1	16
BSC	36	7	1
PHI	50	8	9
Pepco	4	2	8
DPL	—	1	—
ACE	6	—	—
PHISCO	40	5	1

To the extent interest rates decline significantly or the pension and OPEB plans earn less than the expected asset returns, annual pension contribution requirements in future years could increase. Conversely, to the extent interest rates increase significantly or the pension and OPEB plans earn greater than the expected asset returns, annual pension and OPEB contribution requirements in future years could decrease. Additionally, expected contributions could change if Exelon changes its pension or OPEB funding strategy.

On October 3, 2017, the US Department of Treasury and IRS released final regulations updating the mortality tables to be used for defined benefit pension plan funding, as well as the valuation of lump sum and other accelerated distribution options, effective for plan years beginning in 2018. The new mortality tables reflect improved projected life expectancy as compared to the existing table, which is generally expected to increase minimum pension funding requirements, Pension Benefit Guaranty Corporation premiums and the value of lump sum distributions. The IRS permits plan sponsors the option of delaying use of the new mortality tables for determining minimum funding requirements until 2019, which Exelon intends to utilize. The one-year delay does not apply for use of the mortality tables to determine the present value of lump sum distributions. The estimated impact of the new mortality tables along with other current assumptions and market information are reflected in the estimated future pension contributions in the "Contractual Obligations" section below.

The EMA requires CENG to fund the obligation related to pre-transfer service of employees, including the underfunded balance of the pension and other postretirement welfare benefit plans

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measured as of July 14, 2014 by making periodic payments to Generation. These payments will be made on an agreed payment schedule or upon the occurrence of certain specified events, such as EDF's disposition of a majority of its interest in CENG. However, in the event that EDF exercises its rights under the Put Option, all payments not made as of the put closing date shall accelerate to be paid immediately prior to such closing date. See Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding the investment in CENG.

Tax Matters

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

Pursuant to the TCJA, beginning in 2018 Generation is expected to have higher operating cash flows in the range of approximately \$1.2 billion to \$1.6 billion for the period from 2018 to 2021, reflecting the reduction in the corporate federal income tax rate and full expensing of capital investments.

The TCJA is generally expected to result in lower operating cash flows for the Utility Registrants as a result of the elimination of bonus depreciation and lower customer rates. Increased operating cash flows for the Utility Registrants from lower corporate federal income tax rates is expected to be more than offset over time by lower customer rates resulting from lower income tax expense recoveries and the settlement of deferred income tax net regulatory liabilities established pursuant to the TCJA. The amount and timing of settlement of the net regulatory liabilities will be determined by the Utility Registrants' respective rate regulators, subject to certain IRS "normalization" rules. The table below sets forth the Registrants' estimated categorization of their net regulatory liabilities as of December 31, 2017. The amounts in the table below are shown on an after-tax basis reflecting future net cash outflows after taking into consideration the income tax benefits associated with the ultimate settlement with customers.

	Exelon	ComEd	PECO ^(a)	Successor			PEPCO	DPL	ACE
Subject to IRS Normalization Rules	\$3,040	\$1,400	\$ 533	\$459	\$ 648	\$ 299	\$195	\$153	
Subject to Rate Regulator Determination	1,694	573	43	324	754	391	194	170	
Net Regulatory Liabilities	\$4,734	\$1,973	\$ 576	\$783	\$ 1,402	\$ 690	\$389	\$323	

Given the regulatory treatment of income tax benefits related to electric and gas distribution repairs, PECO remains in an overall net regulatory asset position as of December 31, 2017 after recording the impacts related to the TCJA.

(a) As a result, the amount of customer benefits resulting from the TCJA subject to the discretion of PECO's rate regulators are lower relative to the other Utility Registrants. Refer to Note 3 - Regulatory Matters for additional information.

Net regulatory liability amounts subject to normalization rules generally may not be passed back to customers any faster than over the remaining useful lives of the underlying assets giving rise to the associated deferred income taxes. Such deferred income taxes generally relate to property, plant and equipment with remaining useful lives ranging from 30 to 40 years across the Utility Registrants. For the remaining amounts, rate regulators could require the passing back of amounts to customers over shorter time frames, which could materially decrease operating cash outflows at each of the Utility Registrants in the near term.

The Utility Registrants expect to fund any such required incremental operating cash outflows using a combination of third party debt financings and equity funding from Exelon in combinations generally consistent with existing capitalization ratio structures. To fund any additional equity contributions to the Utility Registrants, Exelon would have available to it its typical sources, including, but not limited to, the increased operating cash flows at Generation

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referenced above, which over time are expected to exceed the incremental equity needs at the Utility Registrants.

The Utility Registrants continue to work with their state regulatory commissions to determine the amount and timing of the passing back of TCJA income tax savings benefits to customers; with filings either made, or expected to be made, at Pepco, DPL and ACE, and approved filings at ComEd and BGE. The amounts being passed back or proposed to be passed back to customers reflect the benefit of lower income tax expense beginning January 1, 2018 (Feb. 1, 2018 for DPL Delaware), and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. To date, neither the PAPUC nor FERC has yet issued guidance on how and when to reflect the impacts of the TCJA in customer rates. Refer to Note 3 - Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information on their filings.

In general, most states use federal taxable income as the starting point for computing state corporate income tax. Now that the TCJA has been enacted, state governments are beginning to analyze the impact of the TCJA on their state revenues. Exelon is uncertain regarding what the state governments will do, and there is a possibility that state corporate income taxes could change due to the enactment of the TCJA. In 2018, Exelon will be closely monitoring the states' responses to the TCJA as these could have an impact on Exelon's future cash flows.

See Note 14 - Income Taxes of the Combined Notes to Consolidated Financial Information for further information on the amounts of the net regulatory liabilities subject to determinations by rate regulators.

Exelon appealed the Tax Court's like-kind exchange decision in the third quarter of 2017. In the fourth quarter of 2017, the IRS assessed the tax, penalties and interest of approximately \$1.3 billion related to the like-kind exchange, including \$300 million attributable to ComEd. While Exelon will receive a tax benefit of approximately \$350 million associated with the deduction for the interest, Exelon currently has a net operating loss carryforward and thus does not expect to realize the cash benefit until 2018. After taking into account these interest deduction tax benefits, the total estimated net cash outflow for the like-kind exchange is approximately \$950 million, of which approximately \$300 million is attributable to ComEd after giving consideration to Exelon's agreement to hold ComEd harmless from any unfavorable impacts on ComEd's equity from the like-kind exchange position.

Of the above amounts payable, Exelon deposited with the IRS \$1.25 billion in October of 2016. Exelon funded the \$1.25 billion deposit with a combination of cash on hand and short-term borrowings. As a result of the IRS's assessment of the tax, penalties and interest in the fourth quarter of 2017, the deposit is no longer available to Exelon and thus was reclassified from a current asset and is now reflected as an offset to the related liabilities for the tax, penalties, and interest that are included on Exelon's balance sheet as current liabilities. The remaining amount due of approximately \$20 million was paid in the fourth quarter of 2017. In the third quarter of 2017, the \$300 million payable discussed above attributable to ComEd, net of ComEd's receivable pursuant to the hold harmless agreement, was settled with Exelon. See Note 14 - Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the like-kind exchange tax position.

State and local governments continue to face increasing financial challenges, which may increase the risk of additional income tax, property taxes and other taxes or the imposition, extension or permanence of temporary tax increases. On July 6, 2017, Illinois enacted Senate Bill 9, which permanently increased Illinois' total corporate income tax rate from 7.75% to 9.50% effective July 1, 2017. The rate increase is not expected to have a material ongoing

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impact to Exelon's, Generation's or ComEd's future cash taxes. See Note 14 - Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the Illinois tax rate change.

Cash flows provided by operations for the year ended December 31, 2017, 2016 and 2015 by Registrant were as follows:

	2017	2016	2015
Exelon	\$7,480	\$8,445	\$7,616
Generation	3,299	4,444	4,199
ComEd	1,527	2,505	1,896
PECO	755	829	770
BGE	821	945	782
Pepco	407	651	373
DPL	321	310	266
ACE	206	385	256
Successor For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	Predecessor January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI	\$ 888	\$ 264	\$ 939

Changes in Registrants' cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. In addition, significant operating cash flow impacts for the Registrants for 2017, 2016 and 2015 were as follows:

Generation

Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on an exchange or in the OTC markets. During 2017, 2016 and 2015, Generation had net collections/(payments) of counterparty cash collateral of \$(129) million, \$923 million and \$407 million, respectively, primarily due to market conditions that resulted in changes to Generation's net mark-to-market position.

During 2017, 2016 and 2015, Generation had net collections/(payments) of approximately \$28 million, \$(66) million and \$58 million, respectively, related to purchases and sales of options. The level of option activity in a given year may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

During 2017, 2016, and 2015 ComEd (posted)/received approximately \$(27 million), \$7 million, and \$(31 million) of cash collateral with/from PJM, respectively. ComEd's collateral posted with PJM has increased from 2017 to 2016, primarily due to an increase in ComEd's RPM credit requirements and peak market activity with PJM. The collateral posted with PJM decreased from 2016 to 2015 due to lower PJM billings.

For further discussion regarding changes in non-cash operating activities, please refer to Note 24 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements.

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Cash Flows from Investing Activities

Cash flows used in investing activities for the year ended December 31, 2017, 2016 and 2015 by Registrant were as follows:

	2017	2016	2015
Exelon	\$(7,934)	\$(15,503)	\$(7,822)
Generation ^(a)	(2,592)	(3,851)	(4,069)
ComEd	(2,296)	(2,685)	(2,362)
PECO	(597)	(798)	(588)
BGE	(849)	(910)	(675)
Pepco	(630)	(647)	(477)
DPL	(429)	(336)	(345)
ACE	(310)	(309)	(306)

Successor

Predecessor

January

For the
Year

March 24,

1,

For the
YearEnded
December
31, 20172016 to
December
31, 20162016
to
March
23,
2016Ended
December
31, 2015

PHI \$(1,396) \$ (1,030) \$ (343) \$ (1,161)

Significant investing cash flow impacts for the Registrants for 2017, 2016 and 2015 were as follows:

Exelon

During 2017, Exelon had additional expenditures of \$23 million and \$178 million relating to the ConEdison Solutions and the acquisitions of the FitzPatrick nuclear generating station, respectively. During 2016, Exelon had expenditures of \$6.6 billion, \$235 million, and \$58 million relating to the acquisitions of PHI, ConEdison Solutions and the acquisitions of the FitzPatrick nuclear generating station, respectively.

During 2017, Exelon had proceeds of \$219 million from sales of long-lived assets.

During 2016, Exelon had proceeds of \$360 million as a result of early termination of direct financing leases.

Generation

During 2017, Generation had additional expenditures of \$23 million and \$178 million relating to the ConEdison Solutions and the acquisitions of the FitzPatrick nuclear generating station, respectively. During 2016, Generation had expenditures of \$235 million, and \$58 million relating to the acquisitions of ConEdison Solutions and the acquisitions of the FitzPatrick nuclear generating station, respectively.

During 2017, Generation had proceeds of \$218 million from sales of long-lived assets.

Capital Expenditure Spending

Generation

Generation has entered into several agreements to acquire equity interests in privately held development stage entities which develop energy-related technology. The agreements contain a series of scheduled investment commitments, including in-kind services contributions. There are anticipated expenditures to fund anticipated planned capital and operating needs of the associated companies.

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Capital expenditures by Registrant for the year ended December 31, 2017, 2016 and 2015 and projected amounts for 2018 are as follows:

	Projected 2018 (a)	2017	2016	2015
Exelon ^(b)	\$ 7,825	\$ 7,584	\$ 8,553	\$ 7,624
Generation	2,100	2,259	3,078	3,841
ComEd ^(c)	2,125	2,250	2,734	2,398
PECO	800	732	686	601
BGE	1,000	882	934	719
Pepco	725	628	586	544
DPL	400	428	349	352
ACE	375	312	311	300
	Successor		Predecessor	
	For the		January	
	Year	March 24,	1,	For the
	Ended	2016 to	2016	Year
Projected	December	December	to	Ended
2018 (a)	31,	31, 2016	March	December
	2017		23,	31, 2015
			2016	
PHI ^(d)	\$ 1,500	\$ 1,396	\$ 1,008	\$ 273
				\$ 1,230

(a) Total projected capital expenditures do not include adjustments for non-cash activity.

(b) Includes corporate operations, BSC and PHISCO rounded to the nearest \$25 million.

The capital expenditures and 2018 projections include \$86 million of expected incremental spending pursuant to (c) EIMA, ComEd has committed to invest approximately \$2.6 billion over a ten-year period to modernize and storm-harden its distribution system and to implement smart grid technology.

(d) Includes PHISCO rounded to the nearest \$25 million.

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

Generation

Approximately 40% and 10% of the projected 2018 capital expenditures at Generation are for the acquisition of nuclear fuel, and the construction of new natural gas plants and solar facilities, respectively, with the remaining amounts reflecting investment in renewable energy and additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Generation anticipates that they will fund capital expenditures with internally generated funds and borrowings.

ComEd, PECO, BGE, Pepco, DPL and ACE

Projected 2018 capital expenditures at the Utility Registrants are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA, and the Utility Registrants' construction commitments under PJM's RTEP.

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. In 2010, NERC provided guidance to transmission owners that recommended the Utility Registrants perform assessments of their transmission lines. ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and

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expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2018 capital expenditures above reflect capital spending for remediation to be completed through 2019. Pepco, DPL and ACE have substantially completed their assessments and thus do not expect significant capital expenditures related to this guidance in 2018.

The Utility Registrants anticipate that they will fund their capital expenditures with a combination of internally generated funds and borrowings and additional capital contributions from parent.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the year ended December 31, 2017, 2016 and 2015 by Registrant were as follows:

	2017	2016	2015
Exelon	\$717	\$1,191	\$4,830
Generation(581)	(734)	(479)	
ComEd	789	169	467
PECO	50	(263)	83
BGE	22	(21)	(162)
Pepco	219	—	103
DPL	64	67	80
ACE	5	22	51
Successor For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	Predecessor January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI	\$306	\$ (7)	\$372
			\$ 233

Debt

See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances and retirements. Debt activity for 2017, 2016 and 2015 by Registrant was as follows:

During the year ended December 31, 2017, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Junior Subordinated Notes	3.50	% June 1, 2022	\$ 1,150	Refinance Exelon's Junior Subordinated Notes issued in June 2014.
Generation	Albany Green Energy Project Financing ^(a)	LIBOR + 1.25%	November 17, 2017	\$ 14	Albany Green Energy biomass generation development.
Generation	Energy Efficiency Project Financing ^(a)	3.90	% February 1, 2018	\$ 19	Funding to install energy conservation measures for the Naval Station Great Lakes project.
Generation	Energy Efficiency Project Financing ^(a)	3.72	% May 1, 2018	\$ 5	Funding to install energy conservation measures for the Smithsonian Zoo project.

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Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Energy Efficiency Project Financing (a)	2.61	% September 30, 2018	\$ 13	Funding to install energy conservation measures for the Pensacola project.
Generation	Energy Efficiency Project Financing (a)	3.53	% April 1, 2019	\$ 8	Funding to install energy conservation measures for the State Department project.
Generation	Senior Notes	2.95	% January 15, 2020	\$ 250	Repay outstanding commercial paper obligations and for general corporate purposes.
Generation	Senior Notes	3.40	% March 15, 2022	\$ 500	Repay outstanding commercial paper obligations and for general corporate purposes.
Generation	ExGen Texas Power Nonrecourse Debt (b)(c)	LIBOR + 4.75%	September 18, 2021	\$ 6	General corporate purposes.
Generation	ExGen Renewables IV, Nonrecourse Debt (b)	LIBOR + 3.00%	November 30, 2024	\$ 850	General corporate purposes.
ComEd	First Mortgage Bonds, Series 122	2.95	% August 15, 2027	\$ 350	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
ComEd	First Mortgage Bonds, Series 123	3.75	% August 15, 2047	\$ 650	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
PECO	First and Refunding Mortgage Bonds	3.70	% September 15, 2047	\$ 325	General corporate purposes.
BGE	Senior Notes	3.75	% August 15, 2047	\$ 300	Redeem \$250 million in principal amount of the 6.20% Deferrable Interest Subordinated Debentures due October 15, 2043 issued by BGE's affiliate BGE Capital Trust II, repay commercial paper obligations and for general corporate purposes.
Pepco	Energy Efficiency Project Financing (a)	3.30	% December 15, 2017	\$ 2	Funding to install energy conservation measures for the DOE Germantown project.
Pepco	First Mortgage Bonds	4.15	% March 15, 2043	\$ 200	Funding to repay outstanding commercial paper and for general corporate purposes.

(a) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

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

(c) As a result of the bankruptcy filing for EGTP on November 7, 2017, the nonrecourse debt was deconsolidated from Exelon's and Generation's consolidated financial statements. Refer to Note 4 — Mergers, Acquisitions and

Dispositions of the Combined Notes to Consolidated Financial Statements for further discussion.

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During the year ended December 31, 2016, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Senior Unsecured Notes	2.45	% April 15, 2021	\$ 300	Repay commercial paper issued by PHI and for general corporate purposes.
Exelon Corporate	Senior Unsecured Notes	3.40	% April 15, 2026	\$ 750	Repay commercial paper issued by PHI and for general corporate purposes.
Exelon Corporate	Senior Unsecured Notes	4.45	% April 15, 2046	\$ 750	Repay commercial paper issued by PHI and for general corporate purposes.
Generation	Renewable Power Generation Nonrecourse Debt ^(a)	4.11	% March 31, 2035	\$ 150	Paydown long-term debt obligations at Sacramento PV Energy and Constellation Solar Horizons and for general corporate purposes.
Generation	Albany Green Energy Project Financing ^(b)	LIBOR + 1.25%	November 17, 2017	\$ 98	Albany Green Energy biomass generation development
Generation	Energy Efficiency Project Financing ^(b)	3.17	% December 31, 2017	\$ 16	Funding to install energy conservation measures in Brooklyn, NY.
Generation	Energy Efficiency Project Financing ^(b)	3.90	% January 31, 2018	\$ 19	Funding to install energy conservation measures for the Naval Station Great Lakes project.
Generation	Energy Efficiency Project Financing ^(b)	3.52	% April 30, 2018	\$ 14	Funding to install energy conservation measures for the Smithsonian Zoo project.
Generation	SolGen Nonrecourse Debt ^(a)	3.93	% September 30, 2036	\$ 150	General corporate purposes.
Generation	Energy Efficiency Project Financing ^(b)	3.46	% October 1, 2018	\$ 36	Funding to install energy conservation measures or the Marine Corps Logistics Base project.
Generation	Energy Efficiency Project Financing ^(b)	2.61	% September 30, 2018	\$ 4	Funding to install energy conservation measures for the Pensacola project
ComEd	First Mortgage Bonds, Series 120	2.55	% June 15, 2026	\$ 500	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
ComEd	First Mortgage Bonds, Series 121	3.65	% June 15, 2046	\$ 700	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
PECO	First Mortgage Bonds	1.70	% September 15, 2021	\$ 300	Refinance maturing mortgage bonds.
BGE	Notes	2.40	% August 15, 2026	\$ 350	Redeem the \$190M of outstanding preference shares and for general corporate purposes.

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BGE	Notes	3.50%	August 15, 2046	\$ 500	Redeem the \$190M of outstanding preference shares and for general corporate purposes.
Pepco	Energy Efficiency Project Financing ^(b)	3.30%	December 15, 2017	\$ 4	Funding to install energy conservation measures for the DOE Germantown project.
DPL	First Mortgage Bonds	4.15%	May 15, 2045	\$ 175	Refinance maturing mortgage bonds, repay commercial paper and for general corporate purposes.

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

(b) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

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

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Senior Unsecured Notes	1.55	% June 9, 2017	\$ 550	Finance a portion of the pending merger with PHI and related costs and expenses and for general corporate purposes.
Exelon Corporate	Senior Unsecured Notes	2.85	% June 15, 2020	\$ 900	Finance a portion of the pending merger with PHI and related costs and expenses and for general corporate purposes.
Exelon Corporate	Senior Unsecured Notes	3.95	% June 15, 2025	\$ 1,250	Finance a portion of the pending merger with PHI and related costs and expenses and for general corporate purposes.
Exelon Corporate	Senior Unsecured Notes	4.95	% June 15, 2035	\$ 500	Finance a portion of the pending merger with PHI and related costs and expenses and for general corporate purposes.
Exelon Corporate	Senior Unsecured Notes	5.10	% June 15, 2045	\$ 1,000	Finance a portion of the pending merger with PHI and related costs and expenses and for general corporate purposes.
Exelon Corporate	Long-Term Software License Agreement	3.95	% May 1, 2024	\$ 111	Procurement of software licenses.
Generation	Senior Unsecured Notes	2.95	% January 15, 2020	\$ 750	Fund the optional redemption of Exelon's \$550 million, 4.550% Senior Notes and for general corporate purposes.
Generation	AVSR DOE Nonrecourse Debt ^(a)	2.29 - 2.96%	January 5, 2037	\$ 39	Antelope Valley solar development.
Generation	Energy Efficiency Project Financing ^(b)	3.71	% July 31, 2017	\$ 42	Funding to install energy conservation measures in Coleman, Florida.

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Generation	Energy Efficiency Project Financing ^(b)	3.55	%	November 15, 2016	\$ 19	Funding to install energy conservation measures in Frederick, Maryland.
Generation	Tax Exempt Pollution Control Revenue Bonds	2.50 - 2.70%		2019 - 2020	\$435	General corporate purposes.
Generation	Albany Green Energy Project Financing ^(b)	LIBOR + 1.25%		November 17, 2017	\$ 100	Albany Green Energy biomass generation development.
Generation	Nuclear Fuel Purchase Contract	3.15	%	September 30, 2020	\$57	Procurement of uranium.
ComEd	First Mortgage Bonds, Series 118	3.70	%	March 1, 2045	\$400	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
ComEd	First Mortgage Bonds, Series 119	4.35	%	November 15, 2045	\$450	Repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
PECO	First and Refunding Mortgage Bonds	3.15	%	October 15, 2025	\$350	General corporate purposes
Pepco	First Mortgage Bonds	4.15	%	March 15, 2043	\$200	Repay outstanding commercial paper obligations and general corporate purposes
DPL	First Mortgage Bonds	4.15	%	May 15, 2045	\$200	Repay outstanding commercial paper obligations and general corporate purposes
ACE	First Mortgage Bonds	3.50	%	December 1, 2025	\$ 150	Repay outstanding commercial paper obligations and general corporate purposes

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

(b) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

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During the year ended December 31, 2017, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon Corporate	Long-Term Software License Agreement	3.95%	May 1, 2024	\$ 24
Exelon Corporate	Senior Notes	1.55%	June 9, 2017	\$ 550
Generation	Senior Notes - Exelon Wind	2.00%	July 31, 2017	\$ 1
Generation	CEU Upstream Nonrecourse Debt ^(a)	LIBOR + 2.25%	January 14, 2019	\$ 6
Generation	SolGen Nonrecourse Debt ^(a)	3.93%	September 30, 2036	\$ 2
Generation	AVSR DOE Nonrecourse Debt ^(a)	2.29% - 3.56%	January 5, 2037	\$ 22
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	\$ 2
Generation	Continental Wind Nonrecourse Debt ^(a)	6.00%	February 28, 2033	\$ 31
Generation	PES - PGOV Notes Payable	6.70-7.60%	2017 - 2018	\$ 1
Generation	ExGen Texas Power Nonrecourse Debt ^{(a)(b)}	LIBOR + 4.75%	September 18, 2021	\$ 665
Generation	Renewable Power Generation Nonrecourse Debt ^(a)	4.11%	March 31, 2035	\$ 14
Generation	NUKEM	3.25% - 3.35%	June 30, 2018	\$ 23
Generation	ExGen Renewables I, Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	\$ 233
Generation	Senior Notes	6.20%	October 1, 2017	\$ 700
Generation	Albany Green Energy Project Financing	LIBOR + 1.25%	November 17, 2017	\$ 212
ComEd	First Mortgage Bonds	6.15%	September 15, 2017	\$ 425
BGE	Rate Stabilization Bonds	5.82%	April 1, 2017	\$ 41
BGE	Capital Trust Preferred Securities	6.20%	October 15, 2043	\$ 258
PHI	Senior Notes	6.13%	June 1, 2017	\$ 81
DPL	Medium Term Notes, Unsecured	7.56% - 7.58%	February 1, 2017	\$ 14
DPL	Variable Rate Demand Bonds	Variable	October 1, 2017	\$ 26
Pepco	Third Party Financing	6.97% - 7.99%	2018 - 2022	\$ 1
ACE	Transition Bonds	5.05% - 5.55%	2020 - 2023	\$ 35

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

As a result of the bankruptcy filing for EGTP on November 7, 2017, the nonrecourse debt was deconsolidated from (b) Exelon's and Generation's consolidated financial statements. Refer to Note 4 — Mergers, Acquisitions and Dispositions for further discussion.

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During the year ended December 31, 2016, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon Corporate	Long Term Software License Agreement	3.95%	May 1, 2024	\$ 8
Exelon Corporate	Senior Notes	4.95%	June 15, 2035	\$ 1
Generation	AVSR DOE Nonrecourse Debt ^(a)	2.29% - 3.56%	January 5, 2037	\$ 22
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	\$ 4
Generation	Continental Wind Nonrecourse Debt ^(a)	6.00%	February 28, 2033	\$ 29
Generation	CEU Upstream Nonrecourse Debt ^(a)	LIBOR + 2.25%	January 14, 2019	\$ 46
Generation	ExGen Texas Power Nonrecourse Debt ^{(a)(b)}	5.00%	September 18, 2021	\$ 7
Generation	Sacramento Solar Nonrecourse Debt	LIBOR + 2.25%	December 31, 2030	\$ 33
Generation	Clean Horizons Nonrecourse Debt	LIBOR + 2.25%	September 7, 2030	\$ 32
Generation	ExGen Renewables I, Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	\$ 24
Generation	PES - PGOV Notes Payable	6.70% - 7.46%	2017-2018	\$ 1
Generation	NUKEM	3.35%	June 30, 2018	\$ 12
Generation	NUKEM	3.25%	July 1, 2018	\$ 10
Generation	Renewable Power Generation Nonrecourse Debt ^(a)	4.11%	March 31, 2035	\$ 9
Generation	SolGen Nonrecourse Debt ^(a)	3.93%	September 30, 2036	\$ 2
ComEd	First Mortgage Bonds, Series 104	5.95%	August 15, 2016	\$ 415
ComEd	First Mortgage Bonds, Series 111	1.95%	August 1, 2016	\$ 250
PECO	First and Refunding Mortgage Bonds	1.20%	October 15, 2016	\$ 300
BGE	Rate Stabilization Bonds	5.72%	April 1, 2016	\$ 1
BGE	Rate Stabilization Bonds	5.82%	April 1, 2017	\$ 38
BGE	Notes	5.90%	October 1, 2016	\$ 300
BGE	Rate Stabilization Bonds	5.82%	April 1, 2017	\$ 40
PHI	Senior Unsecured Notes	5.90%	December 12, 2016	\$ 190
DPL	First Mortgage Bonds	5.22%	December 30, 2016	\$ 100
ACE	Transition Bonds	5.05%	October 20, 2020	\$ 12
ACE	Transition Bonds	5.55%	October 20, 2023	\$ 34
ACE	First Mortgage Bonds	7.68%	August 23, 2016	\$ 2

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

As a result of the bankruptcy filing for EGTP on November 7, 2017, the nonrecourse debt was deconsolidated from (b)Exelon's and Generation's consolidated financial statements. Refer to Note 4 — Mergers, Acquisitions and Dispositions for further discussion.

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

Company	Type	Interest Rate	Maturity	Amount
Exelon Corporate	Senior Unsecured Notes	4.55%	June 15, 2015	\$ 550
Exelon Corporate	Senior Notes	4.90%	June 15, 2015	\$ 800
Exelon Corporate	Senior Unsecured Notes	3.95%	June 15, 2025	\$ 443
Exelon Corporate	Senior Unsecured Notes	4.95%	June 15, 2035	\$ 167
Exelon Corporate	Senior Unsecured Notes	5.10%	June 15, 2045	\$ 259
Exelon Corporate	Long-Term Software License Agreement	3.95%	May 1, 2024	\$ 1
Generation	Senior Unsecured Notes	4.55%	June 15, 2015	\$ 550
Generation	CEU Upstream Nonrecourse Debt ^(a)	LIBOR + 2.25%	January 14, 2019	\$ 9
Generation	AVSR DOE Nonrecourse Debt ^(a)	2.29%-3.56%	January 5, 2037	\$ 23
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	\$ 3
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	\$ 20
Generation	ExGen Texas Power Nonrecourse Debt ^{(a)(b)}	LIBOR + 4.75%	September 8, 2021	\$ 5
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	\$ 24
Generation	Constellation Solar Horizons Nonrecourse Debt	2.56%	September 7, 2030	\$ 2
Generation	Sacramento PV Energy Nonrecourse Debt	2.58%	December 31, 2030	\$ 2
Generation	Energy Efficiency Project ^(b)	3.55%	November 15, 2016	\$ 19
ComEd	First Mortgage Bonds, Series 101	4.70%	April 15, 2015	\$ 260
BGE	Rate Stabilization Bonds	5.72%	April 1, 2016	\$ 75
PHI	Senior Unsecured Notes	2.70%	October 1, 2015	\$ 250
PHI ^(c)	Energy Efficiency Project Financing	4.68%	February 10, 2015	\$ 7
PHI ^(c)	Energy Efficiency Project Financing	8.87%	June 1, 2021	\$ 5
PHI ^(c)	Energy Efficiency Project Financing	7.61%	August 1, 2015	\$ 1
PHI ^(c)	PES - PGOV Notes Payable	6.70%	2017-2018	\$ 1
Pepco	Energy Efficiency Project Financing	3.12%	February 20, 2015	\$ 12
DPL	Senior Unsecured Notes	5.00%	June 1, 2015	\$ 100
ACE	Secured Medium-Term Notes Series C	7.68%	August 24, 2015	\$ 15
ACE	Transition Bonds	5.05%	October 20, 2020	\$ 12
ACE	Transition Bonds	5.55%	October 20, 2023	\$ 32

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

As a result of the bankruptcy filing for EGTP on November 7, 2017, the nonrecourse debt was deconsolidated from (b) Exelon's and Generation's consolidated financial statements. Refer to Note 4 — Mergers, Acquisitions and Dispositions for further discussion.

^(c) Represents Pepco Energy Services energy efficiency project financing. As of the date of the merger, PES financing was included with Generation.

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

Dividends

Cash dividend payments and distributions for the year ended December 31, 2017, 2016 and 2015 by Registrant were as follows:

	2017	2016	2015
Exelon	\$1,236	\$1,166	\$1,105
Generation659	659	922	2,474
ComEd	422	369	299
PECO	288	277	279
BGE ^(a)	198	187	171
Pepco	133	136	146
DPL	112	54	92
ACE	68	63	12
Successor For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	Predecessor January 1, For the 2016 Year to Ended March 23, 31, 2015	
PHI\$311	\$ 273	\$ —	\$ 275

(a) Includes dividends paid on BGE's preference stock during 2016 and 2015.

Quarterly dividends declared by the Exelon Board of Directors during the year ended December 31, 2017 and for the first quarter of 2018 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share
First Quarter 2017	January 31, 2017	February 15, 2017	March 10, 2017	\$ 0.3275
Second Quarter 2017	April 25, 2017	May 15, 2017	June 9, 2017	\$ 0.3275
Third Quarter 2017	July 25, 2017	August 15, 2017	September 8, 2017	\$ 0.3275
Fourth Quarter 2017	September 25, 2017	November 15, 2017	December 8, 2017	\$ 0.3275
First Quarter 2018 ^(a)	January 30, 2018	February 15, 2018	March 9, 2018	\$ 0.3450

(a) Exelon's Board of Directors approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

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Short-Term Borrowings

Short-term borrowings incurred (repaid) during 2017, 2016 and 2015 by Registrant were as follows:

	2017	2016	2015
Exelon	\$(261)	\$(353)	\$80
Generation	(620)	620	—
ComEd	—	(294)	(10)
BGE	32	(165)	90
Pepco	3	(41)	(40)
DPL	216	(105)	(1)
ACE	108	(5)	(122)
Successor		Predecessor	
For		January	
the		1,	For the
Year	March 24,	2016	Year
Ended	2016 to	to	Ended
December	December	March	December
31,	31, 2016	23,	31, 2015
2017		2016	
PHI	\$328	\$(121)	\$ 34

Retirement of Long-Term Debt to Financing Affiliates

On August 28, 2017, BGE redeemed all of the outstanding shares of BGE Capital Trust II 6.20% Preferred Securities. See Note 13 — Debt and Credit Agreements for further discussion.

Contributions from Parent/Member

Contributions from Parent/Member (Exelon) during 2017, 2016 and 2015 by Registrant were as follows:

	2017	2016	2015
Generation	\$102	\$142	\$ 47
ComEd ^{(a)(b)}	672	473	209
PECO ^(b)	16	18	16
BGE ^(b)	184	61	7
Pepco ^(c)	161	187	112
DPL ^(c)	—	152	75
ACE ^(c)	—	139	95
Successor		Predecessor	
For		January	
the		1,	For the
Year	March 24,	2016	Year
Ended	2016 to	to	Ended
December	December	March	December
31,	31, 2016	23,	31, 2015
2017		2016	
PHI ^(b)	\$758	\$ 1,251	\$ —

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

(a) Contribution paid by Exelon.

(b) Contribution paid by PHI.

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Pursuant to the orders approving the merger, Exelon made equity contributions of \$73 million, \$46 million and \$49 million to Pepco, DPL and ACE, respectively, in the second quarter of 2016 to fund the after-tax amount of the customer bill credit and the customer base rate credit.

Redemptions of Preference Stock. BGE had \$190 million of cumulative preference stock that was redeemable at its option at any time after October 1, 2015 for the redemption price of \$100 per share, plus accrued and unpaid dividends. On July 3, 2016, BGE redeemed all 400,000 shares of its outstanding 7.125% Cumulative Preference Stock, 1993 Series and all 600,000 shares of its outstanding 6.990% Cumulative Preference Stock, 1995 Series for \$100 million, plus accrued and unpaid dividends. On September 18, 2016, BGE redeemed the remaining 500,000 shares of its outstanding 6.970% Cumulative Preference Stock, 1993 Series and the remaining 400,000 shares of its outstanding 6.700% Cumulative Preference Stock, 1993 Series for \$90 million, plus accrued and unpaid dividends. As of December 31, 2017, BGE no longer has any preferred stock outstanding. See Note 21 - Earnings Per Share of the Combined Notes to Consolidated Financial Statements for further details.

Other

For the year ended December 31, 2017, other financing activities primarily consists of debt issuance costs. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements' for additional information.

Credit Matters

Market Conditions

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include \$9.5 billion in aggregate total commitments of which \$8.3 billion was available as of December 31, 2017, and of which no financial institution has more than 7% of the aggregate commitments for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE. The Registrants had access to the commercial paper market during 2017 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A. RISK FACTORS for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of December 31, 2017, it would have been required to provide incremental collateral of \$1.8 billion to meet collateral obligations for derivatives, non-derivatives, normal purchases and normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of \$4.7 billion.

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The following table presents the incremental collateral that each Utility Registrant would have been required to provide in the event each Utility Registrant lost its investment grade credit rating at December 31, 2017 and available credit facility capacity prior to any incremental collateral at December 31, 2017:

	PJM Credit Policy Collateral	Other Incremental Collateral Required ^(a)	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	\$ 18	\$ —	\$ 998
PECO	3	34	599
BGE	3	66	600
Pepco	4	—	300
DPL	1	11	300
ACE	—	—	300

(a) Represents incremental collateral related to natural gas procurement contracts.

Exelon Credit Facilities

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool. PHI meets its short-term liquidity requirements primarily through the issuance of short-term notes and the Exelon intercompany money pool. Pepco, DPL and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and short-term notes.

The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

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

Other Credit Matters

Capital Structure. At December 31, 2017, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Long-term debt	51 %	32 %	44 %	44 %	45 %	39 %	50 %	46 %	49 %
Long-term debt to affiliates ^(a)	1 %	4 %	1 %	3 %	— %	— %	— %	— %	— %
Common equity	47 %	— %	55 %	53 %	54 %	— %	49 %	46 %	46 %
Member's equity	— %	64 %	— %	— %	— %	59 %	— %	— %	— %
Commercial paper and notes payable	1 %	— %	— %	— %	1 %	2 %	1 %	8 %	5 %

Includes approximately \$389 million, \$205 million and \$184 million owed to unconsolidated affiliates of Exelon, ComEd, and PECO respectively. These special purpose entities were created for the sole purposes of issuing (a) mandatorily redeemable trust preferred securities of ComEd and PECO. See Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding the authoritative guidance for VIEs.

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Security Ratings

The Registrants' access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants' borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant's securities could increase fees and interest charges under that Registrant's credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, both Exelon and PHI operate an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of December 31, 2017, are presented in the following tables:

	For the Year		As of	
Exelon Intercompany Money Pool	Ended December		December 31,	
	31, 2017		2017	
Contributed (borrowed)	Maximum	Maximum	Contributed	
	Contributed	Borrowed	(Borrowed)	
Exelon Corporate	\$ 579	\$ —	\$ 217	
Generation	20	(589)	(54)	
PECO	336	(22)	—	
BSC	—	(423)	(217)	
PHI Corporate	—	(47)	—	
PCI	55	—	54	

	For the Year		As of	
PHI Intercompany Money Pool	Ended		December 31,	
	December 31,		2017	
	2017		2017	
Contributed (borrowed)	Maximum	Maximum	Contributed	
	Contributed	Borrowed	(Borrowed)	
PHI Corporate	\$ 9	\$ (2)	\$ 1	
Pepco	—	—	—	
DPL	—	—	—	
ACE	—	—	—	
PHISCO	3	(9)	—	

Investments in Nuclear Decommissioning Trust Funds. Exelon, Generation and CENG maintain trust funds, as required by the NRC, to fund certain costs of decommissioning nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with

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Generation's NDT fund investment policy. Generation's and CENG's investment policies establish limits on the concentration of holdings in any one company and also in any one industry. See Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC's minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements. Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in August 2019. The ability of each Registrant to sell securities off the shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations. ComEd, PECO, BGE, Pepco, DPL and ACE are required to obtain short-term and long-term financing authority from Federal and State Commissions as follows:

	Short-term Financing Authority ^(a)			Long-term Financing Authority ^(a)		
	Commission	Expiration Date	Amount	Commission	Expiration Date ^(c)	Amount
ComEd ^(b)	FERC	December 31, 2019	\$ 2,500	ICC	2019	\$ 1,383
PECO	FERC	December 31, 2019	1,500	PAPUC	December 31, 2018	1,275
BGE	FERC	December 31, 2019	700	MDPSC	N/A	700
Pepco	FERC	December 31, 2019	500	MDPSC	September 25, 2017	—
				DCPSC	December 31, 2020	600
DPL	FERC	December 31, 2019	500	MDPSC	December 31, 2017	—
				DPSC	December 31, 2020	350
ACE	NJBPU	December 31, 2019	350	NJBPU	December 31, 2019	350

^(a) Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.

^(b) ComEd had \$1,140 million available in long-term debt refinancing authority and \$243 million available in new money long term debt financing authority from the ICC as of December 31, 2017 and has an expiration date of June 1, 2019 and March 1, 2019, respectively.

^(c) Pepco and DPL are currently in the process of renewing their long-term financing authority with the MDPSC. Exelon's ability to pay dividends on its common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." In addition, under Illinois law, ComEd may not pay any dividend on its stock, unless, among other things, its earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless ComEd has specific authorization from the ICC. BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE was prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. Pepco, DPL and ACE are subject to certain dividend restrictions established by settlements approved in NJ, DE, MD and the DC. Pepco, DPL and ACE are prohibited from paying a dividend on their common shares if (a) after the dividend payment, Pepco's, DPL's or ACE's equity ratio would be below 48% as equity levels are calculated under the ratemaking precedents of the Commissions

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and the Board or (b) Pepco's, DPL's or ACE's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. At December 31, 2017, Exelon had retained earnings of \$13,503 million, including Generation's undistributed earnings of \$4,310 million, ComEd's retained earnings of \$1,132 million consisting of retained earnings appropriated for future dividends of \$2,771 million partially offset by \$1,639 million of unappropriated retained deficit, PECO's retained earnings of \$1,087 million and BGE's retained earnings \$1,536 million. At December 31, 2017, Pepco had retained earnings of \$1,063 million, DPL had retained earnings of \$571 million and ACE had retained earnings of \$131 million. See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions. Contractual Obligations and Off-Balance Sheet Arrangements

The following tables summarize the Registrants' future estimated cash payments as of December 31, 2017 under existing contractual obligations, including payments due by period. See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the Registrants' commercial and other commitments, representing commitments potentially triggered by future events.

Exelon

	Total	Payment due within			
		2018	2019 - 2020	2021 - 2022	Due 2023 and beyond
Long-term debt ^(a)	\$33,994	\$2,057	\$4,459	\$4,574	\$22,904
Interest payments on long-term debt ^(b)	15,999	1,346	2,579	2,231	9,843
Capital leases	53	18	25	2	8
Operating leases ^(c)	1,512	188	276	261	787
Purchase power obligations ^(d)	1,153	358	498	103	194
Fuel purchase agreements ^(e)	7,270	1,229	2,241	1,385	2,415
Electric supply procurement ^(e)	3,417	2,213	1,204	—	—
AEC purchase commitments ^(e)	3	1	2	—	—
Curtailed services commitments ^(e)	119	52	54	13	—
Long-term renewable energy and REC commitments ^(f)	1,666	111	224	235	1,096
Other purchase obligations ^(g)	7,765	4,844	1,585	561	775
DC PLUG obligation ^(h)	188	28	60	60	40
Construction commitments ⁽ⁱ⁾	57	56	1	—	—
PJM regional transmission expansion commitments ⁽ⁱ⁾	569	179	270	120	—
SNF obligation ^(k)	1,147	—	—	—	1,147
Pension contributions ^(l)	1,393	301	493	386	213
Total contractual obligations	\$76,305	\$12,981	\$13,971	\$9,931	\$39,422

(a) Includes \$390 million due after 2023 to ComEd and PECO financing trusts.

Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest

(b) obligations are estimated based on rates as of December 31, 2017. Includes estimated interest payments due to ComEd, PECO, BGE, PHI, Pepco, DPL and ACE financing trusts.

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- Excludes Generation's contingent operating lease payments associated with contracted generation agreements.
- (c) These amounts are included within purchase power obligations. Includes estimated cash payments for service fees related to PECO's meter reading operating lease.
- Purchase power obligations include contingent operating lease payments associated with contracted generation agreements. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2017, including those related to CENG. Expected payments include certain fixed capacity charges
- (d) which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. Contained within Purchase power obligations are Net Capacity Purchases of \$106 million, \$99 million, \$40 million, \$31 million, \$19 million and \$171 million for 2018, 2019, 2020, 2021, 2022 and thereafter, respectively.
- Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and
- (e) services, procure electric renewable energy and RECs, procure electric supply, and purchase AECs and curtailment services.
- Primarily related to ComEd 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments
- (f) represent the earliest and maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
- Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both
- (g) cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
- Related to DC PLUG project costs for assets funded by the District of Columbia for which the District of Columbia
- (h) has assessed a charge on Pepco. Pepco will recover this charge from customers through a volumetric distribution rider. See Note 3 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
- Represents commitments for Generation's ongoing investments in new natural gas and biomass generation
- (i) construction.
- Under their operating agreements with PJM, ComEd, PECO, BGE, Pepco, DPL and ACE are committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd, PECO,
- (j) BGE, Pepco, DPL and ACE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
- See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for
- (k) further information regarding SNF obligations.
- These amounts represent Exelon's expected contributions to its qualified pension plans. The projected contributions reflect a funding strategy of contributing the greater of \$300 million (which has been updated for the inclusion of PHI) until the qualified plans are fully funded on an accumulated benefit obligation basis, and the minimum amounts under ERISA to avoid benefit restrictions and at-risk status thereafter. The remaining qualified pension plans' contributions are generally based on the estimated minimum pension contributions required under ERISA and
- (l) the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status. These amounts represent estimates that are based on assumptions that are subject to change. Qualified pension contributions for years after 2023 are not included. See Note 16 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

Generation

	Payment due within			
Total	2018	2019 - 2020	2021 - 2022	Due 2023 and beyond

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Long-term debt	\$8,937	\$341	\$2,747	\$1,023	\$4,826
Interest payments on long-term debt ^(a)	4,808	391	705	530	3,182
Capital leases	18	5	11	2	—
Operating leases ^(b)	817	74	76	94	573
Purchase power obligations ^(c)	1,153	358	498	103	194
Fuel purchase agreements ^(d)	6,147	1,000	1,909	1,184	2,054
Other purchase obligations ^(e)	1,456	398	249	181	628
Construction commitments ^(f)	57	56	1	—	—
SNF obligation ^(g)	1,147	—	—	—	1,147
Total contractual obligations	\$24,540	\$2,623	\$6,196	\$3,117	\$12,604

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2017.

(b) Excludes Generation's contingent operating lease payments associated with contracted generation agreements. These amounts are included within purchase power obligations.

(c) Purchase power obligations include contingent operating lease payments associated with contracted generation agreements. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2017. Expected

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payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. Contained within Purchase power obligations are Net Capacity Purchases of \$106 million, \$99 million, \$40 million, \$31 million, \$19 million and \$171 million for 2018, 2019, 2020, 2021, 2022 and thereafter, respectively.

(d) Represents commitments to purchase fuel supplies for nuclear and fossil generation, including those related to CENG.

(e) Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

(f) Represents commitments for Generation's ongoing investments in new natural gas generation construction. As of December 31, 2017, the commitments relate to the construction of a new dual fuel, natural peaking facility in Massachusetts. Achievement of commercial operation related to this project is expected in 2018.

(g) See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding SNF obligations.

ComEd

	Total	Payment due within			
		2018	2019 - 2020	2021 - 2022	Due 2023 and beyond
Long-term debt ^(a)	\$7,874	\$840	\$800	\$350	\$ 5,884
Interest payments on long-term debt ^(b)	4,937	269	517	469	3,682
Capital leases	8	—	—	—	8
Operating leases ^(c)	23	7	10	6	—
Electric supply procurement	741	476	265	—	—
Long-term renewable energy and REC commitments ^(d)	1,321	82	166	177	896
Other purchase obligations ^(e)	1,035	927	82	16	10
PJM regional transmission expansion commitments ^(f)	164	36	104	24	—
Total contractual obligations	\$16,103	\$2,637	\$1,944	\$1,042	\$ 10,480

(a) Includes \$206 million due after 2023 to a ComEd financing trust.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2017. Includes estimated interest payments due to the ComEd financing trust.

(c) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, ComEd, has excluded these payments from the remaining years as such amounts would not be meaningful.

(d) ComEd's average annual obligation for these arrangements, included in each of the years 2018-2022, was \$2 million.

(e) Primarily related to ComEd 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum and earliest settlements with suppliers for renewable energy and RECs under the existing contract terms. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

(f) Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

(g) Under its operating agreement with PJM, ComEd is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's expected portion of the costs to pay for the

completion of the required construction projects. See Note 3 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

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In January 2018, ComEd entered into 10-year ZEC procurement contracts with Generation. The following table summarizes ComEd's future estimated cash payments under the executed contract. See Note 3 — Regulatory Matters and Note 28 — Subsequent Events of the Combined Notes to Consolidated Financial Statements for more information.

	Total	Payment due within			
		2018	2019	2020	2021
ZEC commitments ^(a)	\$1,589	\$271	\$327	\$314	\$ 677

Annual ZEC commitment amounts will be published by the IPA each May prior to the start of the subsequent planning year. Amounts presented in the table represent management's estimate of ComEd's obligation based on forward energy prices and load forecasts. ComEd is permitted to recover its ZEC costs from retail customers with no mark-up.

PECO

	Total	Payment due within			
		2018	2019	2020	2021
Long-term debt ^(a)	\$3,109	\$500	\$—	\$650	\$ 1,959
Interest payments on long-term debt ^(b)	1,916	105	210	202	1,399
Operating leases ^(c)	25	5	10	10	—
Fuel purchase agreements ^(d)	339	113	151	35	40
Electric supply procurement ^(d)	526	420	106	—	—
AEC purchase commitments ^(d)	6	2	4	—	—
Other purchase obligations ^(e)	465	257	157	46	5
PJM regional transmission expansion commitments ^(f)	53	16	29	8	—
Total contractual obligations	\$6,439	\$1,418	\$667	\$951	\$ 3,403

(a) Includes \$184 million due after 2023 to PECO financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances.

(c) Includes estimated cash payments for service fees related to PECO's meter reading operating lease. Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, PECO has excluded these payments from the remaining years as such amounts would not be meaningful. PECO's average annual obligation for these arrangements, included in each of the years 2018-2022, was \$5 million.

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

(e) Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

(f) Under its operating agreement with PJM, PECO is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PECO's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

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BGE

	Total	Payment due within			
		2018	2019 2020	2021 2022	Due 2023 and beyond
Long-term debt	\$2,600	\$—	\$—	\$550	\$ 2,050
Interest payments on long-term debt ^(a)	1,689	101	201	186	1,201
Operating leases ^{(b)(c)(d)}	170	34	68	49	19
Fuel purchase agreements ^(e)	514	86	121	106	201
Electric supply procurement ^(e)	1,026	645	381	—	—
Curtailed services commitments ^(e)	50	22	21	7	—
Other purchase obligations ^(f)	453	394	50	4	5
PJM regional transmission expansion commitments ^(g)	118	35	70	13	—
Total contractual obligations	\$6,620	\$1,317	\$912	\$915	\$ 3,476

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances.

Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, BGE has excluded these payments from the remaining years as such amounts would not be meaningful.

(b) BGE's average annual obligation for these arrangements, included in each of the years 2018—2022, was \$1 million, respectively.

(c) Includes all future lease payments on a 99-year real estate lease that expires in 2106.

The BGE column above includes minimum future lease payments associated with a 6-year lease for the Baltimore City conduit system that became effective during the fourth quarter of 2016. BGE's total commitments under the lease agreement are \$25 million, \$26 million, \$28 million, \$28 million and \$14 million related to years 2018, 2019, 2020, 2021 and 2022, respectively.

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

(f) Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the BGE and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

(g) Under its operating agreement with PJM, BGE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

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PHI

	Total	Payment due within			
		2018	2019 - 2020	2021 - 2022	Due 2023 and beyond
Long-term debt	\$5,162	\$370	\$12	\$551	\$ 4,229
Interest payments on long-term debt ^(a)	1,328	231	461	433	203
Capital leases	27	13	14	—	—
Operating leases	415	56	86	79	194
Fuel purchase agreements ^(b)	270	30	60	60	120
Long-term renewable energy and REC commitments ^(b)	345	29	58	58	200
Electric supply procurement ^(b)	1,720	1,060	660	—	—
Curtailement services commitments ^(b)	69	30	33	6	—
Other purchase obligations ^(c)	3,434	2,368	822	196	48
DC PLUG obligation ^(d)	188	28	60	60	40
PJM regional transmission expansion commitments ^(e)	234	92	67	75	—
Total contractual obligations	\$13,192	\$4,307	\$2,333	\$1,518	\$ 5,034

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances.

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

(c) Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

(d) Related to DC PLUG project costs for assets funded by the District of Columbia for which the District of Columbia has assessed a charge on Pepco. Pepco will recover this charge from customers through a volumetric distribution rider. See Note 3 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

(e) Under its operating agreement with PJM, PHI is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PHI's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

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Pepco

	Total	Payment due within			Due 2023 and beyond
		2018	2019 - 2020	2021 - 2022	
Long-term debt	\$2,543	\$6	\$—	\$312	\$ 2,225
Interest payments on long-term debt ^(a)	755	129	259	251	116
Capital leases	27	13	14	—	—
Operating leases	38	8	13	9	8
Electric supply procurement ^(b)	675	433	242	—	—
Curtailed services commitments ^(b)	26	13	10	3	—
Other purchase obligations ^(c)	1,676	995	497	146	38
DC PLUG obligation ^(d)	188	28	60	60	40
PJM regional transmission expansion commitments ^(e)	86	5	38	43	—
Total contractual obligations	\$6,014	\$1,630	\$1,133	\$824	\$ 2,427

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances.

(b) Represents commitments to purchase procure electric supply and curtailed services.

Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

(c) Related to DC PLUG project costs for assets funded by the District of Columbia for which the District of Columbia has assessed a charge on Pepco. Pepco will recover this charge from customers through a volumetric distribution rider. See Note 3 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

(d) Under its operating agreement with PJM, Pepco is committed to the construction of transmission facilities to maintain system reliability. These amounts represent Pepco's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

DPL

	Total	Payment due within			Due 2023 and beyond
		2018	2019 - 2020	2021 - 2022	
Long-term debt	\$1,309	\$83	\$12	\$—	\$ 1,214
Interest payments on long-term debt ^(a)	288	49	97	96	46
Operating leases ^(b)	121	20	23	24	54
Fuel purchase agreements ^(c)	270	30	60	60	120
Long-term renewable energy and associated REC commitments ^(c)	345	29	58	58	200
Electric supply procurement ^(c)	504	312	192	—	—
Curtailed services commitments ^(c)	36	14	19	3	—
Other purchase obligations ^(d)	963	776	152	32	3
PJM regional transmission expansion commitments ^(e)	27	19	3	5	—
Total contractual obligations	\$3,863	\$1,332	\$616	\$278	\$ 1,637

(a)

Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances.

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Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, DPL has excluded these payments from the remaining years as such amounts would not be meaningful.

DPL's average annual obligation for these arrangements, included in each of the years 2018-2022, was \$2 million.

Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric renewable energy and RECs, procure electric supply, and curtailment services.

Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

Under its operating agreement with PJM, DPL is committed to the construction of transmission facilities to maintain system reliability. These amounts represent DPL's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

ACE

	Total	Payment due within			
		2018	2019	2020	2021
Long-term debt	\$1,127	\$281	\$—	\$239	\$ 607
Interest payments on long-term debt ^(a)	201	39	77	58	27
Operating leases	57	9	16	13	19
Electric supply procurement ^(b)	541	315	226	—	—
Curtailment services commitments ^(b)	7	3	4	—	—
Other purchase obligations ^(c)	581	439	124	15	3
PJM regional transmission expansion commitments ^(d)	121	68	26	27	—
Total contractual obligations	\$2,635	\$1,154	\$473	\$352	\$ 656

^(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances.

^(b) Represents commitments to procure electric supply and curtailment services.

Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

Under its operating agreement with PJM, ACE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ACE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

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

For additional information regarding:

• commercial paper, see Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.

• long-term debt, see Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.

• liabilities related to uncertain tax positions, see Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements.

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capital lease obligations, see Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.

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operating leases and rate relief commitments, see Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

the nuclear decommissioning and SNF obligations, see Notes 15 — Asset Retirement Obligations and 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

regulatory commitments, see Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

variable interest entities, see Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements.

nuclear insurance, see Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

new accounting pronouncements, see Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk (All Registrants)

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

Generation

Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of the Utility Registrants' retail load, is sold into the wholesale markets. To reduce commodity price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including swaps, futures, forwards and options, with approved counterparties to hedge anticipated exposures. Generation uses derivative instruments as economic hedges to mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2018 through 2020.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Exelon's hedging program involves the hedging of commodity price risk for Exelon's expected generation, typically on a ratable basis over three-year periods. As of December 31, 2017, the percentage of expected generation hedged is 85%-88%, 55%-58% and 26%-29% for 2018, 2019 and 2020,

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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, which include economic hedges and certain non-derivative contracts, including Generation's sales to ComEd, PECO and BGE to serve their retail load. A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire economic hedge portfolio associated with a \$5 reduction in the annual average around-the-clock energy price based on December 31, 2017 market conditions and hedged position would be decreases in pre-tax net income of approximately \$110 million, \$400 million and \$630 million, respectively, for 2018, 2019 and 2020. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation actively manages its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Proprietary Trading Activities

Proprietary trading portfolio activity for the year ended December 31, 2017, resulted in pre-tax gains of \$18 million due to net mark-to-market gains of \$5 million and realized gains of \$13 million. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation's total Revenue net of purchased power and fuel expense. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Fuel Procurement

Generation procures natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are 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 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 59% of Generation's uranium concentrate requirements from 2018 through 2022 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial positions.

ComEd

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction

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of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014.

ComEd has block energy contracts to procure electric supply that are executed through a competitive procurement process, which is further discussed in Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements. The block energy contracts are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. ComEd does not execute derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

PECO, BGE, Pepco, DPL and ACE

PECO, BGE, Pepco, DPL and ACE have contracts to procure electric supply that are executed through a competitive procurement process, which are further discussed in Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements. PECO, BGE, Pepco, DPL and ACE have certain full requirements contracts, which are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. Other full requirements contracts are not derivatives.

PECO, BGE and DPL have also executed derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge their long-term price risk in the natural gas market. The hedging programs for natural gas procurement have no direct impact on their results of operations or financial position.

PECO, BGE, Pepco, DPL and ACE do not execute derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities

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

The following table provides detail on changes in Exelon's, Generation's, ComEd's, PHI's and DPL's commodity mark-to-market net asset or liability balance sheet position from December 31, 2015 to December 31, 2017. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings. This table excludes all NPNS contracts and does not segregate proprietary trading activity. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2017 and 2016.

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	Exelon	Generation	ComEd	DPL	PHI	PHI	Successor March 24 to December 31,	Predecessor January 1 to March 23, PHI
Total mark-to-market energy contract net assets (liabilities) at December 31, 2015 ^(a)	\$1,506	\$ 1,753	\$(247)	\$ —	\$ —	\$ —		
Total change in fair value during 2016 of contracts recorded in result of operations	236	236	—	—	—	—		
Reclassification to be realized at settlement of contracts recorded in results of operations	(265)	(265)	—	—	—	—		
Contracts received at acquisition date ^(b)	(59)	(59)	—	—	—	—		
Changes in fair value—recorded through regulatory assets and liabilities ^(c)	(8)	—	(11)	4	3	1		
Changes in allocated collateral	(908)	(905)	—	(4)	(3)	(1)		
Changes in net option premium paid	66	66	—	—	—	—		
Option premium amortization	11	11	—	—	—	—		
Upfront payments and amortizations ^(d)	140	140	—	—	—	—		
Total mark-to-market energy contract net assets (liabilities) at December 31, 2016 ^(a)	\$719	\$ 977	\$(258)	\$ —	\$ —	\$ —		

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

(b) Includes fair value from contracts received at acquisition of ConEdison Solutions of \$(59) million.

For ComEd and DPL, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2016, ComEd recorded a regulatory liability of \$258 million, respectively, related to its

(c) mark-to-market derivative liabilities with Generation and unaffiliated suppliers. ComEd recorded \$29 million of decreases in fair value and an increase for realized losses due to settlements of \$18 million in purchased power expense associated with floating-to-fixed energy swap suppliers for the year ended December 31, 2016.

(d) Includes derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums, and the associated amortizations.

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	Exelon	Generation	ComEd	DPL	PHI	Successor
Total mark-to-market energy contract net assets (liabilities) at December 31, 2016 ^(a)	\$ 719	\$ 977	\$ (258)	\$ —	\$ —	—
Total change in fair value during 2016 of contracts recorded in result of operations	110	110	—	—	—	—
Reclassification to be realized at settlement of contracts recorded in results of operations	(273)	(273)	—	—	—	—
Changes in fair value—recorded through regulatory assets and liabilities	(1)	—	2	(3)	(3))
Changes in allocated collateral	140	137	—	3	3	
Changes in net option premium received	(28)	(28)	—	—	—	
Option premium amortization	(7)	(7)	—	—	—	
Upfront payments and amortizations ^(b)	(24)	(24)	—	—	—	
Other miscellaneous ^(d)	31	31	—	—	—	
Total mark-to-market energy contract net assets (liabilities) at December 31, 2017 ^(a)	\$ 667	\$ 923	\$ (256)	\$ —	\$ —	—

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

(b) Includes derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums, and the associated amortizations.

(c) For ComEd and DPL, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2017, ComEd recorded a regulatory liability of \$256 million, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. For the year ended December 31, 2017, ComEd also recorded \$18 million of decreases in fair value and realized losses due to settlements of \$20 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2017.

(d) As a result of the bankruptcy filing for EGTP on November 7, 2017, the net mark-to-market commodity contracts were deconsolidated from Exelon's and Generation consolidated financial statements.

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Fair Values

The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities) net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 11 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within					2023 and Beyond	Total Fair Value
	2018	2019	2020	2021	2022		
Normal Operations, Commodity derivative contracts ^{(a)(b)} :							
Actively quoted prices (Level 1)	\$(32)	\$(43)	\$(15)	\$2	\$(2)	\$ —	\$ (90)
Prices provided by external sources (Level 2)	462	(6)	(1)	6	—	—	461
Prices based on model or other valuation methods (Level 3) ^(c)	315	130	23	(27)	(58)	(87)	296
Total	\$745	\$81	\$7	\$(19)	\$(60)	\$(87)	\$ 667

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

(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of \$466 million at December 31, 2017.

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

Generation

	Maturities Within					2023 and Beyond	Total Fair Value
	2018	2019	2020	2021	2022		
Normal Operations, Commodity derivative contracts ^{(a)(b)} :							
Actively quoted prices (Level 1)	\$(32)	\$(43)	\$(15)	\$2	\$(2)	\$ —	\$ (90)
Prices provided by external sources (Level 2)	462	(6)	(1)	6	—	—	461
Prices based on model or other valuation methods (Level 3) ^(c)	336	152	44	(6)	(37)	63	552
Total	\$766	\$103	\$28	\$2	\$(39)	\$ 63	\$ 923

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

(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of \$466 million at December 31, 2017.

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ComEd

	Maturities Within					2023 and Beyond	Fair Value
	2018	2019	2020	2021	2022		
Prices based on model or other valuation methods (Level 3) ^(a)	\$(21)	\$(22)	\$(21)	\$(21)	\$(21)	\$(150)	\$(256)

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

Credit Risk, Collateral and Contingent Related Features (All Registrants)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that execute derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchases and normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2017. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs and commodity exchanges, which are discussed below. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of \$28 million, \$22 million, \$24 million, \$36 million, \$12 million and \$6 million respectively. See Note 26 — Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Rating as of December 31, 2017	Total Exposure Before Credit Collateral	Credit Collateral ^(a)	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	\$ 738	\$ 4	\$ 734	1	\$ 244
Non-investment grade	90	12	78	—	—
No external ratings					
Internally rated—investment grade	253	—	253	—	—
Internally rated—non-investment grade	83	11	72	—	—
Total	\$ 1,164	\$ 27	\$ 1,137	1	\$ 244

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Rating as of December 31, 2017	Maturity of Credit Risk Exposure			
	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	\$657	\$ 80	\$ 1	\$ 738
Non-investment grade	74	16	—	90
No external ratings				
Internally rated—investment grade	191	30	32	253
Internally rated—non-investment grade	19	4	—	83
Total	\$1,001	\$ 130	\$ 33	\$ 1,164
Net Credit Exposure by Type of Counterparty	As of December 31, 2017			
Financial institutions	\$ 41			
Investor-owned utilities, marketers, power producers	558			
Energy cooperatives and municipalities	452			
Other	86			
Total	\$ 1,137			

(a) As of December 31, 2017, credit collateral held from counterparties where Generation had credit exposure included \$8 million of cash and \$19 million of letters of credit.

The Utility Registrants

Credit risk for the Utility Registrants is governed by credit and collection policies, which are aligned with state regulatory requirements. The Utility Registrants are currently obligated to provide service to all electric customers within their franchised territories. The Utility Registrants record a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. The Utility Registrants will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. The Utility Registrants did not have any customers representing over 10% of their revenues as of December 31, 2017. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

As of December 31, 2017, ComEd's net credit exposure to suppliers was approximately \$1 million. PECO and BGE had no net credit exposure to suppliers as of December 31, 2017. As of December 31, 2017 Pepco, DPL and ACE's net credit exposures were immaterial. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Collateral (All Registrants)Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, natural gas and other commodities. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation

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at the time of the demand. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements. See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

Generation transacts output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. As market prices rise above or fall below contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. To post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See ITEM 7. Liquidity and Capital Resources — Credit Matters — Exelon Credit Facilities for additional information.

The Utility Registrants

As of December 31, 2017, ComEd held \$10 million in collateral from suppliers in association with energy procurement contracts, approximately \$2 million in collateral from suppliers for REC contract obligations and approximately \$19 million in collateral from suppliers for long-term renewable energy contracts. BGE is not required to post collateral under its electric supply contracts but was holding an immaterial amount of collateral under its electric supply procurement contracts. BGE was not required to post collateral under its natural gas procurement contracts, but was holding an immaterial amount of collateral under its natural gas procurement contracts. PECO, Pepco, DPL and ACE were not required to post collateral under their energy and/or natural gas procurement contracts. See Note 3 — Regulatory Matters and Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

RTOs and ISOs (All Registrants)

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

Exchange Traded Transactions (Exelon, Generation, PHI and DPL)

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

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Interest Rate and Foreign Exchange Risk (All Registrants)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2017, Exelon had \$800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had \$636 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 basis point increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a \$6 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2017. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. See Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning its nuclear plants. As of December 31, 2017, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a \$662 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

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

Generation

General

Generation's integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. These segments are discussed in further detail in ITEM 1. BUSINESS — Exelon Generation Company, LLC of this Form 10-K.

Executive Overview

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

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

A discussion of Generation's results of operations for 2017 compared to 2016 and 2016 compared to 2015 is set forth under Results of Operations—Generation in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

Generation's business is capital intensive and requires considerable capital resources. Generation's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, participation in the intercompany money pool or capital contributions from Exelon. Generation's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where Generation no longer has access to the capital markets at reasonable terms, Generation has access to credit facilities in the aggregate of \$5.8 billion that Generation currently utilizes to support its commercial paper program and to issue letters of credit.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

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

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Cash Flows from Operating Activities

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

Cash Flows from Investing Activities

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

Cash Flows from Financing Activities

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

Credit Matters

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

Contractual Obligations and Off-Balance Sheet Arrangements

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

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of Generation's critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Generation

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

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

ComEd

General

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

Executive Overview

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

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

A discussion of ComEd's results of operations for 2017 compared to 2016 and for 2016 compared to 2015 is set forth under Results of Operations—ComEd in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

ComEd's business is capital intensive and requires considerable capital resources. ComEd's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ComEd's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2017, ComEd had access to a revolving credit facility with aggregate bank commitments of \$1 billion.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

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

Cash Flows from Operating Activities

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

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Cash Flows from Investing Activities

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

Cash Flows from Financing Activities

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

Credit Matters

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

Contractual Obligations and Off-Balance Sheet Arrangements

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

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of ComEd's critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ComEd

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

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

PECO

General

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

Executive Overview

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

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

A discussion of PECO's results of operations for 2017 compared to 2016 and for 2016 compared to 2015 is set forth under Results of Operations—PECO in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

PECO's business is capital intensive and requires considerable capital resources. PECO's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or participation in the intercompany money pool. PECO's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where PECO no longer has access to the capital markets at reasonable terms, PECO has access to a revolving credit facility. At December 31, 2017, PECO had access to a revolving credit facility with aggregate bank commitments of \$600 million.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

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

Cash Flows from Operating Activities

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

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Cash Flows from Investing Activities

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

Cash Flows from Financing Activities

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

Credit Matters

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

Contractual Obligations and Off-Balance Sheet Arrangements

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

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of PECO's critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PECO

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

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

BGE

General

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

Executive Overview

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

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

A discussion of BGE's results of operations for 2017 compared to 2016 and for 2016 compared to 2015 is set forth under Results of Operations—BGE in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

BGE's business is capital intensive and requires considerable capital resources. BGE's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. BGE's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where BGE no longer has access to the capital markets at reasonable terms, BGE has access to a revolving credit facility. At December 31, 2017, BGE had access to a revolving credit facility with aggregate bank commitments of \$600 million.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

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

Cash Flows from Operating Activities

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

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Cash Flows from Investing Activities

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

Cash Flows from Financing Activities

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

Credit Matters

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

Contractual Obligations and Off-Balance Sheet Arrangements

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

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of BGE's critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BGE

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

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

PHI

General

PHI has three reportable segments Pepco, DPL, and ACE. Its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services, and to a lesser extent, the purchase and regulated retail sale and supply of natural gas in Delaware. This segment is discussed in further detail in ITEM 1.

BUSINESS — PHI of this Form 10-K.

Executive Overview

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

Results of Operations

Successor Period Year Ended December 31, 2017, Successor Period of March 24, 2016 to December 31, 2016 and Predecessor Period of January 1, 2016 to March 23, 2016, Predecessor Period Year Ended December 31, 2015

A discussion of PHI's results of operations for 2017 compared to 2016, March 24, 2016 to December 31, 2016 and January 1, 2016 to March 23, 2016, and the year ended December 31, 2015 is set forth under Results of

Operations—PHI in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

PHI's business is capital intensive and requires considerable capital resources. PHI's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper, borrowings from the Exelon money pool or capital contributions from Exelon. PHI's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

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

Cash Flows from Operating Activities

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

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Cash Flows from Investing Activities

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

Cash Flows from Financing Activities

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

Credit Matters

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

Contractual Obligations and Off-Balance Sheet Arrangements

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

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of PHI's critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PHI

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

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

Pepco

General

Pepco operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in District of Columbia and major portions of Prince George's County and Montgomery County in Maryland. This segment is discussed in further detail in ITEM 1. BUSINESS — Pepco of this Form 10-K.

Executive Overview

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

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

A discussion of Pepco's results of operations for 2017 compared to 2016 and for 2016 compared to 2015 is set forth under Results of Operations—Pepco in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

Pepco's business is capital intensive and requires considerable capital resources. Pepco's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. Pepco's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2017, Pepco had access to a revolving credit facility with aggregate bank commitments of \$300 million.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

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

Cash Flows from Operating Activities

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

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Cash Flows from Investing Activities

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

Cash Flows from Financing Activities

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

Credit Matters

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

Contractual Obligations and Off-Balance Sheet Arrangements

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

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of Pepco's critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Pepco

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

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

DPL

General

DPL operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale and supply of natural gas in New Castle County, Delaware. This segment is discussed in further detail in ITEM 1. BUSINESS — DPL of this Form 10-K.

Executive Overview

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

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

A discussion of DPL's results of operations for 2017 compared to 2016 and for 2016 compared to 2015 is set forth under Results of Operations—DPL in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

DPL's business is capital intensive and requires considerable capital resources. DPL's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. DPL's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where DPL no longer has access to the capital markets at reasonable terms, DPL has access to a revolving credit facility. At December 31, 2017, DPL had access to a revolving credit facility with aggregate bank commitments of \$300 million.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

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

Cash Flows from Operating Activities

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

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Cash Flows from Investing Activities

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

Cash Flows from Financing Activities

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

Credit Matters

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

Contractual Obligations and Off-Balance Sheet Arrangements

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

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of DPL's critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

DPL

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

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

ACE

General

ACE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in portions of southern New Jersey. This segment is discussed in further detail in ITEM 1. BUSINESS — ACE of this Form 10-K.

Executive Overview

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

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

A discussion of ACE's results of operations for 2017 compared to 2016 and for 2016 compared to 2015 is set forth under Results of Operations—ACE in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

ACE's business is capital intensive and requires considerable capital resources. ACE's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ACE's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2017, ACE had access to a revolving credit facility with aggregate bank commitments of \$300 million.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

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

Cash Flows from Operating Activities

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

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Cash Flows from Investing Activities

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

Cash Flows from Financing Activities

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

Credit Matters

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

Contractual Obligations and Off-Balance Sheet Arrangements

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

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of ACE's critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ACE

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

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

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

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

Exelon's management conducted an assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of December 31, 2017, Exelon's internal control over financial reporting was effective.

The effectiveness of Exelon's internal control over financial reporting as of December 31, 2017, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 9, 2018

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Management's Report on Internal Control Over Financial Reporting

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

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

Generation's management conducted an assessment of the effectiveness of Generation's internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Generation's management concluded that, as of December 31, 2017, Generation's internal control over financial reporting was effective.

The effectiveness of Generation's internal control over financial reporting as of December 31, 2017, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 9, 2018

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Management's Report on Internal Control Over Financial Reporting

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

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

ComEd's management conducted an assessment of the effectiveness of ComEd's internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ComEd's management concluded that, as of December 31, 2017, ComEd's internal control over financial reporting was effective.

The effectiveness of ComEd's internal control over financial reporting as of December 31, 2017, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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Management's Report on Internal Control Over Financial Reporting

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

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

PECO's management conducted an assessment of the effectiveness of PECO's internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PECO's management concluded that, as of December 31, 2017, PECO's internal control over financial reporting was effective.

The effectiveness of PECO's internal control over financial reporting as of December 31, 2017, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 9, 2018

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Management's Report on Internal Control Over Financial Reporting

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

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

BGE's management conducted an assessment of the effectiveness of BGE's internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, BGE's management concluded that, as of December 31, 2017, BGE's internal control over financial reporting was effective.

The effectiveness of BGE's internal control over financial reporting as of December 31, 2017, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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Management's Report on Internal Control Over Financial Reporting

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

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

PHI's management conducted an assessment of the effectiveness of PHI's internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PHI's management concluded that, as of December 31, 2017, PHI's internal control over financial reporting was effective.

The effectiveness of PHI's internal control over financial reporting as of December 31, 2017, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 9, 2018

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Management's Report on Internal Control Over Financial Reporting

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

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

Pepco's management conducted an assessment of the effectiveness of Pepco's internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Pepco's management concluded that, as of December 31, 2017, Pepco's internal control over financial reporting was effective.

February 9, 2018

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Management's Report on Internal Control Over Financial Reporting

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

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

DPL's management conducted an assessment of the effectiveness of DPL's internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, DPL's management concluded that, as of December 31, 2017, DPL's internal control over financial reporting was effective.

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Management's Report on Internal Control Over Financial Reporting

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

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

ACE's management conducted an assessment of the effectiveness of ACE's internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ACE's management concluded that, as of December 31, 2017, ACE's internal control over financial reporting was effective.

February 9, 2018

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Report of Independent Registered Public Accounting Firm
To the Board of Directors and Shareholders of Exelon Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedules listed in the index appearing under Item 15(a)(2), of Exelon Corporation and its subsidiaries (collectively referred to as the “consolidated financial statements”). We also have audited the Company’s internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management’s Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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Definition and Limitations of Internal Control over Financial Reporting

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 9, 2018

We have served as the Company's auditor since 2000.

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Report of Independent Registered Public Accounting Firm

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

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of Exelon Generation Company, LLC and its subsidiaries (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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Definition and Limitations of Internal Control over Financial Reporting

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 9, 2018

We have served as the Company's auditor since 2001.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Commonwealth Edison Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of Commonwealth Edison Company and its subsidiaries (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 9, 2018

We have served as the Company's auditor since 2000.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of PECO Energy Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of PECO Energy Company and its subsidiaries (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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Definition and Limitations of Internal Control over Financial Reporting

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 9, 2018

We have served as the Company's auditor since 1932.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Baltimore Gas and Electric Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of Baltimore Gas and Electric Company and its subsidiaries (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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Definition and Limitations of Internal Control over Financial Reporting

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 9, 2018

We have served as the Company's auditor since at least 1993. We have not determined the specific year we began serving as auditor of the Company.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Pepco Holdings LLC

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of Pepco Holdings LLC and its subsidiaries (Successor) (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for the year ended December 31, 2017, for the period from March 24, 2016 to December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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Definition and Limitations of Internal Control over Financial Reporting

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 9, 2018

We have served as the Company's auditor since 2001.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Pepco Holdings LLC

In our opinion, the financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the results of operations and the cash flows of Pepco Holdings LLC and its subsidiaries (formerly Pepco Holdings, Inc.) (Predecessor) for the period January 1, 2016 to March 23, 2016 and for the year ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the financial statements, the Company changed the manner in which it accounts for interest on uncertain tax positions in 2016.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 13, 2017

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Potomac Electric Power Company

Opinion on the Financial Statements

We have audited the financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of Potomac Electric Power Company (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 9, 2018

We have served as the Company's auditor since at least 1993. We have not determined the specific year we began serving as auditor of the Company.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Delmarva Power & Light Company

Opinion on the Financial Statements

We have audited the financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of Delmarva Power & Light Company (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 9, 2018

We have served as the Company's auditor since at least 1993. We have not determined the specific year we began serving as auditor of the Company.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Atlantic City Electric Company

Opinion on the Financial Statements

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of Atlantic City Electric Company and its subsidiary (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 9, 2018

We have served as the Company's auditor since 1998.

Table of ContentsExelon Corporation and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions, except per share data)	For the Years Ended		
	December 31,		
	2017	2016	2015
Operating revenues			
Competitive businesses revenues	\$17,360	\$16,324	\$18,395
Rate-regulated utility revenues	16,171	15,036	11,052
Total operating revenues	33,531	31,360	29,447
Operating expenses			
Competitive businesses purchased power and fuel	9,668	8,817	10,007
Rate-regulated utility purchased power and fuel	4,367	3,823	3,077
Operating and maintenance	10,126	10,048	8,322
Depreciation and amortization	3,828	3,936	2,450
Taxes other than income	1,731	1,576	1,200
Total operating expenses	29,720	28,200	25,056
Gain (Loss) on sales of assets	3	(48)	18
Bargain purchase gain	233	—	—
Gain on deconsolidation of business	213	—	—
Operating income	4,260	3,112	4,409
Other income and (deductions)			
Interest expense, net	(1,524)	(1,495)	(992)
Interest expense to affiliates	(36)	(41)	(41)
Other, net	1,056	413	(46)
Total other income and (deductions)	(504)	(1,123)	(1,079)
Income before income taxes	3,756	1,989	3,330
Income taxes	(125)	761	1,073
Equity in losses of unconsolidated affiliates	(32)	(24)	(7)
Net income	3,849	1,204	2,250
Net income (loss) attributable to noncontrolling interests and preference stock dividends	79	70	(19)
Net income attributable to common shareholders	\$3,770	\$1,134	\$2,269
Comprehensive income, net of income taxes			
Net income	\$3,849	\$1,204	\$2,250
Other comprehensive income (loss), net of income taxes			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	(56)	(48)	(46)
Actuarial loss reclassified to periodic benefit cost	197	184	220
Pension and non-pension postretirement benefit plan valuation adjustment	10	(181)	(99)
Unrealized gain on cash flow hedges	3	2	9
Unrealized gain on marketable securities	6	1	—
Unrealized gain (loss) on equity investments	4	(4)	(3)
Unrealized gain (loss) on foreign currency translation	7	10	(21)
Other comprehensive income (loss)	171	(36)	60
Comprehensive income	4,020	1,168	2,310
Comprehensive income (loss) attributable to noncontrolling interests and preference stock dividends	77	70	(19)
Comprehensive income attributable to common shareholders	\$3,943	\$1,098	\$2,329

Average shares of common stock outstanding:			
Basic	947	924	890
Diluted	949	927	893
Earnings per average common share:			
Basic	\$3.98	\$1.23	\$2.55
Diluted	\$3.97	\$1.22	\$2.54
Dividends per common share	\$1.31	\$1.26	\$1.24

See the Combined Notes to Consolidated Financial Statements

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Table of ContentsExelon Corporation and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended		
	December 31, 2017	2016	2015
Cash flows from operating activities			
Net income	\$3,849	\$1,204	\$2,250
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	5,427	5,576	3,987
Impairment losses of long-lived assets, intangibles and regulatory assets	573	306	36
Gain on deconsolidation of business	(213)	—	—
(Gain) Loss on sales of assets	(3)	48	(18)
Bargain purchase gain	(233)	—	—
Deferred income taxes and amortization of investment tax credits	(361)	664	752
Net fair value changes related to derivatives	151	24	(367)
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(616)	(229)	131
Other non-cash operating activities	721	1,333	1,109
Changes in assets and liabilities:			
Accounts receivable	(426)	(432)	240
Inventories	(72)	7	4
Accounts payable and accrued expenses	(390)	771	(121)
Option premiums received (paid), net	28	(66)	58
Collateral (posted) received, net	(158)	931	347
Income taxes	299	576	97
Pension and non-pension postretirement benefit contributions	(405)	(397)	(502)
Deposit with IRS	—	(1,250)	—
Other assets and liabilities	(691)	(621)	(387)
Net cash flows provided by operating activities	7,480	8,445	7,616
Cash flows from investing activities			
Capital expenditures	(7,584)	(8,553)	(7,624)
Proceeds from termination of direct financing lease investment	—	360	—
Proceeds from nuclear decommissioning trust fund sales	7,845	9,496	6,895
Investment in nuclear decommissioning trust funds	(8,113)	(9,738)	(7,147)
Acquisitions of businesses, net	(208)	(6,934)	(40)
Proceeds from sales of long-lived assets	219	61	147
Change in restricted cash	(50)	(42)	66
Other investing activities	(43)	(153)	(119)
Net cash flows used in investing activities	(7,934)	(15,503)	(7,822)
Cash flows from financing activities			
Changes in short-term borrowings	(261)	(353)	80
Proceeds from short-term borrowings with maturities greater than 90 days	621	240	—
Repayments on short-term borrowings with maturities greater than 90 days	(700)	(462)	—
Issuance of long-term debt	3,470	4,716	6,709
Retirement of long-term debt	(2,490)	(1,936)	(2,687)
Retirement of long-term debt to financing trust	(250)	—	—
Restricted proceeds from issuance of long-term debt	(50)	—	—
Issuance of common stock	—	—	1,868

Common stock issued from treasury stock	1,150	—	—
Redemption of preference stock	—	(190)	—
Dividends paid on common stock	(1,236)	(1,166)	(1,105)
Proceeds from employee stock plans	150	55	32
Sale of noncontrolling interests	396	372	32
Other financing activities	(83)	(85)	(99)
Net cash flows provided by financing activities	717	1,191	4,830
Increase (Decrease) in cash and cash equivalents	263	(5,867)	4,624
Cash and cash equivalents at beginning of period	635	6,502	1,878
Cash and cash equivalents at end of period	\$898	\$635	\$6,502

See the Combined Notes to Consolidated Financial Statements

Table of ContentsExelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31,	
	2017	2016
ASSETS		
Current assets		
Cash and cash equivalents	\$898	\$635
Restricted cash and cash equivalents	207	253
Deposit with IRS	—	1,250
Accounts receivable, net		
Customer	4,401	4,158
Other	1,132	1,201
Mark-to-market derivative assets	976	917
Unamortized energy contract assets	60	88
Inventories, net		
Fossil fuel and emission allowances	340	364
Materials and supplies	1,311	1,274
Regulatory assets	1,267	1,342
Other	1,242	930
Total current assets	11,834	12,412
Property, plant and equipment, net	74,202	71,555
Deferred debits and other assets		
Regulatory assets	8,021	10,046
Nuclear decommissioning trust funds	13,272	11,061
Investments	640	629
Goodwill	6,677	6,677
Mark-to-market derivative assets	337	492
Unamortized energy contract assets	395	447
Pledged assets for Zion Station decommissioning	—	113
Other	1,322	1,472
Total deferred debits and other assets	30,664	30,937
Total assets ^(a)	\$116,700	\$114,904

See the Combined Notes to Consolidated Financial Statements

Table of ContentsExelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

	December 31,	
	2017	2016
(In millions)		
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	\$929	\$1,267
Long-term debt due within one year	2,088	2,430
Accounts payable	3,532	3,441
Accrued expenses	1,835	3,460
Payables to affiliates	5	8
Regulatory liabilities	523	602
Mark-to-market derivative liabilities	232	282
Unamortized energy contract liabilities	231	407
Renewable energy credit obligation	352	428
PHI Merger related obligation	87	151
Other	982	981
Total current liabilities	10,796	13,457
Long-term debt	32,176	31,575
Long-term debt to financing trusts	389	641
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,222	18,138
Asset retirement obligations	10,029	9,111
Pension obligations	3,736	4,248
Non-pension postretirement benefit obligations	2,093	1,848
Spent nuclear fuel obligation	1,147	1,024
Regulatory liabilities	9,865	4,187
Mark-to-market derivative liabilities	409	392
Unamortized energy contract liabilities	609	830
Payable for Zion Station decommissioning	—	14
Other	2,097	1,827
Total deferred credits and other liabilities	41,207	41,619
Total liabilities ^(a)	84,568	87,292
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2000 shares authorized, 963 shares and 924 shares outstanding at December 31, 2017 and 2016, respectively)	18,964	18,794
Treasury stock, at cost (2 shares and 35 shares at December 31, 2017 and 2016, respectively)	(123)	(2,327)
Retained earnings	13,503	12,030
Accumulated other comprehensive loss, net	(2,487)	(2,660)
Total shareholders' equity	29,857	25,837
Noncontrolling interests	2,275	1,775
Total equity	32,132	27,612
Total liabilities and equity	\$116,700	\$114,904

Exelon's consolidated assets include \$9,565 million and \$8,893 million at December 31, 2017 and December 31, 2016, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include \$3,612 million and \$3,356 million at December 31, 2017 and December 31, 2016, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 2—Variable Interest Entities.

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Exelon Corporation and Subsidiary Companies

Consolidated Statements of Changes in Equity

Shareholders' Equity

(In millions, shares in thousands)	Shareholders' Equity				Accumulated		Noncontrolling Interests	Preference Stock	Total Equity
	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Other Comprehensive Loss				
Balance, December 31, 2014	894,568	\$16,709	\$(2,327)	\$10,910	\$(2,684)	\$1,332	\$193	\$24,133	
Net income (loss)	—	—	—	2,269	—	(32)	13	2,250	
Long-term incentive plan activity	1,430	70	—	—	—	—	—	70	
Employee stock purchase plan issuances	1,170	32	—	—	—	—	—	32	
Issuance of common stock	57,500	1,868	—	—	—	—	—	1,868	
Tax benefit on stock compensation	—	(3)	—	—	—	—	—	(3)	
Acquisition of noncontrolling interests	—	—	—	—	—	4	—	4	
Adjustment of contingently redeemable noncontrolling interests due to release of contingency	—	—	—	—	—	4	—	4	
Common stock dividends	—	—	—	(1,111)	—	—	—	(1,111)	
Preference stock dividends	—	—	—	—	—	—	(13)	(13)	
Other comprehensive income, net of income taxes	—	—	—	—	60	—	—	60	
Balance, December 31, 2015	954,668	\$18,676	\$(2,327)	\$12,068	\$(2,624)	\$1,308	\$193	\$27,294	
Net income	—	—	—	1,134	—	62	8	1,204	
Long-term incentive plan activity	2,868	85	—	—	—	—	—	85	
Employee stock purchase plan issuances	1,242	55	—	—	—	—	—	55	
Tax benefit on stock compensation	—	(18)	—	—	—	—	—	(18)	
Changes in equity of noncontrolling interests	—	—	—	—	—	5	—	5	
Sale of noncontrolling interest	—	(4)	—	—	—	243	—	239	
Adjustment of contingently redeemable noncontrolling interests due to release of contingency	—	—	—	—	—	157	—	157	
Common stock dividends	—	—	—	(1,172)	—	—	—	(1,172)	
Redemption of preference stock	—	—	—	—	—	—	(193)	(193)	
Preference stock dividends	—	—	—	—	—	—	(8)	(8)	
Other comprehensive loss, net of income taxes	—	—	—	—	(36)	—	—	(36)	

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Balance, December 31, 2016	958,778	\$18,794	\$(2,327)	\$12,030	\$(2,660)) \$1,775	\$—	\$27,612
Net income	—	—	—	3,770	—	79	—	3,849
Long-term incentive plan activity	5,066	56	—	—	—	—	—	56
Employee stock purchase plan issuances	1,324	150	—	—	—	—	—	150
Common stock issued from treasury stock	—	—	2,204	(1,054)	—	—	—	1,150
Changes in equity of noncontrolling interests	—	—	—	—	—	(20)) —	(20)
Sale of noncontrolling interests	—	(36)) —	—	—	443	—	407
Common stock dividends	—	—	—	(1,243)	—	—	—	(1,243)
Other comprehensive income, net of income taxes	—	—	—	—	173	(2)) —	171
Balance, December 31, 2017	965,168	\$18,964	\$(123)) \$13,503	\$(2,487)) \$2,275	\$—	\$32,132

See the Combined Notes to Consolidated Financial Statements

Table of ContentsExelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended		
	December 31,		
	2017	2016	2015
Operating revenues			
Operating revenues	\$17,351	\$16,312	\$18,386
Operating revenues from affiliates	1,115	1,439	749
Total operating revenues	18,466	17,751	19,135
Operating expenses			
Purchased power and fuel	9,671	8,818	10,007
Purchased power and fuel from affiliates	19	12	14
Operating and maintenance	5,594	4,978	4,688
Operating and maintenance from affiliates	697	663	620
Depreciation and amortization	1,457	1,879	1,054
Taxes other than income	555	506	489
Total operating expenses	17,993	16,856	16,872
Gain (Loss) on sales of assets	2	(59)	12
Bargain purchase gain	233	—	—
Gain on deconsolidation of business	213	—	—
Operating income	921	836	2,275
Other income and (deductions)			
Interest expense, net	(401)	(325)	(322)
Interest expense to affiliates	(39)	(39)	(43)
Other, net	948	401	(60)
Total other income and (deductions)	508	37	(425)
Income before income taxes	1,429	873	1,850
Income taxes	(1,375)	290	502
Equity in losses of unconsolidated affiliates	(33)	(25)	(8)
Net income	2,771	558	1,340
Net income (loss) attributable to noncontrolling interests	77	62	(32)
Net income attributable to membership interest	\$2,694	\$496	\$1,372
Comprehensive income, net of income taxes			
Net income	\$2,771	\$558	\$1,340
Other comprehensive income (loss), net of income taxes			
Unrealized gain (loss) on cash flow hedges	3	2	(3)
Unrealized gain (loss) on equity investments	4	(4)	(3)
Unrealized gain (loss) on foreign currency translation	7	10	(21)
Unrealized gain on marketable securities	1	1	—
Other comprehensive income (loss)	15	9	(27)
Comprehensive income	\$2,786	\$567	\$1,313
Comprehensive income (loss) attributable to noncontrolling interests	75	62	(32)
Comprehensive income attributable to membership interest	\$2,711	\$505	\$1,345

See the Combined Notes to Consolidated Financial Statements

Table of ContentsExelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended		
	December 31, 2017	2016	2015
Cash flows from operating activities			
Net income	\$2,771	\$558	\$1,340
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	3,056	3,519	2,589
Impairment losses of long-lived assets	510	243	12
Gain on deconsolidation of business	(213)	—	—
(Gain) Loss on sales of assets	(2)	59	(12)
Bargain purchase gain	(233)	—	—
Deferred income taxes and amortization of investment tax credits	(2,022)	(269)	49
Net fair value changes related to derivatives	167	40	(249)
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(616)	(229)	131
Other non-cash operating activities	112	15	268
Changes in assets and liabilities:			
Accounts receivable	(276)	(152)	194
Receivables from and payables to affiliates, net	(7)	(21)	15
Inventories	(29)	(4)	16
Accounts payable and accrued expenses	2	29	(149)
Option premiums received (paid), net	28	(66)	58
Collateral (posted) received, net	(129)	923	407
Income taxes	496	182	(18)
Pension and non-pension postretirement benefit contributions	(148)	(152)	(245)
Other assets and liabilities	(168)	(231)	(207)
Net cash flows provided by operating activities	3,299	4,444	4,199
Cash flows from investing activities			
Capital expenditures	(2,259)	(3,078)	(3,841)
Proceeds from nuclear decommissioning trust fund sales	7,845	9,496	6,895
Investment in nuclear decommissioning trust funds	(8,113)	(9,738)	(7,147)
Proceeds from sales of long-lived assets	218	37	147
Acquisitions of businesses, net	(208)	(293)	(40)
Change in restricted cash	(17)	(35)	35
Other investing activities	(58)	(240)	(118)
Net cash flows used in investing activities	(2,592)	(3,851)	(4,069)
Cash flows from financing activities			
Change in short-term borrowings	(620)	620	—
Proceeds from short-term borrowings with maturities greater than 90 days	121	240	—
Repayments of short-term borrowings with maturities greater than 90 days	(200)	(162)	—
Issuance of long-term debt	1,645	388	1,309
Retirement of long-term debt	(1,261)	(202)	(89)
Restricted proceeds from issuance of long-term debt	(50)	—	—
Retirement of long-term debt to affiliate	—	—	(550)
Changes in Exelon intercompany money pool	(1)	(1,191)	1,252
Distributions to member	(659)	(922)	(2,474)

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Contributions from member	102	142	47
Sale of noncontrolling interests	396	372	32
Other financing activities	(54)	(19)	(6)
Net cash flows used in financing activities	(581)	(734)	(479)
Increase (Decrease) in cash and cash equivalents	126	(141)	(349)
Cash and cash equivalents at beginning of period	290	431	780
Cash and cash equivalents at end of period	\$416	\$290	\$431

See the Combined Notes to Consolidated Financial Statements

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Table of ContentsExelon Generation Company, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31,	
	2017	2016
ASSETS		
Current assets		
Cash and cash equivalents	\$416	\$290
Restricted cash and cash equivalents	138	158
Accounts receivable, net		
Customer	2,653	2,433
Other	321	558
Mark-to-market derivative assets	976	917
Receivables from affiliates	140	156
Unamortized energy contract assets	60	88
Inventories, net		
Fossil fuel and emission allowances	264	292
Materials and supplies	937	935
Other	915	701
Total current assets	6,820	6,528
Property, plant and equipment, net	24,906	25,585
Deferred debits and other assets		
Nuclear decommissioning trust funds	13,272	11,061
Investments	433	418
Goodwill	47	47
Mark-to-market derivative assets	334	476
Prepaid pension asset	1,502	1,595
Pledged assets for Zion Station decommissioning	—	113
Unamortized energy contract assets	395	447
Deferred income taxes	16	16
Other	662	688
Total deferred debits and other assets	16,661	14,861
Total assets ^(a)	\$48,387	\$46,974

See the Combined Notes to Consolidated Financial Statements

Table of ContentsExelon Generation Company, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31,	
	2017	2016
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	\$2	\$699
Long-term debt due within one year	346	1,117
Accounts payable	1,773	1,610
Accrued expenses	1,020	989
Payables to affiliates	123	137
Borrowings from Exelon intercompany money pool	54	55
Mark-to-market derivative liabilities	211	263
Unamortized energy contract liabilities	43	72
Renewable energy credit obligation	352	428
Other	265	313
Total current liabilities	4,189	5,683
Long-term debt	7,734	7,202
Long-term debt to affiliate	910	922
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,798	5,585
Asset retirement obligations	9,844	8,922
Non-pension postretirement benefit obligations	916	930
Spent nuclear fuel obligation	1,147	1,024
Payables to affiliates	3,065	2,608
Mark-to-market derivative liabilities	174	153
Unamortized energy contract liabilities	48	80
Payable for Zion Station decommissioning	—	14
Other	658	595
Total deferred credits and other liabilities	19,650	19,911
Total liabilities ^(a)	32,483	33,718
Equity		
Member's equity		
Membership interest	9,357	9,261
Undistributed earnings	4,310	2,275
Accumulated other comprehensive loss, net	(37) (54
Total member's equity	13,630	11,482
Noncontrolling interests	2,274	1,774
Total equity	15,904	13,256
Total liabilities and equity	\$48,387	\$46,974

Generation's consolidated assets include \$9,524 million and \$8,817 million at December 31, 2017 and 2016, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include \$3,510 million and \$3,170 million at December 31, 2017 and 2016, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 2—Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Table of ContentsExelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Changes in Equity

(In millions)	Member's Equity			Noncontrolling Interests	Total Equity
	Members' Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net		
Balance, December 31, 2014	\$8,951	\$ 3,803	\$ (36)	\$ 1,333	\$14,051
Net income (loss)	—	1,372	—	(32)	1,340
Acquisition of noncontrolling interests	(1)	—	—	2	1
Adjustment of contingently redeemable noncontrolling interests due to release of contingency	—	—	—	4	4
Allocation of tax benefit from member	47	—	—	—	47
Distribution to member	—	(2,474)	—	—	(2,474)
Other comprehensive loss, net of income taxes	—	—	(27)	—	(27)
Balance, December 31, 2015	\$8,997	\$ 2,701	\$ (63)	\$ 1,307	\$12,942
Net income	—	496	—	62	558
Sale of noncontrolling interests	(4)	—	—	243	239
Adjustment of contingently redeemable noncontrolling interests due to release of contingency	—	—	—	157	157
Changes in equity of noncontrolling interests	—	—	—	5	5
Allocation of tax benefit from member	98	—	—	—	98
Contribution from member	170	—	—	—	170
Distribution to member	—	(922)	—	—	(922)
Other comprehensive income, net of income taxes	—	—	9	—	9
Balance, December 31, 2016	\$9,261	\$ 2,275	\$ (54)	\$ 1,774	\$13,256
Net income	—	2,694	—	77	2,771
Sale of noncontrolling interests	(36)	—	—	443	407
Changes in equity of noncontrolling interests	—	—	—	(18)	(18)
Distribution of net retirement benefit obligation to member	33	—	—	—	33
Allocation of tax benefit from member	99	—	—	—	99
Distribution to member	—	(659)	—	—	(659)
Other comprehensive income, net of income taxes	—	—	17	(2)	15
Balance, December 31, 2017	\$9,357	\$ 4,310	\$ (37)	\$ 2,274	\$15,904

See the Combined Notes to Consolidated Financial Statements

Table of ContentsCommonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended		
	December 31,		
	2017	2016	2015
Operating revenues			
Electric operating revenues	\$5,521	\$5,239	\$4,901
Operating revenues from affiliates	15	15	4
Total operating revenues	5,536	5,254	4,905
Operating expenses			
Purchased power	1,533	1,411	1,301
Purchased power from affiliate	108	47	18
Operating and maintenance	1,157	1,303	1,372
Operating and maintenance from affiliate	270	227	195
Depreciation and amortization	850	775	707
Taxes other than income	296	293	296
Total operating expenses	4,214	4,056	3,889
Gain on sales of assets	1	7	1
Operating income	1,323	1,205	1,017
Other income and (deductions)			
Interest expense, net	(348)	(448)	(319)
Interest expense to affiliates	(13)	(13)	(13)
Other, net	22	(65)	21
Total other income and (deductions)	(339)	(526)	(311)
Income before income taxes	984	679	706
Income taxes	417	301	280
Net income	\$567	\$378	\$426
Comprehensive income	\$567	\$378	\$426

See the Combined Notes to Consolidated Financial Statements

Table of ContentsCommonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31,		
	2017	2016	2015
Cash flows from operating activities			
Net income	\$ 567	\$ 378	\$ 426
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	850	775	707
Deferred income taxes and amortization of investment tax credits	659	439	353
Other non-cash operating activities	164	215	416
Changes in assets and liabilities:			
Accounts receivable	(59)	(25)	(93)
Receivables from and payables to affiliates, net	8	3	(19)
Inventories	4	1	(40)
Accounts payable and accrued expenses	(297)	339	68
Counterparty collateral received (posted), net and cash deposits	(26)	7	(33)
Income taxes	(308)	306	192
Pension and non-pension postretirement benefit contributions	(41)	(38)	(150)
Other assets and liabilities	6	105	69
Net cash flows provided by operating activities	1,527	2,505	1,896
Cash flows from investing activities			
Capital expenditures	(2,250)	(2,734)	(2,398)

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Change in restricted cash	(66)	—	2		
Other investing activities	20		49	34		
Net cash flows used in investing activities	(2,296)	(2,685)	(2,362)
Cash flows from financing activities						
Changes in short-term borrowings	—		(294)	(10)
Issuance of long-term debt	1,000		1,200		850	
Retirement of long-term debt	(425)	(665)	(260)
Contributions from parent	651		315		202	
Dividends paid on common stock	(422)	(369)	(299)
Other financing activities	(15)	(18)	(16)
Net cash flows provided by financing activities	789		169		467	
Increase (Decrease) in cash and cash equivalents	20		(11)	1	
Cash and cash equivalents at beginning of period	56		67		66	
Cash and cash equivalents at end of period	\$ 76		\$ 56		\$ 67	

See the Combined Notes to Consolidated Financial Statements

Table of ContentsCommonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31,	
	2017	2016
ASSETS		
Current assets		
Cash and cash equivalents	\$76	\$56
Restricted cash	5	2
Accounts receivable, net		
Customer	559	528
Other	266	218
Receivables from affiliates	13	356
Inventories, net	152	159
Regulatory assets	225	190
Other	68	45
Total current assets	1,364	1,554
Property, plant and equipment, net	20,723	19,335
Deferred debits and other assets		
Regulatory assets	1,054	977
Investments	6	6
Goodwill	2,625	2,625
Receivable from affiliates	2,528	2,170
Prepaid pension asset	1,188	1,343
Other	238	325
Total deferred debits and other assets	7,639	7,446
Total assets	\$29,726	\$28,335

See the Combined Notes to Consolidated Financial Statements

Table of ContentsCommonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31,	
	2017	2016
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	\$840	\$425
Accounts payable	568	645
Accrued expenses	327	1,250
Payables to affiliates	74	65
Customer deposits	112	121
Regulatory liabilities	249	329
Mark-to-market derivative liability	21	19
Other	103	84
Total current liabilities	2,294	2,938
Long-term debt	6,761	6,608
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,469	5,364
Asset retirement obligations	111	119
Non-pension postretirement benefits obligations	219	239
Regulatory liabilities	6,328	3,369
Mark-to-market derivative liability	235	239
Other	562	529
Total deferred credits and other liabilities	10,924	9,859
Total liabilities	20,184	19,610
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	6,822	6,150
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	2,771	2,626
Total shareholders' equity	9,542	8,725
Total liabilities and shareholders' equity	\$29,726	\$28,335

See the Combined Notes to Consolidated Financial Statements

Table of ContentsCommonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholders' Equity

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2014	\$ 1,588	\$ 5,468	\$ (1,639)	\$ 2,490	\$ 7,907
Net income	—	—	426	—	426
Common stock dividends	—	—	—	(299)	(299)
Contribution from parent	—	202	—	—	202
Parent tax matter indemnification	—	7	—	—	7
Appropriation of retained earnings for future dividends	—	—	(426)	426	—
Balance, December 31, 2015	\$ 1,588	\$ 5,677	\$ (1,639)	\$ 2,617	\$ 8,243
Net income	—	—	378	—	378
Common stock dividends	—	—	—	(369)	(369)
Contribution from parent	—	315	—	—	315
Parent tax matter indemnification	—	158	—	—	158
Appropriation of retained earnings for future dividends	—	—	(378)	378	—
Balance, December 31, 2016	\$ 1,588	\$ 6,150	\$ (1,639)	\$ 2,626	\$ 8,725
Net income	—	—	567	—	567
Common stock dividends	—	—	—	(422)	(422)
Contribution from parent	—	651	—	—	651
Parent tax matter indemnification	—	21	—	—	21
Appropriation of retained earnings for future dividends	—	—	(567)	567	—
Balance, December 31, 2017	\$ 1,588	\$ 6,822	\$ (1,639)	\$ 2,771	\$ 9,542

See the Combined Notes to Consolidated Financial Statements

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PECO Energy Company and Subsidiary Companies			
Consolidated Statements of Operations and Comprehensive Income			
	For the Years Ended		
	December 31,		
(In millions)	2017	2016	2015
Operating revenues			
Electric operating revenues	\$2,369	\$2,524	\$2,485
Natural gas operating revenues	494	462	545
Operating revenues from affiliates	7	8	2
Total operating revenues	2,870	2,994	3,032
Operating expenses			
Purchased power	648	598	735
Purchased fuel	186	162	235
Purchased power from affiliate	135	287	220
Operating and maintenance	657	665	684
Operating and maintenance from affiliates	149	146	110
Depreciation and amortization	286	270	260
Taxes other than income	154	164	160
Total operating expenses	2,215	2,292	2,404
Gain on sales of assets	—	—	2
Operating income	655	702	630
Other income and (deductions)			
Interest expense, net	(115)	(111)	(102)
Interest expense to affiliates, net	(11)	(12)	(12)
Other, net	9	8	5
Total other income and (deductions)	(117)	(115)	(109)
Income before income taxes	538	587	521
Income taxes	104	149	143
Net income	\$434	\$438	\$378
Comprehensive income	\$434	\$438	\$378

See the Combined Notes to Consolidated Financial Statements

Table of ContentsPECO Energy Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended		
	2017	2016	2015
Cash flows from operating activities			
Net income	\$434	\$438	\$378
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	286	270	260
Deferred income taxes and amortization of investment tax credits	19	78	90
Other non-cash operating activities	54	65	70
Changes in assets and liabilities:			
Accounts receivable	(44)	(71)	37
Receivables from and payables to affiliates, net	(6)	6	3
Inventories	1	6	10
Accounts payable and accrued expenses	6	67	(25)
Income taxes	34	8	(9)
Pension and non-pension postretirement benefit contributions	(24)	(30)	(40)
Other assets and liabilities	(5)	(8)	(4)
Net cash flows provided by operating activities	755	829	770
Cash flows from investing activities			
Capital expenditures	(732)	(686)	(601)
Changes in intercompany money pool	131	(131)	—
Change in restricted cash	—	(1)	(1)
Other investing activities	4	20	14
Net cash flows used in investing activities	(597)	(798)	(588)
Cash flows from financing activities			
Issuance of long-term debt	325	300	350
Retirement of long-term debt	—	(300)	—
Contributions from parent	16	18	16
Dividends paid on common stock	(288)	(277)	(279)
Other financing activities	(3)	(4)	(4)
Net cash flows provided by (used in) financing activities	50	(263)	83
Increase (Decrease) in cash and cash equivalents	208	(232)	265
Cash and cash equivalents at beginning of period	63	295	30
Cash and cash equivalents at end of period	\$271	\$63	\$295

See the Combined Notes to Consolidated Financial Statements

Table of ContentsPECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31,	
	2017	2016
ASSETS		
Current assets		
Cash and cash equivalents	\$271	\$63
Restricted cash and cash equivalents	4	4
Accounts receivable, net		
Customer	327	306
Other	105	131
Receivables from affiliates	—	4
Receivable from Exelon intercompany pool	—	131
Inventories, net		
Fossil fuel	31	35
Materials and supplies	30	27
Prepaid utility taxes	8	9
Regulatory assets	29	29
Other	17	18
Total current assets	822	757
Property, plant and equipment, net	8,053	7,565
Deferred debits and other assets		
Regulatory assets	381	1,681
Investments	25	25
Receivable from affiliates	537	438
Prepaid pension asset	340	345
Other	12	20
Total deferred debits and other assets	1,295	2,509
Total assets	\$10,170	\$10,831

See the Combined Notes to Consolidated Financial Statements

Table of ContentsPECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31,	
	2017	2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Long-term debt due within one year	\$500	\$—
Accounts payable	370	342
Accrued expenses	114	104
Payables to affiliates	53	63
Customer deposits	66	61
Regulatory liabilities	141	127
Other	23	30
Total current liabilities	1,267	727
Long-term debt	2,403	2,580
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,789	3,006
Asset retirement obligations	27	28
Non-pension postretirement benefits obligations	288	289
Regulatory liabilities	549	517
Other	86	85
Total deferred credits and other liabilities	2,739	3,925
Total liabilities	6,593	7,416
Commitments and contingencies		
Shareholder's equity		
Common stock	2,489	2,473
Retained earnings	1,087	941
Accumulated other comprehensive income, net	1	1
Total shareholder's equity	3,577	3,415
Total liabilities and shareholder's equity	\$10,170	\$10,831

See the Combined Notes to Consolidated Financial Statements

Table of ContentsPECO Energy Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholder's Equity
Balance, December 31, 2014	\$ 2,439	\$ 681	\$ 1	\$ 3,121
Net income	—	378	—	378
Common stock dividends	—	(279)	—	(279)
Allocation of tax benefit from parent	16	—	—	16
Balance, December 31, 2015	\$ 2,455	\$ 780	\$ 1	\$ 3,236
Net income	—	438	—	438
Common stock dividends	—	(277)	—	(277)
Allocation of tax benefit from parent	18	—	—	18
Balance, December 31, 2016	\$ 2,473	\$ 941	\$ 1	\$ 3,415
Net income	—	434	—	434
Common stock dividends	—	(288)	—	(288)
Allocation of tax benefit from parent	16	—	—	16
Balance, December 31, 2017	\$ 2,489	\$ 1,087	\$ 1	\$ 3,577

See the Combined Notes to Consolidated Financial Statements

Table of ContentsBaltimore Gas and Electric Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended		
	December 31,		
	2017	2016	2015
Operating revenues			
Electric operating revenues	\$2,484	\$2,603	\$2,490
Natural gas operating revenues	676	609	631
Operating revenues from affiliates	16	21	14
Total operating revenues	3,176	3,233	3,135
Operating expenses			
Purchased power	566	528	602
Purchased fuel	183	162	205
Purchased power from affiliate	384	604	498
Operating and maintenance	563	605	565
Operating and maintenance from affiliates	153	132	118
Depreciation and amortization	473	423	366
Taxes other than income	240	229	224
Total operating expenses	2,562	2,683	2,578
Gain on sales of assets	—	—	1
Operating income	614	550	558
Other income and (deductions)			
Interest expense, net	(95)	(87)	(83)
Interest expense to affiliates	(10)	(16)	(16)
Other, net	16	21	18
Total other income and (deductions)	(89)	(82)	(81)
Income before income taxes	525	468	477
Income taxes	218	174	189
Net income	307	294	288
Preference stock dividends	—	8	13
Net income attributable to common shareholder	\$307	\$286	\$275
Comprehensive income	\$307	\$294	\$288
Comprehensive income attributable to preference stock dividends	—	8	13
Comprehensive income attributable to common shareholder	\$307	\$286	\$275

See the Combined Notes to Consolidated Financial Statements

Table of ContentsBaltimore Gas and Electric Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31,		
	2017	2016	2015
Cash flows from operating activities			
Net income	\$ 307	\$ 294	\$ 288
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	473	423	366
Impairment losses on long-lived assets and regulatory assets		52	—
Deferred income taxes and amortization of investment tax credits	145	118	165
Other non-cash operating activities	65	88	137
Changes in assets and liabilities:			
Accounts receivable	(5)	(98)	84
Receivables from and payables to affiliates, net	(4)	3	(2)
Inventories	(9)	1	18
Accounts payable and accrued expenses	(15)	138	(3)
Collateral received (posted), net	—	—	(27)
Income taxes	60	18	(54)
Pension and non-pension postretirement benefit contributions	(53)	(49)	(17)
Other assets and liabilities	(150)	(43)	(173)
Net cash flows provided by operating activities	821	945	782
Cash flows from investing activities			

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Capital expenditures	(882)	(934)	(719)
Change in restricted cash	26		—		26	
Other investing activities	7		24		18	
Net cash flows used in investing activities	(849)	(910)	(675)
Cash flows from financing activities						
Changes in short-term borrowings	32		(165)	90	
Issuance of long-term debt	300		850		—	
Retirement of long-term debt	(41)	(379)	(75)
Retirement of long-term debt to financing trust	(250)	—		—	
Redemption of preference stock	—		(190)	—	
Dividends paid on preference stock	—		(8)	(13)
Dividends paid on common stock	(198)	(179)	(158)
Contributions from parent	184		61		7	
Other financing activities	(5)	(11)	(13)
Net cash flows provided by (used in) financing activities	22		(21)	(162)
(Decrease) Increase in cash and cash equivalents	(6)	14		(55)
Cash and cash equivalents at beginning of period	23		9		64	
Cash and cash equivalents at end of period	\$ 17		\$ 23		\$ 9	

See the Combined Notes to Consolidated Financial Statements

Table of ContentsBaltimore Gas and Electric Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31,	
	2017	2016
ASSETS		
Current assets		
Cash and cash equivalents	\$ 17	\$ 23
Restricted cash and cash equivalents	1	24
Accounts receivable, net		
Customer	375	395
Other	94	102
Receivable from affiliates	1	—
Inventories, net		
Gas held in storage	37	30
Materials and supplies	40	38
Prepaid utility taxes	69	15
Regulatory assets	174	208
Other	3	7
Total current assets	811	842
Property, plant and equipment, net	7,602	7,040
Deferred debits and other assets		
Regulatory assets	397	504
Investments	5	12
Prepaid pension asset	285	297
Other	4	9
Total deferred debits and other assets	691	822
Total assets ^(a)	\$9,104	\$8,704

See the Combined Notes to Consolidated Financial Statements

Table of ContentsBaltimore Gas and Electric Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31,	
	2017	2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	\$77	\$45
Long-term debt due within one year	—	41
Accounts payable	265	205
Accrued expenses	164	175
Payables to affiliates	52	55
Customer deposits	116	110
Regulatory liabilities	62	50
Other	24	26
Total current liabilities	760	707
Long-term debt	2,577	2,281
Long-term debt to financing trust	—	252
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,244	2,219
Asset retirement obligations	23	21
Non-pension postretirement benefits obligations	202	205
Regulatory liabilities	1,101	110
Other	56	61
Total deferred credits and other liabilities	2,626	2,616
Total liabilities ^(a)	5,963	5,856
Commitments and contingencies		
Shareholder's equity		
Common stock	1,605	1,421
Retained earnings	1,536	1,427
Total shareholder's equity	3,141	2,848
Total liabilities and shareholder's equity	\$9,104	\$8,704

BGE's consolidated assets include \$26 million at December 31, 2016 of BGE's consolidated VIE that can only be used to settle the liabilities of the VIE. BGE's consolidated liabilities include \$42 million at December 31, 2016 of (a) BGE's consolidated VIE for which the VIE creditors do not have recourse to BGE. BGE no longer has interests in any VIEs as of December 31, 2017. See Note 2 - Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Table of ContentsBaltimore Gas and Electric Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2014	\$ 1,360	\$ 1,203	\$ 2,563	\$ 190	\$2,753
Net income	—	288	288	—	288
Preference stock dividends	—	(13)	(13)	—	(13)
Common stock dividends	—	(158)	(158)	—	(158)
Contribution from parent	7	—	7	—	7
Balance, December 31, 2015	\$ 1,367	\$ 1,320	\$ 2,687	\$ 190	\$2,877
Net income	—	294	294	—	294
Preference stock dividends	—	(8)	(8)	—	(8)
Common stock dividends	—	(179)	(179)	—	(179)
Distribution to parent	(7)	—	(7)	—	(7)
Contribution from parent	61	—	61	—	61
Redemption of preference stock	—	—	—	(190)	(190)
Balance, December 31, 2016	\$ 1,421	\$ 1,427	\$ 2,848	\$ —	\$2,848
Net income	—	307	307	—	307
Common stock dividends	—	(198)	(198)	—	(198)
Contribution from parent	184	—	184	—	184
Balance, December 31, 2017	\$ 1,605	\$ 1,536	\$ 3,141	\$ —	\$3,141

See the Combined Notes to Consolidated Financial Statements

Table of ContentsPepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income (Loss)

	Successor		Predecessor	
	For the Year Ended December 31, 2017	March 24 to December 31, 2016	January 1 to March 23, 2016	For the Year Ended December 31, 2015
(In millions)				
Operating revenues				
Electric operating revenues	\$4,468	\$ 3,506	\$1,096	\$ 4,770
Natural gas operating revenues	161	92	57	165
Operating revenues from affiliates	50	45	—	—
Total operating revenues	4,679	3,643	1,153	4,935
Operating expenses				
Purchased power	1,182	925	471	1,986
Purchased fuel	71	36	26	87
Purchased power and fuel from affiliates	463	486	—	—
Operating and maintenance	918	1,144	294	1,156
Operating and maintenance from affiliates	150	89	—	—
Depreciation, amortization and accretion	675	515	152	624
Taxes other than income	452	354	105	455
Total operating expenses	3,911	3,549	1,048	4,308
Gain (loss) on sales of assets	1	(1)	—	46
Operating income	769	93	105	673
Other income and (deductions)				
Interest expense, net	(245)	(195)	(65)	(280)
Other, net	54	44	(4)	88
Total other income and (deductions)	(191)	(151)	(69)	(192)
Income (loss) before income taxes	578	(58)	36	481
Income taxes	217	3	17	163
Equity in earnings of unconsolidated affiliates	1	—	—	—
Net income (loss) from continuing operations	362	(61)	19	318
Net income from discontinued operations	—	—	—	9
Net income (loss) attributable to membership interest/common shareholders	\$362	\$ (61)	\$19	\$ 327
Comprehensive income (loss), net of income taxes				
Net income (loss)	\$362	\$ (61)	\$19	\$ 327
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Actuarial loss reclassified to periodic cost	—	—	1	9
Unrealized loss on cash flow hedges	—	—	—	1
Other comprehensive income	—	—	1	10
Comprehensive income (loss)	\$362	\$ (61)	\$20	\$ 337

See the Combined Notes to Consolidated Financial Statements

Table of ContentsPepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Cash Flows

	Successor		Predecessor	
	For	March 24	January	For the
	the	to	1 to	Year
	Year	December	March	Ended
	Ended	31,	23,	December
	December	31,	2016	2015
	2017	2016	2016	2015
(In millions)				
Cash flows from operating activities				
Net income (loss)	\$362	\$ (61)	\$19	\$ 327
Income from discontinued operations, net of income taxes	—	—	—	(9)
Adjustments to reconcile net income (loss) to net cash from operating activities:				
Depreciation and amortization	675	515	152	624
Impairment losses on intangibles and regulatory assets	52	—	—	—
(Gain) loss on sales of assets	(1)	1	—	(46)
Deferred income taxes and amortization of investment tax credits	252	295	19	134
Net fair value changes related to derivatives	—	—	18	—
Other non-cash operating activities	59	514	46	167
Changes in assets and liabilities:				
Accounts receivable	(26)	(21)	(28)	(105)
Receivables from and payables to affiliates, net	(2)	42	—	—
Inventories	(37)	3	(4)	—
Accounts payable and accrued expenses	(106)	19	42	(41)
Income taxes	79	(22)	12	8
Pension and non-pension postretirement benefit contributions	(99)	(86)	(4)	(21)
Other assets and liabilities	(258)	(311)	(8)	(99)
Net cash flows provided by operating activities	950	888	264	939
Cash flows from investing activities				
Capital expenditures	(1,396)	(1,008)	(273)	(1,230)
Proceeds from sales of long-lived assets	1	24	—	54
Changes in restricted cash	1	(37)	3	6
Purchases of investments	—	—	(68)	—
Other investing activities	(2)	(9)	(5)	9
Net cash flows used in investing activities	(1,396)	(1,030)	(343)	(1,161)
Cash flows from financing activities				
Changes in short-term borrowings	328	(515)	(121)	34
Proceeds from short-term borrowings with maturities greater than 90 days	—	—	500	300
Repayments of short-term borrowings with maturities greater than 90 days	(500)	(300)	—	—
Issuance of long-term debt	202	179	—	558
Retirement of long-term debt	(169)	(338)	(11)	(430)
Issuance of preferred stock	—	—	—	54
Dividends paid on common stock	—	—	—	(275)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation	—	—	2	18
Distribution to member	(311)	(273)	—	—
Contributions from member	758	1,251	—	—
Change in Exelon intercompany money pool	—	(6)	—	—

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Other financing activities	(2)	(5)	2	(26)
Net cash flows provided by (used in) financing activities	306	(7)	372	233
(Decrease) Increase in cash and cash equivalents	(140)	(149)	293	11
Cash and cash equivalents at beginning of period	170	319	26	15
Cash and cash equivalents at end of period	\$30	\$ 170	\$319	\$ 26

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Table of ContentsPepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	Successor	
	December 31, 2017	2016
ASSETS		
Current assets		
Cash and cash equivalents	\$30	\$170
Restricted cash and cash equivalents	42	43
Accounts receivable, net		
Customer	486	496
Other	206	283
Inventories, net		
Gas held in storage	7	6
Materials and supplies	151	116
Regulatory assets	554	653
Other	75	71
Total current assets	1,551	1,838
Property, plant and equipment, net	12,498	11,598
Deferred debits and other assets		
Regulatory assets	2,493	2,851
Investments	132	133
Goodwill	4,005	4,005
Long-term note receivable	4	4
Prepaid pension asset	490	509
Deferred income taxes	4	6
Other	70	81
Total deferred debits and other assets	7,198	7,589
Total assets ^(a)	\$21,247	\$21,025

See the Combined Notes to Consolidated Financial Statements

Table of ContentsPepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	Successor December 31,	
	2017	2016
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	\$350	\$522
Long-term debt due within one year	396	253
Accounts payable	348	458
Accrued expenses	261	272
Payables to affiliates	90	94
Unamortized energy contract liabilities	188	335
Customer deposits	119	123
Merger related obligation	42	101
Regulatory liabilities	56	79
Other	81	47
Total current liabilities	1,931	2,284
Long-term debt	5,478	5,645
Deferred credits and other liabilities		
Regulatory liabilities	1,872	158
Deferred income taxes and unamortized investment tax credits	2,070	3,775
Asset retirement obligations	16	14
Non-pension postretirement benefit obligations	105	134
Unamortized energy contract liabilities	561	750
Other	389	249
Total deferred credits and other liabilities	5,013	5,080
Total liabilities ^(a)	12,422	13,009
Commitments and contingencies		
Member's equity		
Membership interest	8,835	8,077
Undistributed (losses)	(10)	(61)
Total member's equity	8,825	8,016
Total liabilities and member's equity	\$21,247	\$21,025

PHI's consolidated total assets include \$41 million and \$49 million at December 31, 2017 and 2016, respectively, of which \$10 million and \$10 million are included in the consolidated balance sheet of PHI's consolidated VIE that can only be used to settle the liabilities of the VIE. PHI's consolidated total liabilities include \$102 million and \$143 million at December 31, 2017 and 2016, respectively, of PHI's consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 2 - Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Table of ContentsPepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Changes in Equity

(In millions, except share data)	Common Stock ^(a)	Retained Earnings	Accumulated Other Comprehensive Loss, net	Total Shareholders' Equity
Predecessor				
Balance, December 31, 2014	\$ 3,803	\$ 565	\$ (46)	\$ 4,322
Net income	—	327	—	327
Common stock dividends	—	(275)	—	(275)
Original issue shares, net	15	—	—	15
DRP original issue shares	11	—	—	11
Net activity related to stock-based awards	3	—	—	3
Other comprehensive income, net of income taxes	—	—	10	10
Balance, December 31, 2015	\$ 3,832	\$ 617	\$ (36)	\$ 4,413
Net income	—	19	—	19
Original issue shares, net	3	—	—	3
Net activity related to stock-based awards	3	—	—	3
Other comprehensive income, net of income taxes	—	—	1	1
Balance, March 23, 2016	\$ 3,838	\$ 636	\$ (35)	\$ 4,439
Successor				
	Membership Interest	Undistributed Losses	Accumulated Other Comprehensive Loss, net	Total Member's Equity
Balance, March 24, 2016 ^(b)	\$ 7,200	\$ —	\$ —	\$ 7,200
Net loss	—	(61)	—	(61)
Distribution to member ^(c)	(400)	—	—	(400)
Contribution from member	1,251	—	—	1,251
Measurement period adjustment of Exelon's deferred tax liabilities to reflect unitary state income tax consequences of the merger	35	—	—	35
Distribution of net retirement benefit obligation to member	53	—	—	53
Assumption of member liabilities ^(d)	(62)	—	—	(62)
Balance, December 31, 2016	\$ 8,077	\$ (61)	\$ —	\$ 8,016
Net Income	—	362	—	362
Distribution to member	—	(311)	—	(311)
Contribution from member	751	—	—	751
Allocation of tax benefit from member	7	—	—	7
Balance, December 31, 2017	\$ 8,835	\$ (10)	\$ —	\$ 8,825

(a) At March 23, 2016 and December 31, 2015, PHI's (predecessor) shareholders' equity included \$3,835 million and \$3,829 million of other paid-in capital, and \$3 million and \$3 million of common stock, respectively.

The March 24, 2016, beginning balance differs from the PHI Merger total purchase price by \$59 million related to (b) an acquisition accounting adjustment recorded at Exelon Corporate to reflect unitary state income tax consequences of the merger.

Distribution to member includes \$235 million of net assets associated with PHI's unregulated business interests and (c) \$165 million of cash, each of which were distributed by PHI to Exelon.

The liabilities assumed include \$29 million for PHI stock-based compensation awards and \$33 million for a merger related obligation, each assumed by PHI from Exelon. See Note 4 — Mergers, Acquisitions and Dispositions.

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Potomac Electric Power Company

Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended		
	December 31,		
	2017	2016	2015
Operating revenues			
Electric operating revenues	\$2,152	\$2,181	\$2,124
Operating revenues from affiliates	6	5	5
Total operating revenues	2,158	2,186	2,129
Operating expenses			
Purchased power	359	411	719
Purchased power from affiliates	255	295	—
Operating and maintenance	396	607	435
Operating and maintenance from affiliates	58	35	4
Depreciation and amortization	321	295	256
Taxes other than income	371	377	376
Total operating expenses	1,760	2,020	1,790
Gain on sales of assets	1	8	46
Operating income	399	174	385
Other income and (deductions)			
Interest expense, net	(121)	(127)	(124)
Other, net	32	36	28
Total other income and (deductions)	(89)	(91)	(96)
Income before income taxes	310	83	289
Income taxes	105	41	102
Net income	\$205	\$42	\$187
Comprehensive income	\$205	\$42	\$187

See the Combined Notes to Consolidated Financial Statements

Table of ContentsPotomac Electric Power Company
Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	2017	2016	2015
Cash flows from operating activities			
Net income	\$205	\$42	\$187
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	321	295	256
Impairment losses on regulatory assets	14	—	—
Gain on sales of assets	(1)	(8)	(46)
Deferred income taxes and amortization of investment tax credits	113	153	150
Other non-cash operating activities	(5)	183	54
Changes in assets and liabilities:			
Accounts receivable	(20)	(41)	(43)
Receivables from and payables to affiliates, net	—	44	—
Inventories	(24)	1	(5)
Accounts payable and accrued expenses	(63)	32	(21)
Income taxes	81	110	(46)
Pension and non-pension postretirement benefit contributions	(72)	(32)	(14)
Other assets and liabilities	(142)	(128)	(99)
Net cash flows provided by operating activities	407	651	373
Cash flows from investing activities			
Capital expenditures	(628)	(586)	(544)
Proceeds from sale of long-lived assets	1	12	54
Purchases of investments	—	(30)	—
Changes in restricted cash	(2)	(31)	3
Other investing activities	(1)	(12)	10
Net cash flows used in investing activities	(630)	(647)	(477)
Cash flows from financing activities			
Changes in short-term borrowings	3	(41)	(40)
Issuance of long-term debt	202	4	208
Retirement of long-term debt	(13)	(11)	(22)
Dividends paid on common stock	(133)	(136)	(146)
Contributions from parent	161	187	112
Other financing activities	(1)	(3)	(9)
Net cash flows provided by financing activities	219	—	103
(Decrease) Increase in cash and cash equivalents	(4)	4	(1)
Cash and cash equivalents at beginning of period	9	5	6
Cash and cash equivalents at end of period	\$5	\$9	\$5

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Potomac Electric Power Company

Balance Sheets

(In millions)	December 31,	
	2017	2016
ASSETS		
Current assets		
Cash and cash equivalents	\$5	\$9
Restricted cash and cash equivalents	35	33
Accounts receivable, net		
Customer	250	235
Other	87	150
Inventories, net	87	63
Regulatory assets	213	162
Other	33	32
Total current assets	710	684
Property, plant and equipment, net	6,001	5,571
Deferred debits and other assets		
Regulatory assets	678	690
Investments	102	102
Prepaid pension asset	322	282
Other	19	6
Total deferred debits and other assets	1,121	1,080
Total assets	\$7,832	\$7,335

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Potomac Electric Power Company

Balance Sheets

	December 31,	
(In millions)	2017	2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	\$26	\$23
Long-term debt due within one year	19	16
Accounts payable	139	209
Accrued expenses	137	113
Payables to affiliates	74	74
Customer deposits	54	53
Regulatory liabilities	3	11
Merger related obligation	42	68
Current portion of DC PLUG obligation	28	—
Other	28	29
Total current liabilities	550	596
Long-term debt	2,521	2,333
Deferred credits and other liabilities		
Regulatory liabilities	829	20
Deferred income taxes and unamortized investment tax credits	1,063	1,910
Non-pension postretirement benefit obligations	36	43
Other	300	133
Total deferred credits and other liabilities	2,228	2,106
Total liabilities	5,299	5,035
Commitments and contingencies		
Shareholder's equity		
Common stock	1,470	1,309
Retained earnings	1,063	991
Total shareholder's equity	2,533	2,300
Total liabilities and shareholder's equity	\$7,832	\$7,335

See the Combined Notes to Consolidated Financial Statements

Table of ContentsPotomac Electric Power Company
Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2014	\$ 1,010	\$ 1,077	\$ 2,087
Net income	—	187	187
Common stock dividends	—	(146)	(146)
Contribution from Parent	112	—	112
Balance, December 31, 2015	\$ 1,122	\$ 1,118	\$ 2,240
Net income	—	42	42
Common stock dividends	—	(169)	(169)
Contribution from Parent	187	—	187
Balance, December 31, 2016	\$ 1,309	\$ 991	\$ 2,300
Net income	—	205	205
Common stock dividends	—	(133)	(133)
Contribution from Parent	161	—	161
Balance, December 31, 2017	\$ 1,470	\$ 1,063	\$ 2,533

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Delmarva Power & Light Company

Statements of Operations and Comprehensive Income (Loss)

(In millions)	For the Years Ended		
	December 31,		
	2017	2016	2015
Operating revenues			
Electric operating revenues	\$1,131	\$1,122	\$1,132
Natural gas operating revenues	161	148	164
Operating revenues from affiliates	8	7	6
Total operating revenues	1,300	1,277	1,302
Operating expenses			
Purchased power	282	369	555
Purchased fuel	71	60	79
Purchased power from affiliate	179	154	—
Operating and maintenance	283	422	303
Operating and maintenance from affiliates	32	19	1
Depreciation and amortization	167	157	148
Taxes other than income	57	55	51
Total operating expenses	1,071	1,236	1,137
Gain on sales of assets	—	9	—
Operating income	229	50	165
Other income and (deductions)			
Interest expense, net	(51)	(50)	(50)
Other, net	14	13	10
Total other income and (deductions)	(37)	(37)	(40)
Income before income taxes	192	13	125
Income taxes	71	22	49
Net income (loss)	\$121	\$(9)	\$76
Comprehensive income (loss)	\$121	\$(9)	\$76

See the Combined Notes to Consolidated Financial Statements

Table of ContentsDelmarva Power & Light Company
Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	2017	2016	2015
Cash flows from operating activities			
Net income (loss)	\$121	\$(9)	\$76
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:			
Depreciation and amortization	167	157	148
Impairment losses on regulatory assets	6	—	—
Deferred income taxes and amortization of investment tax credits	89	109	73
Other non-cash operating activities	9	114	33
Changes in assets and liabilities:			
Accounts receivable	(22)	(5)	(24)
Receivables from and payables to affiliates, net	11	13	3
Inventories	(5)	—	6
Accounts payable and accrued expenses	(8)	(4)	(8)
Collateral (posted) received, net	—	1	(1)
Income taxes	26	28	(26)
Pension and non-pension postretirement benefit contributions	(2)	(22)	—
Other assets and liabilities	(71)	(72)	(14)
Net cash flows provided by operating activities	321	310	266
Cash flows from investing activities			
Capital expenditures	(428)	(349)	(352)
Proceeds from sales of long-lived assets	—	9	—
Change in restricted cash	—	—	5
Other investing activities	(1)	4	2
Net cash flows used in investing activities	(429)	(336)	(345)
Cash flows from financing activities			
Change in short-term borrowings	216	(105)	(1)
Issuance of long-term debt	—	175	200
Retirement of long-term debt	(40)	(100)	(100)
Dividends paid on common stock	(112)	(54)	(92)
Contributions from parent	—	152	75
Other financing activities	—	(1)	(2)
Net cash flows provided by financing activities	64	67	80
(Decrease) Increase in cash and cash equivalents	(44)	41	1
Cash and cash equivalents at beginning of period	46	5	4
Cash and cash equivalents at end of period	\$2	\$46	\$5

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Delmarva Power & Light Company

Balance Sheets

(In millions)	December 31,	
	2017	2016
ASSETS		
Current assets		
Cash and cash equivalents	\$2	\$46
Accounts receivable, net		
Customer	146	136
Other	38	63
Receivables from affiliates	—	3
Inventories, net		
Gas held in storage	7	7
Materials and supplies	36	32
Regulatory assets	69	59
Other	27	24
Total current assets	325	370
Property, plant and equipment, net	3,579	3,273
Deferred debits and other assets		
Regulatory assets	245	289
Goodwill	8	8
Prepaid pension asset	193	206
Other	7	7
Total deferred debits and other assets	453	510
Total assets	\$4,357	\$4,153

See the Combined Notes to Consolidated Financial Statements

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Delmarva Power & Light Company

Balance Sheets

	December 31,	
(In millions)	2017	2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	\$216	\$—
Long-term debt due within one year	83	119
Accounts payable	82	88
Accrued expenses	35	36
Payables to affiliates	46	38
Customer deposits	35	36
Regulatory liabilities	42	43
Merger related obligation	—	13
Other	8	8
Total current liabilities	547	381
Long-term debt	1,217	1,221
Deferred credits and other liabilities		
Regulatory liabilities	593	97
Deferred income taxes and unamortized investment tax credits	603	1,056
Non-pension postretirement benefit obligations	14	19
Other	48	53
Total deferred credits and other liabilities	1,258	1,225
Total liabilities	3,022	2,827
Commitments and contingencies		
Shareholder's equity		
Common stock	764	764
Retained earnings	571	562
Total shareholder's equity	1,335	1,326
Total liabilities and shareholder's equity	\$4,357	\$4,153

See the Combined Notes to Consolidated Financial Statements

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Delmarva Power & Light Company

Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2014	\$ 537	\$ 641	\$ 1,178
Net income	—	76	76
Common stock dividends	—	(92)	(92)
Contribution from parent	75	—	75
Balance, December 31, 2015	\$ 612	\$ 625	\$ 1,237
Net loss	—	(9)	(9)
Common stock dividends	—	(54)	(54)
Contribution from parent	152	—	152
Balance, December 31, 2016	\$ 764	\$ 562	\$ 1,326
Net income	—	121	121
Common stock dividends	—	(112)	(112)
Balance, December 31, 2017	\$ 764	\$ 571	\$ 1,335

See the Combined Notes to Consolidated Financial Statements

Table of ContentsAtlantic City Electric Company and Subsidiary Company
Consolidated Statements of Operations and Comprehensive Income (Loss)

(In millions)	For the Years Ended		
	December 31,		
	2017	2016	2015
Operating revenues			
Electric operating revenues	\$1,184	\$1,254	\$1,291
Operating revenues from affiliates	2	3	4
Total operating revenues	1,186	1,257	1,295
Operating expenses			
Purchased power	541	614	708
Purchased power from affiliates	29	37	—
Operating and maintenance	279	410	268
Operating and maintenance from affiliates	28	18	3
Depreciation and amortization	146	165	175
Taxes other than income	6	7	7
Total operating expenses	1,029	1,251	1,161
Gain on sale of assets	—	1	—
Operating income	157	7	134
Other income and (deductions)			
Interest expense, net	(61)	(62)	(64)
Other, net	7	9	3
Total other income and (deductions)	(54)	(53)	(61)
Income (loss) before income taxes	103	(46)	73
Income taxes	26	(4)	33
Net income (loss)	\$77	\$(42)	\$40
Comprehensive income (loss)	\$77	\$(42)	\$40

See the Combined Notes to Consolidated Financial Statements

Table of ContentsAtlantic City Electric Company and Subsidiary Company
Consolidated Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	2017	2016	2015
Cash flows from operating activities			
Net income (loss)	\$77	\$(42)	\$40
Adjustments to reconcile net income (loss) to net cash from operating activities:			
Depreciation and amortization	146	165	175
Impairment losses on regulatory assets	7	—	—
Deferred income taxes and amortization of investment tax credits	32	22	31
Other non-cash operating activities	17	155	37
Changes in assets and liabilities:			
Accounts receivable	14	(8)	(67)
Receivables from and payables to affiliates, net	—	13	1
Inventories	(7)	(1)	(1)
Accounts payable and accrued expenses	(2)	9	9
Income taxes	(11)	174	(34)
Pension and non-pension postretirement benefit contributions	(20)	(17)	(2)
Other assets and liabilities	(47)	(85)	67
Net cash flows provided by operating activities	206	385	256
Cash flows from investing activities			
Capital expenditures	(312)	(311)	(300)
Proceeds from sale of long-lived assets	—	2	—
Changes in restricted cash	3	(2)	(6)
Other investing activities	(1)	2	—
Net cash flows used in investing activities	(310)	(309)	(306)
Cash flows from financing activities			
Change in short-term borrowings	108	(5)	(122)
Issuance of long-term debt	—	—	150
Retirement of long-term debt	(35)	(48)	(58)
Dividends paid on common stock	(68)	(63)	(12)
Contributions from parent	—	139	95
Other financing activities	—	(1)	(2)
Net cash flows provided by financing activities	5	22	51
(Decrease) Increase in cash and cash equivalents	(99)	98	1
Cash and cash equivalents at beginning of period	101	3	2
Cash and cash equivalents at end of period	\$2	\$101	\$3

See the Combined Notes to Consolidated Financial Statements

Table of ContentsAtlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets

(In millions)	December 31,	
	2017	2016
ASSETS		
Current assets		
Cash and cash equivalents	\$2	\$101
Restricted cash and cash equivalents	6	9
Accounts receivable, net		
Customer	92	125
Other	56	44
Inventories, net	29	22
Regulatory assets	71	96
Other	2	2
Total current assets	258	399
Property, plant and equipment, net	2,706	2,521
Deferred debits and other assets		
Regulatory assets	359	405
Long-term note receivable	4	4
Prepaid pension asset	73	84
Other	45	44
Total deferred debits and other assets	481	537
Total assets ^(a)	\$3,445	\$3,457

See the Combined Notes to Consolidated Financial Statements

Table of ContentsAtlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets

(In millions)	December 31,	
	2017	2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	\$ 108	\$—
Long-term debt due within one year	281	35
Accounts payable	118	132
Accrued expenses	33	38
Payables to affiliates	29	29
Customer deposits	31	33
Regulatory liabilities	11	25
Merger related obligation	—	20
Other	8	8
Total current liabilities	619	320
Long-term debt	840	1,120
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	493	917
Non-pension postretirement benefit obligations	14	34
Regulatory liabilities	411	—
Other	25	32
Total deferred credits and other liabilities	943	983
Total liabilities ^(a)	2,402	2,423
Commitments and contingencies		
Shareholder's equity		
Common stock	912	912
Retained earnings	131	122
Total shareholder's equity	1,043	1,034
Total liabilities and shareholder's equity	\$3,445	\$3,457

ACE's consolidated assets include \$29 million and \$32 million at December 31, 2017 and 2016, respectively, of
 (a) ACE's consolidated VIE that can only be used to settle the liabilities of the VIE. ACE's consolidated liabilities include \$90 million and \$126 million at December 31, 2017 and 2016, respectively, of ACE's consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 2 - Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Table of ContentsAtlantic City Electric Company and Subsidiary Company
Consolidated Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2014	\$ 678	\$ 199	\$ 877
Net income	—	40	40
Common stock dividends	—	(12)	(12)
Contribution from parent	95	—	95
Balance, December 31, 2015	\$ 773	\$ 227	\$ 1,000
Net loss	—	(42)	(42)
Common stock dividends	—	(63)	(63)
Contribution from parent	139	—	139
Balance, December 31, 2016	\$ 912	\$ 122	\$ 1,034
Net income	—	77	77
Common stock dividends	—	(68)	(68)
Balance, December 31, 2017	\$ 912	\$ 131	\$ 1,043

See the Combined Notes to Consolidated Financial Statements

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Combined Notes to Consolidated Financial Statements

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

Index to Combined Notes to Consolidated Financial Statements

The notes to the consolidated financial statements that follow are a combined presentation. The following list indicates the Registrants to which the footnotes apply:

Applicable Notes

Registrant	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
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

1. Significant Accounting Policies (All Registrants)

Description of Business (All Registrants)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution and transmission businesses. Prior to March 23, 2016, Exelon's principal, wholly owned subsidiaries included Generation, ComEd, PECO and BGE. On March 23, 2016, in conjunction with the Amended and Restated Agreement and Plan of Merger (the PHI Merger Agreement), Purple Acquisition Corp, a wholly owned subsidiary of Exelon, merged with and into PHI, with PHI continuing as the surviving entity as a wholly owned subsidiary of Exelon. PHI is a utility services holding company engaged through its principal wholly owned subsidiaries, Pepco, DPL and ACE, in the energy distribution and transmission businesses. Refer to Note 4 — Mergers, Acquisitions and Dispositions for further information regarding the merger transaction.

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Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Name of Registrant	Business	Service Territories
Exelon Generation Company, LLC	Generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity to both wholesale and retail customers. Generation also sells natural gas, renewable energy and other energy-related products and services.	Six reportable segments: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions
Commonwealth Edison Company	Purchase and regulated retail sale of electricity Transmission and distribution of electricity to retail customers	Northern Illinois, including the City of Chicago
PECO Energy Company	Purchase and regulated retail sale of electricity and natural gas Transmission and distribution of electricity and distribution of natural gas to retail customers	Southeastern Pennsylvania, including the City of Philadelphia (electricity) Pennsylvania counties surrounding the City of Philadelphia (natural gas)
Baltimore Gas and Electric Company	Purchase and regulated retail sale of electricity and natural gas Transmission and distribution of electricity and distribution of natural gas to retail customers	Central Maryland, including the City of Baltimore (electricity and natural gas)
Pepco Holdings LLC	Utility services holding company engaged, through its reportable segments Pepco, DPL and ACE	Service Territories of Pepco, DPL and ACE
Potomac Electric Power Company	Purchase and regulated retail sale of electricity Transmission and distribution of electricity to retail customers	District of Columbia, and major portions of Montgomery and Prince George's Counties, Maryland.
Delmarva Power & Light Company	Purchase and regulated retail sale of electricity and natural gas Transmission and distribution of electricity and distribution of natural gas to retail customers	Portions of Delaware and Maryland (electricity) Portions of New Castle County, Delaware (natural gas)
Atlantic City Electric Company	Purchase and regulated retail sale of electricity Transmission and distribution of electricity to retail customers	Portions of Southern New Jersey

Basis of Presentation (All Registrants)

This is a combined annual report of all Registrants. The Notes to the Consolidated Financial Statements apply to the Registrants as indicated above in the Index to Combined Notes to Consolidated Financial Statements and parenthetically next to each corresponding disclosure. When appropriate, the Registrants are named specifically for their related activities and disclosures. Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

As a result of the acquisition of PHI, Exelon's financial reporting reflects PHI's consolidated financial results subsequent to the March 23, 2016, acquisition date. Exelon has accounted for the merger transaction applying the acquisition method of accounting, which requires the assets acquired and liabilities assumed by Exelon to be reported in Exelon's financial statements at fair value, with any excess of the purchase price over the fair value of net assets acquired reported as goodwill. Exelon has pushed-down the application of the acquisition method of accounting to the consolidated financial statements of PHI such that the assets and liabilities of PHI are similarly recorded at their respective fair values, and goodwill has been established as of the acquisition date. Accordingly, the consolidated financial statements of PHI for periods before and after the March 23, 2016, acquisition date reflect different bases of accounting, and the results of operations and the financial positions of the predecessor and successor periods are not comparable. The acquisition method of accounting has not been pushed down to PHI's wholly owned subsidiary utility registrants, Pepco, DPL and ACE.

For financial statement purposes, beginning on March 24, 2016, disclosures related to Exelon now also apply to PHI, Pepco, DPL and ACE, unless otherwise noted.

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Combined Notes to Consolidated Financial Statements - (Continued)
 (Dollars in millions, except per share data unless otherwise noted)

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

PHISCO, 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 PHISCO and the participating operating subsidiaries.

Exelon owns 100% of its significant consolidated subsidiaries, including PHI, either directly or indirectly, except for ComEd, of which Exelon owns more than 99%. As of December 31, 2017, Exelon owned none of BGE's preferred securities, which BGE redeemed in 2016. Exelon has reflected the third-party interests in ComEd, which totaled less than \$1 million at December 31, 2017 and December 31, 2016, as equity, in its consolidated financial statements. BGE is subject to certain ring-fencing measures established by order of the MDPSC. As part of this arrangement, BGE common stock is held directly by RF Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (BGE Utility), an unrelated party, holds a nominal non-economic interest in RF Holdco LLC with limited voting rights on specified matters. PHI is subject to some ring-fencing measures established by orders of the DCPSC, DPSC, MDPSC and NJBPU, pursuant to which all of the membership interest in PHI is held directly by PH Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (PH Utility), Inc., an unrelated party, holds a nominal non-economic interest in PH Holdco LLC with limited voting rights on specified matters. PHI owns 100% of its subsidiaries including Pepco, DPL and ACE.

Generation owns 100% of its significant consolidated subsidiaries, either directly or indirectly, except for certain consolidated VIEs, including CENG and ExGen Renewables Partners, LLC, of which Generation holds a 50.01% and 51% interest, respectively. The remaining interests in these consolidated VIEs are included in noncontrolling interests on Exelon's and Generation's Consolidated Balance Sheets. See Note 2 — Variable Interest Entities for further discussion of Exelon's and Generation's consolidated VIEs.

The Registrants consolidate the accounts of entities in which a Registrant has a controlling financial interest, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% in which the Registrant can exercise control over the operations and policies of the investee, or the results of a model that identifies the Registrant or one of its subsidiaries as the primary beneficiary of a VIE. Where the Registrants do not have a controlling financial interest in an entity, proportionate consolidation, equity method accounting or cost method accounting is applied. The Registrants apply proportionate consolidation when they have an undivided interest in an asset and are proportionately liable for their share of each liability associated with the asset. The Registrants proportionately consolidate their undivided ownership interests in jointly owned electric plants and transmission facilities. Under proportionate consolidation, the Registrants separately record their proportionate share of the assets, liabilities, revenues and expenses related to the undivided interest in the asset. The Registrants apply equity method accounting when they have significant influence over an investee through an ownership in common stock, which generally approximates a 20% to 50% voting interest. The Registrants apply equity method accounting to certain investments and joint ventures, including certain financing trusts of ComEd, PECO and BGE. Under equity method accounting, the Registrants report their interest in the entity as an investment and the Registrants' percentage share of the earnings from the entity as single line items in their financial statements. The Registrants use cost

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Combined Notes to Consolidated Financial Statements - (Continued)

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

method accounting if they lack significant influence, which generally results when they hold less than 20% of the common stock of an entity. Under cost method accounting, the Registrants report their investments at cost and recognize income only to the extent dividends or distributions are received.

The accompanying consolidated financial statements have been prepared in accordance with GAAP for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC.

Use of Estimates (All Registrants)

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

Reclassifications (All Registrants)

Certain prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows, Consolidated Balance Sheets and Consolidated Statements of Changes in Shareholders' Equity have been reclassified between line items for comparative purposes. The reclassifications did not affect any of the Registrants' net income, cash flows from operating activities or financial positions.

Accounting for the Effects of Regulation (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

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

With the exception of income tax-related regulatory assets and liabilities, the Registrants classify regulatory assets and liabilities with a recovery or settlement period greater than one year as both current and non-current in their Consolidated Balance Sheets, with the current portion representing the amount expected to be recovered from or settled to customers over the next twelve-month period as of the balance sheet date. Income tax-related regulatory assets and liabilities are classified entirely as non-

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Combined Notes to Consolidated Financial Statements - (Continued)
 (Dollars in millions, except per share data unless otherwise noted)

current on the Registrants' Consolidated Balance Sheets to align with the classification of the related deferred income tax balances.

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

Revenues (All Registrants)

Operating Revenues

Operating revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers. ComEd records its best estimate of its electric distribution, energy efficiency and transmission revenue impacts resulting from changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. PECO, BGE, Pepco, DPL and ACE record their best estimate of the transmission revenue impacts resulting from changes in rates that they each believe are probable of approval by FERC in accordance with their formula rate mechanisms. See Note 3 — Regulatory Matters and Note 5 — Accounts Receivable for further information.

RTOs and ISOs

In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, the Registrants generally report sales and purchases conducted on a net hourly basis in either revenues or purchased power on their Consolidated Statements of Operations and Comprehensive Income, the classification of which depends on the net hourly activity. In addition, capacity revenue and expense classification is based on the net sale or purchase position of Exelon in the different RTOs and ISOs.

Option Contracts, Swaps and Commodity Derivatives

Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. For example, gas transactions may be used to hedge the sale of power. This will result in the change in fair value recorded through revenue. To the extent a Utility Registrant receives full cost recovery for energy procurement and related costs from retail customers, it records the fair value of its energy swap contracts with unaffiliated suppliers as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets. Refer to Note 3 — Regulatory Matters and Note 12 — Derivative Financial Instruments for further information.

Income Taxes (All Registrants)

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

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Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

deductions (interest income) and recognize penalties related to unrecognized tax benefits in Other, net on their Consolidated Statements of Operations and Comprehensive Income.

In the first quarter of 2016, PHI, Pepco, DPL and ACE changed their accounting 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 was \$34 million and \$4 million for PHI and Pepco, respectively. The impact on all other PHI Registrants for the year ended December 31, 2015 was less than \$1 million. Pursuant to the IRC and relevant state taxing authorities, Exelon and its subsidiaries file consolidated or combined income tax returns for Federal and certain state jurisdictions where allowed or required. See Note 14 — Income Taxes for further information.

Taxes Directly Imposed on Revenue-Producing Transactions (All Registrants)

The Registrants collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges and fees that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer, but paid by the Registrants, while others are imposed on the Registrants. Where these taxes are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Consolidated Statements of Operations and Comprehensive Income. However, where these taxes are imposed on the Registrants, such as gross receipts taxes or other surcharges or fees, they are reported on a gross basis. Accordingly, revenues are recognized for the taxes collected from customers along with an offsetting expense. See Note 24 — Supplemental Financial Information for Generation's, ComEd's, PECO's, BGE's, Pepco's, DPL's and ACE's utility taxes that are presented on a gross basis.

Cash and Cash Equivalents (All Registrants)

The Registrants consider investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Cash Equivalents (All Registrants)

Restricted cash and cash equivalents represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2017 and 2016, Exelon Corporate's restricted cash and cash equivalents primarily represented restricted funds for payment of medical, dental, vision and long-term disability benefits. Generation's restricted cash and cash equivalents primarily included cash at various project-specific nonrecourse financing structures for debt service and financing of operations of the underlying entities, see Note 13 — Debt and Credit Agreements for additional information on Generation's project-specific financing structures. ComEd's restricted cash primarily represented cash collateral held from suppliers associated with ComEd's energy and REC procurement contracts, any over-recovered RPS costs and alternative compliance payments received from RES pursuant to FEJA and certain funds set aside for the remediation of one of ComEd's MGP sites. PECO's restricted cash primarily represented funds from the sales of assets that were subject to PECO's mortgage indenture. BGE's restricted cash primarily represented funds restricted for certain energy conservation incentive programs. PHI Corporate's restricted cash and cash equivalents primarily represented funds restricted for the payment

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Combined Notes to Consolidated Financial Statements - (Continued)
 (Dollars in millions, except per share data unless otherwise noted)

of merger commitments and cash collateral held from its utility suppliers. Pepco's restricted cash and cash equivalents primarily represented funds restricted for the payment of merger commitments and collateral held from its utility suppliers. DPL's restricted cash and cash equivalents primarily represented cash collateral held from suppliers associated with procurement contracts. ACE's restricted cash and cash equivalents primarily represented funds restricted at its consolidated variable interest entity for repayment of transition bonds and cash collateral held from suppliers.

Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets.

Allowance for Uncollectible Accounts (All Registrants)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the customers' accounts receivable balances. For Generation, the allowance is based on accounts receivable aging historical experience and other currently available information. ComEd, PECO, BGE, Pepco, DPL and ACE estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by customer risk segment. Risk segments represent a group of customers with similar credit quality indicators that are comprised based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on a historical average of charge-offs as a percentage of accounts receivable in each risk segment. Utility Registrants' customer 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 3 — Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd and ACE.

Variable Interest Entities (All Registrants)

Exelon accounts for its investments in and arrangements with VIEs based on the authoritative guidance which includes the following specific requirements:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity has a controlling financial interest, meaning (1) has the power to direct the activities that most significantly impact the VIE's economic performance, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events, and
- requires the entity that consolidates a VIE (the primary beneficiary) to disclose (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

See Note 2 — Variable Interest Entities for additional information.

Inventories (All Registrants)

Inventory is recorded at the lower of weighted average cost or net realizable value. Provisions are recorded for excess and obsolete inventory.

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Combined Notes to Consolidated Financial Statements - (Continued)
 (Dollars in millions, except per share data unless otherwise noted)

Fossil Fuel

Fossil fuel inventory includes natural gas held in storage, propane and oil. The costs of natural gas, propane and oil are generally included in inventory when purchased and charged to purchased power and fuel expense at weighted average cost when used or sold.

Materials and Supplies

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

Emission Allowances

Emission allowances are included in inventory (for emission allowances exercisable in the current year) and other deferred debits (for emission allowances that are exercisable beyond one year) and charged to purchased power and fuel expense at weighted average cost as they are used in operations.

Marketable Securities (All Registrants)

All marketable securities are reported at fair value. Marketable securities held in the NDT funds are classified as trading securities, and all other securities are classified as available-for-sale securities. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the Regulatory Agreement Units are included in regulatory liabilities at Exelon, ComEd and PECO and in Noncurrent payables to affiliates at Generation and in Noncurrent receivables from affiliates at ComEd and PECO. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the Non-Regulatory Agreement Units are included in earnings at Exelon and Generation. Unrealized gains and losses, net of tax, for Exelon's available-for-sale securities are reported in OCI. Exelon's and Generation's NDT funds, which are designated to satisfy future decommissioning obligations, are classified as either noncurrent or current assets, depending on the timing of the decommissioning activities and income taxes on trust earnings. Beginning January 1, 2018, the authoritative guidance eliminates the available-for-sale classification for equity securities and requires that all equity investments (other than those accounted for using the equity method of accounting) be measured and recorded at fair value with any changes in fair value recorded through earnings. The new authoritative guidance does not impact the classification or measurement of investments in debt securities. See Note 3 — Regulatory Matters for additional information regarding ComEd's and PECO's regulatory assets and liabilities and Note 11 — Fair Value of Financial Assets and Liabilities and Note 15 — Asset Retirement Obligations for information regarding marketable securities held by NDT funds.

Property, Plant and Equipment (All Registrants)

Property, plant and equipment is recorded at original cost. Original cost includes construction-related direct labor and material costs. The Utility Registrants also include indirect construction costs including labor and related costs of departments associated with supporting construction activities. When appropriate, original cost also includes capitalized interest for Generation, Exelon Corporate and PHI and AFUDC for regulated property at ComEd, PECO, BGE, Pepco, DPL and ACE. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to Operating and maintenance expense as incurred.

Third parties reimburse the Utility Registrants for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, plant and equipment. DOE SGIG and other funds reimbursed to the Utility Registrants have been accounted for as CIAC.

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

For the Utility Registrants, upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation consistent with the composite and group methods of depreciation. Depreciation expense at ComEd, BGE, Pepco, DPL and ACE includes the estimated cost of dismantling and removing plant from service upon retirement. Actual incurred removal costs are applied against a related regulatory liability or recorded to a regulatory asset if in excess of previously collected removal costs. PECO's removal costs are capitalized to accumulated depreciation when incurred, and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method.

See Note 6 — Property, Plant and Equipment, Note 9 — Jointly Owned Electric Utility Plant and Note 24 — Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel (Exelon and Generation)

The cost of nuclear fuel is capitalized within Property, plant and equipment and charged to fuel expense using the unit-of-production method. Prior to May 16, 2014, the estimated disposal cost of SNF was established per the Standard Waste Contract with the DOE and was expensed through fuel expense at one mill (\$0.001) per kWh of net nuclear generation. Effective May 16, 2014, the SNF disposal fee was set to zero by the DOE and Exelon and Generation are not accruing any further costs related to SNF disposal fees until a new fee structure goes into effect. Certain on-site SNF storage costs are being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed. See Note 23 — Commitments and Contingencies for additional information regarding the SNF disposal fee.

Nuclear Outage Costs (Exelon and Generation)

Costs associated with nuclear outages, including planned major maintenance activities, are expensed to Operating and maintenance expense or capitalized to Property, plant and equipment (based on the nature of the activities) in the period incurred.

New Site Development Costs (Exelon and Generation)

New site development costs represent the costs incurred in the assessment and design of new power generating facilities. Such costs are capitalized when management considers project completion to be probable, primarily based on management's determination that the project is economically and operationally feasible, management and/or the Exelon Board of Directors has approved the project and has committed to a plan to develop it, and Exelon and Generation have received the required regulatory approvals or management believes the receipt of required regulatory approvals is probable. As of December 31, 2017 and 2016, Generation has capitalized \$228 million and \$1.7 billion, respectively, to Property, plant and equipment, net on its Consolidated Balance Sheets. Capitalized development costs are charged to Operating and maintenance expense when project completion is no longer probable. New site development costs incurred prior to a project's completion being deemed probable are expensed as incurred.

Approximately \$4 million, \$30 million and \$22 million of costs were expensed by Exelon and Generation for the years ended December 31, 2017, 2016 and 2015, respectively. These costs are primarily related to the possible development of new power generating facilities with the exception of

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approximately \$13 million of costs expensed in 2016 which relate to projects for which completion is no longer probable.

Capitalized Software Costs (All Registrants)

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

Net unamortized software costs	Successor								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2017	\$ 834	\$ 173	\$ 227	\$ 111	\$ 179	\$ 133	\$ 2	\$ 1	\$ 1
December 31, 2016	808	173	213	91	164	153	1	1	1
Amortization of capitalized software costs	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	
2017		\$ 270	\$ 73	\$ 73	\$ 39	\$ 46	\$ —	\$ —	\$ —
2016		255	72	62	33	44	—	—	—
2015		208	73	47	33	46	(2)	—	—
		Successor		Predecessor					
		For		January					
		the		1,		For the			
		Year		March 24,		2016 Year			
		Ended		to		Ended			
		December		March		December			
		31,		31, 2016		23, 31, 2015			
		2017		2016					
Amortization of capitalized software costs	\$ 34	\$ 29	\$ 8	\$ 36					

Depreciation and Amortization (All Registrants)

Except for the amortization of nuclear fuel, depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the group, composite or unitary methods of depreciation. The group approach is typically for groups of similar assets that have approximately the same useful lives and the composite approach is used for dissimilar assets that have different lives. Under both methods, a reporting entity depreciates the assets over the average life of the assets in the group. The Utility Registrants' depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with each utility's regulatory recovery method. The estimated service lives for the Utility Registrants are primarily based on each company's most recent depreciation studies of historical asset retirement and removal cost experience. 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. For its nuclear generating facilities, except for Oyster Creek, Clinton and TMI, Generation estimates each unit will operate through the full term of its initial 20-year operating license renewal period. See Note 8 — Early Nuclear Plant Retirements for additional information on the impacts of expected and potential early plant retirements. The estimated service lives of Generation's hydroelectric generating facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of 40 years. See Note 6 — Property, Plant and Equipment for further information regarding depreciation.

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Amortization of regulatory assets and liabilities are recorded over the recovery or refund period specified in the related legislation or regulatory order or agreement. When the recovery or refund period is less than one year, amortization is recorded to the line item in which the deferred cost or income would have originally been recorded in the Registrants' Consolidated Statements of Operations and Comprehensive Income. Amortization of ComEd's electric distribution and energy efficiency formula rate regulatory assets and ComEd's, PECO's, BGE's, Pepco's, DPL's and ACE's transmission formula rate regulatory assets is recorded to Operating revenues.

Amortization of income tax related regulatory assets and liabilities are generally recorded to Income tax expense. With the exception of the regulatory assets and liabilities discussed above, when the recovery period is more than one year, the amortization is generally recorded to Depreciation and amortization in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

See Note 3 — Regulatory Matters and Note 24 — Supplemental Financial Information for additional information regarding Generation's nuclear fuel, Generation's ARC and the amortization of the Utility Registrants' regulatory assets.

Asset Retirement Obligations (All Registrants)

The authoritative guidance for accounting for AROs requires the recognition of a liability for a legal obligation to perform an asset retirement activity even though the timing and/or method of settlement may be conditional on a future event. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic future cash flow models and discount rates. Generation generally updates its ARO annually, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various decommissioning scenarios. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years unless circumstances warrant more frequent updates (such as a change in assumed operating life for a nuclear plant). As part of the annual cost study update process, Generation evaluates newly assumed costs or substantive changes in previously assumed costs to determine if the cost estimate impacts are sufficiently material to warrant application of the updated estimates to the AROs across the nuclear fleet outside of the normal five-year rotating cost study update cycle. The liabilities associated with Exelon's non-nuclear AROs are adjusted on an ongoing rotational basis, at least once every five years unless circumstances warrant more frequent updates. Changes to the recorded value of an ARO result from the passage of new laws and regulations, revisions to either the timing or amount of estimated undiscounted cash flows, and estimates of cost escalation factors. AROs are accreted throughout each year to reflect the time value of money for these present value obligations through a charge to Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income or, in the case of the Utility Registrants' accretion, through an increase to regulatory assets. See Note 15 — Asset Retirement Obligations for additional information.

Capitalized Interest and AFUDC (All Registrants)

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

Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE apply the authoritative guidance for accounting for certain types of regulation to calculate AFUDC, which is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded to construction work in progress and as a non-cash credit to AFUDC that is included

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in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities.

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

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
2017 Total incurred interest ^(a)	\$ 1,658	\$ 502	\$ 369	\$ 130	\$ 111	\$ 133	\$ 54	\$ 64
Capitalized interest	63	63	—	—	—	—	—	—
Credits to AFUDC debt and equity	108	—	20	12	22	34	10	9
2016 Total incurred interest ^(a)	\$ 1,678	\$ 472	\$ 469	\$ 127	\$ 114	\$ 137	\$ 52	\$ 65
Capitalized interest	108	107	—	—	—	—	—	—
Credits to AFUDC debt and equity	98	—	22	11	30	29	7	9
2015 Total incurred interest ^(a)	\$ 1,170	\$ 445	\$ 336	\$ 116	\$ 113	\$ 131	\$ 51	\$ 65
Capitalized interest	79	79	—	—	—	—	—	—
Credits to AFUDC debt and equity	44	—	9	7	28	19	2	2
	Successor		Predecessor					
	For		January					
	the		1,					
	Year	March 24,	2016					
	Ended	2016 to	to					
	December	December	March					
	31,	31, 2016	23,					
	2017		31, 2015					
	2016		2016					
Total incurred interest ^(a)	\$ 263	\$ 207	\$ 68	\$ 289				
Credits to AFUDC debt and equity	54	35	10	23				

(a) Includes interest expense to affiliates.

Guarantees (All Registrants)

The Registrants recognize, at the inception of a guarantee, a liability for the fair market value of the obligations they have undertaken by issuing the guarantee, including the ongoing obligation to perform over the term of the guarantee in the event that the specified triggering events or conditions occur.

The liability that is initially recognized at the inception of the guarantee is reduced as the Registrants are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of the Registrant may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 23 — Commitments and Contingencies for additional information.

Asset Impairments (All Registrants)

Long-Lived Assets

The Registrants evaluate the carrying value of their long-lived assets or asset groups, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life. The Registrants determine if long-lived

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assets and asset groups are impaired by comparing the undiscounted expected future cash flows to the carrying value. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value.

Cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. The cash flows from the generating units are generally evaluated at a regional portfolio level along with cash flows generated from the customer supply and risk management activities, including cash flows from related intangible assets and liabilities on the balance sheet. In certain cases, generating assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generation assets (typically contracted renewables). See Note 7 — Impairment of Long-Lived Assets and Intangibles for additional information.

Goodwill

Goodwill represents the excess of the purchase price paid over the estimated fair value of the net assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized, but is tested for impairment at least annually or in an interim basis if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 10 — Intangible Assets for additional information regarding Exelon's, Generation's, ComEd's, PHI's and DPL's goodwill.

Equity Method Investments

Exelon and Generation regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature. Additionally, if the entity in which Generation holds an investment recognizes an impairment loss, Exelon and Generation would record their proportionate share of that impairment loss and evaluate the investment for an other-than-temporary decline in value.

Debt and Equity Security Investments

Declines in the fair value of Exelon's debt and equity investments below the cost basis are reviewed to determine if such decline is other-than-temporary. For available-for-sale securities and cost investments, if the decline is determined to be other-than-temporary, the cost basis is written down to fair value as a new cost basis. For equity securities and cost investments, the amount of the impairment loss is included in earnings. For debt securities, the amount of the impairment loss is included in earnings or separated between earnings and OCI depending on whether Exelon intends to sell the debt securities before recovery of its cost basis. Beginning January 1, 2018, the authoritative guidance eliminates the available-for-sale and cost method classifications for equity securities and requires that all equity investments (other than those accounted for using the equity method of accounting) be measured and recorded at fair value with any changes in fair value recorded through earnings. Investments in equity securities without readily determinable fair values must be qualitatively assessed for impairment each reporting period and fair value determined if any significant impairment indicators exist. If fair value is less than carrying value, the impairment is recorded through earnings immediately in the period in which it is identified without regard to whether the decline in value is temporary in nature. The new authoritative guidance does not impact the classification or measurement of investments in debt securities.

Derivative Financial Instruments (All Registrants)

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a

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recognized asset or liability or of an unrecognized firm commitment (fair value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in AOCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For derivative contracts intended to serve as economic hedges and that are not designated or do not qualify for hedge accounting or the normal purchases and normal sales exception, changes in the fair value of the derivatives are recognized in earnings each period, except for the Utility Registrants where changes in fair value may be recorded as a regulatory asset or liability if there is an ability to recover or return the associated costs. See Note 3 — Regulatory Matters and Note 12 — Derivative Financial Instruments for additional information. Amounts classified in earnings are included in revenue, purchased power and fuel, interest expense or other, net on the Consolidated Statements of Operations and Comprehensive Income based on the activity the transaction is economically hedging. For energy-related derivatives entered into for proprietary trading purposes, which are subject to Exelon's Risk Management Policy, changes in the fair value of the derivatives are recognized in earnings each period. All amounts classified in earnings related to proprietary trading are included in revenue on the Consolidated Statements of Operations and Comprehensive Income. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statements of Cash Flows, depending on the nature of each transaction.

As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the energy markets with the intent and ability to deliver or take delivery of the underlying physical commodity. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and will not be financially settled. Revenues and expenses on derivative contracts that qualify, and are designated, as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but rather are recorded on an accrual basis of accounting. See Note 12 — Derivative Financial Instruments for additional information.

Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all employees. The measurement of the plan obligations and costs of providing benefits under these plans involve various factors, including numerous assumptions and inputs and accounting elections. The assumptions are reviewed annually and at any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the Consolidated Statements of Operations and Comprehensive Income. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. See Note 16 — Retirement Benefits for additional information.

Equity Investment Earnings (Losses) of Unconsolidated Affiliates (Exelon and Generation)

Exelon and Generation include equity in earnings from equity method investments in qualifying facilities and power projects in Equity in earnings (losses) of unconsolidated affiliates within their Consolidated Statements of Operations and Comprehensive Income.

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New Accounting Standards (All Registrants)

New Accounting Standards Issued and Adopted as of January 1, 2018: The following new authoritative accounting guidance issued by the FASB has been adopted as of January 1, 2018 and will be reflected by the Registrants in their consolidated financial statements beginning in the first quarter of 2018. Unless otherwise indicated, adoption of the new guidance in each instance will have no or insignificant impacts on the Registrants' Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows, Consolidated Balance Sheets and disclosures.

Revenue from Contracts with Customers (Issued May 2014 and subsequently amended to address implementation questions; Adopted January 1, 2018): Changes the criteria for recognizing revenue from a contract with a customer. The new revenue recognition guidance, including subsequent amendments, is effective for annual reporting periods beginning on or after December 15, 2017, with the option to early adopt the standard for annual periods beginning on or after December 15, 2016. The Registrants did not early adopt this standard.

The new standard replaces existing guidance on revenue recognition, including most industry specific guidance, with a five-step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries, and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Registrants will apply the new guidance using the full retrospective method, which will not have a material impact on previously issued financial statements.

In coordination with the AICPA Power and Utilities Industry Task Force, the Registrants reached conclusions on the following key accounting issues:

The Utility Registrants' tariff sale contracts, including those with lower credit quality customers, are generally deemed to be probable of collection under the guidance and, thus, the timing of revenue recognition will continue to be concurrent with the delivery of electricity or natural gas, consistent with current practice;

Consistent with current industry practice, revenues recognized from sales of bundled energy commodities (i.e., contracts involving the delivery of multiple energy commodities such as electricity, capacity, ancillary services, etc.) are generally expected to be recognized upon delivery to the customer in an amount based on the invoice price given that it corresponds directly with the value of the commodities transferred to the customer; and

Contributions in aid of construction are outside of the scope of the standard and, therefore, will continue to be accounted for as a reduction to Property, Plant, and Equipment.

In assessing the impacts of the new revenue guidance, the Registrants identified the following items that will be accounted for differently:

Costs to acquire certain contracts (e.g., sales commissions associated with retail power contracts) will be deferred and amortized ratably over the term of the contract rather than being expensed as incurred; and

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• Variable consideration within certain contracts (e.g., performance bonuses) will be estimated and recognized as revenue over the term of the contract rather than being recognized when realized.

Based on an assessment of existing contracts and revenue streams, the new guidance, including the identified changes above, will not have a material impact on the amount and timing of the Registrants' revenue recognition.

One of the new disclosure requirements is to present disaggregated revenue into categories that show how economic factors affect the nature, amount, timing, and uncertainty of revenue and cash flows. In order to comply with this new disclosure requirement, Generation will disclose disaggregated revenue by operating segment and provide further differentiation by major products (i.e., electric power and gas) and the Utility Registrants will disclose disaggregated revenue by major customer class (i.e., residential and commercial and industrial) separately for electric and gas in the Combined Notes to Consolidated Financial Statements. In addition, pursuant to the requirements of the new standard, Exelon and the Utility Registrants will present alternative revenue program revenue separately from revenue from contracts with customers on the face of their Consolidated Statements of Operations and Comprehensive Income.

Recognition and Measurement of Financial Assets and Financial Liabilities (Issued January 2016; Adopted January 1, 2018): Eliminates the available-for-sale and cost method classification for equity securities and requires that all equity investments (other than those accounted for using the equity method of accounting) be measured and recorded at fair value with any changes in fair value recorded through earnings and, for equity investments without a readily determinable fair value, provides a measurement alternative of cost less impairment plus or minus adjustments for observable price changes in identical or similar assets. In addition, equity investments without readily determinable fair values must be qualitatively assessed for impairment each reporting period and fair value determined if any significant impairment indicators exist. If fair value is less than carrying value, the impairment is recorded through net income immediately in the period in which it is identified. The guidance does not impact the classification or measurement of investments in debt securities. The guidance also amends several disclosure requirements, including requiring i) financial assets and financial liabilities to be presented separately in the balance sheet or note, grouped by measurement category and form, ii) disclosure of the methods and significant assumptions used to estimate fair value or a description of the changes in the methods and assumptions used to estimate fair value, and iii) for financial assets and liabilities measured at amortized cost, disclosure of the fair value of the amount that would be received to sell the asset or paid to transfer the liability. The guidance is effective January 1, 2018 and must be applied using a modified retrospective transition approach with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of adoption. The Registrants recorded an insignificant adjustment to opening retained earnings as of January 1, 2018 related to unrealized gains/losses on available for sale equity securities.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments (Issued August 2016; Adopted January 1, 2018) and Restricted Cash (Issued November 2016; Adopted January 1, 2018): In 2016, the FASB issued two standards impacting the Statement of Cash Flows. The first adds or clarifies guidance on the classification of certain cash receipts and payments on the statement of cash flows as follows: debt prepayment or extinguishment costs, settlement of zero-coupon bonds, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies and bank-owned life insurance policies, distributions received from equity method investees, beneficial interest in securitization transactions, and the application of the predominance principle to separately identifiable cash flows. The second states that amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows (instead of being presented as

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cash flow activities). The new standards are effective on January 1, 2018 and must be applied on a full retrospective basis. Adoption of the second standard will result in a change in presentation of restricted cash on the face of the Statement of Cash Flows; otherwise this guidance will not have a significant impact on the Registrants' Consolidated Statements of Cash Flows and disclosures.

Intra-Entity Transfers of Assets Other Than Inventory (Issued October 2016; Adopted January 1, 2018): Requires entities to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs (current GAAP prohibits the recognition of current and deferred income taxes for an intra-entity asset transfer until the asset has been sold to an outside party). The standard is effective January 1, 2018 with early adoption permitted. The guidance requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption.

Clarifying the Definition of a Business (Issued January 2017; Adopted January 1, 2018): Clarifies the definition of a business with the objective of addressing whether acquisitions (or dispositions) should be accounted for as acquisitions/dispositions of assets or as acquisitions/dispositions of businesses. If substantially all the fair value of the assets acquired/disposed of is concentrated in a single identifiable asset or a group of similar identifiable assets, the set of transferred assets and activities is not a business. If the fair value of the assets acquired/disposed of is not concentrated in a single identifiable asset or a group of similar identifiable assets, then an entity must evaluate whether an input and a substantive process exist, which together significantly contribute to the ability to produce outputs. The standard also revises the definition of outputs to focus on goods and services to customers. The standard will likely result in more acquisitions being accounted for as asset acquisitions. The standard is effective January 1, 2018, with early adoption permitted, and must be applied on a prospective basis. The Registrants did not early adopt the guidance.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (Issued March 2017; Adopted January 1, 2018): Changes the accounting and presentation of pension and OPEB costs at the plan sponsor (i.e., Exelon) level. The guidance requires plan sponsors to report the service cost and other non-service cost components of net periodic pension cost and net periodic OPEB cost (together, net benefit cost) separately. Under the new guidance, service cost is presented as part of income from operations and the other non-service cost components are classified outside of income from operations on the Consolidated Statements of Operations and Comprehensive Income. Additionally, service cost is the only component eligible for capitalization. Under prior GAAP, the total amount of net benefit cost was recorded as part of income from operations and all components were eligible for capitalization.

Generation, ComEd, PECO, BGE, BSC, PHI, Pepco, DPL, ACE and PHISCO participate in Exelon's single employer pension and OPEB plans and apply multi-employer accounting. Multi-employer accounting is not impacted by this standard; therefore, Exelon's subsidiary financial statements will not change upon its adoption. On Exelon's consolidated financial statements, non-service cost components of pension and OPEB cost capitalizable under a regulatory framework are prospectively reported as regulatory assets (currently, they are capitalizable under pension and OPEB accounting guidance and reported as PP&E). These regulatory assets are amortized outside of operating income.

The presentation of the service cost component and the other non-service cost components of net benefit cost will be applied retrospectively in the Exelon consolidated financial statements beginning in the first quarter of 2018. On Exelon's consolidated financial statements, service cost will continue to be reported in Operating and maintenance and Non-service cost will be reported outside of operating income. The prospective change in the capitalization eligibility is not expected to have a significant impact on Exelon's consolidated net income.

New Accounting Standards Issued and Not Yet Adopted as of December 31, 2017: The following new authoritative accounting guidance issued by the FASB has not yet been adopted and

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reflected by the Registrants in their consolidated financial statements as of December 31, 2017. Unless otherwise indicated, the Registrants are currently assessing the impacts such guidance may have (which could be material) on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures, as well as the potential to early adopt where applicable. The Registrants have assessed other FASB issuances of new standards which are not listed below given the current expectation such standards will not significantly impact the Registrants' financial reporting.

Leases (Issued February 2016): Increases transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The standard is effective January 1, 2019. Early adoption is permitted, however the Registrants will not early adopt the standard. The issued guidance required a modified retrospective transition approach, which requires lessees and lessors to recognize and measure leases at the beginning of the earliest period presented (January 1, 2017). In January 2018, the FASB proposed amending the standard to give entities another option for transition. The proposed transition method would allow entities to initially apply the requirements of the standard in the period of adoption (January 1, 2019). The Registrants will assess this transition option when the FASB issues the standard.

The new guidance requires lessees to recognize both the right-of-use assets and lease liabilities in the balance sheet for most leases, whereas today only finance lease liabilities (referred to as capital leases) are recognized in the balance sheet. In addition, the definition of a lease has been revised when an arrangement conveys the right to control the use of the identified asset which may change the classification of an arrangement as a lease. Quantitative and qualitative disclosures related to the amount, timing and judgments of an entity's accounting for leases and the related cash flows are also expanded. Disclosure requirements apply to both lessees and lessors, whereas current disclosures relate only to lessees. Significant changes to lease systems, processes and procedures are required to implement the requirements of the new standard. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from current GAAP. Lessor accounting is also largely unchanged.

The standard provides a number of transition practical expedients that entities may elect. These include a "package of three" expedients that must be taken together and allow entities to (1) not reassess whether existing contracts contain leases, (2) carryforward the existing lease classification, and (3) not reassess initial direct costs associated with existing leases. In January 2018, the FASB issued additional guidance which provides another optional transition practical expedient. This practical expedient allows entities to not evaluate land easements under the new guidance at adoption if they were not previously accounted for as leases.

The Registrants have assessed the lease standard and are executing a detailed implementation plan in preparation for adoption on January 1, 2019. Key activities in the implementation plan include:

- Developing a complete lease inventory and abstracting the required data attributes into a lease accounting system that supports the Registrants' lease portfolios and integrates with existing systems.

- Evaluating the transition practical expedients available under the guidance.

- Identifying, assessing and documenting technical accounting issues, policy considerations and financial reporting implications. Includes completing a detailed contract assessment for a sample of transactions to determine whether they are leases under the new guidance.

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Identifying and implementing changes to processes and controls to ensure all impacts of the new guidance are effectively addressed.

Accounting and implementation issues continue to be identified and evaluated by the implementation team.

Impairment of Financial Instruments (Issued June 2016): Provides for a new Current Expected Credit Loss (CECL) impairment model for specified financial instruments including loans, trade receivables, debt securities classified as held-to-maturity investments and net investments in leases recognized by a lessor. Under the new guidance, on initial recognition and at each reporting period, an entity is required to recognize an allowance that reflects the entity's current estimate of credit losses expected to be incurred over the life of the financial instrument. The standard does not make changes to the existing impairment models for non-financial assets such as fixed assets, intangibles and goodwill. The standard will be effective January 1, 2020 (with early adoption as of January 1, 2019 permitted) and, for most debt instruments, requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption.

Goodwill Impairment (Issued January 2017): Simplifies the accounting for goodwill impairment by removing Step 2 of the current test, which requires calculation of a hypothetical purchase price allocation. Under the revised guidance, goodwill impairment will be measured as the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill (currently Step 1 of the two-step impairment test). Entities will continue to have the option to perform a qualitative assessment to determine if a quantitative impairment test is necessary. Exelon, Generation, ComEd, PHI, and DPL have goodwill as of December 31, 2017. This updated guidance is not currently expected to impact the Registrants' financial reporting. The standard is effective January 1, 2020, with early adoption permitted, and must be applied on a prospective basis.

Derivatives and Hedging (Issued September 2017): Allows more financial and nonfinancial hedging strategies to be eligible for hedge accounting. The amendments are intended to more closely align hedge accounting with companies' risk management strategies, simplify the application of hedge accounting, and increase transparency as to the scope and results of hedging programs. There are also amendments related to effectiveness testing and disclosure requirements. The guidance is effective January 1, 2019 and early adoption is permitted with a modified retrospective transition approach. The Registrants are currently assessing this standard but do not currently expect a significant impact given the limited activity for which the Registrants elect hedge accounting and because the Registrants do not anticipate increasing their use of hedge accounting as a result of this standard.

2. Variable Interest Entities (All Registrants)

A VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly affect the entity's economic performance.

At December 31, 2017, Exelon, Generation, PHI and ACE collectively consolidated five VIEs or VIE groups for which the applicable Registrant was the primary beneficiary. At December 31, 2016, Exelon, Generation, BGE, PHI and ACE collectively consolidated nine VIEs or VIE groups for which the applicable Registrant was the primary beneficiary (see Consolidated Variable Interest Entities below). As of December 31, 2017 and 2016, Exelon and Generation collectively had significant interests in seven and eight other VIEs, respectively, for which the applicable Registrant does not have the power to direct

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the entities' activities and, accordingly, was not the primary beneficiary (see Unconsolidated Variable Interest Entities below).

Consolidated Variable Interest Entities

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the Registrants' consolidated financial statements at December 31, 2017 and 2016 are as follows:

	December 31, 2017				
	Exelon ^(a)	Generation	Successor PHI ^(a)	ACE	
Current assets	\$630	\$ 620	\$ 10	6	
Noncurrent assets	9,317	9,286	31	23	
Total assets	\$9,947	\$ 9,906	\$ 41	\$ 29	
Current liabilities	\$306	\$ 270	\$ 36	32	
Noncurrent liabilities	3,312	3,246	66	58	
Total liabilities	\$3,618	\$ 3,516	\$ 102	\$ 90	
	December 31, 2016				
	Exelon ^(a)	Generation	Successor BGE PHI ^(a)	ACE	
Current assets	\$954	\$ 916	\$ 23	\$ 14	\$9
Noncurrent assets	8,563	8,525	3	35	23
Total assets	\$9,517	\$ 9,441	\$ 26	\$ 49	\$32
Current liabilities	\$885	\$ 802	\$ 42	\$ 42	\$37
Noncurrent liabilities	2,713	2,612	—	101	89
Total liabilities	\$3,598	\$ 3,414	\$ 42	\$ 143	\$126

(a) Includes certain purchase accounting adjustments not pushed down to the ACE standalone entity.

(b) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.

Except as specifically noted below, the assets in the table above are restricted for settlement of the VIE obligations and the liabilities in the table can only be settled using VIE resources.

As of December 31, 2017, Exelon's and Generation's consolidated VIEs consist of:

Investments in Other Energy Related Companies

During 2015, Generation sold 69% of its equity interest in a company to a tax equity investor. The company holds an equity method investment in a distributed energy company that is an unconsolidated VIE (see unconsolidated VIE section for additional details). Generation and the tax equity investor contributed a total of \$227 million of equity in proportion to their ownership interests to the company. The company meets the definition of a VIE because it has a similar structure to a limited partnership and the limited partners do not have kick-out rights with respect to the general partner. Generation is the primary beneficiary because Generation manages the day-to-day activities of the entity.

During 2015, Generation formed a limited liability company to build, own, and operate a backup generator. While Generation owns 100% of the backup generator company, it was determined that the entity is a VIE because the customer absorbs price variability from the entity through the fixed price

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backup generator agreement. Generation provides operating and capital funding to the backup generator company. During the fourth quarter of 2017 Generation acquired a controlling financial interest in an energy development company. The company is in the development stage and requires additional subordinated financial support from the equity holders to fund activities. Generation is the majority owner with a 62% equity interest and has the power to direct the activities that most significantly affect the economic performance of the company.

Renewable Energy Project Companies

In July 2017, Generation entered into an arrangement to sell a 49% interest in ExGen Renewable Partners, LLC (the Renewable JV) to an outside investor for \$400 million of cash plus immaterial working capital and other customary post-closing adjustments. The Renewable JV meets the definition of a VIE because the Renewable JV has a similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner. Generation is the primarily beneficiary because Generation manages the day-to-day activities of the entity; therefore, Generation will continue to consolidate the Renewable JV. The Renewable JV is a collection of wind and solar project entities and some of these project entities are VIEs that are consolidated by the Renewable JV. The details relating to these VIEs are discussed below.

Generation owns a number of limited liability companies that build, own, and operate solar and wind power facilities some of which are owned by the Renewable JV. While Generation or the Renewable JV owns 100% of the solar entities and 100% of the majority of the wind entities, it has been determined that certain of the solar and wind entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of these solar and wind entities that qualify as VIEs because Generation controls the design, construction, and operation of the facilities. Generation provides operating and capital funding to the solar and wind entities for ongoing construction, operations and maintenance and there is limited recourse related to Generation related to certain solar and wind entities.

While Generation or the Renewable JV owns 100% of the majority of the wind entities, six of the projects have noncontrolling equity interests of 1% held by third parties and one of the projects has noncontrolling equity interests related to its Class B Membership Interest (see additional details below). The entities with noncontrolling equity interests of 1% held by third parties meet the definition of a VIE because the entities have noncontrolling equity interest holders that absorb variability from the wind projects. Generation's or the Renewable JV's current economic interests in five of these projects is significantly greater than its stated contractual governance rights and all of these projects have reversionary interest provisions that provide the noncontrolling interest holder with a purchase option, certain of which are considered bargain purchase prices, which, if exercised, transfers ownership of the projects to the noncontrolling interest holder upon either the passage of time or the achievement of targeted financial returns. The ownership agreements with the noncontrolling interests state that Generation or the Renewable JV are to provide financial support to the projects in proportion to its current 99% economic interests in the projects. Generation provides operating and capital funding to the wind project entities for ongoing construction, operations and maintenance and there is limited recourse to Generation related to certain wind project entities. However, no additional support to these projects beyond what was contractually required has been provided during 2017. Generation is the primary beneficiary of these wind entities because Generation controls the design, construction, and operation of the facilities.

In December 2016, Generation sold 100% of the Class B Membership Interests to a tax equity investor and retained 100% of the Class A Membership Interests of its equity interest in one of its wind

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entities that was previously consolidated under the voting interest model. The wind entity meets the definition of a VIE because the company has a similar structure to a limited partnership and the limited partners do not have kick-out rights with respect to the general partner. While Generation is the minority interest holder, Generation is the primary beneficiary, because Generation manages the day-to-day activities of the entity. Therefore, the entity continues to be consolidated by Generation.

The renewable energy project companies VIE group was previously separated into two VIE groups for solar project limited liability companies and wind project companies as of December 31, 2016.

Retail Power and Gas Companies

In March 2014, Generation began consolidating retail power and gas VIEs for which Generation is the primary beneficiary as a result of energy supply contracts that give Generation the power to direct the activities that most significantly affect the economic performance of the entities. Generation does not have an equity ownership interest in these entities, but provides approximately \$30 million in credit support for the retail power and gas companies for which Generation is the sole supplier of energy. These entities are included in Generation's consolidated financial statements, and the consolidation of the VIEs do not have a material impact on Generation's financial results or financial condition.

CENG

CENG is a joint venture between Generation and EDF. On April 1, 2014, Generation, CENG, and subsidiaries of CENG executed the Nuclear Operating Services Agreement (NOSA) pursuant to which Generation now conducts all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF. As a result of executing the NOSA, CENG qualifies as a VIE due to the disproportionate relationship between Generation's 50.01% equity ownership interest and its role in conducting the operational activities of CENG and the CENG fleet conveyed through the NOSA. Further, since Generation is conducting the operational activities of CENG and the CENG fleet, Generation qualifies as the primary beneficiary of CENG and, therefore, is required to consolidate the results of operations and financial position of CENG.

Exelon and Generation, where indicated, provide the following support to CENG (see Note 26 — Related Party Transactions for additional information regarding Generation's and Exelon's transactions with CENG):
 under power purchase agreements with CENG, Generation purchased or will purchase 50.01% of the available output generated by the CENG nuclear plants not subject to other contractual agreements from January 2015 through the end of the operating life of each respective plant. However, pursuant to amendments dated March 31, 2015, the energy obligations under the Ginna Nuclear Power Plant (Ginna) PPAs were suspended during the term of the Reliability Support Services Agreement (RSSA), through the end of March 31, 2017. With the expiration of the RSSA, the PPA was reinstated beginning April 1, 2017. (see Note 3 — Regulatory Matters for additional details),
 Generation provided a \$400 million loan to CENG. As of December 31, 2017, the remaining obligation is \$333 million, including accrued interest, which reflects the principal payment made in January 2015,
 Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their

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operations. Exelon guarantees Generation's obligations under this Indemnity Agreement. (See Note 23 — Commitments and Contingencies for more details),

Generation and EDF share in the \$637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance, and

Exelon has executed an agreement to provide up to \$245 million to support the operations of CENG as well as a \$165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

As of December 31, 2016, Exelon and Generation had the following consolidated VIEs that are no longer VIEs as of December 31, 2017:

Retail Gas Group

During 2009, Constellation formed a retail gas group to enter into a collateralized gas supply agreement with a third-party gas supplier. The retail gas group was determined to be a VIE because there was not sufficient equity to fund the group's activities without additional credit support and a \$75 million parental guarantee provided by Generation. As the primary beneficiary, Generation consolidated the retail gas group. During the second quarter of 2017, the collateral structure was terminated with the third-party gas supplier except for the \$75 million parental guarantee provided by Generation. Although the parental guarantee remains, this is considered customary and reasonable for the unsecured position Generation has with the third-party gas supplier. As a result of the termination, the retail gas group no longer met the definition of a VIE. However, the retail gas group continues to be consolidated by Generation under the voting interest model.

Other Generating Facilities

Prior to 2017, Generation owned 90% of a biomass fueled, combined heat and power company. In the second quarter of 2015, the entity was deemed to be a VIE because the entity required additional subordinated financial support in the form of a parental guarantee provided by Generation for up to \$275 million in support of the payment obligations related to the Engineering, Procurement and Construction contract for the facility in support of one of its other generating facilities. During the third quarter of 2017, the ownership of the entity increased to 99%, all payment obligations related to the EPC contract were satisfied, and the parental guarantee provided by Generation was terminated. As a result, the entity is now sufficiently capitalized and no longer meets the definition of a VIE. However, the biomass facility continues to be consolidated by Generation under the voting interest model.

As of December 31, 2017 and 2016, Exelon's and ACE's consolidated VIE consists of:

ACE Transition Funding

A special purpose entity formed by ACE for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of transition bonds. Proceeds from the sale of each series of transition bonds by ATF were transferred to ACE in exchange for the transfer by ACE to ATF of the right to collect a non-bypassable Transition Bond Charge from ACE customers pursuant to bondable stranded costs rate orders issued by the NJBPU in an amount sufficient to fund the principal and interest payments on transition bonds and related taxes, expenses and fees. During the three years ended December 31, 2017, 2016 and 2015, ACE transferred \$48 million, \$60 million and \$61 million to ATF, respectively.

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As of December 31, 2016, Exelon and BGE had the following consolidated VIE that is no longer a VIE as of December 31, 2017:

RSB BondCo LLC.

In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges were assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1. In the second quarter of 2017 the rate stabilization bonds were fully redeemed and BGE remitted its final payment to BondCo. Upon redemption of the bonds, BondCo no longer meets the definition of a variable interest entity.

BondCo's assets were restricted and could only be used to settle the obligations of BondCo. Further, BGE was required to remit all payments it received from customers for rate stabilization charges to BondCo. During 2017, 2016 and 2015, BGE remitted \$22 million, \$86 million and \$86 million, respectively, to BondCo.

For each of the consolidated VIEs noted above, except as otherwise noted:

- the assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE;
 - Exelon, Generation, BGE, PHI and ACE did not provide any additional material financial support to the VIEs;
 - Exelon, Generation, BGE, PHI and ACE did not have any material contractual commitments or obligations to provide financial support to the VIEs; and
 - the creditors of the VIEs did not have recourse to Exelon's, Generation's, BGE's, PHI's or ACE's general credit.
- As of December 31, 2017 and 2016, ComEd, PECO, Pepco and DPL do not have any material consolidated VIEs.

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Assets and Liabilities of Consolidated VIEs

Included within the balances above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors, or beneficiaries, do not have recourse to the general credit of the Registrants. As of December 31, 2017 and 2016, these assets and liabilities primarily consisted of the following:

	December 31, 2017			
	Exelon ^(a) Generation		Successor PHI ^(a) ACE	
Cash and cash equivalents	\$126	\$ 126	\$ —	\$ —
Restricted cash	64	58	6	6
Accounts receivable, net				
Customer	138	138	—	—
Other	25	25	—	—
Inventory				
Materials and supplies	205	205	—	—
Other current assets	45	41	4	—
Total current assets	603	593	10	6
Property, plant and equipment, net	6,186	6,186	—	—
Nuclear decommissioning trust funds	2,502	2,502	—	—
Other noncurrent assets	274	243	31	23
Total noncurrent assets	8,962	8,931	31	23
Total assets	\$9,565	\$ 9,524	\$ 41	\$ 29
Long-term debt due within one year	\$102	\$ 67	\$ 35	\$ 31
Accounts payable	114	114	—	—
Accrued expenses	65	64	1	1
Unamortized energy contract liabilities	18	18	—	—
Other current liabilities	7	7	—	—
Total current liabilities	306	270	36	32
Long-term debt	1,154	1,088	66	58
Asset retirement obligations	2,035	2,035	—	—
Unamortized energy contract liabilities	5	5	—	—
Other noncurrent liabilities	112	112	—	—
Noncurrent liabilities	3,306	3,240	66	58
Total liabilities	\$3,612	\$ 3,510	\$ 102	\$ 90

(a) Includes certain purchase accounting adjustments not pushed down to the ACE standalone entity.

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	December 31, 2016		Successor		
	Exelon (a)(b)	Generation	BGE	PHI ^(a)	ACE
Cash and cash equivalents	\$ 150	\$ 150	\$ —	\$ —	\$ —
Restricted cash	59	27	23	9	9
Accounts receivable, net					
Customer	371	371	—	—	—
Other	48	48	—	—	—
Mark-to-market derivative assets	31	31	—	—	—
Inventory					
Materials and supplies	199	199	—	—	—
Other current assets	50	44	—	5	—
Total current assets	908	870	23	14	9
Property, plant and equipment, net	5,415	5,415	—	—	—
Nuclear decommissioning trust funds	2,185	2,185	—	—	—
Goodwill	47	47	—	—	—
Mark-to-market derivative assets	23	23	—	—	—
Other noncurrent assets	315	277	3	35	23
Total noncurrent assets	7,985				