Exelon

Exelon Corporation 2017 Annual Report

Exelon®

Corporate Profile

Corporate Headquarters
Exelon Corporation
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EQ Shareowner Services
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Employee Stock Purchase Plan
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Employee Stock Options
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Investor Relations Voice Mailbox
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Shareholder Services Voice Mailbox
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Independent Public Accountants
PricewaterhouseCoopers LLP

Website
www.exeloncorp.com

Stock Ticker
EXC

Exelon Corporation (NYSE: EXC) is a Fortune 100 energy company with the largest number of utility customers in the U.S. Exelon does business in 48 states, the District of Columbia and Canada and had 2017 revenue of $33.5 billion. Exelon's six utilities deliver electricity and natural gas to approximately 9 million customers in Delaware, the District of Columbia, Illinois, Maryland, New Jersey and Pennsylvania through its Atlantic City Electric, BGE, ComEd, Delmarva Power, PECO and Pepco subsidiaries. Exelon is one of the largest competitive U.S. power generators, with more than 35,100 megawatts of nuclear, gas, wind, solar and hydroelectric generating capacity comprising one of the nation's cleanest and lowest-cost power generation fleets. The company's Constellation business unit provides energy products and services to approximately 2 million residential, public sector and business customers, including more than two-thirds of the Fortune 100. Exelon trades on the New York and Chicago Stock Exchanges under the ticker EXC.

Shareholder Inquiries

Exelon Corporation has appointed EQ Shareowner Services as its transfer agent, stock registrar, dividend disbursing agent and dividend reinvestment agent. Should you have questions concerning your registered shareholder account or the payment or reinvestment of your dividends, or if you wish to make a stock transaction or stock transfer, you may call shareowner services at EQ at the toll-free number shown to the left or access its website at www.shareowneronline.com.

Morgan Stanley administers the Employee Stock Purchase Plan (ESPP), employee stock options and other employee equity awards. Should you have any questions concerning your employee plan shares or wish to make a transaction, you may call the toll-free numbers shown to the left or access its website at www.stockplanconnect.com.

The company had approximately 105,000 holders of record of its common stock as of Dec. 31, 2017. The 2017 Form 10-K Annual Report to the Securities and Exchange Commission was filed on Feb. 9, 2018.

To obtain a copy without charge, write to Carter Culver, Senior Vice President, Deputy General Counsel and Assistant Secretary, Exelon Corporation, Post Office Box 805379, Chicago, Illinois 60680-5379.

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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.

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

Other Terms and Abbreviations

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

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

Integrys
Integrys Energy Services, Inc.

IPA
Illinois Power Agency

IRC
Internal Revenue Code

IRS
Internal Revenue Service

ISO
Independent System Operator

ISO-NE
ISO New England Inc.

ISO-NY
ISO New York

kV
Kilovolt

kW
Kilowatt

kWh
Kilowatt-hour

LIBOR
London Interbank Offered Rate

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

Other Terms and Abbreviations

MDE
Maryland Department of the Environment

MDPSC
Maryland Public Service Commission

MGP
Manufactured Gas Plant

MISO
Midcontinent Independent System Operator, Inc.

mmcf
Million Cubic Feet

Moody's
Moody's Investor Service

MOPR
Minimum Offer Price Rule

MRV
Market-Related Value

MW
Megawatt

MWh
Megawatt hour

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

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

Other Terms and Abbreviations

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

Filing Format

The information included within this Annual Report has been taken from Exelon's 10-K annual report for the year ended December 31, 2017. That annual report was filed with the SEC on February 9, 2018 and can be viewed and retrieved through the SEC's website at *www.sec.gov* or our website at *www.exeloncorp.com*. We encourage you to consider the entire Form 10-K annual report, which contains more information about us and our subsidiaries than is presented in this Annual Report.

Cautionary Statements Regarding Forward-Looking Information

This Annual 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 Exelon include those factors discussed herein or in Exelon's 2017 Form 10-K, including those discussed in (a) Risk Factors, (b) Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Financial Statements and Supplementary Data: Note 23, Commitments and Contingencies; and (d) other factors discussed in filings with the SEC by Exelon. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Annual Report. Exelon does not undertake any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Annual Report.

Where to find More Information

Exelon's 2017 Form 10-K is available on Exelon's website at *www.exeloncorp.com* and will be made available, without charge, in print to any shareholder who requests such documents from Carter Culver, Senior Vice President, Deputy General Counsel and Assistant Secretary, Exelon Corporation, P.O. Box 805398, Chicago, Illinois, 60680-5398.

General Description of Our Business

General

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 gas to retail customers	Southeastern Pennsylvania, including the City of Philadelphia (electricity) Pennsylvania counties surrounding the City of Philadelphia (natural gas)	2301 Market Street, Philadelphia, Pennsylvania 19103
Baltimore Gas and Electric Company	Maryland (1906)	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)	110 West Fayette Street, Baltimore, Maryland 21201
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 Transmission and distribution of electricity to retail customers	District of Columbia and Major portions of Montgomery and Prince George's Counties, Maryland	701 Ninth Street, N.W., Washington, D.C. 20068
Delmarva Power & Light Company	Delaware (1909) Virginia (1979)	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)	500 North Wakefield Drive, Newark, Delaware 19702
Atlantic City Electric Company	New Jersey (1924)	Purchase and regulated retail sale of electricity Transmission and distribution of electricity to retail customers	Portions of Southern New Jersey	500 North Wakefield Drive, Newark, Delaware 19702

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.

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 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.

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.

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.

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.
(c) Includes wind, hydroelectric and solar generating assets.
(d) Electric supply procured under site specific agreements.
(e) Includes EGTP generating assets that were deconsolidated from Generation's consolidated financial statements. See 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 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 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.

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.

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.

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

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.

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 MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Exelon Corporation, Executive Overview; 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.

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 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.

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-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

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g., CENG). Nuclear generation for 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 MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Marketing

Generation's integrated business operations include 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 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.

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

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

[a] Natural gas from underground storage represents approximately 28%, 46% and 34% of PECO's, BGE's and DPL's 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 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.

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

See Note 3 — Regulatory Matters, Note 25—Segment Information of the Combined Notes to Consolidated Financial Statements and 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) A separate CBA between ComEd and IBEW Local 15 covers approximately 65 employees in ComEd's System Services Group and was renewed in 2016. Generation's and ComEd's separate CBAs with IBEW Local 15 will expire in 2022.

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

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 (SO_2), nitrogen oxides (NOx), 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 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) 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.

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.

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, CO_2. However, Generation's owned-asset emission intensity, or rate of carbon dioxide equivalent (CO_2e) 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 (SF_6) 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.

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.

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 CO_2 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 CO_2 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.

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

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	2015 - Present
		President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation	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	2013 - Present
		Senior Vice President, Portfolio Management and Strategy	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	2013 - Present
		Senior Vice President, Corporate Finance, Exelon	2012 - 2013
Bauer, Matthew N.	41	Vice President and Controller, Generation	2016 - Present
		Vice President and Controller, BGE	2014 - 2016
		Vice President of Power Finance, Exelon Power	2012 - 2014

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

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	2007 - Present
		Treasurer, PECO	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	2016 - Present
		Vice President, Governmental & External Affairs, PECO	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

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

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

Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

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 Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First 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

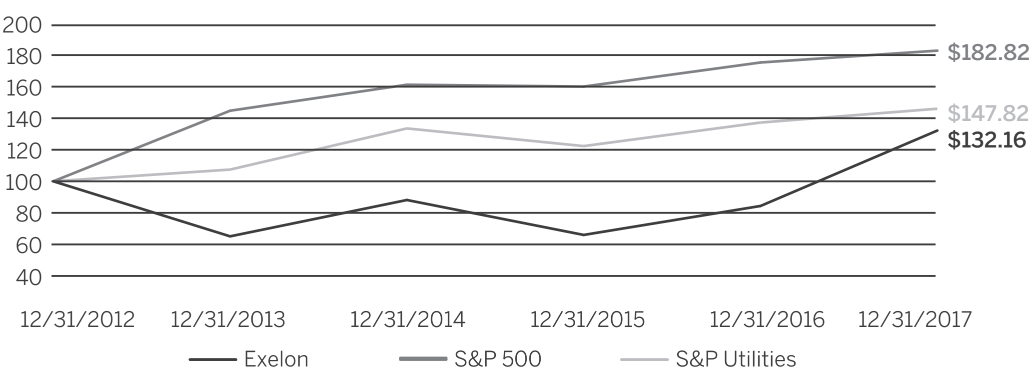
Stock Performance Graph

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.

COMPARISON OF FIVE-YEAR CUMULATIVE RETURN



	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.

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.

Dividends

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

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

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

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

BGE is subject to certain dividend restrictions established by the MDPSC. First, in connection with the Constellation merger, BGE was prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid and notify the MDPSC that BGE's equity ratio is at least 48% within five business days after dividend payment.

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.

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

	2017				2016			
(per share)	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:

	2017				2016			
(in millions)	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.

Selected Financial Data

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 MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

	For the Years Ended December 31,				
(In millions, except per share data)	**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.

	December 31,				
(In millions)	**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

Management's Discussion and Analysis of Financial Condition and Results of Operations

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.

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.

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,								Favorable (Unfavorable) Variance
	2017							2016	
	Generation	ComEd	PECO	BGE	PHI	Other	Exelon	Exelon[b]	
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.

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.

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.

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.

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		2016	
(All amounts after tax; in millions, except per share amounts)		**Earnings per Diluted Share**		**Earnings per Diluted Share**
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

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

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

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

(d) 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 Note 4 - Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail related to merger and acquisition costs.

(e) 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 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.

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

(g) 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 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.

(h) 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 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.

(j) Represents in 2017 adjustments to income tax, penalties and interest expenses as a result of the finalization of the 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.

(p) 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.

(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.

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

	For the Year Ended December 31, 2016					*Successor* March 24, 2016 to December 31, 2016
	Exelon	**Generation**	**Pepco**	**DPL**	**ACE**	**PHI**
Merger commitments[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:

Merger, Integration and Acquisition Expense:	Pre-tax Expense For the Year Ended December 31, 2017								
	Exelon[a]	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)

Merger Integration and Acquisition Expense:	Pre-tax Expense For the Year Ended December 31, 2016								
	Exelon[a]	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.

(d) 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. 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.

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.

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]	
Income statement expense (pre-tax)	**2017**	**2018**	**2019**
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.

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.

Income statement expense (pre-tax)	Projected[b] 2018
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 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 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 Revenue Requirement Increase (in millions)	Approved Return on Equity	Completion Date	Rate Effective Date
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

(a) 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).

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

(c) 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.

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%[(c)]	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

(a) On February 5, 2018, Pepco filed with the MDPSC an update to its current distribution rate case to reflect 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.

(c) 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 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:

	2017				
Annual Transmission Filings[a]	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]	11.50%	10.50%	10.50%	10.50%	10.50%

(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.

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.

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.

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 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.

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, 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 prejudge the investigation or related proceedings. Generation cannot predict the impact the FERC order may ultimately have on future auction results, capacity pricing or decisions related to the potential early retirement of the Clinton nuclear plant, however, such impacts could be material to Generation's future results of operations and cash flows. See Note 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 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.

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 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 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 GENERAL DESCRIPTION OF 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 GENERAL DESCRIPTION OF BUSINESS, "Water Quality" for further discussion.

Solid and Hazardous Waste

In October 2015, the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants became effective. The rule classifies CCR as non-hazardous waste under RCRA. Under the regulation, CCR will continue to be regulated by most states subject to coordination with the federal regulations. Generation has previously recorded 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

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.

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.

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 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.

Goodwill

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, 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

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 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

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 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. 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

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 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

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 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.

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):

	Actual Assumption		Change in			
Actuarial Assumption	**Pension**	**OPEB**	**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)

(a) In general, the discount rate will have a larger impact on the pension and other postretirement benefit cost and obligation as the rate moves closer to 0%. Therefore, the discount rate sensitivities above cannot necessarily be extrapolated for larger increases or decreases in the discount rate. Additionally, Exelon 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 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 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.

Accounting for Derivative Instruments

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 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 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 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

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.

Accounting for Loss Contingencies

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

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, 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.

Allowance for Uncollectible Accounts

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, 2017	For the Years Ended December 31, 2016	Favorable (unfavorable) 2017 vs. 2016 variance	For the Year Ended December 31, 2015	Favorable (unfavorable) 2016 vs. 2015 variance
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		*Predecessor*	
	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI	$362	$(61)	$19	$327

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)

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

Net Income Attributable to Membership Interest

Year Ended December 31, 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.
- 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.

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 vs. 2016			2016 vs. 2015	
	2017	2016	Variance	% Change	2015	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)%

(a) Results of transactions with PECO and BGE are included in the Mid-Atlantic region. Results of transactions with Pepco, DPL, and ACE are included in the Mid-Atlantic region 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.

(c) 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, 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.

Generation's supply sources by region are summarized below:

Supply Source (GWh)	2017	2016	2017 vs. 2016 Variance	2017 vs. 2016 % Change	2015	2016 vs. 2015 Variance	2016 vs. 2015 % 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.

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.

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.

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.

Operating and Maintenance Expense

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

	(Decrease) Increase[(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[(j)]	(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.

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.

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)

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.

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)

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

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

Net Income

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

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) 2017 vs. 2016	Increase (Decrease) 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

(a) 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 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.

(b) Beginning on June 1, 2017, ComEd is deferring energy efficiency costs as a regulatory asset that will be recovered 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.

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 December 31,			% Change	
Heating and Cooling Degree-Days	**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 December 31,			% Change	
Heating and Cooling Degree-Days	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	5,715	6,091	6,198	(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 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)

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

The changes in Operating and maintenance expense for year ended December 31, 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) 2017 vs. 2016	Increase (Decrease) 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[(b)]	(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.

(b) 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 mechani[sm]. ComEd recorded a net 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) 2017 vs. 2016	Increase (Decrease) 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.

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) 2017 vs. 2016	Increase (Decrease) 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

(a) Primarily reflects the recognition of after-tax interest related to the Tax Court's decision on Exelon's like-kind exchange tax position in the 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.

(b) 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) 2017 vs. 2016	Increase (Decrease) 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)

(a) 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.

ComEd 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	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%

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

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

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

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

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

Net Income

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 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 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	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

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 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 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	$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

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for 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.

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

Electric Revenue	2017	2016	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
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%

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

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

(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

Deliveries to customers (in mmcf)	2017	2016	% Change 2017 vs. 2016	Weather-Normal % Change	2015	% Change 2016 vs. 2015	Weather-Normal % Change
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%

Number of Gas Customers	As of December 31, 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

Gas revenue	2017	2016	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
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)%

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

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

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

(a) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenues net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net 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 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%

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 Customers	% of total retail customers	Number of Customers	% of total retail customers	Number of Customers	% of total retail 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 (Decrease)			Increase (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.

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	
Heating and Cooling Degree-Days	**2017**	**2016**	**Normal**	**2017 vs. 2016**	**2017 vs. Normal**
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	
Heating and Cooling Degree-Days	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
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.

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	$672	$701	$(29)	$701	$636	$ 65
Operating and maintenance expense—regulatory required programs[(a)]	44	36	8	36	47	(11)
Total operating and maintenance expense	$716	$737	$(21)	$737	$683	$ 54

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

The changes in Operating and maintenance expense for 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.

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) 2017 vs. 2016	Increase (Decrease) 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.
(b) 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.
(c) 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.

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.

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%

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

(b) Other revenue 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.

BGE NATURAL GAS OPERATING STATISTICS AND REVENUE DETAIL

Deliveries to customers (in mmcf)	2017	2016	% Change 2017 vs. 2016	Weather-Normal % Change	2015	% Change 2016 vs. 2015	Weather-Normal % Change
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	2017	2016	2015
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 2017 vs. 2016	2015	% Change 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)%

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

	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

(a) 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 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 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 onetime 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.

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)

(a) 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.

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 customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail 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.

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) 2017 vs. 2016	Increase (Decrease) 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.

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.

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	$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

[a] Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for 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	$ 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.

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[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.
[b] 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.

(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. 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-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

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	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%

Number of Electric Customers	As of December 31, 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

Electric Revenue	2017	2016	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
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%

(a) 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.

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

(c) 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.

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,		
	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, 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	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 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 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	
Heating and Cooling Degree-Days	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%

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

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

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

Operating and Maintenance Expense

	Year Ended December 31, 2017	Year Ended December 31, 2016	Increase (Decrease)	Year Ended December 31, 2016	Year Ended December 31, 2015	Increase (Decrease)
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

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for 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.

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[(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 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

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	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)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from DPL and customers 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.

DPL GAS OPERATING STATISTICS AND REVENUE DETAIL

Retail Deliveries to Customers (in mmcf)	2017	2016	% Change 2017 vs. 2016	Weather Normal % change	2015	% Change 2016 vs. 2015	Weather Normal % change
Retail Deliveries							
Residential	13,107	13,341	(1.8)%	5.2%	13,816	(3.4)%	(0.4)%
Transportation & other	6,538	6,201	5.4%	6.9%	6,193	0.1%	1.4%
Total gas deliveries	19,645	19,542	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	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
Retail Sales[a]					
Retail sales	$136	$127	7.1%	$143	(11.2)%
Transportation & other[b]	25	21	19.0%	21	—%
Total gas revenues	$161	$148	8.8%	$164	(9.8)%

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from DPL and customers 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.

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)

(a) 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.

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.

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 customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total 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.

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:

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

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

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.

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	$ 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

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for 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.

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[(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.
(b) 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 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 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

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	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

Electric Revenue	2017	2016	% Change 2017 vs. 2016	2015	% Change 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)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from ACE and customers 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.

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. 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 Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

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 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 Exelon's 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

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 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.

					Successor			
	Exelon	ComEd	PECO[a]	BGE	PHI	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

(a) 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. 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 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 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		Predecessor	
	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI	$950	$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.

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	
	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended 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.

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

	Projected 2018[a]	Successor: For the Year Ended December 31, 2017	Successor: March 24, 2016 to December 31, 2016	Predecessor: January 1, 2016 to March 23, 2016	Predecessor: For the Year Ended December 31, 2015
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.
(c) The capital expenditures and 2018 projections include $86 million of expected incremental spending pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten-year period to modernize and storm-harden its distribution system and to implement smart grid technology.
(d) 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 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		Predecessor	
	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	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.
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.

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
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.

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.

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
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.
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.
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.

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
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.

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.

(b) 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 for further discussion.

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.

(b) 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 for further discussion.

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.

(b) 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 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.

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
Generation	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		Predecessor	
	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 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.

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 the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI	$328	$(515)	$(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 the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI[(b)]	$758	$1,251	$—	$—

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

(b) Contribution paid by Exelon.

(c) Contribution paid by PHI.

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.

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.

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%

(a) 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 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.

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:

EXELON INTERCOMPANY MONEY POOL

	For the Year Ended December 31, 2017		As of December 31, 2017
Contributed (borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Exelon Corporate	$ 579	$ —	$ 217
Generation	20	(589)	(54)
PECO	336	(22)	—
BSC	—	(423)	(217)
PHI Corporate	—	(47)	—
PCI	55	—	54

PHI INTERCOMPANY MONEY POOL

	For the Year Ended December 31, 2017		As of December 31, 2017
Contributed (borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (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 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 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.

		Payment due within			
	Total	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	—	—
Curtailment 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[j]	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.

[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 ComEd, PECO, BGE, PHI, Pepco, DPL and ACE financing trusts.

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

[d] Purchase power obligations include contingent operating lease payments associated with contracted generation agreements. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2017, including those related to CENG. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. 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.

[e] Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and services, procure electric renewable energy and RECs, procure electric supply, and purchase AECs and curtailment services.

(f) 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 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.
(g) 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.
(h) 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.
(i) Represents commitments for Generation's ongoing investments in new natural gas and biomass generation construction.
(j) 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, 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.
(k) See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding SNF obligations.
(l) These amounts represent Exelon's expected contributions to its qualified pension plans. The projected contributions reflect a funding strategy of contributing the greater of $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 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.

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

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, 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 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.

					Successor	*Predecessor*
					March 24 to December 31,	**January 1 to March 23,**
	Exelon	**Generation**	**ComEd**	**DPL**	**PHI**	**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.

(c) 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 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.

	Exelon	Generation	ComEd	DPL	Successor PHI
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[c]	(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.

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.

	Maturities Within						
	2018	2019	2020	2021	2022	2023 and Beyond	Total Fair Value
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.

Credit Risk, Collateral and Contingent Related Features

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

	Maturity of Credit Risk Exposure			
Rating as of December 31, 2017	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	79	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

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 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 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 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

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.

Interest Rate and Foreign Exchange Risk

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 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 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.

Certifications

The CEO of Exelon has made the required annual certifications for 2017 to the New York Stock Exchange in compliance with the New York Stock Exchange listing standards. The CEO and CFO have filed with the SEC all required certifications under section 302 of the Sarbanes-Oxley Act of 2002. These certifications are filed as exhibits 31-1 and 31-2 to Exelon's 2017 Form 10-K.

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

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 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA. 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.

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.

Exelon 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

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	**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

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

	December 31,	
(In millions)	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

Exelon Corporation and Subsidiary Companies Consolidated Balance Sheets

(In millions)	December 31, 2017	2016
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

(a) 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.

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Changes in Equity

	Shareholders' Equity							
(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Preference Stock	Total Equity
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)
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

Combined Notes to Consolidated Financial Statements

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

1. Significant Accounting Policies

Description of Business

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.

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	Northern Illinois, including the City of Chicago
	Transmission and distribution of electricity to retail customers	
PECO Energy Company	Purchase and regulated retail sale of electricity and natural gas	Southeastern Pennsylvania, including the City of Philadelphia (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Pennsylvania counties surrounding the City of Philadelphia (natural gas)
Baltimore Gas and Electric Company	Purchase and regulated retail sale of electricity and natural gas	Central Maryland, including the City of Baltimore (electricity and natural gas)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	
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	District of Columbia, and major portions of Montgomery and Prince George's Counties, Maryland.
	Transmission and distribution of electricity to retail customers	
Delmarva Power & Light Company	Purchase and regulated retail sale of electricity and natural gas	Portions of Delaware and Maryland (electricity)
	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	Purchase and regulated retail sale of electricity	Portions of Southern New Jersey
	Transmission and distribution of electricity to retail customers	

Basis of Presentation

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.

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 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

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

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

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-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

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

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 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

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

The Registrants consider investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Cash Equivalents

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 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

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

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

Inventory is recorded at the lower of weighted average cost or net realizable value. Provisions are recorded for excess and obsolete inventory.

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 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

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.

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

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

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

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 approximately $13 million of costs expensed in 2016 which relate to projects for which completion is no longer probable.

Capitalized Software Costs

Costs incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized within Property, plant and equipment. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives based on the expected life or pursuant to prescribed regulatory requirements. The following table presents net unamortized capitalized software costs and amortization of capitalized software costs by year:

Net unamortized software costs	Exelon
December 31, 2017	$ 834
December 31, 2016	808

Amortization of capitalized software costs	Exelon
2017	$270
2016	255
2015	208

Depreciation and Amortization

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.

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

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

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 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:

	For the Years Ended December 31,		
	2017	2016	2015
Total incurred interest[a]	$1,658	$1,678	$1,170
Capitalized interest	63	108	79
Credits to AFUDC debt and equity	108	98	44

(a) Includes interest expense to affiliates.

Guarantees

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

Long-Lived Assets

The Registrants evaluate the carrying value of their long-lived assets or asset groups, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life. The Registrants determine if long-lived assets and asset groups are impaired by comparing the undiscounted expected future cash flows to the carrying value. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value.

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 derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in 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

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 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.

New Accounting Standards

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
- 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 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 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.
- 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

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 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 Exelon's consolidated financial statements at December 31, 2017 and 2016 are as follows:

	As of December 31,	
	2017[(a)]	2016[(a)(b)]
Current assets	$ 630	$ 954
Noncurrent assets	9,317	8,563
Total assets	$9,947	$9,517
Current liabilities	$ 306	$ 885
Noncurrent liabilities	3,312	2,713
Total liabilities	$3,618	$3,598

(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 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 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 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.

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.

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 Exelon. As of December 31, 2017 and 2016, these assets and liabilities primarily consisted of the following:

	As of December 31,	
	2017[(a)]	2016[(a)(b)]
Cash and cash equivalents	$ 126	$ 150
Restricted cash	64	59
Accounts receivable, net		
Customer	138	371
Other	25	48
Inventory		
Materials and supplies	205	199
Other current assets	45	50
Total current assets	603	908
Property, plant and equipment, net	6,186	5,415
Nuclear decommissioning trust funds	2,502	2,185
Goodwill	—	47
Mark-to-market derivative assets	—	23
Other noncurrent assets	274	315
Total noncurrent assets	8,962	7,985
Total assets	$9,565	$8,893
Long-term debt due within one year	$ 102	$ 181
Accounts payable	114	269
Accrued expenses	65	119
Mark-to-market derivative liabilities	—	60
Unamortized energy contract liabilities	18	15
Other current liabilities	7	30
Total current liabilities	306	674
Long-term debt	1,154	641
Asset retirement obligations	2,035	1,904
Pension obligation[(c)]	—	9
Unamortized energy contract liabilities	5	22
Other noncurrent liabilities	112	106
Noncurrent liabilities	3,306	2,682
Total liabilities	$3,612	$3,356

(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.
(c) Includes the CNEG retail gas pension obligation, which is presented as a net asset balance within the Prepaid pension asset line item on Generation's balance sheet. See Note 16 - Retirement Benefits for additional details.

Unconsolidated Variable Interest Entities

Exelon's and Generation's variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected on Exelon's and Generation's Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

As of December 31, 2017 and 2016, Exelon and Generation had significant unconsolidated variable interests in seven and eight VIEs, respectively, for which Exelon or Generation, as applicable, was not the primary beneficiary. These interests include certain equity method investments and certain commercial agreements. Exelon and Generation only include unconsolidated VIEs that are individually material in the tables below. However, Generation has several individually immaterial VIEs that in aggregate represent a total investment of $8 million. These immaterial VIEs are equity and debt securities in energy development companies. The maximum exposure to loss related to these securities is limited to the $8 million included in Investments on Exelon's and Generation's Consolidated Balance Sheets.

The following tables present summary information about Exelon and Generation's significant unconsolidated VIE entities:

December 31, 2017	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$625	$509	$1,134
Total liabilities[(a)]	37	228	265
Exelon's ownership interest in VIE[(a)]	—	251	251
Other ownership interests in VIE[(a)]	588	30	618
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	251	251
Contract intangible asset	8	—	8
Debt and payment guarantees	—	—	—
Net assets pledged for Zion Station decommissioning[(b)]	2	—	2
December 31, 2016			
Total assets[(a)]	$638	$567	$1,205
Total liabilities[(a)]	215	287	502
Exelon's ownership interest in VIE[(a)]	—	248	248
Other ownership interests in VIE[(a)]	423	32	455
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	264	264
Contract intangible asset	9	—	9
Debt and payment guarantees	—	3	3
Net assets pledged for Zion Station decommissioning[(b)]	9	—	9

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.

(b) These items represent amounts on Exelon's and Generation's Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $39 million and $113 million as of December 31, 2017 and December 31, 2016, respectively; offset by payables to ZionSolutions LLC of $37 million and $104 million as of December 31, 2017 and December 31, 2016, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

For each unconsolidated VIE, Exelon and Generation assessed the risk of a loss equal to their maximum exposure to be remote and accordingly, Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no agreements with, or commitments by, third parties that would materially affect the fair value or risk of their variable interests in these variable interest entities.

As of December 31, 2017, Exelon's and Generation's unconsolidated VIEs consist of:

Energy Purchase and Sale Agreements

Generation has several energy purchase and sale agreements with generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each entity, and determined that certain of the entities are VIEs because the entity absorbs risk through the sale of fixed price power and renewable energy credits. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the VIEs because Generation does not have the power to direct the activities that most significantly impact the VIEs economic performance.

ZionSolutions

Generation has an asset sale agreement with EnergySolutions, Inc. and certain of its subsidiaries, including ZionSolutions, LLC (ZionSolutions), which is further discussed in Note 15 — Asset Retirement Obligations. Under this agreement, ZionSolutions can put the assets and liabilities back to Generation when decommissioning activities under the asset sale agreement are complete. Generation has evaluated this agreement and determined that, through the put option, it has a variable interest in ZionSolutions but is not the primary beneficiary. As a result, Generation has concluded that consolidation is not required. Other than the asset sale agreement, Exelon and Generation do not have any contractual or other obligations to provide additional financial support and ZionSolutions' creditors do not have any recourse to Exelon's or Generation's general credit.

Investment in Distributed Energy Companies

In July 2014, Generation entered into an arrangement to purchase a 90% equity interest and 90% of the tax attributes of a distributed energy company. Generation contributed a total $85 million of equity. The distributed energy company 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 of the general partner. Generation is not the primary beneficiary; therefore, the investment continues to be recorded using the equity method. During 2015, a company that is consolidated by Generation as a VIE entered into an arrangement to purchase a 90% equity interest and 99% of the tax attributes of another distributed energy company (see additional details in the Consolidated Variable Interest Entities section above). The equity holders (of which Generation is one) contributed to the distributed energy company a total of $227 million of equity in proportion to their ownership interests. The equity holders provided a parental guarantee of up to $275 million in support of equity contributions to the distributed energy company. As all equity contributions were made as of the first quarter of 2017, there is no further payment obligation under the parental guarantee. The distributed energy company 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 of the general partner. Generation is not the primary beneficiary; therefore, the investment is recorded using the equity method.

Both distributed energy companies from the 2015 and 2014 arrangements are considered related parties to Generation.

As of December 31, 2016, Exelon and Generation had the following unconsolidated VIE that is no longer a VIE as of December 31, 2017:

Investment in Energy Generating Facility

As of December 31, 2016, Generation had an equity investment in an energy generating facility. The entity was a VIE because Generation guaranteed the debt of the entity, provided equity support, and provided operating services to the entity. Generation was not the primary beneficiary of the entity because Generation did not have the power to direct the activities that most significantly impacted the VIE's economic performance. During 2017, Generation sold its equity investment in the entity; therefore, the entity is no longer a VIE as of December 31, 2017.

ComEd, PECO and BGE

The financing trust of ComEd, ComEd Financing III, and the financing trusts of PECO, PECO Trust III and PECO Trust IV, are not consolidated in Exelon's, ComEd's, or PECO's financial statements. These financing trusts were created to issue mandatorily redeemable trust preferred securities. ComEd and PECO have concluded that they do not have a significant variable interest in ComEd Financing III, PECO Trust III, or PECO Trust IV as each Registrant financed its equity interest in the financing trusts through the issuance of subordinated debt and, therefore, has no equity at risk.

The financing trust of BGE, BGE Capital Trust II, was created for the purpose of issuing mandatorily redeemable trust preferred securities. In the third quarter of 2017, BGE redeemed the securities pursuant to the optional redemption provisions of the Indenture, under which the subordinated debt securities were issued, and dissolved BGE Capital Trust II. Prior to dissolution, the BGE Capital Trust II was not consolidated in Exelon's or BGE's financial statements. BGE concluded it did not have a significant variable interest in BGE Capital Trust II as BGE financed its equity interest in the financing trust through the issuance of subordinated debt and, therefore, had no equity at risk. See Note 13 — Debt and Credit Agreements for additional information.

3. Regulatory Matters

The following matters below discuss the status of material regulatory and legislative proceedings of the Registrants.

Illinois Regulatory Matters

Tax Cuts and Jobs Act. On January 18, 2018, the ICC approved ComEd's petition filed on January 5, 2018 seeking approval to pass back to customers beginning February 1, 2018 $201 million in tax savings resulting from the enactment of the TCJA through a reduction in electric distribution rates. The amounts being passed back to customers reflect the benefit of lower income tax rates beginning January 1, 2018 and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. Refer to Note 14 - Income Taxes for more detail on Corporate Tax Reform.

Electric Distribution Formula Rate. ComEd's electric distribution rates are established through a performance-based formula rate. ComEd is required to file an annual update to the performance-based formula rate on or before May 1, with resulting rates effective in January of the following year. This annual electric distribution formula rate update is based on prior year actual costs and current year projected capital additions (initial revenue requirement). The update also reconciles any differences between the revenue requirement in effect for the prior year and actual costs incurred for that year (annual reconciliation). Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to Operating revenues for any differences between the revenue requirement in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation. The regulatory asset associated with electric distribution formula rate is amortized to Operating revenues in ComEd's Consolidated Statement of Operations and Comprehensive Income as the associated amounts are recovered through rates. Changes to the distribution formula rate as a result of FEJA are discussed below.

For each of the following years, the ICC approved the following total increases/(decreases) in ComEd's electric distributions formula rate filings:

Annual Electric Distribution Filings	**2017**	**2016**	**2015**
ComEd's requested total revenue requirement increase (decrease)	$ 96	$ 138	$ (50)
Final ICC Order			
Initial revenue requirement increase	$ 78	$ 134	$ 85
Annual reconciliation increase (decrease)	18	(7)	(152)
Total revenue requirement increase (decrease)	$ 96	$ 127[(a)]	$ (67)
Allowed Return on Rate Base:			
Initial revenue requirement	6.47%	6.71%	7.05%
Annual reconciliation	6.45%	6.69%	7.02%
Allowed ROE:			
Initial revenue requirement	8.40%	8.64%	9.14%
Annual reconciliation	8.34%[(b)]	8.59%[(b)]	9.09%[(b)]
Effective date of rates	January 2018	January 2017	January 2016

(a) On March 22, 2017, the ICC issued an order approving ComEd's proposal to reduce the 2016 revenue requirement by $18 million, which was reflected in customer rates beginning in April 2017. This reduction is not reflected in the 2016 revenue requirement amounts above.

(b) Includes a reduction of 6 basis points in 2017 and 5 basis points in 2016 and 2015 for a reliability performance metric penalty.

Illinois Future Energy Jobs Act

Background

On December 7, 2016, FEJA was signed into law by the Governor of Illinois. FEJA went into effect on June 1, 2017, and includes, among other provisions, (1) a ZES providing compensation for certain nuclear-powered generating facilities, (2) an extension of and certain adjustments to ComEd's electric distribution formula rate, (3) new cumulative persisting annual energy efficiency MWh savings goals for ComEd, (4) revisions to the Illinois RPS requirements, (5) provisions for adjustments to or termination of FEJA programs if the average impact on ComEd's customer rates exceeds specified limits, (6) revisions to the existing net metering statute to (i) mandate net metering for community generation projects, and establish billing procedures for subscribers to those projects, (ii) provide immediately for netting at the energy-only rate for nonresidential customers, and (iii) transition from netting at the full retail rate to the energy-only rate for certain residential net metering customers once the net meter customer load equals 5% of total peak demand supplied in the previous year and (7) support for low income rooftop and community solar programs.

Zero Emission Standard

FEJA includes a ZES that provides compensation through the procurement of ZECs targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet specific eligibility criteria.

On September 11, 2017, the ICC approved the IPA's ZES Procurement Plan filed with the ICC on July 31, 2017. Bidders interested in participating in the procurement process had 14 days following the ICC's approval of the plan to submit the required eligibility information and become qualified bidders. Generation's Clinton and Quad Cities nuclear plants timely submitted the required eligibility information to the ICC and responded to follow up questions. Winning bidders will contract directly with Illinois utilities, including ComEd, for 10-year terms extending through May 31, 2027. The ZEC price will be based upon the current social cost of carbon as determined by the Federal government and is initially established at $16.50 per MWh of production, subject to annual future adjustments determined by the IPA for specified escalation and pricing adjustment mechanisms designed to lower the ZEC price based on increases in underlying energy and capacity prices. Illinois utilities will be required to purchase all ZECs delivered by the zero-emissions nuclear-powered generating facilities, subject to annual cost caps. For the initial delivery year, June 1, 2017 to May 31, 2018, the ZEC annual cost cap is set at $235 million (ComEd's share is approximately $170 million). For subsequent delivery years, the IPA-approved targeted ZEC procurement amounts will change based on forward energy and capacity prices. ZECs delivered to Illinois utilities in excess of the annual cost cap will be paid in subsequent years if the payments do not exceed the prescribed annual cost cap for that year.

ComEd recovers all costs associated with purchasing ZECs through a rate rider that provides for an annual reconciliation and true-up to actual costs incurred by ComEd to purchase ZECs, with any difference to be credited to or collected from ComEd's retail customers in subsequent periods with interest. ComEd began billing its retail customers under its new ZEC rate rider on June 1, 2017.

On February 14, 2017, two lawsuits were filed in the Northern District of Illinois against the IPA alleging that the state's ZEC program violates certain provisions of the U.S. Constitution. One lawsuit was filed by customers of ComEd, led by the Village of Old Mill Creek, and the other was brought by the EPSA and three other electric suppliers. Both lawsuits argue that the Illinois ZEC program will distort PJM's FERC-approved energy and capacity market auction system of setting wholesale prices, and seek a permanent injunction preventing the implementation of the program. Exelon intervened and filed motions to dismiss in both lawsuits. In addition, on March 31, 2017, plaintiffs in both lawsuits filed motions for preliminary injunction with the court; the court stayed briefing on the motions for preliminary injunction until the resolution of the motions to dismiss. On July 14, 2017, the district court granted the motions to dismiss. On July 17, 2017, the plaintiffs appealed the decision to the Seventh Circuit. Briefs were fully submitted on December 12, 2017, 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. Exelon cannot predict the outcome of these lawsuits. It is possible that resolution of these matters could have a material, unfavorable impact on Exelon's and Generation's results of operations, cash flows and financial positions.

See Note 8 — Early Nuclear Plant Retirements for additional information regarding the economic challenges facing Generation's Clinton and Quad Cities nuclear plants and the expected benefits of the ZES.

ComEd Electric Distribution Rates

FEJA extended the sunset date for ComEd's performance-based electric distribution formula rate from 2019 to the end of 2022, allowed ComEd to revise the electric distribution formula rate to eliminate the ROE collar, and allowed ComEd to implement a decoupling tariff if the electric distribution formula rate is terminated at any time. ComEd revised its electric distribution formula rate to eliminate the ROE collar, which eliminates any unfavorable or favorable impacts of weather or load from ComEd's electric distribution formula rate revenues 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 ComEd's electric distribution formula rate revenues associated with variations in delivery volumes associated with above or below normal weather, numbers of customers or usage per customer. ComEd began reflecting the impacts of this change in its electric distribution services costs regulatory asset in the first quarter 2017. As of December 31, 2017, ComEd recorded an increase to its electric distribution services costs regulatory asset of approximately $32 million for this change.

FEJA requires ComEd to make non-recoverable contributions to low income energy assistance programs of $10 million per year for 5 years as long as the electric distribution formula rate remains in effect. With the exception of these contributions, ComEd will recover from customers, subject to certain caps explained below, the costs it incurs pursuant to FEJA either through its electric distribution formula rate or other recovery mechanisms.

Energy Efficiency

Prior to FEJA, Illinois law required ComEd to implement cost-effective energy efficiency measures and, for a 10-year period ending May 31, 2018, cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers.

Beginning January 1, 2018, FEJA provides for new cumulative annual energy efficiency MWh savings goals for ComEd, which are designed to achieve 21.5% of cumulative persisting annual MWh savings by 2030, as compared to the deemed baseline of 88 million MWhs of electric power and energy sales. FEJA deems the cumulative persisting annual MWh savings to be 6.6% from 2012 through the end of 2017. ComEd expects to spend approximately $350 million to $400 million annually through 2030 to achieve these energy efficiency MWh savings goals. In addition, FEJA extends the peak demand reduction requirement from 2018 to 2026. Because the new requirements apply beginning in 2018, FEJA extends the existing energy efficiency plans, which were due to end on May 31, 2017, through December 31, 2017. FEJA also exempts customers with demands over 10 MW from energy efficiency plans and requirements beginning June 1, 2017. On September 11, 2017, the ICC approved ComEd's 2018-2021 energy efficiency plan with minor modifications filed by ComEd with the ICC on June 30, 2017.

As allowed by FEJA, ComEd cancelled its existing energy efficiency rate rider effective June 2, 2017. On August 1, 2017, ComEd filed with the ICC a reconciliation of revenues and costs incurred through the cancellation date. On August 30, 2017, the ICC approved ComEd's request, filed on August 1, 2017, to issue an $80 million credit on retail customers' bills in October 2017 for the majority of the over-recoveries with any final adjustment applicable to the over-recoveries to be billed or credited in the future. As of December 31, 2017, ComEd's over-recoveries associated with its former energy efficiency rate rider were $4 million and are expected to be refunded to customers in future rates.

FEJA allows ComEd to defer energy efficiency costs (except for any voltage optimization costs which are recovered through the electric distribution formula rate) as a separate regulatory asset that is recovered through the energy efficiency formula rate over the weighted average useful life, as approved by the ICC, of the related energy efficiency measures. ComEd earns a return on the energy efficiency regulatory asset at a rate equal to its weighted average cost of capital, which is based on a year-end capital structure and calculated using the same methodology applicable to ComEd's electric distribution formula rate. Beginning January 1, 2018 through December 31, 2030, the return on equity that ComEd earns on its energy efficiency regulatory asset 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 incremental savings goal. ComEd is required to file an update to its energy efficiency formula rate on or before June 1 each year, with resulting rates effective in January of the following year. The annual update will be based on projected current year energy efficiency costs, PJM capacity revenues, and the projected year-end regulatory asset balance less any related deferred income taxes. The update will also include a reconciliation of any differences between the revenue requirement in effect for the prior year and the revenue requirement based on actual prior year costs and actual year-end energy efficiency regulatory asset balances less any related deferred income taxes. ComEd records a regulatory asset or liability and corresponding increase or decrease to Operating revenues for any differences between the revenue requirement in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation.

On August 15, 2017, the ICC approved ComEd's new initial energy efficiency formula rate filed pursuant to FEJA. The order establishes the formula under which energy efficiency rates will be calculated going forward and the revenue requirement used to set the initial rates for the period October 1, 2017 through December 31, 2017. The initial revenue requirement is based on projected costs and projected PJM capacity revenues for the period from June 1, 2017 through December 31, 2017, and projected year-end 2017 energy efficiency regulatory asset balances (less related deferred income taxes). The approved energy efficiency formula rate also provides for revenue decoupling to effectively offset the favorable or unfavorable impacts to ComEd's energy efficiency formula rate revenues associated with variations in delivery volumes associated with above or below normal weather, numbers of customers or usage per customer.

On September 11, 2017, the ICC approved ComEd's annual energy efficiency formula rate. The order establishes the revenue requirement used to set rates that will take effect in January 2018. The revenue requirement for 2018 is based on projected 2018 energy efficiency costs and PJM capacity revenues, and year-end 2018 energy efficiency regulatory asset balances (less related deferred income taxes).

For each of the following years, the ICC approved the following total increases/(decreases) in ComEd's requested energy efficiency revenue requirement:

Annual Energy Efficiency Filings	Initial	2017
ComEd's requested total revenue requirement (decrease) increase	$ (7)[(a)]	$ 12
Allowed Return on Rate Base:		
Initial revenue requirement	6.47%	6.47%
Allowed ROE:		
Initial revenue requirement	8.40%	8.40%
Effective date of rates[(b)]	October 2017	January 2018

(a) Reflects higher projected PJM capacity revenues compared to projected energy efficiency costs.

(b) An ICC order on the annual reconciliation of any differences between the revenue requirement in effect and the revenue requirement based on actual costs for 2017 and 2018 is expected in December 2018 and December 2019, respectively.

Renewable Portfolio Standard

Existing Illinois law requires ComEd to purchase each year an increasing percentage of renewable energy resources for the customers for which it supplies electricity. This obligation is satisfied through the procurement of RECs. FEJA revises the Illinois RPS to require ComEd to procure RECs for all retail customers by June 2019, regardless of the customers' electricity supplier, and provides support for low-income rooftop and community solar programs, which will be funded by the existing Renewable Energy Resources Fund and ongoing RPS collections. FEJA also requires ComEd to use RPS collections to fund utility job training and workforce development programs in the amounts of $10 million in each of the years 2017, 2021, and 2025. ComEd recorded a $20 million noncurrent liability as of December 31, 2017 associated with this obligation. ComEd will recover all costs associated with purchasing RECs and funding utility job training and workforce development programs through a new RPS rate rider that provides for a reconciliation and true-up to actual costs, with any difference between revenues and expenses to be credited to or collected from ComEd's retail customers in subsequent periods with interest. The first reconciliation and true-up for RECs will occur in 2021 and cover revenues and costs for the four-year period beginning June 1, 2017 through May 31, 2021. Subsequently, the RPS rate rider will provide for an annual reconciliation and true-up. ComEd began billing its retail customers under its new RPS rate rider on June 1, 2017 and recorded a related regulatory liability of $21 million as of December 31, 2017. ComEd also recorded a regulatory liability of $41 million for alternative compliance payments received from RES to purchase RECs on behalf of the RES in the future.

As of December 31, 2017, ComEd had received $62 million of over-recovered RPS costs and alternative compliance payments from RES, which are deposited into a separate interest-bearing bank account pursuant to FEJA. The current portion is classified as Restricted cash and the non-current portion is classified as other deferred debits on Exelon's and ComEd's Balance Sheets.

Customer Rate Increase Limitations

FEJA includes provisions intended to limit the average impact on ComEd customer rates for recovery of costs incurred under FEJA as follows: (1) for a typical ComEd residential customer, the average impact must be less than $0.25 cents per month, (2) for nonresidential customers with a peak demand less than 10 MW, the average annual impact must be less than 1.3% of the average amount paid per kWh for electric service by Illinois commercial retail customers during 2015, and (3) for nonresidential customers with a peak demand greater than 10 MW, the average annual impact must be less than 1.3% of the average amount paid per kWh for electric service by Illinois industrial retail customers during 2015.

On June 30, 2017, ComEd submitted a 10-year projection to the ICC of customer rate impacts for residential customers and nonresidential customers with a peak demand less than 10 MW. Such projections indicate that customer rate impacts will not exceed the limitations set by FEJA discussed below. Thereafter, beginning in 2018, ComEd must submit a report to the ICC for residential customers and nonresidential customers with a peak demand less than 10 MW by February 15th and June 30th of each year, respectively. For nonresidential customers with a peak demand greater than 10 MW, ComEd must submit a report to the ICC by May 1 of each year if a rate reduction will be necessary in the following year. For residential customers, the reports will include the actual costs incurred under FEJA during the preceding year and a rolling 10-year customer rate impact projection. The reports for nonresidential customers with a peak demand less than 10 MW will also include the actual costs incurred under FEJA during the preceding year, as well as the average annual rate increase from January 1, 2017 through the end of the preceding year and the average annual rate increase projected for the remainder of the 10-year period.

If the projected residential customer or nonresidential customer with a peak demand less than 10 MW rate increase exceeds the limitations during the first four years, ComEd is required to decrease costs associated with FEJA investments, including reductions to ZEC contract quantities. If the projected residential customer or nonresidential customer with a peak demand less than 10 MW rate increase exceeds the limitations during the last six years, ComEd is required to demonstrate how it will reduce FEJA investments to ensure compliance. If the actual residential customer or nonresidential customer with a peak demand less than 10 MW rate increase exceeds the limitations for any one year, ComEd is required to submit a corrective action plan to decrease future year costs to reduce customer rates to ensure future compliance. If the actual residential customer or nonresidential customer rate exceeds the limitations for two consecutive years, ComEd can offer to credit customers for amounts billed in excess of the limitations or ComEd can terminate FEJA investments. If ComEd chooses to terminate FEJA investments, the ICC shall order termination of ZEC contracts and further initiate proceedings to reduce energy efficiency savings goals and terminate support for low-income rooftop and community solar programs. ComEd is allowed to fully recover all costs incurred as of and up to the date of the programs' termination.

Renewable Energy Resources. In accordance with FEJA, beginning with the plan or plans to be implemented in the 2017 delivery year, the IPA filed its long term renewable resource procurement plan (LT Plan) with the ICC on December 4, 2017. The LT Plan requires a certain percentage of electricity sales be met with a climbing percentage of REC procurement. The 2017 delivery year requirement was 13%, with the obligation increasing by at least 1.5% each year thereafter to at least 25% by the 2025 delivery year; and continuing at no less than 25% for each delivery year thereafter.

Each RES and each Illinois utility, which includes ComEd, is responsible for the renewable resource obligation for the customers to which it supplies power. Over time, this will change and ComEd will procure renewable resources based on the retail load of substantially all customers in its service territory. For the delivery year beginning June 1, 2017, the LT Plan shall include cost effective renewable energy resources procured by ComEd for the retail load it supplies and for 50% of the retail customer load supplied by RES in ComEd's service territory on February 28, 2017. ComEd's procurement for RES supplied retail customer load will increase to 75% June 1, 2018 and to 100% beginning June 1, 2019. All goals are subject to rate impact criteria set forth by Illinois legislation. As of December 31, 2017, ComEd had purchased renewable energy resources or equivalents, such as RECs, in accordance with the IPA Plan. ComEd currently retires all RECs upon transfer and acceptance. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates.

Pennsylvania Regulatory Matters

Tax Cuts and Jobs Act. PECO is working with the PAPUC and stakeholders on behalf of its distribution customers to determine the proper regulatory mechanisms and timing to reflect the tax benefits from the TCJA.

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

The IPAF Program provides for forgiveness of a portion of the eligible arrearage balance of its low-income Customer Assistance Program (CAP) accounts receivable at program inception. The forgiveness will be granted to the extent CAP customers remain current over the duration of the five-year payment agreement term. The Settlement guarantees PECO's recovery of two-thirds of the arrearage balance through a combination of customer payments and rate recovery, including through future rates cases if necessary. The remaining one-third of the arrearage balance has been absorbed by PECO through bad debt expense on its Consolidated Statements of Operations. In October 2016, the IPAF was fully implemented. PECO recorded a regulatory asset representing previously incurred bad debt expense associated with the eligible accounts receivable balances, which is included in the Regulatory assets table below.

Maryland Regulatory Matters

Tax Cuts and Jobs Act. On January 12, 2018, the MDPSC issued an order that directed each of BGE, Pepco and DPL to track the impacts of the TCJA beginning January 1, 2018 and file by February 15, 2018 how and when they expect to pass through such impacts to their customers.

On January 31, 2018, the MDPSC approved BGE's petition to pass back to customers beginning February 1, 2018 $103 million in tax savings resulting from the enactment of the TCJA through a reduction in distribution rates, of which $72 million and $31 million were related to electric and natural gas, respectively. On February 5, 2018, Pepco filed with the MDPSC an update to its current distribution rate case to reflect $31 million in TCJA tax savings. By mid-February 2018, DPL is planning to file with the MDPSC seeking approval to pass back to customers beginning in 2018 $13 million in TCJA tax savings through a reduction in electric distribution rates. The amounts being passed back or proposed to be passed back to customers reflect the annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. Refer to Note 14 — Income Taxes for more detail on Corporate Tax Reform.

After the filings due by February 15, 2018, it is expected that the MDPSC will address the treatment of the TCJA tax savings tracked by BGE, Pepco and DPL for the period January 1, 2018 through the effective date of their respective $103 million, $31 million and $13 million customer rate adjustments described above.

2018 Maryland Electric Distribution Rates. On January 2, 2018, Pepco filed an application with the MDPSC to increase its annual electric distribution base rates by $41 million, reflecting a requested ROE of 10.1%. On February 5, 2018, Pepco filed with the MDPSC an update to its current distribution rate case to reflect $31 million in TCJA tax savings, thereby reducing the requested annual base rate increase to $11 million. Pepco expects a decision in the matter in the third quarter of 2018, but cannot predict how much of the requested increase the MDPSC will approve.

2017 Maryland Electric Distribution Rates. On March 24, 2017, Pepco filed an application with the MDPSC to increase its annual electric distribution base rates by $69 million, which was updated to $67 million on August 24, 2017, reflecting a requested ROE of 10.1%. The application included a request for an income tax adjustment to reflect full normalization of removal costs associated with pre-1981 property, which accounted for $18 million of the requested increase. On October 20, 2017, the MDPSC approved an increase in Pepco electric distribution rates of $34 million, reflecting a ROE of 9.5%. On October 27, 2017, the MDPSC issued an errata order revising the approved increase in Pepco electric distribution rates to $32 million. The errata order corrected a number of computational errors in the original order but did not alter any of the findings. The new rates became effective for services rendered on or after October 20, 2017. In its decision, the MDPSC denied Pepco's request regarding the income tax adjustment without prejudice to Pepco filing another similar proposal with additional information. On November 20, 2017, an interested party in the proceeding filed a request for rehearing. On December 4, 2017, Pepco filed its response in opposition to the request for rehearing. Pepco cannot predict the outcome of this matter or when it will be decided.

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

2017 Maryland Electric Distribution Rates. On July 14, 2017, DPL filed an application with the MDPSC to increase its annual electric distribution base rates by $27 million, which was updated to $19 million on November 16, 2017, reflecting a requested ROE of 10.1%. 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 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.

2016 Maryland Electric Distribution Base Rates. On February 15, 2017, the MDPSC approved an increase in DPL electric distribution rates of $38 million reflecting a ROE of 9.6%. The new rates became effective for services rendered on or after February 15, 2017. The MDPSC also denied DPL's request to continue its Grid Resiliency Program, through which DPL proposed to invest $5 million a year for two years to improve priority feeders and install single-phase reclosing fuse technology. The final order did not result in the recognition of any incremental regulatory assets or liabilities.

2015 Maryland Electric and Natural Gas Distribution Base Rates. On November 6, 2015, and as amended through the course of the proceeding, BGE filed for electric and natural gas distribution base rate increases with the MDPSC, ultimately requesting annual increases of $116 million and $78 million, respectively, of which $104 million and $37 million were related to recovery of electric and natural gas smart grid initiative costs, respectively. BGE also proposed to recover an annual increase of approximately $30 million for Baltimore City underground conduit fees through a surcharge.

On June 3, 2016, the MDPSC issued an order in which the MDPSC found compelling evidence to conclude that BGE's smart grid initiative overall was cost beneficial to customers. However, the June 3 order contained several cost disallowances and adjustments, including not allowing BGE to defer or recover through a surcharge the $30 million increase in annual Baltimore City underground conduit fees.

On June 30, 2016, BGE filed a petition for rehearing of the June 3 order requesting that the MDPSC modify its order to reverse certain decisions including the decision associated with the Baltimore City underground conduit fees. OPC also subsequently filed for a petition for rehearing of the June 3 order.

On July 29, 2016, the MDPSC issued an order on the petitions for rehearing that reversed certain of its prior cost disallowances and adjustments related to the smart grid initiative. Through the combination of the orders, the MDPSC authorized electric and natural gas rate increases of $44 million and $48 million, respectively, and an allowed ROE for the electric and natural gas distribution businesses of 9.75% and 9.65%, respectively. The new electric and natural gas base rates took effect for service rendered on or after June 4, 2016. However, MDPSC's July 29 order on the petition on rehearing still did not allow BGE to defer or recover through a surcharge the increase in Baltimore City underground conduit fees.

On August 26, 2016, BGE filed an appeal of the MDPSC's orders with the Circuit Court for Baltimore County. On August 29, 2016, the residential consumer advocate also filed an appeal of the MDPSC's order but with the Circuit Court for Baltimore City. On November 15, 2016, Baltimore County Circuit Court issued an order deciding that the cases should be consolidated and should proceed in Baltimore County Circuit Court. However, on January 9, 2017, BGE filed to withdraw its appeal of the MDPSC's orders and on January 10, 2017, the residential consumer advocate filed to withdraw its appeal as well. Refer to the Smart Meter and Smart Grid Investments disclosure below for further details on the impact of the ultimate disallowances contained in the orders to BGE. See Conduit Lease with City of Baltimore in Litigation and Regulatory Matters of Note 23 - Commitments and Contingencies for information about the settlement agreement related to BGE's use of the City-owned underground conduit system.

Cash Working Capital Order. On November 17, 2016, the MDPSC rendered a decision in the proceeding to review BGE's request to recover its cash working capital (CWC) requirement for its Provider of Last Resort service, also known as Standard Offer Service (SOS), as well as other components that make up the Administrative Charge, the mechanism that enables BGE to recover all of its SOS-related costs. The Administrative Charge is now comprised of five components: CWC, uncollectibles, incremental costs, return, and an administrative adjustment, which is an adder to the utility's SOS rate to act as a proxy for retail suppliers' costs. The Commission accepted BGE's positions on recovery of CWC and pass-through recovery of BGE's actual uncollectibles and incremental costs. The order also grants BGE a return on the SOS. The Commission ruled that the level of the administrative adjustment will be determined in BGE's next rate case. On December 16, 2016, MDPSC Staff requested clarification concerning the amount of return on the SOS awarded to BGE and on December 19, 2016, the residential consumer advocate sought rehearing of the return awarded. On January 24, 2017, the MDPSC issued an order denying the MDPSC Staff request for clarification and the residential consumer advocate request for rehearing. On February 22, 2017, the residential consumer advocate filed an appeal of the

MDPSC's orders with the Circuit Court for Baltimore City. The residential consumer advocate filed its Memorandum on Appeal on June 5, 2017 and subsequent Reply Memoranda were filed by BGE and the MDPSC on July 7, 2017 and July 12, 2017, respectively. On August 7, 2017, following oral argument by the parties, a decision was issued from the Circuit Court affirming the decision of the MDPSC. On September 5, 2017, the residential consumer advocate filed an appeal of the Circuit Court's decision to the Maryland Court of Special Appeals. BGE cannot predict the outcome of this appeal.

Smart Meter and Smart Grid Investments. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that included the planned installation of 2 million residential and commercial electric and natural gas smart meters at an expected total cost of $480 million of which $200 million was funded by SGIG. The MDPSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. Refer to AMI programs in the Regulatory Assets and Liabilities section below for further details.

As part of the 2015 electric and natural gas distribution rate case filed on November 6, 2015, BGE sought recovery of its smart grid initiative costs, supported by evidence demonstrating that BGE had, in fact, implemented a cost-beneficial advanced metering system. On June 3, 2016, the MDPSC issued an order concluding that the smart grid initiative overall is cost beneficial to its customers. However, the June 3 order contained several cost disallowances and adjustments including disallowances of certain program and meter installation costs and denial of recovery of any return on unrecovered costs for non-AMI meters replaced under the program. On June 30, 2016, BGE filed a petition for rehearing of the June 3 order requesting that the MDPSC modify its order to reverse certain decisions and change certain of the cost disallowances and adjustments to enable BGE to defer those costs for recovery through future electric and natural gas rates. The residential consumer advocate also subsequently filed for a petition for rehearing of the June 3 order. On July 29, 2016, the MDPSC issued an order on the petitions for rehearing that reversed certain of its prior cost disallowances and adjustments related to the smart grid initiative.

As a combined result of the MDPSC orders in BGE's 2015 electric and natural gas distribution rate case, BGE recorded a $52 million charge in June 2016 to Operating and maintenance expense in Exelon's and BGE's Consolidated Statements of Operations and Comprehensive Income reducing certain regulatory assets and other long-lived assets and reclassified $56 million of non-AMI plant costs from Property, plant and equipment, net to Regulatory assets on Exelon's and BGE's Consolidated Balance Sheets.

The Maryland Strategic Infrastructure Development and Enhancement Program. In 2013, legislation intended to accelerate gas infrastructure replacements in Maryland was signed into law. The law established a mechanism, separate from base rate proceedings, for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects incurred after June 1, 2013. The monthly surcharge and infrastructure replacement costs must be approved by the MDPSC and are subject to a cap and require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation.

On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and surcharge. On July 1, 2016, BGE filed an amendment to its infrastructure replacement plan, which the MDPSC conditionally approved in an order dated November 23, 2016. The revised surcharge reflecting the costs of the amendment became effective January 1, 2017. On November 1, 2017, BGE filed a surcharge update to be effective January 1, 2018 along with its 2018 project list and projected capital estimates of $136 million to be included in the 2018 surcharge calculation. The MDPSC subsequently approved BGE's 2018 project list and the proposed surcharge for 2018. As of December 31, 2017, BGE recorded a regulatory liability of less than $1 million, representing the difference between the surcharge revenues and program costs.

On December 1, 2017 (and as amended on January 22, 2018), BGE filed an application with the MDPSC seeking approval for a new infrastructure replacement plan and associated surcharge, effective for the five-year period from 2019 through 2023. BGE's new plan calls for capital expenditures over the 2019-2023 timeframe of $963 million, with an associated revenue requirement of $242 million. BGE expects a decision in the matter by May 31, 2018, but cannot predict whether the MDPSC will approve the plan as filed.

Delaware Regulatory Matters

Tax Cuts and Jobs Act. On January 16, 2018, the DPSC opened a docket to examine the impacts of the TCJA on the cost of service and rates of all regulated public utilities in Delaware, which includes DPL. The DPSC also stated the TCJA benefits would be addressed in DPL's pending rate case.

In response, by mid-February 2018, DPL is planning to file with the DPSC updates to its electric and gas distribution rate cases described below to reflect approximately $26 million in tax savings resulting from the enactment of the TCJA, of which $19 million and $7 million are related to electric and natural gas, respectively. The updated requests for amounts being passed back to customers would reflect the annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. Refer to Note 14 - Income Taxes for more detail on Corporate Tax Reform. DPL expects a decision in the matter in the third quarter of 2018 for the electric distribution proceeding and in the fourth quarter of 2018 for the gas distribution proceeding, but cannot predict how much of the requested increase the DPSC will approve. It is expected that the DPSC will address in a future rate proceeding DPL's treatment of the TCJA tax savings for the period February 1, 2018 through the effective date of any customer rate adjustments in the pending rate proceedings.

2017 Delaware Electric and Natural Gas Distribution Rates. On August 17, 2017, DPL filed applications with the DPSC to increase its annual electric and natural gas distribution base rates by $24 million and $13 million respectively, reflecting a requested ROE of 10.1%. DPL filed updated testimony on October 18, 2017, to request a $31 million increase in electric distribution rates, and updated testimony on November 7, 2017, to request an $11 million increase in natural gas distribution rates. While the DPSC is not required to issue a decision on the applications within a specified period of time, Delaware law allows DPL to put into effect $2.5 million of the rate increases for both electric and natural gas two months after filing the application and the entire requested rate increases seven months after filing, subject to a cap and a refund obligation based on the final DPSC order. On October 24, 2017, the Staff of the DPSC and the Public Advocate filed a joint motion to dismiss DPL's electric distribution base rate application without prejudice to refiling, arguing that the amount of the requested increase to $31 million required additional time to review and additional public notice. In November 2017, the DPSC denied the joint motion to dismiss.

2016 Delaware Electric and Natural Gas Distribution Base Rates. On May 17, 2016, DPL filed applications with the DPSC to increase its annual electric and natural gas distribution base rates by $63 million, which was updated to $60 million on March 8, 2017, and $22 million, respectively, reflecting a requested ROE of 10.6%. Delaware law allowed DPL to put into effect $2.5 million of each of the rate increases effective July 16, 2016. On December 17, 2016, the DPSC approved that an additional $30 million in electric distribution rates and an additional $10 million in gas distribution rates effective December 17, 2016, subject to refund based on the final DPSC orders.

On March 8, 2017, DPL entered into a settlement agreement with the Division of the Public Advocate, Delaware Electric Users Group and the DPSC Staff in its electric distribution rate proceeding, which provides for an increase in DPL annual electric distribution base rates of $31.5 million reflecting a ROE of 9.7% compared to the $32 million increase previously put into effect. On May 23, 2017, the DPSC issued an order approving the settlement agreement, with the new rates effective June 1, 2017. Pursuant to the settlement agreement, no refund of the interim rates put into effect on July 16, 2016 and December 17, 2016 (as discussed above) is required.

On April 6, 2017, DPL entered into a settlement agreement with the Division of the Public Advocate and the DPSC Staff in its natural gas distribution rate proceeding, which provides for an increase in DPL annual natural gas distribution base rates of $4.9 million reflecting a ROE of 9.7%. The settlement agreement also provides that DPL will refund amounts collected under the temporary rates effective July 16, 2016 and December 17, 2016 (as discussed above) in excess of the $4.9 million, and that the new rates will be effective within thirty days of DPSC approval of the settlement agreement. On June 6, 2017, the DPSC issued an order approving the settlement agreement, with the new rates effective July 1, 2017. Pursuant to the settlement agreement, a rate refund plus interest of approximately $5 million was issued to customers beginning in August 2017. This was a one-time refund and was included on customer bills from mid-August through mid-September.

District of Columbia Regulatory Matters

Tax Cuts and Jobs Act. On January 23, 2018, the DCPSC opened a rate proceeding directing Pepco to track the impacts of the TCJA beginning January 1, 2018 and file its plan to reduce the current revenue requirement by customer class by February 12, 2018. The DCPSC stated it will address the impact of the TCJA on future rates within Pepco's pending electric distribution rate case discussed below and Pepco will accordingly update its current distribution rate case in February 2018.

Separately, on February 6, 2018, Pepco filed with the DCPSC seeking approval to pass back to customers beginning in 2018 $39 million in tax savings resulting from the enactment of the TCJA through a reduction in electric distribution rates. The amounts being passed back to customers would reflect the annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. It is expected that the DCPSC will address in a future rate proceeding Pepco's treatment of the TCJA tax savings for the period January 1, 2018 through the effective date of any customer rate adjustments. Refer to Note 14 - Income Taxes for more detail on Corporate Tax Reform.

2017 District of Columbia Electric Distribution Base Rates. On December 19, 2017, Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by $66 million, reflecting a requested ROE of 10.1%. By mid-February, Pepco will update its current distribution rate case to reflect the TCJA impacts from January 1, 2018 through the effective date of the $39 million customer rate adjustment described above. Pepco expects a decision in the matter in the fourth quarter of 2018, but cannot predict how much of the requested increase the DCPSC will approve.

2016 District of Columbia Electric Distribution Base Rates. On June 30, 2016, Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by $86 million, which was updated to $77 million on February 1, 2017, reflecting a requested ROE of 10.6%.

On July 25, 2017, the DCPSC approved an increase in Pepco electric distribution base rates of $37 million reflecting a ROE of 9.5%. The new rates became effective for services rendered on or after August 15, 2017. In its decision, the DCPSC ordered that the $26 million customer rate credit created as a result of the Exelon and PHI merger will be provided primarily to residential customers and some small commercial customers to offset the impact of this increase until that amount has been exhausted, which is expected to take approximately two years. Additionally, the Commission is holding approximately $6 million to $7 million of the customer rate credit for use toward a possible new class of customers for certain senior citizens and disabled persons. The DCPSC also held that Pepco's bill stabilization adjustment, which decouples distribution revenues from utility customers from the amount of electricity delivered, will continue to be in place and that no refund of previously collected funds is required. Several parties filed requests that the DCPSC reconsider the order on various issues, and on October 6, 2017, the Commission issued an order denying each of the requests.

District of Columbia Power Line Undergrounding Initiative. The District of Columbia government enacted on an emergency basis (effective May 17, 2017) and thereafter on a permanent basis (effective July 11, 2017) legislation to amend the Electric Company Infrastructure Improvement Financing Act of 2014 (as amended) (the Infrastructure Improvement Financing Act) to authorize the District of Columbia Power Line Undergrounding (DC PLUG) initiative, a projected six year, $500 million project to place underground some of the District of Columbia's most outage-prone power lines with $250 million of the project costs funded by Pepco and $250 million funded by the District of Columbia.

The $250 million of project costs funded by Pepco will be recovered through a volumetric surcharge on the electric bill of substantially all of Pepco's customers in the District of Columbia. Pepco will earn a return on these project costs.

The $250 million of project costs funded by the District of Columbia will come from two sources. Project costs of $187.5 million will be funded through a charge assessed on Pepco by the District of Columbia; Pepco will recover this charge from customers through a volumetric distribution rider. The remaining costs up to $62.5 million are to be funded by the existing capital projects program of the District Department of Transportation (DDOT). Ownership and responsibility for the operation and maintenance of all the assets funded by the District of Columbia will be transferred to Pepco for a nominal amount upon completion. Pepco will not recover or earn a return on the cost of the assets transferred to it by the District of Columbia.

In accordance with the Infrastructure Improvement Financing Act, Pepco filed an application for approval of the first two-year plan in the DC PLUG initiative (the First Biennial Plan) on July 3, 2017. After the initial application, Pepco will be required to make two additional applications. On November 9, 2017, the DCPSC issued an order approving the First Biennial Plan and the application for a financing order. Pursuant to that order, Pepco is obligated to pay $187.5 million to the District of Columbia over the six-year project term, of which it expects to pay $27.5 million in 2018. Pepco recorded an obligation and offsetting regulatory asset in November. On December 11, 2017, an interested party filed for reconsideration of the DCPSC's November 9 order and on January 18, 2018, the DCPSC denied the interested party's request. Rates for the DC PLUG initiative went into effect on February 7, 2018.

New Jersey Regulatory Matters

Tax Cuts and Jobs Act. On January 31, 2018, the NJBPU issued an order mandating that New Jersey utility companies, including ACE, pass any economic benefit from the TCJA to rate payers. The order directed New Jersey utility companies to file by March 2, 2018 proposed tariff sheets reflecting TCJA benefits, with new rates to be implemented effective April 1, 2018. In addition, the NJBPU directed New Jersey utility companies to file by March 2, 2018 a Petition with the NJBPU outlining how they propose to refund any over-collection associated with revised rates not being in place from January 1, 2018 through March 31, 2018, with interest.

ACE estimates that approximately $23 million in TCJA savings will be passed back to ACE customers, reflecting the annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. Refer to Note 14 - Income Taxes for more detail on Corporate Tax Reform.

New Jersey Consolidated Tax Adjustment. The Consolidated Tax Adjustment (CTA) is a New Jersey ratemaking policy that requires utilities that are part of a consolidated tax group to share with customers the tax benefits that came from losses at unregulated affiliates through a reduction in rate base. In 2013, the NJBPU opened a generic proceeding to review the policy. In 2014, the NJBPU issued a decision which retained the CTA, but in a highly modified format that significantly reduced the impact of the CTA to ACE. On September 18, 2017, the Appellate Division of the Superior Court of New Jersey reversed the NJBPU's decision in adopting the revised CTA policy and held that NJBPU's actions related to the CTA constituted a rulemaking that should have been undertaken pursuant to the requirements of the Administrative Procedures Act. The Court did not address the merits of the CTA methodology itself. No party filed an appeal of the Court's decision, and the NJBPU has issued a proposed rule for comment, consistent with the requirements of the Administrative Procedures Act. The substance of the proposed rule is consistent with the NJBPU's decision in the generic proceeding. If the NJBPU were to apply the CTA in its unmodified form, it could have a material prospective impact to ACE through a reduction in rate base in future rate cases.

2017 New Jersey Electric Distribution Rates. On March 30, 2017, ACE filed an application with the NJBPU to increase its annual electric distribution rates by $70 million (before New Jersey sales and use tax), which was updated to $73 million on July 14, 2017, reflecting a requested ROE of 10.1%. The application also requests approval of a rate surcharge mechanism called the "System Renewal Recovery Charge," which would permit more timely recovery of certain costs associated with reliability and system renewal-related capital investments.

On September 8, 2017, ACE entered into a settlement agreement with the NJBPU staff, the New Jersey Division of Rate Counsel and Wal-Mart Stores, Inc. in its electric distribution rate proceeding, which provides for an increase in ACE annual electric distribution base rates of $43 million (before New Jersey sales and use tax) reflecting a ROE of 9.6%. In addition, pursuant to the settlement agreement, ACE agreed to withdraw its request for approval of a System Renewal Recovery Charge without prejudice to its right to refile. On September 22, 2017, the NJBPU issued an order approving the settlement agreement, with the new rates effective on October 1, 2017.

2016 New Jersey Electric Distribution Base Rates. On August 24, 2016, the NJBPU issued an order approving a stipulation of settlement among ACE, the New Jersey Division of Rate Counsel, NJBPU Staff and Unimin Corporation, which, among other things, provided that a determination on ACE's grid resiliency program, PowerAhead, would be separated into a phase II of the rate proceeding and decided at a later date. PowerAhead includes capital investments to enhance the resiliency of the system through improvements focused on improving the distribution system's ability to withstand major storm events. A stipulation of settlement with respect to the PowerAhead program (the PowerAhead Stipulation) was approved by the NJBPU on May 31, 2017. As adopted, the PowerAhead program includes an approved investment level of $79 million to be recovered through the cost recovery mechanism described in the PowerAhead Stipulation. The NJBPU order adopting the PowerAhead Stipulation was effective on June 10, 2017.

2017 Update and Reconciliation of Certain Under-Recovered Balances. On February 1, 2017, ACE submitted its 2017 annual petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE's long-term power purchase contracts with the non-utility generators and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE's uncollectible accounts. As filed, the net impact of adjusting the charges as proposed would have been an overall annual rate decrease of approximately $29 million (revised to approximately $32 million in April 2017, based upon an update for actuals through March 2017), including New Jersey sales and use tax. On May 31, 2017, the NJBPU approved a stipulation of settlement entered into by the parties providing for an overall annual rate decrease of approximately $32 million, effective June 1, 2017. The rate decrease was placed into effect provisionally, subject to a review by NJBPU and the Division of Rate Counsel of the final underlying costs for reasonableness and prudence. This rate decrease will have no effect on ACE's operating income, since these revenues provide for recovery of deferred costs under an approved deferral mechanism. On November 1, 2017, ACE entered into a Stipulation of Final Rates with the NJBPU staff and the New Jersey Division of Rate Counsel which was unchanged from the provisional rates. On November 21, 2017, the NJBPU issued an order approving the Stipulation of Final Rates as filed.

2016 Update and Reconciliation of Certain Under-Recovered Balances. On February 1, 2016, ACE submitted its 2016 annual petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE's long-term power purchase contracts with the non-utility generators and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE's uncollectible accounts.

As filed, the net impact of adjusting the charges as proposed would have been an overall annual rate increase of $9 million (revised to $19 million in April 2016, based upon an update for actuals through March 2016), including New Jersey sales and use tax.

On November 30, 2016, the NJBPU approved a stipulation of settlement entered into by the parties providing for an overall annual rate increase of $1 million effective January 1, 2017. This settlement included a credit of approximately $10 million to the Non-Utility Generation charge deferral balance and a credit of approximately $7 million to the Uncollectible deferral balance. These credits were directed to be applied to the deferral balances in an NJBPU order dated October 31, 2016. That order approved the Joint Recommendation for Settlement of the Most Favored Nation Provision, which was a condition of the merger between Exelon Corporation and Pepco Holdings, Inc. This rate increase will have no effect on ACE's operating income, since these revenues provide for recovery of deferred costs under an approved deferral mechanism.

New York Regulatory Matters

New York Clean Energy Standard. On August 1, 2016, the New York Public Service Commission (NYPSC) issued an order establishing the New York CES, a component of which is a Tier 3 ZEC program targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet the criteria demonstrating public necessity as determined by the NYPSC. The New York State Energy Research and Development Authority (NYSERDA) will centrally procure the ZECs from eligible plants through a 12-year contract, to be administered in six two-year tranches, extending from April 1, 2017 through March 31, 2029. ZEC payments will be made to the eligible resources based upon the number of MWh produced, subject to specified caps and minimum performance requirements. The price to be paid for the ZECs under each tranche will be administratively determined using a formula based on the social cost of carbon as determined in 2016 by the federal government, subject to pricing adjustments designed to lower the ZEC price based on increases in underlying energy and capacity prices. The ZEC price for the first tranche has been set at $17.48 per MWh of production. Following the first tranche, the price will be updated bi-annually. Each Load Serving Entity (LSE) shall be required to purchase an amount of ZECs equivalent to its load ratio share of the total electric energy in the New York Control Area. Cost recovery from ratepayers shall be incorporated into the commodity charges on customer bills.

The NYPSC initially identified three plants eligible for the ZEC program: the FitzPatrick, Ginna, and Nine Mile Point nuclear facilities. As issued, the order also provided that the duration of the program beyond the first tranche was conditional upon a buyer purchasing the FitzPatrick facility and taking title prior to September 1, 2018. On November 18, 2016, the required contracts with NYSERDA were executed for Ginna and Nine Mile Point, in addition to Entergy's execution of the required contract for the FitzPatrick facility. On March 31, 2017, Generation closed on the acquisition of FitzPatrick. Generation is currently recognizing revenue for the sale of New York ZECs in the month following generation when the ZECs are transferred to NYSERDA. For the year ended December 31, 2017, Generation has recognized $311 million of ZEC revenue.

Several parties filed with the NYPSC requests for rehearing or reconsideration of the New York CES. Generation and CENG also filed a request for clarification, or in the alternative limited rehearing, that the condition limiting the duration of the program beyond the first tranche be limited to the eligibility of the FitzPatrick plant only and have no bearing on Ginna or Nine Mile Point's eligibility for the full 12-year duration. On December 15, 2016, the NYPSC approved Exelon's petition to clarify this condition and denied all petitions for rehearing of the New York CES. Parties had until mid-April 2017 to appeal to New York State court the denials of the requests for rehearing.

On October 19, 2016, a coalition of fossil-generation companies filed a complaint in federal district court against the NYPSC alleging that the ZEC program violates certain provisions of the U.S. Constitution; specifically, that the ZEC program interferes with FERC's jurisdiction over wholesale rates and that it discriminates against out of state competitors. On December 9, 2016, Generation and CENG filed a motion to intervene in the case and to dismiss the lawsuit. The State also filed a motion to dismiss. On July 25, 2017, the court granted both motions to dismiss. On August 24, 2017, plaintiffs appealed the decision to the Second Circuit. Plaintiffs-Appellants' initial brief was filed on October 13, 2017. 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.

Other legal challenges remain possible, the outcomes of which remain uncertain. See Note 8 - Early Nuclear Plant Retirements for additional information relative to Ginna and Nine Mile Point, and Note 4 -Mergers, Acquisitions and Dispositions for additional information on Generation's proposed acquisition of FitzPatrick.

Ginna Nuclear Power Plant Reliability Support Services Agreement. In November 2014, in response to a petition filed by Ginna Nuclear Power Plant (Ginna) regarding the possible retirement of Ginna, the NYPSC directed Ginna and Rochester Gas & Electric Company (RG&E) to negotiate a Reliability Support Services Agreement (RSSA) to support the continued operation of Ginna to maintain the reliability of the RG&E transmission grid for a specified period of time. During 2015 and 2016, Ginna and RG&E made filings with the NYPSC and FERC for their approval of the proposed RSSA. Although the RSSA was still subject to regulatory approvals, on April 1, 2015, Ginna began delivering the power and capacity from the Ginna plant into the ISO-NY consistent with the technical provisions of the RSSA.

On March 22, 2016, Ginna submitted a compliance filing with FERC with revisions to the RSSA requested by FERC. On April 8, 2016, FERC accepted the compliance filing and on April 20, 2016, the NYPSC accepted the revised RSSA with a term expiring on March 31, 2017. In April 2016, Generation began recognizing revenue based on the final approved pricing contained in the RSSA and also recognized a one-time revenue adjustment of approximately $101 million representing the net cumulative previously unrecognized amount of revenue retroactive from the April 1, 2015 effective date through March 31, 2016. A 49.99% portion of the one-time adjustment was removed from Generation's results of operations as a result of the noncontrolling interests in CENG.

The RSSA required Ginna to continue operating through the RSSA term. On September 30, 2016, Ginna filed the required notice with the NYPSC of its intent to continue operating beyond the March 31, 2017 expiry of the RSSA, conditioned upon successful execution of an agreement between Ginna and NYSERDA for the sale of ZECs under the New York CES. As stated previously, on November 18, 2016 the required contract with NYSERDA was executed by Generation and CENG for Ginna. Upon the expiry of the RSSA on March 31, 2017, Ginna was required to make refund payments of $20 million to RG&E related to capital expenditures. Ginna paid RG&E the $20 million in June 2017. Additionally, the provisions of the RSSA provided for a one-time payment of $12 million to be paid from RG&E to Ginna at the end of the contract. This $12 million was recognized in revenue as of March 31, 2017. RG&E paid the $12 million to Ginna in May 2017. Subject to prevailing over any administrative or legal challenges, it is expected the New York CES will allow Ginna to continue to operate through the end of its current operating license in 2029. See Note 8 - Early Nuclear Plant Retirements for further information regarding the impacts of a decision to early retire one or more nuclear plants.

Federal Regulatory Matters

Tax Cuts and Jobs Act. To date, the FERC has not yet issued guidance to utilities on how and when to reflect the impacts of the TCJA in customer rates. However, pursuant to their respective transmission formula rates, ComEd, BGE, Pepco, DPL and ACE will begin passing back to customers on June 1, 2018, the benefit of lower income tax rates effective January 1, 2018. ComEd's, BGE's, Pepco's, DPL's and ACE's transmission formula rates currently do not provide for the pass back or recovery of income tax-related regulatory liabilities or assets. As discussed above, on December 13, 2016 (and as amended on March 13, 2017), BGE filed with FERC to begin recovering certain existing and future transmission-related income tax regulatory assets through its transmission formula rate. On November 16, 2017, FERC issued an order rejecting BGE's proposed revisions to its transmission formula rate and on December 18, 2017, BGE filed for clarification and rehearing of FERC's order. ComEd, Pepco, DPL and ACE also have similar transmission-related income tax regulatory assets and liabilities, for which FERC approval is required, separate from their transmission formula rate mechanisms, to pass back or recover those regulatory liabilities and assets through customer rates. PECO is currently in settlement discussions regarding its transmission formula rate and expects to pass back TCJA benefits to customers through its annual formula rate update.

Refer to Deferred income taxes in the Regulatory Assets and Liabilities section below for the balances of transmission-related income tax regulatory assets as of December 31, 2017 and 2016.

Transmission Formula Rate. ComEd's, BGE's, Pepco's, DPL's and ACE's transmission rates are each established based on a FERC-approved formula. ComEd, BGE, Pepco, DPL and ACE are required to file an annual update to the FERC-approved formula on or before May 15, with the resulting rates effective on June 1 of the same year. The annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement in effect beginning June 1 of the prior year and actual costs incurred for that year. ComEd, BGE, Pepco, DPL, and ACE record regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement in effect and ComEd's, BGE's, Pepco's, DPL's and ACE's best estimate of the revenue requirement expected to be filed with the FERC for that year's reconciliation. The regulatory asset associated with transmission true-up is amortized to Operating revenues within their Consolidated Statements of Operations of Comprehensive Income as the associated amounts are recovered through rates.

For each of the following years, the following total increases/(decreases) were included in ComEd's, BGE's, Pepco's, DPL's and ACE's electric transmission formula rate filings:

	ComEd			BGE		
Annual Transmission Filings[(a)]	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Initial revenue requirement increase	$ 44	$ 90	$ 68	$ 31	$ 12	$ —
Annual reconciliation increase (decrease)	(33)	4	18	3	3	(3)
Dedicated facilities (decrease) increase[(b)]	—	—	—	(8)	13	13
Total revenue requirement increase	$ 11	$ 94	$ 86	$ 26	$ 28	$ 10
Allowed return on rate base[(d)]	8.43%	8.47%	8.61%	7.47%	8.09%	8.46%
Allowed ROE[(e)]	11.50%	11.50%	11.50%	10.50%	10.50%	11.30%

	Pepco			DPL			ACE		
Annual Transmission Filings[(a)]	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Initial revenue requirement increase (decrease)	$ 5	$ 2	$ 10	$ 6	$ 8	$ 15	$ 20	$ 8	$ 10
Annual reconciliation (decrease) increase	15	(10)	(3)	8	(10)	(1)	22	(14)	2
MAPP abandonment recovery (decrease) increase[(c)]	—	(15)	(2)	—	(12)	(2)	—	—	—
Total revenue requirement (decrease) increase	$ 20	$ (23)	$ 5	$ 14	$ (14)	$ 12	$ 42	$ (6)	$ 12
Allowed return on rate base[(d)]	7.92%	7.88%	8.36%	7.16%	7.21%	7.80%	8.02%	7.83%	8.51%
Allowed ROE[(e)]	10.50%	10.50%	11.30%	10.50%	10.50%	11.30%	10.50%	10.50%	11.30%

(a) The time period for any challenges to the annual transmission formula rate update flings expired with no challenges submitted.

(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) In 2012, PJM terminated the MAPP transmission line construction project planned for the Pepco and DPL service territories. Pursuant to a FERC approved settlement agreement, the abandonment costs associated with MAPP were being recovered in transmission rates over a three-year period that ended in May 2016.

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

(e) 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.

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. The parties currently are engaged in settlement discussions. PECO cannot predict the final outcome of the settlement or hearing proceedings, or the transmission formula FERC may approve.

Transmission-Related Income Tax Regulatory Assets. On December 13, 2016 (and as amended on March 13, 2017), BGE filed with FERC to begin recovering certain existing and future transmission-related income tax regulatory assets through its transmission formula rate. BGE's existing regulatory assets included (1) amounts that, if BGE's transmission formula rate provided for recovery, would have been previously amortized and (2) amounts that would be amortized and recovered prospectively. On November 16, 2017, FERC issued an order rejecting BGE's proposed revisions to its transmission formula rate to recover these transmission-related income tax regulatory assets. On December 18, 2017, BGE filed for clarification and rehearing of FERC's order, still seeking full recovery of its existing transmission-related income tax regulatory asset amounts.

ComEd, Pepco, DPL and ACE have similar transmission-related income tax regulatory assets also requiring FERC approval separate from their transmission formula rate mechanisms. Similar regulatory assets at PECO are not subject to the same FERC transmission rate recovery formula and, thus, are not impacted by the November 16, 2017 FERC order.

Each of BGE, ComEd, Pepco, DPL and ACE believe there is sufficient basis to support full recovery of their existing transmission-related income tax regulatory assets, and each intends to further pursue such full recovery with FERC. However, upon further consideration of the November 16, 2017 FERC order, management of each company concluded that the portion of the total transmission-related income tax regulatory assets that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery was no longer probable of recovery. As a result, Exelon recorded a $35 million charge to income tax expense within it's Consolidated Statements of Operations and Comprehensive Income in the fourth quarter 2017, reducing the associated transmission-related income tax regulatory asset.

To the extent any of the companies are ultimately successful with the FERC allowing future recovery of these amounts, the associated regulatory assets will be reestablished, with corresponding decreases to Income tax expense. To the extent all or a portion of the prospective amortization amounts were no longer considered probable of recovery, Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE would record additional charges to Income tax expense, which could be up to approximately $81 million, $41 million, $22 million, $18 million, $8 million, $7 million and $3 million, respectively, as of December 31, 2017.

Refer to Deferred income taxes in the Regulatory Assets and Liabilities section below for the balances of these transmission-related income tax regulatory assets as of December 31, 2017 and 2016.

PJM Transmission Rate Design and Operating Agreements. PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO, BGE, Pepco, DPL and ACE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM's current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. A number of parties appealed to the U.S. Court of Appeals for the Seventh Circuit for review of the decision.

In August 2009, the court issued its decision affirming the FERC's order with regard to the existing facilities, but remanded to FERC the issue of the cost allocation associated with the new facilities 500 kV and above (Cost Allocation Issue) for further consideration by the FERC. On remand, FERC reaffirmed its earlier decision to socialize the costs of new facilities 500 kV and above. A number of parties filed appeals of these orders. In June 2014, the court again remanded the Cost Allocation Issue to FERC. On December 18, 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the Cost Allocation Issue. On June 15, 2016, a number of parties, including Exelon and the Utility Registrants, filed a proposed Settlement with FERC. If the Settlement is approved, 50% of the costs of the 500 kV and above facilities approved by the PJM Board on or before February 1, 2013 will be socialized across PJM and 50% will be allocated according to a formula that calculates the flows on the transmission facilities. Each state that is a party in this proceeding either signed, or did not oppose, the settlement. The Settlement is opposed by a number of merchant transmission owners and New York load-serving entities. The Settlement includes provisions for monthly credits or charges that are expected to be mostly refunded or recovered through customer rates over a 10-year period based on negotiated numbers for charges prior to January 1, 2016.

Exelon expects that the Settlement will not have a material impact on the results of operations, cash flows and financial position of Generation, ComEd, PECO, BGE, Pepco, DPL or ACE. The Settlement is subject to approval by FERC. The FERC is not required to issue a decision on the matter within a specified period of time.

The Utility Registrants are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. The Utility Registrants will work with PJM to continue to evaluate the scope and timing of any required construction projects. The Utility Registrants' estimated commitments are as follows:

	Total	2018	2019	2020	2021	2022
ComEd	$164	$36	$60	$44	$24	$ —
PECO	53	16	19	10	5	3
BGE	118	35	35	35	13	—
Pepco	86	5	11	27	33	10
DPL	27	19	2	1	2	3
ACE	121	68	20	6	21	6

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.

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 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.

Operating License Renewals. On August 29, 2012, Generation submitted a hydroelectric license application to FERC for a 46-year license for the Conowingo Hydroelectric Project (Conowingo). In connection with Generation's efforts to obtain a water quality certification pursuant to Section 401 of the Clean Water Act with Maryland Department of the Environment (MDE) for Conowingo, Generation continues to work with MDE and other stakeholders to resolve water quality licensing issues, including: (1) water quality, (2) fish habitat, and (3) sediment.

On April 21, 2016, Exelon and the US Fish and Wildlife Service of the US Department of the Interior executed a Settlement Agreement resolving all fish passage issues between the parties. The financial impact of the Settlement Agreement is estimated to be $3 million to $7 million per year, on average, over the 46-year life of the new license, including both capital and operating costs. The actual timing and amount of these costs are not currently fixed and may vary significantly from year to year throughout the life of the new license.

Resolution of the remaining issues relating to Conowingo involving various stakeholders may have a material effect on Exelon's and Generation's results of operations and financial positions through an increase in capital expenditures and operating costs. As of December 31, 2017, $31 million of direct costs associated with Conowingo licensing efforts have been capitalized.

Regulatory Assets and Liabilities

Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE each prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

As a result of applying the acquisition method of accounting and pushing it down to the consolidated financial statements of PHI, certain regulatory assets and liabilities were established at Exelon and PHI to offset the impacts of fair valuing the acquired assets and liabilities assumed which are subject to regulatory recovery. In total, Exelon and PHI recorded a net $2.4 billion regulatory asset reflecting adjustments recorded as a result of the acquisition method of accounting. See Note 4 - Mergers, Acquisitions and Dispositions for additional information.

The following tables provide information about the regulatory assets and liabilities of Exelon as of December 31, 2017 and December 31, 2016:

	December 31,	
	2017	2016
Regulatory assets		
Pension and other postretirement benefits	$ 3,848	$ 4,162
Deferred income taxes	306	2,016
AMI programs	640	701
Electric distribution formula rate	244	188
Energy efficiency costs	166	—
Debt costs	116	124
Fair value of long-term debt	758	812
Fair value of PHI's unamortized energy contracts	750	1,085
Asset retirement obligations	109	111
MGP remediation costs	295	305
Under-recovered uncollectible accounts	61	56
Renewable energy	258	260
Energy and transmission programs	82	89
Deferred storm costs	27	36
Electric generation-related regulatory asset	—	10
Rate stabilization deferral	—	7
Energy efficiency and demand response programs	596	621
Merger integration costs	45	25
Under-recovered revenue decoupling	55	27
COPCO acquisition adjustment	5	8
Workers compensation and long-term disability costs	35	34
Vacation accrual	19	31
Securitized stranded costs	79	138
CAP arrearage	8	11
Removal costs	529	477
DC PLUG charge	190	—
Other	67	54
Total regulatory assets	9,288	11,388
Less: current portion	1,267	1,342
Total noncurrent regulatory assets	$ 8,021	$ 10,046

	December 31, 2017	December 31, 2016
Regulatory liabilities		
Other postretirement benefits	$ 30	$ 47
Deferred income taxes	5,241	—
Nuclear decommissioning	3,064	2,607
Removal costs	1,573	1,601
Deferred rent	36	39
Energy efficiency and demand response programs	23	185
DLC program costs	7	8
Electric distribution tax repairs	35	76
Gas distribution tax repairs	9	20
Energy and transmission programs	111	134
Renewable portfolio standards costs	63	—
Zero emission credit costs	112	—
Over-recovered uncollectible accounts	2	—
Other	82	72
Total regulatory liabilities	10,388	4,789
Less: current portion	523	602
Total noncurrent regulatory liabilities	$ 9,865	$ 4,187

Descriptions of the regulatory assets and liabilities included in the tables above are summarized below, including their recovery and amortization periods. Unless otherwise noted, the Utility Registrants are not earning or paying a return on these amounts.

Pension and other postretirement benefits. PECO's regulatory recovery for pension is based on cash contributions and, thus, is not included in the regulatory asset balances above. Otherwise, these amounts represent the Utility Registrants' portion of deferred costs associated with Exelon's pension and other postretirement benefit plans, which are recovered through customer rates. These amounts are generally amortized over the plan participants' average remaining service periods, subject to applicable cost recognition policies allowed under the authoritative guidance for pensions and postretirement benefits. See Note 16 - Retirement Benefits for additional information. These amounts also include regulatory assets established at the Constellation and PHI merger dates of $440 million and $953 million, respectively, as of December 31, 2017 and $492 million and $1,027 million, respectively, as of December 31, 2016 related to the rate regulated portions of the deferred costs associated with legacy Constellation's and PHI's pension and other postretirement benefit plans that are being amortized and recovered over approximately 12 years and 3 to 15 years, respectively (as established at the respective acquisition dates).

Deferred income taxes. These amounts represent deferred income taxes that are recoverable or refundable through customer rates, primarily associated with accelerated depreciation, the equity component of the allowance for funds used during construction, and the effects of income tax rate changes, including those resulting from the TCJA. These amounts are being amortized over the period in which the related deferred income taxes reverse, which is generally based on the expected life of the underlying assets, but may vary for certain deferred income taxes based on the determination of the rate regulators. These amounts include transmission-related regulatory liabilities that require FERC approval separate from the transmission formula rate of $484 million, $137 million, $147 million, $148 million and $147 million for ComEd, BGE, Pepco, DPL and ACE, respectively, as of December 31, 2017. The December 31, 2017 balances reflect the impact of regulatory liabilities recorded in the fourth quarter, 2017 associated with the income tax rate reductions under the TCJA of $553 million, $174 million, $161 million, $160 million and $152 million for ComEd, BGE, Pepco, DPL and ACE, respectively, as well as the impact of impairment charges discussed above. As of December 31, 2016 the comparative amounts are a regulatory asset of $22 million, $38 million, $31 million, $20 million and $19 million for ComEd, BGE, Pepco, DPL and ACE, respectively. See Note 14 — Income Taxes and the Transmission-Related Income Tax Regulatory Assets section above for additional information.

AMI programs. For ComEd, this amount primarily represents accelerated depreciation costs resulting from the early retirements of non-AMI meters, which will be amortized over an average ten-year period pursuant to the ICC approved AMI Deployment plan. ComEd is earning a return on the regulatory asset.

For PECO, this amount primarily represents accelerated depreciation on PECO's non-AMI meter assets over a 10-year period ending December 31, 2020. Recovery of smart meter costs are reflected in base rates effective January 1, 2016.

For BGE, this amount represents AMI costs associated with the installation of smart meters and the early retirement of legacy meters. The incremental costs associated with the installation, along with depreciation, amortization, and an appropriate return, had been building in a regulatory asset since the MDPSC approved the comprehensive smart grid initiative for BGE in August 2010 through approval of the program in BGE's rate order issued June 2016. As of December 31, 2017, the balance of BGE's regulatory asset was $214 million, which consists of three major components, including $129 million of unamortized incremental deployment costs of the AMI program, $53 million of unamortized costs of the non-AMI meters replaced under the program, and $32 million related to post-test year incremental program deployment costs incurred prior to approval became effective June 2016. As of December 31, 2016, the balance of BGE's regulatory asset was $230 million, which consists of three major components, including $144 million of unamortized incremental deployment costs of the AMI program, $54 million of unamortized costs of the non-AMI meters replaced under the program, and $32 million related to post-test year incremental program deployment costs incurred prior to approval became effective June 2016. The balances above reflect the impact of the cost allowances and adjustments in BGE's 2015 electric and natural gas distribution rate case. The incremental deployment costs for the AMI program and the non-AMI meter components of the regulatory asset are being amortized and recovered through rates over a 10-year period, which began in June 2016, while the post-test year incremental program deployment costs have not yet been approved for recovery by the MDPSC. A return on the regulatory asset is currently included in rates, except for the portion representing the unamortized cost of the retired non-AMI meters and the portion related to post-test year incremental program deployment costs.

For PHI, this amount represents AMI costs associated with the installation of smart meters and the early retirement of legacy meters throughout the service territories for Pepco and DPL. An AMI program has not been approved by the NJBPU for ACE in New Jersey. Pepco has received approval for recovery of deferred AMI program costs from the DCPSC and the MDPSC in its District of Columbia and Maryland service territories. Pepco does earn a return on the AMI deployment costs, but not on the early retirement of legacy meters. DPL has received approval for recovery of deferred AMI program costs from the DPSC and the MDPSC in its Delaware and Maryland service territories. DPL earns a return on the AMI deployment costs, but not on the early retirement of legacy meters.

Electric Distribution Formula Rate. These amounts represent under recoveries related to electric distribution services costs recoverable through ComEd's performance based formula rate. Under (over) recoveries for the annual reconciliations are recoverable (refundable) over a one-year period and costs for certain one-time events, such as large storms, are recoverable over a five-year period. ComEd earns and pays a return on under and over-recovered costs, respectively. As of December 31, 2017, the regulatory asset was comprised of $186 million for the 2016 and 2017 annual reconciliations and $58 million related to significant one-time events. As of December 31, 2016, the regulatory asset of $188 million was comprised of $134 million for the 2015 and 2016 annual reconciliations and $54 million related to significant one-time events.

Energy efficiency costs. These amounts represent deferred energy efficiency costs beginning June 1, 2017 that will be recovered through ComEd's energy efficiency formula rate tariff over the weighted average useful life of the related energy efficiency measures. The balance also includes the reconciliation of the difference of the revenue requirement in effect for the prior year and the revenue requirement based on actual prior year costs. ComEd earns a return on the energy efficiency regulatory asset.

Debt costs. The Utility Registrants' debt costs are used in the determination of their weighted average cost of capital, which is applied to rate base for rate-making purposes. Consistent with the treatment for ratemaking purposes, ComEd's, PECO's, and Pepco's recoverable losses or refundable gains on reacquired long-term debt are deferred and amortized to interest expense over the life of the new debt issued to finance the debt redemption or over the life of the original debt issuance if the debt is not refinanced, while BGE's, DPL's, and ACE's recoverable losses or refundable gains on reacquired long-term debt are deferred and amortized to interest expense over the life of the original debt issuance even if the debt was refinanced. The regulatory asset for Pepco, DPL and ACE as of March 23, 2016 was eliminated at Exelon and PHI as part of acquisition accounting.

Fair value of long-term debt. These amounts represent the unamortized regulatory assets recorded at Exelon for the difference between the carrying value and fair value of the long-term debt of BGE as of the Constellation merger date based on the MDPSC practice to allow BGE to recover its debt costs through rates and at Exelon and PHI for the difference between carrying value and fair value of long-term debt of Pepco, DPL and ACE as of the PHI Merger date. Exelon is amortizing the regulatory asset and the associated fair value over the life of the underlying debt.

Fair value of PHI's unamortized energy contracts. These amounts represent the regulatory asset recorded at Exelon and PHI offsetting the fair value adjustments related to Pepco's, DPL's and ACE's electricity and natural gas energy supply contracts recorded at PHI as of the PHI Merger date. Pepco, DPL and ACE are allowed full recovery of the costs of these contracts through their respective rate making processes.

Asset retirement obligations. These costs represent future legally required removal costs associated with existing asset retirement obligations. PECO will begin to earn a return on, and a recovery of, these costs once the removal activities have been performed. ComEd and BGE will recover these costs through future depreciation rates and will earn a return on these costs once the removal activities have been performed. The recovery period will be over the expected life of the related assets. See Note 15 — Asset Retirement Obligations for additional information.

MGP remediation costs. ComEd is allowed recovery of these costs under ICC approved rates. For PECO, these costs are recoverable through rates as affirmed in the 2010 approved natural gas distribution rate case settlement. The period of recovery for both ComEd and PECO will depend on the timing of the actual expenditures, currently estimated to be completed in 2022 for both ComEd and PECO. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. For BGE, $5 million of clean-up costs incurred during the period from July 2000 through November 2005 and an additional $1 million from December 2005 through November 2010 are recoverable through rates in accordance with MDPSC orders. BGE is earning a return on this regulatory asset and these costs are being amortized over 10-year periods that began in January 2006 and December 2010, respectively. The recovery period for the 10-year period that began January 2006 was extended for an additional 24 months, in accordance with the MDPSC approved 2014 electric and natural gas distribution rate case order. See Note 23 — Commitments and Contingencies for additional information.

Under-recovered uncollectible accounts. These amounts represent the difference between ComEd's annual uncollectible accounts expense and revenues collected in rates through an ICC-approved rider. The difference between net uncollectible account charge-offs and revenues collected through the rider each calendar year is recovered or refunded over a twelve-month period beginning in June of the following calendar year.

Renewable energy. In December 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs through 2032 in order to meet a portion of its obligations under the Illinois RPS. Delivery under the contracts began in June 2012. Since the swap contracts were deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period as well as an offsetting regulatory asset or liability are recorded by ComEd. ComEd does not earn (pay) a return on the regulatory asset (liability). Recovery of these costs will continue through 2032. The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd's cost to purchase energy at the market price and the contracted price.

Beginning with the 2012 compliance year the DPSC required DPL to be responsible for the RPS compliance obligation with respect to energy delivered to all end use customers, including RES supplied customers. This obligation has been met by DPL entering into long term contract(s) for the procurement of renewable energy. This energy is then sold into the market at current energy prices to offset the net cost to customers. An RPS surcharge is billed to customers to ensure recovery of the procurement costs with any variance recorded as an asset or liability. The balance at year end represents an under-recovery of the net procurement costs. These costs will be recovered over the life of the contracts, which range from 15 to 20 years.

In 2008 the NJBPU directed ACE to file a program for the purchase of Solar Renewable Energy Credits (SREC's). In 2009 the NJBPU approved ACE's SREC based contracting program and authorized ACE to enter into long-term contracts to purchase SREC's generated by solar generation projects. ACE is required to auction the purchased SREC's under Purchase and Sale Agreements (PSA) with the solar project developers. In 2015 the NJBPU authorized a "phase II" SREC program. A Regional Greenhouse Gas Initiative (RGGI) surcharge rider ensures recovery of the SREC costs. The balance at year end represents an under-recovery of the SREC costs. These costs will be recovered over the life of the contracts, which range from 15 to 20 years.

Energy and transmission programs. These amounts represent under (over) recoveries related to energy and transmission costs recoverable (refundable) under ComEd's ICC and/or FERC-approved rates. Under (over) recoveries are recoverable (refundable) over a one-year period or less. ComEd earns a return or interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2017, ComEd's regulatory asset of $6 million represents transmission costs recoverable through its FERC approved formula rate. As of December 31, 2017, ComEd's regulatory liability of $47 million included $14 million related to over-recovered energy costs and $33 million associated with revenues received for renewable energy requirements. As of December 31, 2016, ComEd's regulatory asset of $23 million included $15 million associated with transmission costs recoverable through its FERC-approved formula rate tariff and $8 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2016, ComEd's regulatory liability of $60 million included $30 million related to over-recovered energy costs and $30 million associated with revenues received for renewable energy requirements. See *Transmission Formula Rate* above for further details.

The PECO energy costs represent the electric and gas supply related costs recoverable (refundable) under PECO's GSA and PGC, respectively. PECO earns interest on the under-recovered energy and natural gas costs and pays interest on over-recovered energy and natural gas costs to customers. In addition, the DSP Program costs are presented on a net basis with PECO's GSA under (over)-recovered energy costs. These amounts represent recoverable administrative costs incurred relating to the filing and procurement associated with PECO's PAPUC-approved DSP programs for the procurement of electric supply. The filings and procurements of these DSP Programs are recoverable through the GSA over each respective term. DSP III has a 24-month term that began June 1, 2015, and DSP IV has a 48-month term that began June 1, 2017.

The independent evaluator costs associated with conducting procurements are recoverable over a 12-month period after the PAPUC approves the results of the procurements. PECO is not earning a return on these costs. Certain costs included in PECO's original DSP program related to information technology improvements were recovered over a 5-year period that began January 1, 2011. PECO earns a return on the recovery of information technology costs. The PECO transmission costs represent the electric transmission costs recoverable (refundable) under the TSC under which PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2017, PECO's regulatory liability of $60 million included $36 million related to over-recovered costs under the DSP program, $12 million related to over-recovered non-bypassable transmission service charges and $12 million related to the over-recovered natural gas costs under the PGC. As of December 31, 2016, PECO's regulatory liability of $56 million included $34 million related to over-recovered costs under the DSP program, $10 million related to over-recovered non-bypassable transmission service charges, $8 million related to the over-recovered natural gas costs under the PGC and $4 million related to over-recovered electric transmission costs.

The BGE energy costs represent the electric supply, gas supply, and transmission related costs recoverable (refundable) from (to) customers under BGE's market-based SOS program, MBR program, and FERC approved transmission rates, respectively. BGE earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. BGE does not earn or pay interest to customers on under-recovered or over-recovered SOS and MBR costs. The recovery or refund period is a twelve-month period beginning in June of the following calendar year. As of December 31, 2017, BGE's regulatory asset of $23 million included $7 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $5 million related to under-recovered electric energy costs, $3 million of abandonment costs to be recovered upon FERC approval, and $8 million related to under-recovered natural gas costs. As of December 31, 2016, BGE's regulatory asset of $38 million included $4 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $28 million related to under-recovered electric energy costs, $3 million of abandonment costs to be recovered upon FERC approval and $3 million related to under-recovered natural gas costs.

The Pepco energy costs represent the electric supply and transmission related costs recoverable (refundable) from (to) customers under Pepco's market-based SOS program and FERC approved transmission rates. Pepco earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. Pepco does not earn or pay interest to customers on under- or over-recovered SOS costs. The asset is being amortized and recovered over the life of the associated assets. As of December 31, 2017, Pepco's regulatory asset of $11 million included $3 million of transmission costs recoverable through its FERC approved formula rate and $8 million of under-recovered electric energy costs. As of December 31, 2017, Pepco's regulatory liability was zero. As of December 31, 2016, Pepco's regulatory asset of $6 million related to under-recovered electric energy costs. As of December 31, 2016, Pepco's regulatory liability of $8 million included $5 million of over-recovered transmission costs and $3 million of over-recovered electric energy costs.

The DPL energy costs represent the electric supply, gas supply, and transmission related costs recoverable (refundable) from (to) customers under DPL's market-based SOS program, GCR and FERC approved transmission rates. DPL earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. In Delaware, DPL earns interest on under-recovered costs and pays interest to customers on over-recovered SOS and GCR costs. In Maryland, DPL does not earn or pay interest to customers on under- or over-recovered SOS costs. The asset is being amortized and recovered over the life of the associated assets. As of December 31, 2017, DPL's regulatory asset of $15 million included $8 million of transmission costs recoverable through its FERC approved formula rate and $7 million of under-recovered electric energy costs. As of December 31, 2017, DPL's regulatory liability of $1 million related to over-recovered electric energy costs. As of December 31, 2016, DPL's regulatory asset of $5 million included $1 million of transmission costs recoverable through its FERC approved formula rate and $4 million of under-recovered electric energy costs. As of December 31, 2016, DPL's regulatory liability of $5 million included $2 million of over-recovered electric energy costs and $3 million of over-recovered transmission costs.

The ACE energy costs represent the electric supply and transmission related costs recoverable (refundable) from (to) customers under ACE's market-based BGS program and FERC approved transmission rates. ACE earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. ACE earns interest on under-recovered and pays interest to customers on over-recovered BGS costs. As of December 31, 2017, ACE's regulatory asset of $26 million included $11 million of transmission costs recoverable through its FERC approved formula rate and $15 million of under-recovered electric energy costs. As of December 31, 2017, ACE's regulatory liability of $3 million related to over-recovered electric energy costs. As of December 31, 2016, ACE's regulatory asset of $17 million included $6 million of transmission costs recoverable through its FERC approved formula rate and $11 million of under-recovered electric energy costs. As of December 31, 2016, ACE's regulatory liability of $5 million included $4 million of over-recovered transmission costs and $1 million of over-recovered electric energy costs.

Deferred storm costs. In the MDPSC's March 2011 rate order, BGE was authorized to defer $16 million in storm costs incurred in February 2010. BGE earns a return on this regulatory asset and the original recovery period of five years was extended for an additional 25 months, in accordance with the MDPSC 2014 electric and natural gas distribution rate case order. This regulatory asset has now been fully amortized as of December 31, 2017.

For Pepco, DPL and ACE, amounts represent total incremental storm restoration costs incurred for repair work due to major storm events in 2017, 2016, 2015, 2012 and 2011 recoverable from customers in the Maryland and New Jersey jurisdictions. These incremental storm restoration costs are amortized over a three or five year period dependent on jurisdiction.

Electric generation-related regulatory asset. As a result of the deregulation of electric generation, BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities and established a single, generation-related regulatory asset to be collected through its regulated rates, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules. The portion of this regulatory asset that does not earn a regulated rate of return was $9 million as of December 31, 2016. This regulatory asset has now been fully amortized as of December 31, 2017.

Rate stabilization deferral. In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006, to May 31, 2007. As a result, BGE recorded a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006 to May 31, 2007. In addition, as required by Senate Bill 1, the MDPSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007 to January 1, 2008. During 2007, BGE deferred $306 million of electricity purchased for resale expenses and certain applicable carrying charges, which are calculated using the implied interest rates of the rate stabilization bonds, as a regulatory asset related to the rate stabilization plans. During 2017 and 2016, BGE recovered $7 million and $81 million, respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007. This regulatory asset has now been fully amortized as of December 31, 2017.

Energy efficiency and demand response programs. For ComEd, these amounts represent over recoveries related to ComEd's ICC-approved Energy Efficiency and Demand Response Plan under the energy efficiency rate rider cancelled on June 2, 2017. ComEd expects to refund these over recoveries in future rates. ComEd earns a return on the capital investment incurred under the program, but does not earn or pay a return or interest on under or over recoveries, respectively. For PECO, these amounts represent over recoveries of program costs related to both Phase II and Phase III of its PAPUC-approved EE&C Plan. PECO began recovering the costs of its Phase II and Phase III EE&C Plans through a surcharge in June 2013 and June 2016, respectively, based on projected spending under the programs. Phase II of the program began on June 1, 2013 and expired on May 31, 2016. Phase III of the program began on June 1, 2016 and will expire on May 31, 2021. PECO earns a return on the capital portion of the EE&C Plan. For BGE, these amounts represent under (over) recoveries related to BGE's Smart Energy Savers Program®, which includes both MDPSC-approved demand response and energy efficiency programs. For the BGE Peak Rewards℠ demand response program which began in January 2008, actual marketing and customer bonus costs incurred in the demand response program are being recovered over a 5-year amortization period from the date incurred pursuant to an order by the MDPSC. Fixed assets related to the demand response program are recovered over the life of the equipment. Also included in the demand response program are customer bill credits related to BGE's Smart Energy Rewards program which began in July 2013 and are being recovered through the surcharge. Actual costs incurred in the energy efficiency program are being amortized over a 5-year period with recovery beginning in 2010 pursuant to an order by the MDPSC. BGE earns a rate of return on the capital investments and deferred costs incurred under the program and earns (pays) interest on under (over) collections.

For Pepco, DPL and ACE, amounts represent recoverable costs associated with customer direct load control and energy efficiency and conservation programs in all jurisdictions that are being recovered from customers. These programs are designed to reduce customers' energy consumption. Pepco Maryland and DPL Maryland energy efficiency program costs are recovered over 5 years and the direct load control program costs are recovered over 5 years and 15 years, depending on the type. ACE costs are recovered over 10 years. Pepco, DPL and ACE earn a return on these regulatory assets.

Merger integration costs. These amounts include integration costs to achieve distribution synergies related to the Constellation merger transaction. As a result of the MDPSC's February 2013 rate order, BGE deferred $8 million related to non-severance merger integration costs incurred during 2012 and the first quarter of 2013. Of these costs, $4 million was authorized to be amortized over a 5-year period that began in March 2013. The recovery of the remaining $4 million was deferred. In the MDPSC's December 2013 rate order, BGE was authorized to recover the remaining $4 million and an additional $4 million of non-severance merger integration costs incurred during 2013. These costs are being amortized over a 5-year period that began in December 2013. BGE is earning a return on this regulatory asset.

These amounts also include integration costs to achieve distribution synergies related to the PHI acquisition. As of December 31, 2017 and 2016, BGE's regulatory asset of $6 million and $10 million, respectively, included $4 million and $6 million, respectively, of previously incurred PHI integration costs as authorized by the June 2016 rate case order. As of December 31, 2017, Pepco's regulatory asset of $20 million represents previously incurred PHI integration costs, including $11 million authorized for recovery in Maryland and $9 million expected to be recovered in the District of Columbia service territory. As of December 31, 2016, Pepco's regulatory asset of $11 million represents previously incurred PHI integration costs authorized for recovery in Maryland. As of December 31, 2017, DPL's regulatory asset of $10 million represents previously incurred PHI integration costs, including $4 million authorized for recovery in Maryland, $5 million authorized for recovery in Delaware electric rates, and $1 million expected to be recovered in electric and gas rates in the Maryland and Delaware service territories. As of December 31, 2016, DPL's regulatory asset of $4 million represents previously incurred PHI integration costs expected to be recovered in the Maryland service territory. As of December 31, 2017, ACE's regulatory asset of $9 million represents previously incurred PHI integration costs expected to be recovered in the New Jersey service territory. Pepco and DPL are earning a return on the regulatory assets being recovered in Maryland and these costs are being amortized over five years. DPL is earning a return on the regulatory asset being recovered in Delaware and the cost is being amortized over five years. Amounts deferred for Pepco in the District of Columbia and ACE in New Jersey do not earn a return.

Under (Over)-recovered electric and gas revenue decoupling. For BGE, these amounts represent the electric and gas distribution costs recoverable from or (refundable) to customers under BGE's decoupling mechanisms and are being recovered over the life of the associated assets. As of December 31, 2017, BGE had a regulatory asset of $10 million related to under-recovered electric revenue decoupling and $4 million related to under-recovered natural gas revenue decoupling. As of December 31, 2016, BGE had a regulatory asset of $2 million related to under-recovered natural gas revenue decoupling and $1 million related to under-recovered electric revenue decoupling.

For Pepco and DPL, these amounts represent the electric distribution costs recoverable from customers under Pepco's Maryland and District of Columbia decoupling mechanisms and DPL's Maryland decoupling mechanism. Pepco and DPL earn a return on these regulatory assets.

COPCO acquisition adjustment. On July 19, 2007, the MDPSC issued an order which provided for the recovery of a portion of DPL's goodwill. As a result of this order, $41 million in DPL goodwill was transferred to a regulatory asset. In February 2017 the MDPSC ruled that the remaining amortization be extended for an additional three years, and this item is now amortized from August 2007 through February 2020. DPL earns a return on these regulatory assets.

Workers compensation and long-term disability costs. These amounts represent accrued workers' compensation and long-term disability costs for Pepco, which are recoverable from customers when actual claims are paid to employees. The recovery period for these regulatory assets is over the life of the associated assets.

Vacation accrual. These amounts represent accrued vacation costs for PECO, DPL and ACE. PECO, DPL and ACE and the costs are recoverable from customers when actual payments are made to employees or when vacation is taken.

Securitized stranded costs. These amounts represent certain contract termination payments under a contract between ACE and an unaffiliated non-utility generator and costs associated with the regulated operations of ACE's electricity generation business that are no longer recoverable through customer rates (collectively referred to as "stranded costs"). The stranded costs are amortized over the life of Transition Bonds issued by Atlantic City Electric Transition Funding LLC (ACE Funding) to securitize the recoverability of these stranded costs. These bonds mature between 2018 and 2023. A customer surcharge is collected by ACE to fund principal and interest payments on the Transition Bonds. PHI earns a return on these regulatory assets.

CAP arrearage. These amounts represent the guaranteed recovery of PECO's previously incurred bad debt expense associated with the eligible CAP accounts receivable balances under the IPAF Program as provided by the 2015 electric distribution rate case settlement. These costs are amortized as recovery is received through a combination of customer payments over the duration of the five-year payment agreement term and rate recovery, including through future rate cases if necessary.

Removal costs. These amounts represent funds ComEd, BGE, PHI, Pepco, DPL and ACE have received from customers through depreciation rates to cover the future non-legally required cost of removal of property, plant and equipment which reduces rate base for ratemaking purposes. This liability is reduced as costs are incurred. PHI, Pepco, DPL, and ACE have a regulatory asset which represents removal costs incurred in excess of amounts received from customers through depreciation rates recoverable from ratepayers. The recovery period of these regulatory assets is over the life of the associated assets.

DC PLUG charge. On November 9, 2017, the DCPSC issued an order approving the First Biennial Plan and the application for a financing order. As a result, Pepco's obligation of $187 million will be recovered from customers and therefore, a $187 million regulatory asset was established. Pepco will recover $60 million over a two-year period and the remainder will be recovered based on future biennial plans filed with the DCPSC. In addition, $3 million of previously deferred costs from the first Triennial Plan were approved for recovery from customers over a one year recovery period.

Nuclear decommissioning. These amounts represent estimated future nuclear decommissioning costs for the Regulatory Agreement Units that exceed (regulatory asset) or are less than (regulatory liability) the associated decommissioning trust fund assets. Exelon believes the trust fund assets, including prospective earnings thereon and any future collections from customers, will be sufficient to fund the associated future decommissioning costs at the time of decommissioning. See Note 15 — Asset Retirement Obligations for additional information.

Deferred rent. Represents the regulatory liability recorded at Exelon and PHI for deferred rent related to a lease. The costs of the lease are recoverable through the ratemaking process at Pepco, DPL and ACE.

DLC program costs. The DLC program costs include equipment, installation, and information technology costs necessary to implement the DLC Program under PECO's EE&C Phase I Plans. PECO received full cost recovery through Phase I collections and will amortize the costs as a credit to the income statement to offset the related depreciation expense during the same period through September 2025, which is the remaining useful life of the assets.

Electric distribution tax repairs. PECO's 2010 electric distribution rate case settlement required that the expected cash benefit from the application of Revenue Procedure 2011-43, which was issued on August 19, 2011, to prior tax years be refunded to customers over a seven-year period. Credits began being reflected in customer bills on January 1, 2012. PECO's 2015 electric distribution rate case settlement requires PECO to pay interest on the unamortized balance of the tax-effected catch-up deduction beginning January 1, 2016.

Gas distribution tax repairs. PECO's 2010 natural gas distribution rate case settlement required that the expected cash benefit from the application of new tax repairs deduction methodologies for 2010 and prior tax years be refunded to customers over a seven-year period. In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. Credits began being reflected in customer bills on January 1, 2013. No interest will be paid to customers.

Renewable portfolio standards costs. Beginning June 1, 2017, ComEd recovers all costs associated with purchasing renewable energy credits through a new tariff rate rider that provides for a reconciliation and true-up to actual costs, with any difference to be credited to or collected from ComEd's retail customers in subsequent periods with interest. In addition, this balance includes the over recovery of renewable energy credits associated with RPS alternative compliance payments recovered under supply base rates. These collections were required under the Illinois Public Utilities Act to be used for renewable energy purchases in accordance with ICC procurement orders. The amortization period is in accordance with the applicable ICC procurement orders.

Zero emission credit costs. Beginning June 1, 2017, ComEd recovers all costs associated with purchasing ZECs through a new tariff rate rider that provides for an annual reconciliation and true-up to actual costs incurred by ComEd to purchase ZECs, with any difference to be credited to or collected from ComEd's retail customers in subsequent periods with interest.

Over-recovered uncollectible accounts. These amounts represent the difference between ACE's annual uncollectible accounts expense and revenues collected in rates through an NJBPU-approved rider. The difference between GAAP uncollectible expense and revenues collected through the rider each calendar year is recovered or refunded over a twelve-month period beginning in June of the following calendar year.

Capitalized Ratemaking Amounts Not Recognized

The following table illustrates our authorized amounts capitalized for ratemaking purposes related to earnings on shareholders' investment that are not recognized for financial reporting purposes on our Consolidated Balance Sheets. These amounts will be recognized as revenues in our Consolidated Statements of Operations and Comprehensive Income in the periods they are billable to our customers.

December 31, 2017	$69
December 31, 2016	$72

Purchase of Receivables Programs

ComEd, PECO, BGE, Pepco, DPL and ACE are required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia and New Jersey, to purchase certain receivables from retail electric and natural gas suppliers that participate in the utilities' consolidated billing. ComEd, BGE, Pepco and DPL purchase receivables at a discount primarily to recover uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and is permitted to recover uncollectible accounts expense, including those from Third Party Suppliers, from customers through distribution rates. ACE purchases receivables at face value. ACE recovers all uncollectible accounts expense, including those from Third Party Suppliers, through the Societal Benefits Charge (SBC) rider, which includes uncollectible accounts expense as a component. The SBC is filed annually with the NJBPU. Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon's, ComEd's, PECO's, BGE's, PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of those companies as of December 31, 2017 and December 31, 2016.

	As of December 31,	
	2017	2016
Purchased receivables	$298	$313
Allowance for uncollectible accounts[a]	(31)	(37)
Purchased receivables, net	$267	$276

[a] For ComEd, BGE, Pepco and DPL, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing tariff.

4. Mergers, Acquisitions and Dispositions

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 located in Scriba, New York from Entergy Nuclear FitzPatrick LLC (Entergy) for a total purchase price of $289 million, which consisted of a cash purchase price of $110 million and a net cost reimbursement to and on behalf of Entergy of $179 million. As part of the acquisition agreements, Generation provided nuclear fuel and reimbursed Entergy for incremental costs to prepare for and conduct a plant refueling outage; and Generation reimbursed Entergy for incremental costs to operate and maintain the plant for the period after the refueling outage through the acquisition closing date. These reimbursements covered costs that Entergy otherwise would have avoided had it shut down the plant as originally intended in January 2017. The amounts reimbursed by Generation were offset by FitzPatrick's electricity and capacity sales revenues for this same post-outage period. As part of the transaction, Generation received the FitzPatrick NDT fund assets and assumed the obligation to decommission FitzPatrick. The NRC license for FitzPatrick expires in 2034. In 2017, the final purchase price consideration of $289 million (including $235 million of cash and $54 million of nuclear fuel) was remitted to and on behalf of Entergy.

The fair values of FitzPatrick's assets and liabilities were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing), discount rates reflecting risk inherent in the future cash flows and future power and fuel market prices. The valuations performed in the first quarter of 2017 to determine the fair value of the FitzPatrick assets acquired and liabilities assumed were preliminary. Accounting guidance provides that the allocation of the purchase price may be modified up to one year from the date of the acquisition to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date.

During the third quarter of 2017, certain modifications were made to the initial preliminary valuation amounts for acquired property, plant and equipment, the decommissioning ARO, pension and OPEB obligations and related deferred tax liabilities, resulting in a $3 million net increase in assets acquired and liabilities assumed. Additionally, in the third quarter a purchase price settlement payment of $4 million was received from Entergy. These resulted in an adjustment to the after-tax bargain purchase gain recorded at Generation. For the year ended December 31, 2017, the after-tax bargain purchase gain of $233 million is included within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and primarily reflects differences in strategies between Generation and Entergy for the intended use and ultimate decommissioning of the plant. There are no further adjustments expected to be made to the allocation of the purchase price. See Note 15 - Asset Retirement Obligations and Note 16 - Retirement Benefits for additional information regarding the FitzPatrick decommissioning ARO and pension and OPEB updates.

The following table summarizes the final acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the FitzPatrick acquisition by Generation as of December 31, 2017:

Cash paid for purchase price	$ 110
Cash paid for net cost reimbursement	125
Nuclear fuel transfer	54
Total consideration transferred	$ 289
Identifiable assets acquired and liabilities assumed	
Current assets	$ 60
Property, plant and equipment	298
Nuclear decommissioning trust funds	807
Other assets[(a)]	114
Total assets	$1,279
Current liabilities	$ 6
Nuclear decommissioning ARO	444
Pension and OPEB obligations	33
Deferred income taxes	149
Spent nuclear fuel obligation	110
Other liabilities	15
Total liabilities	$ 757
Total net identifiable assets, at fair value	$ 522
Bargain purchase gain (after-tax)	$ 233

(a) Includes a $110 million asset associated with a contractual right to reimbursement from the New York Power Authority (NYPA), a prior owner of FitzPatrick, associated with the DOE one-time fee obligation. See Note 23-Commitments and Contingencies for additional background regarding SNF obligations to the DOE.

For the year ended December 31, 2017, Exelon and Generation incurred $57 million of merger and integration related costs which are included within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Acquisition of ConEdison Solutions

On September 1, 2016, Generation acquired the competitive retail electricity and natural gas business of Consolidated Edison Solutions, Inc. (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 Solutions are excluded from the transaction.

The fair values of ConEdison Solutions' assets and liabilities were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing), discount rates reflecting risk inherent in the future cash flows and future power and fuel market prices. The purchase price equaled the estimated fair value of the net assets acquired and the liabilities assumed and, therefore, no goodwill or bargain purchase was recorded as of the acquisition date. The purchase price allocation is now final.

The following table summarizes the final acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the ConEdison Solutions acquisition by Generation:

Total consideration transferred	$257
Identifiable assets acquired and liabilities assumed	
Working capital assets	$204
Property, plant and equipment	2
Mark-to-market derivative assets	6
Unamortized energy contract assets	100
Customer relationships	9
Other assets	1
Total assets	$322
Mark-to-market derivative liabilities	$ 65
Total liabilities	$ 65
Total net identifiable assets, at fair value	$257

Merger with Pepco Holdings, Inc.

Description of Transaction

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.

Regulatory Matters

Approval of the merger in Delaware, New Jersey, Maryland and the District of Columbia was conditioned upon Exelon and PHI agreeing to certain commitments including where applicable: customer rate credits, funding for energy efficiency and delivery system modernization programs, a green sustainability fund, workforce development initiatives, charitable contributions, renewable generation and other required commitments. In addition, the orders approving the merger in Delaware, New Jersey, and Maryland include a "most favored nation" provision which, generally, requires allocation of merger benefits proportionally across all the jurisdictions.

During the third and fourth quarters of 2016, Exelon and PHI filed proposals in Delaware, New Jersey and Maryland for amounts and allocations reflecting the application of the most favored nation provision, resulting in a total nominal cost of commitments of $513 million excluding renewable generation commitments (approximately $444 million on a net present value basis amount, excluding renewable generation commitments and charitable contributions). These filings reflected agreements reached with certain parties to the merger proceedings in these jurisdictions. In 2016, the DPSC and NJBPU approved the amounts and allocations of the additional merger benefits for Delaware and New Jersey, respectively.

On April 12, 2017, the MDPSC issued an order approving the amounts of the additional merger benefits for Maryland, but amending the proposed allocations of the benefits. The amended allocations do not have a material effect on any of the Registrants' financial statements. No changes in commitment cost levels are required in the District of Columbia.

During the second quarter of 2017, Exelon finalized the application of $8 million funding for low- and moderate-income customers in the Pepco Maryland and DPL Maryland service territories. This resulted in an adjustment to merger commitment costs recorded at Exelon Corporate, Pepco, and DPL. Exelon Corporate recorded an increase of $8 million and Pepco and DPL recorded a decrease of $6 million and $2 million, respectively, in Operating and maintenance expense.

The following amounts represent total commitment costs for Exelon, PHI, Pepco, DPL and ACE that have been recorded since the acquisition date:

Description	Expected Payment Period	Pepco	DPL	ACE	*Successor* PHI	Exelon
Rate credits	2016 - 2017	$ 91	$67	$101	$259	$259
Energy efficiency	2016 - 2021	—	—	—	—	122
Charitable contributions	2016 - 2026	28	12	10	50	50
Delivery system modernization	Q2 2017	—	—	—	—	22
Green sustainability fund	Q2 2017	—	—	—	—	14
Workforce development	2016 - 2020	—	—	—	—	17
Other		1	5	—	6	29
Total		$120	$84	$111	$315	$513

Pursuant to the orders approving the merger, Exelon made $73 million, $46 million and $49 million of equity contributions to Pepco, DPL and ACE, respectively, in the second quarter of 2016 to fund the after-tax amounts of the customer bill credit and the customer base rate credit commitments.

In addition, Exelon is committed to develop or to assist in the commercial development of approximately 37 MWs of new generation in Maryland, District of Columbia, and Delaware, 27 MWs of which are expected to be completed by 2018. These investments are expected to total approximately $137 million, are expected to be primarily capital in nature, and will generate future earnings at Exelon and Generation. Investment costs will be recognized as incurred and recorded on Exelon's and Generation's financial statements. Exelon has also committed to purchase 100 MWs of wind energy in PJM, to procure 120 MWs of wind RECs for the purpose of meeting Delaware's renewable portfolio standards, and to maintain and promote energy efficiency and demand response programs in the PHI jurisdictions.

Pursuant to the various jurisdictions' merger approval conditions, over specified periods Pepco, DPL and ACE are not permitted to reduce employment levels due to involuntary attrition associated with the merger integration process and have made other commitments regarding hiring and relocation of positions.

In July 2015, the OPC, Public Citizen, Inc., the Sierra Club and the Chesapeake Climate Action Network (CCAN) filed motions to stay the MDPSC order approving the merger. The Circuit Court judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the Circuit Court judge affirmed the MDPSC's order approving the merger and denied the petitions for judicial review filed by the OPC, the Sierra Club, CCAN and Public Citizen, Inc. On January 19, 2016, the OPC filed a notice of appeal to the Maryland Court of Special Appeals, and on January 21, the Sierra Club and CCAN filed notices of appeal. On January 27, 2017, the Maryland Court of Special Appeals affirmed the Circuit Court's judgment that the MDPSC did not err in approving the merger. The OPC and Sierra Club filed petitions seeking further review in the Court of Appeals of Maryland, which is the highest court in Maryland. On June 21, 2017, the Court of Appeals granted discretionary review of the January 27, 2017 decision by the Maryland Court of Special Appeals. The Maryland Court of Appeals will review the OPC argument that the MDPSC did not properly consider the acquisition premium paid to PHI shareholders under Maryland's merger approval standard and the Sierra Club's argument that the merger would harm the renewable and distributed generation markets. The two lower courts examining these issues rejected these arguments, which Exelon believes are without merit. All briefs have been filed and oral arguments were presented to the court on October 10, 2017.

Between March 25, 2016 and April 22, 2016, various parties filed motions with the DCPSC to reconsider its March 23, 2016 order approving the merger. On June 17, 2016, the DCPSC denied all motions. In August 2016, the District Legal Entity of Columbia Office of People's Counsel, the District of Columbia Government, and Public Citizen jointly with DC Sun each filed petitions for judicial review of the DCPSC's March 23, 2016 order with the District of Columbia Court of Appeals. On July 20, 2017, the Court issued an opinion rejecting all of appellants' arguments and affirming the Commission's decision approving the merger.

Accounting for the Merger Transaction

The total purchase price consideration of approximately $7.1 billion for the PHI Merger consisted of cash paid to PHI shareholders, cash paid for PHI preferred securities and cash paid for PHI stock-based compensation equity awards as follows:

(In millions of dollars, except per share data)	Total Consideration
Cash paid to PHI shareholders at $27.25 per share (254 million shares outstanding at March 23, 2016)	$6,933
Cash paid for PHI preferred stock	180
Cash paid for PHI stock-based compensation equity awards[(a)]	29
Total purchase price	$7,142

(a) PHI's unvested time-based restricted stock units and performance-based restricted stock units issued prior to April 29, 2014 were immediately vested and paid in cash upon the close of the merger. PHI's remaining unvested time-based restricted stock units as of the close of the merger were cancelled. There were no remaining unvested performance-based restricted stock units as of the close of the merger.

PHI shareholders received $27.25 of cash in exchange for each share of PHI common stock outstanding as of the effective date of the merger. In connection with the Merger Agreement, Exelon entered into a Subscription Agreement under which it purchased $180 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities of PHI prior to December 31, 2015. On March 23, 2016, the preferred securities were cancelled for no consideration to Exelon, and accordingly, the $180 million cash consideration previously paid to acquire the preferred securities was treated as purchase price consideration.

The preliminary valuations performed in the first quarter of 2016 were updated in the second, third, and fourth quarters of 2016. There were no adjustments to the purchase price allocation in the first quarter of 2017 and the purchase price allocation is now final.

Exelon applied push-down accounting to PHI, and accordingly, the PHI assets acquired and liabilities assumed were recorded at their estimated fair values on Exelon's and PHI's Consolidated Balance Sheets as follows:

Purchase Price Allocation[(a)]	
Current assets	$ 1,441
Property, plant and equipment	11,088
Regulatory assets	5,015
Other assets	248
Goodwill	4,005
Total assets	$21,797
Current liabilities	$ 2,752
Unamortized energy contracts	1,515
Regulatory liabilities	297
Long-term debt, including current maturities	5,636
Deferred income taxes	3,447
Pension and OPEB obligations	821
Other liabilities	187
Total liabilities	$14,655
Total purchase price	$ 7,142

(a) Amounts shown reflect the final purchase price allocation and the correction of a reporting error identified and corrected in the second quarter of 2016. The error had resulted in a gross up of certain assets and liabilities related to legacy PHI intercompany and income tax receivable and payable balances.

On its successor financial statements, PHI has recorded, beginning March 24, 2016, Membership interest equity of $7.2 billion, which is greater than the total $7.1 billion purchase price, reflecting the impact of a $59 million deferred tax liability recorded only at Exelon Corporate to reflect unitary state income tax consequences of the merger.

The excess of the purchase price over the estimated fair value of the assets acquired and the liabilities assumed totaled $4.0 billion, which was recognized as goodwill by PHI and Exelon at the acquisition date, reflecting the value associated with enhancing Exelon's regulated utility portfolio of businesses, including the ability to leverage experience and best practices across the utilities and the opportunities for synergies. For purposes of future required impairment assessments, the goodwill has been assigned to PHI's reportable units Pepco, DPL and ACE in the amounts of $1.7 billion, $1.1 billion and $1.2 billion, respectively. None of this goodwill is expected to be tax deductible.

Immediately following closing of the merger, $235 million of net assets included in the table above associated with PHI's unregulated business interests were distributed by PHI to Exelon. Exelon contributed $163 million of such net assets to Generation.

The fair values of PHI's assets and liabilities were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing), discount rates reflecting risk inherent in the future cash flows, future market prices and impacts of utility rate regulation. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired.

Through its wholly owned rate regulated utility subsidiaries, most of PHI's assets and liabilities are subject to cost-of-service rate regulation. Under such regulation, rates charged to customers are established by a regulator to provide for recovery of costs and a fair return on invested capital, or rate base, generally measured at historical cost. In applying the acquisition method of accounting, for regulated assets and liabilities included in rate base or otherwise earning a return (primarily property, plant and equipment and regulatory assets earning a return), no fair value adjustments were recorded as historical cost is viewed as a reasonable proxy for fair value.

Fair value adjustments were applied to the historical cost bases of other assets and liabilities subject to rate regulation but not earning a return (including debt instruments and pension and OPEB obligations). In these instances, a corresponding offsetting regulatory asset or liability was also established, as the underlying utility asset and liability amounts are recoverable from or refundable to customers at historical cost (and not at fair value) through the rate setting process. Similar treatment was applied for fair value adjustments to record intangible assets and liabilities, such as for electricity and gas energy supply contracts as further described below. Regulatory assets and liabilities established to offset fair value adjustments are amortized in amounts and over time frames consistent with the realization or settlement of the fair value adjustments, with no impact on reported net income. See Note 3 - Regulatory Matters for additional information regarding the fair value of regulatory assets and liabilities established by Exelon and PHI.

Fair value adjustments were recorded at Exelon and PHI for the difference between the contract price and the market price of electricity and gas energy supply contracts of PHI's wholly owned rate regulated utility subsidiaries. These adjustments are intangible assets and liabilities classified as unamortized energy contracts on Exelon's and PHI's Consolidated Balance Sheets as of December 31, 2017. The difference between the contract price and the market price at the acquisition date of the Merger was recognized for each contract as either an intangible asset or liability. In total, Exelon and PHI recorded a net $1.5 billion liability reflecting out-of-the-money contracts. The valuation of the acquired intangible assets and liabilities was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. In certain instances, the valuations were based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power prices and the discount rate. The unamortized energy contract fair value adjustment amounts and the corresponding offsetting regulatory asset and liability amounts are amortized through Purchased power and fuel expense or Operating revenues, as applicable, over the life of the applicable contract in relation to the present value of the underlying cash flows as of the merger date.

As mentioned, under cost-of-service rate regulation, rates charged to customers are established by a regulator to provide for recovery of costs and a fair return on invested capital, or rate base, generally measured at historical cost. Historical cost information therefore is the most relevant presentation for the financial statements of PHI's rate regulated utility subsidiary registrants, Pepco, DPL and ACE. As such, Exelon and PHI did not push-down the application of acquisition accounting to PHI's utility registrants, and therefore the financial statements of Pepco, DPL and ACE do not reflect the revaluation of any assets and liabilities.

The current impact of PHI, including its unregulated businesses, on Exelon's Consolidated Statements of Operations and Comprehensive Income includes Operating revenues of $4,829 million and Net income of $364 million during the year ended December 31, 2017, and Operating revenues of $3,785 million and Net loss of $(66) million for the year ended December 31, 2016.

For the periods ended December 31, 2017 and 2016, the Registrants have recognized costs to achieve the PHI acquisition as follows:

	For the Year Ended December 31,	
Acquisition, Integration and Financing Costs[a]	**2017**	**2016**
Exelon	$16	$143
Generation	22	37
ComEd[b]	1	(6)
PECO	4	5
BGE[b]	4	(1)
Pepco[b]	(6)	28
DPL[b]	(7)	20
ACE[b]	(6)	19

	Successor		*Predecessor*
Acquisition, Integration and Financing Costs[a]	**For the Year Ended December 31, 2017**	**March 24, 2016 to December 31, 2016**	**January 1, 2016 to March 23, 2016**
PHI[b]	$(18)	$69	$29

(a) The costs incurred are classified primarily within Operating and maintenance expense in the Registrants' respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the financing costs, which are included within Interest expense. Costs do not include merger commitments discussed above.

(b) 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. 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 for more information.

Pro-forma Impact of the Merger

The following unaudited pro-forma financial information reflects the consolidated results of operations of Exelon as if the merger with PHI had taken place on January 1, 2015. The unaudited pro forma information was calculated after applying Exelon's accounting policies and adjusting PHI's results to reflect purchase accounting adjustments.

The unaudited pro-forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

	Year Ended December 31,	
	2016[(a)]	2015[(b)]
Total operating revenues	$32,342	$33,823
Net income attributable to common shareholders	1,562	2,618
Basic earnings per share	$ 1.69	$ 2.85
Diluted earnings per share	1.69	2.84

(a) The amounts above exclude non-recurring costs directly related to the merger of $680 million and intercompany revenue of $171 million for the year ended December 31, 2016.

(b) The amounts above exclude non-recurring costs directly related to the merger of $92 million and intercompany revenue of $559 million for the year ended December 31, 2015.

Asset Dispositions

EGTP, a Delaware limited liability company, was formed in 2014 with the purpose of financing a portfolio of assets comprised of two combined-cycle gas turbines (CCGTs) and three peaking/simple cycle facilities consisting of approximately 3.4 GW of generation capacity in ERCOT North and Houston Zones. EGTP is an indirect wholly owned subsidiary of Exelon and Generation. Each of the aforementioned facilities are held through a wholly owned direct subsidiary of EGTP. EGTP also owns two equity method investments in shared facility companies. EGTP, its direct parent and its wholly owned subsidiaries secured a nonrecourse senior secured term loan facility, a revolving loan facility and certain commodity and interest rate swaps.

EGTP's operating cash flows were negatively impacted by certain market conditions and the seasonality of its cash flows. On May 2, 2017, as a result of the negative impacts of certain market conditions and the seasonality of its cash flows, 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. As a result, Exelon and Generation classified certain of 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. See Note 13 - Debt and Credit Agreements for details regarding the nonrecourse debt associated with EGTP and Note 7 - Impairment of Long-Lived Assets and Intangibles for further information.

On November 7, 2017, EGTP and all of its wholly owned subsidiaries (collectively with EGTP, the "Debtors") 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. The Debtors sought Bankruptcy Court authorization to jointly administer the Chapter 11 cases. The Debtors are continuing to manage their assets and operate their businesses as "debtors in possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and the orders of the Bankruptcy Court. As a result of the bankruptcy filing, Exelon and Generation deconsolidated EGTP's assets and liabilities from their consolidated financial statements, resulting in a pre-tax gain upon deconsolidation of $213 million. Concurrently with the Chapter 11 filings, Generation entered into an asset purchase agreement to acquire one of EGTP's generating plants, the Handley Generating Station, for approximately $60 million, subject to a potential adjustment for fuel oil and assumption of certain liabilities. In the Chapter 11 Filings, EGTP requested that the proposed acquisition of the Handley Generating Station be consummated through a court-approved and supervised sales process. The acquisition was approved by the Bankruptcy Court in January 2018 and the transaction is expected to be completed in the first half of 2018.

In December 2017, Pepco Building Services, Inc. entered into a purchase and sale agreement to sell its interest in an electrical contracting business that primarily installs, maintains and repairs underground and high-voltage cable transmission and distribution systems. The closing of the sale is expected to be completed in the first quarter of 2018. As a result, as of December 31, 2017, certain assets and liabilities were classified as held for sale at their respective fair values less costs to sell and included in the Other current assets and Other current liabilities balances on Exelon's and Generation's Consolidated Balance Sheet.

During the fourth quarter 2016, as part of its continual assessment of growth and development opportunities, Generation reevaluated and in certain instances terminated or renegotiated certain projects and contracts. As a result, a pre-tax loss of $69 million was recorded within Loss on sale of assets and pre-tax impairment charges of $23 million was recorded within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

In July 2016, DPL completed the sale of a 9-acre land parcel located on South Madison Street in Wilmington, DE, resulting in a pre-tax gain of approximately $4 million. In December 2016, DPL completed the sale of a 48-acre land parcel located in Middletown, DE, resulting in a pre-tax gain of approximately $5 million. Due to the fair value adjustments recorded at Exelon and PHI as part of purchase accounting, no gain was recorded in Exelon's and PHI's Consolidated Statements of Operations and Comprehensive Income.

On June 16, 2016, Generation initiated the sales process of its Upstream business by executing a forbearance agreement with the lenders of the nonrecourse debt. See Note 13 - Debt and Credit Agreements for more information. In December 2016, Generation sold substantially all of the Upstream assets for $37 million which resulted in a pre-tax loss on sale of $10 million which is included in Gain (loss) on sales of assets on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2016.

On May 2, 2016, Pepco completed the sale of the New York Avenue land parcel, located in Washington, D.C., resulting in a pre-tax gain of approximately $8 million at Pepco. Due to the fair value adjustments recorded at Exelon and PHI as part of purchase accounting, no gain was recorded in Exelon's and PHI's Consolidated Statements of Operations and Comprehensive Income.

On April 21, 2016, Generation completed the sale of the retired New Boston generating site, located in Boston, Massachusetts, resulting in a pre-tax gain of approximately $32 million.

On November 10, 2015, Pepco completed the sale of a 3.5-acre parcel of unimproved land (held as non-utility property) in the Buzzard Point area of southeast Washington, D.C., resulting in a pre-tax gain of $37 million.

On December 31, 2015, Pepco completed the sale of a 3.8-acre parcel of unimproved land (held as non-utility property) in the NoMa area of northeast Washington, D.C., resulting in a pre-tax gain of $9 million. The purchase and sale agreement also provided the third party with a 90-day option to purchase the remaining 1.8-acre land parcel.

5. Accounts Receivable

Accounts receivable at December 31, 2017 and 2016 included estimated unbilled revenues, representing an estimate for the unbilled amount of energy or services provided to customers, and is net of an allowance for uncollectible accounts as follows:

	As of December 31,	
	2017	2016
Unbilled customer revenues	$1,858	$1,673
Allowance for uncollectible accounts[(a)]	(322)	(334)

(a) Includes the estimated allowance for uncollectible accounts on billed customer and other accounts receivable.

PECO Installment Plan Receivables

PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $11 million and $9 million at December 31, 2017 and 2016, respectively. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1—Significant Accounting Policies. The allowance for uncollectible accounts balance associated with these receivables at December 31, 2017 of $11 million consists of $3 million and $8 million for medium risk and high-risk segments, respectively. The allowance for uncollectible accounts balance associated with these receivables at December 31, 2016 of $13 million consists of $1 million, $3 million and $9 million for low risk, medium risk and high risk-segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of December 31, 2017 and 2016 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1—Significant Accounting Policies.

6. Property, Plant and Equipment

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2017 and 2016:

	Average Service Life (years)	2017	2016
Asset Category			
Electric—transmission and distribution	5-90	$49,506	$45,698
Electric—generation	2-56	29,019	27,193
Gas—transportation and distribution	5-90	5,050	4,642
Common—electric and gas	5-75	1,447	1,312
Nuclear fuel[(a)]	1-8	6,420	6,546
Construction work in progress	N/A	2,825	4,306
Other property, plant and equipment[(b)]	2-50	999	1,027
Total property, plant and equipment		95,266	90,724
Less: accumulated depreciation[(c)]		21,064	19,169
Property, plant and equipment, net		$74,202	$71,555

(a) Includes nuclear fuel that is in the fabrication and installation phase of $1,196 million and $1,326 million at December 31, 2017 and 2016, respectively.

(b) Includes Generation's buildings under capital lease with a net carrying value of $7 million and $10 million at December 31, 2017 and 2016, respectively. The original cost basis of the buildings was $47 million and $52 million, and total accumulated amortization was $40 million and $42 million, as of December 31, 2017 and 2016, respectively. Also includes ComEd's buildings under capital lease with a net carrying value at both December 31, 2017 and 2016, of $7 million. The original cost basis of the buildings was $8 million and total accumulated amortization was $1 million as of both December 31, 2017 and 2016. Includes land held for future use and non-utility property at ComEd, PECO, BGE, Pepco, DPL and ACE of $44 million, $21 million, $26 million, $59 million, $15 million and $27 million, respectively, at December 31, 2017. Includes the original cost and progress payments associated with Generation's turbine equipment held for future use with a carrying value of $0 million and $17 million as of December 31, 2017 and 2016, respectively. Generation's turbine equipment was impaired by $11 million and the remaining $6 million was moved to the assets held for sale account at December 31, 2017.

(c) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $3,159 million and $3,186 million as of December 31, 2017 and 2016, respectively.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2017	2016	2015
Electric—transmission and distribution	2.75%	2.73%	2.83%
Electric—generation[(a)]	4.36%[(a)]	5.94%[(a)]	3.47%
Gas	2.10%	2.17%	2.17%
Common—electric and gas	7.05%	7.41%	7.79%

(a) See Note 8 — Early Nuclear Plant Retirements for additional information on the accelerated net depreciation and amortization of Clinton, Quad Cities and TMI.

See Note 1 — Significant Accounting Policies for further information regarding property, plant and equipment policies and accounting for capitalized software costs for the Registrants. See Note 13 — Debt and Credit Agreements for further information regarding Exelon's, ComEd's and PECO's property, plant and equipment subject to mortgage liens.

7. Impairment of Long-Lived Assets and Intangibles

Long-Lived Assets

Registrants evaluate long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. At Generation, EGTP's operating cash flows have been negatively impacted by certain market conditions and the seasonality of its cash flows. On May 2, 2017, EGTP entered into a consent agreement with its lenders to initiate an orderly sales process to sell the assets of its wholly owned subsidiaries. As a result, Exelon and Generation classified certain of EGTP's assets and liabilities as held for sale at their respective fair values less costs to sell and recorded a pre-tax impairment charge of $460 million within Operating and maintenance expense on their Consolidated Statements of Operations and Comprehensive Income during 2017. On November 7, 2017, EGTP and 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 and, as a result, Exelon and Generation deconsolidated EGTP's assets and liabilities from their consolidated financial statements. See Note 4 — Mergers, Acquisitions and Dispositions and Note 13 — Debt and Credit Agreements, for further information.

In the third quarter of 2015, PHI entered into a sponsorship agreement with the District of Columbia for future sponsorship rights associated with public property within the District of Columbia and paid the District of Columbia $25 million, which Exelon and PHI had recorded as a finite-lived intangible asset as of December 31, 2016. The specific sponsorship rights were to be determined over time through future negotiations. In the fourth quarter of 2017, based upon the lack of currently available sponsorship opportunities, the asset was written off and a pre-tax impairment charge of $25 million was recorded within Operating and maintenance expense in Exelon's and PHI's Consolidated Statements of Operations and Comprehensive Income.

During the first quarter of 2016, significant changes in Generation's intended use of the Upstream oil and gas assets, developments with nonrecourse debt held by its Upstream subsidiary CEU Holdings, LLC (as described in Note 13 — Debt and Credit Agreements) and continued declines in both production volumes and commodity prices suggested that the carrying value may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of its Upstream properties were less than their carrying values. As a result, a pre-tax impairment charge of $119 million was recorded in March 2016 within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. On June 16, 2016, Generation initiated the sales process of its Upstream natural gas and oil exploration and production business by executing a forbearance agreement with the lenders of the nonrecourse debt, see Note 13 — Debt and Credit Agreements for additional information. An additional pre-tax impairment charge of $15 million was recorded in September 2016 within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income due to further declines in fair value. In December 2016, Generation sold substantially all of the Upstream Assets. See Note 4 — Mergers, Acquisitions and Dispositions for additional information.

In the second quarter of 2016, updates to Exelon's long-term view of energy and capacity prices suggested that the carrying value of a group of merchant wind assets, located in West Texas, may be impaired. Upon review, the estimated undiscounted future cash flows and fair value of the group were less than their carrying value. The fair value analysis was based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As a result of the fair value analysis, long-lived merchant wind assets held and used with a carrying amount of approximately $60 million were written down to their fair value of $24 million and a pre-tax impairment charge of $36 million was recorded during the second quarter of 2016 in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Also in the second quarter of 2016, updates to Exelon's long-term view, as described above, in conjunction with the retirement announcements of the Quad Cities and Clinton nuclear plants in Illinois suggested that the carrying value of our Midwest asset group may be impaired. Generation completed a comprehensive review of the estimated undiscounted future cash flows of the Midwest asset group and no impairment charge was required.

The fair value analysis used in the above impairments was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue, generation and production forecasts, projected capital and maintenance expenditures and discount rates. Changes in the assumptions described above could potentially result in future impairments of Exelon's long-lived assets, which could be material.

Like-Kind Exchange Transaction

In June 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon Corporation, entered into transactions pursuant to which UII invested in coal-fired generating station leases (Headleases) with the Municipal Electric Authority of Georgia (MEAG). The generating stations were leased back to MEAG as part of the transactions (Leases).

Pursuant to the applicable authoritative guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and record an impairment charge if the review indicates an other-than-temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments based on the income approach, which uses a discounted cash flow analysis, taking into consideration significant unobservable inputs (Level 3) including the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash flows associated with the service contract option discussed above given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

All the Headleases were terminated by the second quarter of 2016, and no events occurred prior to the termination that required Exelon to review the estimated residual values of the direct financing lease investments in 2016. On March 31, 2016, UII and MEAG finalized an agreement to terminate the MEAG Headleases, the MEAG Leases, and other related agreements prior to their expiration dates. As a result of the lease termination, UII received an early termination payment of $360 million from MEAG and wrote-off the $356 million net investment in the MEAG Headleases and the Leases. The transaction resulted in a pre-tax gain of $4 million which is reflected in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income. See Note 14 — Income Taxes for additional information.

8. Early Nuclear Plant Retirements

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation's nuclear plants. Factors that will continue to affect the economic value of Generation's nuclear plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure nuclear plants are fairly compensated for their carbon-free emissions, and the impact of final rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules. The precise timing of an early retirement date for any nuclear plant, and the resulting financial statement impacts, may be affected by a number of factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and decommissioning trust fund requirements, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity or other obligations, where applicable, and just prior to its next scheduled nuclear refueling outage.

In 2015 and 2016, Generation identified the Quad Cities, Clinton, Ginna, Nine Mile Point and Three Mile Island (TMI) nuclear plants as having the greatest risk of early retirement based on economic valuation and other factors. In 2017, PSEG has made public similar financial challenges facing its New Jersey nuclear plants including Salem, of which Generation owns a 42.59% ownership interest.

In Illinois, the Clinton and Quad Cities nuclear plants continued to face significant economic challenges and risk of retirement before the end of each unit's respective operating license period (2026 for Clinton and 2032 for Quad Cities). In April 2016, Clinton cleared the MISO primary reliability auction as a price taker for the 2016-2017 planning year. The resulting capacity price was insufficient to cover cash operating costs and a risk-adjusted rate of return to shareholders. In May 2016, Quad Cities did not clear in the PJM capacity auction for the 2019-2020 planning year. Based on these capacity auction results, and given the lack of progress on Illinois energy legislation and MISO market reforms, on June 2, 2016 Generation announced it would shut down the Clinton and Quad Cities nuclear plants on June 1, 2017 and June 1, 2018, respectively.

On December 7, 2016, Illinois FEJA was signed into law by the Governor of Illinois and included a ZES that provides compensation through the procurement of ZECs targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet specific eligibility criteria, much like the solution implemented with the New York CES. The Illinois ZES will have a 10-year duration extending from June 1, 2017 through May 31, 2027. See Note 3 - Regulatory Matters for additional discussion on the Illinois FEJA and the ZES. With the passage of the Illinois ZES, and subject to prevailing over any related potential administrative or legal challenges, in December 2016 Generation reversed its June 2016 decision to permanently cease generation operations at the Clinton and Quad Cities nuclear generating plants.

In New York, the Ginna and Nine Mile Point nuclear plants continue to face significant economic challenges and risk of retirement before the end of each unit's respective operating license period (2029 for Ginna and Nine Mile Point Unit 1, and 2046 for Nine Mile Point Unit 2). On August 1, 2016, the NYPSC issued an order adopting the CES, which would provide payments to Ginna and Nine Mile Point for the environmental attributes of their production. On November 18, 2016, Ginna and Nine Mile Point executed the necessary contracts with NYSERDA, as required under the CES. Subject to prevailing over any administrative or legal challenges, the New York CES will allow Ginna and Nine Mile Point to continue to operate at least through the life of the program (March 31, 2029). The assumed useful life for depreciation purposes is through the end of their current operating licenses. The approved RSSA required Ginna to operate through the RSSA term expiring on March 31, 2017 and required notification to the NYPSC if Ginna did not plan to retire shortly after the expiration of the RSSA. On September 30, 2016, Ginna filed the required notice with the NYPSC of its intent to continue operating beyond the expiry of the RSSA. Refer to Note 3 - Regulatory Matters for additional discussion on the Ginna RSSA and the New York CES.

Assuming the successful implementation of the Illinois ZES and the New York CES and the continued effectiveness of these programs, Generation and CENG, through its ownership of Ginna and Nine Mile Point, no longer consider Clinton, Quad Cities, Ginna or Nine Mile Point to be at heightened risk for early retirement. However, to the extent either the Illinois ZES or the New York CES programs do not operate as expected over their full terms, each of these plants could again be at heightened risk for early retirement, which could have a material impact on Exelon's and Generation's future results of operations, cash flows and financial positions.

In Pennsylvania, the TMI nuclear plant did not clear in the May 2017 PJM capacity auction for the 2020-2021 planning year, 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 and is licensed to operate through 2034. On May 30, 2017, based on these capacity auction results, prolonged periods of low wholesale power prices, and the absence of federal or state policies that place a value on nuclear energy for its ability to produce electricity without air pollution, Exelon announced that Generation will permanently cease generation operations at TMI on or about September 30, 2019. Generation has filed the required market and regulatory notifications to shut down the plant. PJM has subsequently notified Generation that it has not identified any reliability issues and has approved the deactivation of TMI as proposed.

As a result of these plant retirement decisions, Exelon and Generation recognized one-time charges in Operating and maintenance expense related to materials and supplies inventory reserve adjustments, employee-related costs and CWIP impairments, among other items. In addition to these one-time charges, annual incremental non-cash charges to earnings stemming from shortening the expected economic useful lives 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 were also recorded. See Note 15 — Asset Retirement Obligations for additional detail on changes to the nuclear decommissioning ARO balances. The total annual impact of these charges by year are summarized in the table below.

Income statement expense (pre-tax)	**2017[(a)]**	**2016[(b)]**
Depreciation and Amortization		
Accelerated depreciation[(c)]	$250	$712
Accelerated nuclear fuel amortization	12	60
Operating and Maintenance		
One-time charges[(d,e)]	77	26
Change in ARO accretion, net of any contractual offset[(f)]	—	2
Contractual offset for ARC depreciation[(f)]	—	(86)
Total	$339	$714

(a) Reflects incremental charges for TMI including incremental accelerated depreciation and amortization from May 30, 2017 through December 31, 2017.

(b) Reflects incremental charges for Clinton and Quad Cities including incremental accelerated depreciation and amortization from June 2, 2016 through December 6, 2016. In December 2016, as a result of reversing its retirement decision for Clinton and Quad Cities, Exelon and Generation updated the expected economic useful life for both facilities, to 2027 for Clinton, commensurate with the end of the Illinois ZES, and to 2032 for Quad Cities, the end of its current operating license. Depreciation was therefore adjusted beginning December 7, 2016, to reflect these extended useful life estimates.

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

(d) Primarily includes materials and supplies inventory reserve adjustments, employee related costs and CWIP impairments.

(e) In June 2016, as a result of the retirement decision for Clinton and Quad Cities, Exelon and Generation recognized one-time charges of $146 million. In December 2016, as a result of reversing its retirement decision for Clinton and Quad Cities, Exelon and Generation reversed approximately $120 million of these one-time charges initially recorded in June 2016.

(f) For Quad Cities based on the regulatory agreement with the Illinois Commerce Commission, decommissioning-related activities are offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset results in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability.

Although Salem is committed to operate through May 2021, the plant faces continued economic challenges and PSEG, as the operator of the plant, is exploring all options. The following table provides the balance sheet amounts as of December 31, 2017 for Generation's ownership share of the significant assets and liabilities associated with Salem.

(in millions)	**12/31/2017**
Asset Balances	
Materials and supplies inventory	$ 44
Nuclear fuel inventory, net	113
Completed plant, net	439
Construction work in progress	33
Liability Balances	
Asset retirement obligation	(442)
NRC License Renewal Term	2036 (unit 1)
	2040 (unit 2)

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 for additional information regarding the early retirement of Oyster Creek.

9. Jointly Owned Electric Utility Plant

Exelon's, Generation's, PECO's, BGE's, PHI's and ACE's undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2017 and 2016 were as follows:

	Nuclear Generation				Fossil-Fuel Generation	Transmission		Other
	Quad Cities	Peach Bottom	Salem[(a)]	Nine Mile Point Unit 2	Wyman	PA[(b)]	NJ/DE[(c)]	Other[(d)]
Operator	Generation	Generation	PSEG Nuclear	Generation	FP&L	First Energy	PSEG/DPL	various
Ownership interest	75.00%	50.00%	42.59%	82.00%	5.89%	various	various	various
Exelon's share at December 31, 2017:								
Plant[(e)]	$1,074	$1,417	$631	$839	$ 3	$27	$102	$15
Accumulated depreciation[(e)]	550	461	205	97	3	15	52	13
Construction work in progress	35	18	33	55	—	—	—	—
Exelon's share at December 31, 2016:								
Plant[(e)]	$1,054	$1,384	$596	$830	$ 3	$27	$ 97	$15
Accumulated depreciation[(e)]	515	407	186	68	3	15	52	13
Construction work in progress	—	16	41	37	—	—	—	—

(a) Generation also owns a proportionate share in the fossil-fuel combustion turbine at Salem, which is fully depreciated. The gross book value was $3 million at December 31, 2017 and 2016.

(b) PECO, BGE, Pepco, DPL and ACE own a 22%, 7%, 27%, 9% and 8% share, respectively, in 127 miles of 500kV lines located in Pennsylvania as well as a 20.72%, 10.56%, 9.72%, 3.72% and 3.83% share, respectively, of a 500kV substation immediately outside of the Conemaugh fossil-generating station which supplies power to the 500k Vlines including, but not limited to, the lines noted above.

(c) PECO, DPL and ACE own a 42.55%, 1% and 13.9% share, respectively in 151.3 miles of 500kV lines located in New Jersey and Delaware Station. PECO, DPL and ACE also own a 42.55%, 7.45% and 7.45% share, respectively, in 2.5 miles of 500kV line located over the Delaware River. ACE also has a 21.78% share in a 500kV New Freedom Switching

(d) Generation, DPL and ACE own a 44.24%, 4.83% and 11.91% share, respectively in assets located at Merrill Creek Reservoir located in New Jersey. Pepco, DPL and ACE own a 11.9%, 7.4% and 6.6% share, respectively, in Valley Forge Corporate Center.

(e) Excludes asset retirement costs.

Exelon's, Generation's, PECO's, BGE's, Pepco's, DPL's and ACE's undivided ownership interests are financed with their funds and all operations are accounted for as if such participating interests were wholly owned facilities. Exelon's, Generation's, PECO's, BGE's, Pepco's, DPL's and ACE's share of direct expenses of the jointly owned plants are included in Purchased power and fuel and Operating and maintenance expenses on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and in Operating and maintenance expenses on PECO's, BGE's, Pepco, DPL's and ACE's Consolidated Statements of Operations and Comprehensive Income.

10. Intangible Assets

Goodwill

Exelon's gross amount of goodwill, accumulated impairment losses and carrying amount of goodwill for the years ended December 31, 2017 and 2016 were as follows:

	Balance at January 1, 2016	Goodwill from business combination	Impairment losses	Measurement period adjustments[(a)]	Balance at December 31, 2016	Impairment losses	Balance at December 31, 2017
Gross amount	$4,655	$4,016	$—	$(11)	$8,660	$—	$8,660
Accumulated impairment loss	1,983	—	—	—	1,983	—	1,983
Carrying amount	2,672	4,016	—	(11)	6,677	—	6,677

(a) Represents various measurement period adjustments to the valuation of the fair value of the PHI assets acquired and liabilities assumed as a result of the merger.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the Exelon, Generation, ComEd, PHI and DPL reporting unit below its carrying amount. Under the authoritative guidance for goodwill, a reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is tested for impairment. A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available and its operating results are regularly reviewed by segment management. Generation's operating segments are Mid-Atlantic, Midwest, New England, New York, ERCOT and all other power regions referred to collectively as "Other Power Regions", PHI's operating segments are Pepco, DPL and ACE, and ComEd and DPL have a single operating segment. See Note 25 — Segment Information for additional information. There is no level below these operating segments for which operating results are regularly reviewed by segment management. Therefore, the ComEd, Pepco, DPL and ACE operating segments are also considered reporting units for goodwill impairment testing purposes. Exelon's and ComEd's $2.6 billion of goodwill has been assigned entirely to the ComEd reporting unit, while Exelon's and PHI's $4 billion of goodwill has been assigned to the Pepco, DPL and ACE reporting units in the amounts of $1.7 billion, $1.1 billion and $1.2 billion, respectively. DPL's $8 million of goodwill is assigned entirely to the DPL reporting unit.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment, entities should assess, among other things, macroeconomic conditions, industry and market considerations, overall financial performance, cost factors and entity-specific 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, Generation's, ComEd's, PHI's and DPL's accounting policy is to perform a quantitative test of goodwill at least once every three years. The first step in the quantitative test compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation accounting guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

Application of the goodwill impairment test requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for Generation's, 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.

2017 and 2016 Goodwill Impairment Assessment. Generation performed a quantitative test as of November 1, 2017, for its 2017 annual goodwill impairment assessment. The first step of the test comparing the estimated fair value of Generation's reporting unit with goodwill to its carrying value, including goodwill, indicated no impairments of goodwill; therefore, the second step was not required. Generation performed a qualitative test as of November 1, 2016, for its 2016 annual goodwill impairment assessment. Based on the qualitative factors assessed, Generation concluded that the fair value of its reporting units is more likely than not greater than the carrying amount, and no further testing was required.

As of November 1, 2017, ComEd, PHI and DPL each qualitatively determined that it was more likely than not that the fair value of its reporting units exceeded their carrying values and, therefore, did not perform a quantitative assessment. 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 company EBITDA multiples, while also considering, the passing margin from their last quantitative assessments.

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 ComEd's, PHI's or DPL's goodwill, which could be material. Based on the results of the annual goodwill test 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 ComEd and PHI to fail the first step of their respective impairment tests. The $8 million of goodwill recorded at DPL is related to DPL's 1995 acquisition of the Conowingo Power Company and 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.

Other Intangible Assets and Liabilities

Exelon's other intangible assets and liabilities, included in Unamortized energy contract assets and liabilities and Other deferred debits and other assets in their Consolidated Balance Sheets, consisted of the following as of December 31, 2017 and 2016:

	December 31, 2017			December 31, 2016		
	Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net
Software License[a]	$ 95	$ (25)	$ 70	$ 95	$ (15)	$ 80
Unamortized Energy Contracts[b]	1,938	(1,574)	364	1,926	(1,543)	383
Customer Relationships	305	(133)	172	299	(109)	190
Trade Name	243	(148)	95	243	(125)	118
Service Contract Backlog	—	—	—	9	(7)	2
Chicago Settlement Agreements[c]	162	(141)	21	162	(133)	29
Unamortized Energy Contracts[b]	(1,515)	766	(749)	(1,515)	430	(1,085)
DC Sponsorship Agreement[d]	—	—	—	25	—	25
Total	$ 1,228	$ (1,255)	$ (27)	$ 1,244	$(1,502)	$ (258)

(a) On May 31, 2015, Exelon entered into a long-term software license agreement. Exelon is required to make payments starting August 2015 through May 2024. The intangible asset recognized as a result of these payments is being amortized on a straight-line basis over the contract term.

(b) Includes unamortized energy contract assets and liabilities on Exelon's, Generations and PHI's Consolidated Balance Sheets.

(c) In March 1999 and February 2003, ComEd entered into separate agreements with the City of Chicago and Midwest Generation, LLC. Under the terms of the settlement, ComEd agreed to make payments to the City of Chicago. The intangible asset recognized as a result of the settlement agreement is being amortized ratably over the remaining term of the City of Chicago franchise agreement.

(d) PHI entered into a sponsorship agreement with the District of Columbia for future sponsorship rights associated with public property within the District of Columbia. In December 2017, the asset was written off. See Note 7 - Impairment of Long-Lived Assets and Intangibles for additional information.

The following table summarizes the estimated future amortization expense related to intangible assets and liabilities as of December 31, 2017:

For the Years Ending December 31,	Exelon	Generation	ComEd	PHI
2018	$10	$62	$ 7	$(189)
2019	10	57	7	(119)
2020	10	68	7	(115)
2021	10	77	—	(92)
2022	10	54	—	(89)

The following table summarizes the amortization expense related to intangible assets and liabilities for each of the years ended December 31, 2017, 2016 and 2015:

For the Years Ended December 31,	
2017[a]	$92
2016[a]	87
2015[a]	76

(a) At Exelon, amortization of unamortized energy contracts totaling $35 million, $35 million and $22 million for the years ended December 31, 2017, 2016 and 2015, respectively, was recorded in Operating revenues or Purchased power and fuel expense within Exelon's Consolidated Statements of Operations and Comprehensive Income.

Acquired Intangible Assets and Liabilities

Accounting guidance for business combinations requires the acquirer to separately recognize identifiable intangible assets in the application of purchase accounting.

Unamortized Energy Contracts. Unamortized energy contract assets and liabilities represent the remaining unamortized fair value of non-derivative energy contracts that Exelon and Generation have acquired. The valuation of unamortized energy contracts was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise, the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power and fuel prices and the discount rate. The Exelon Wind unamortized energy contracts are amortized on a straight-line basis over the period in which the associated contract revenues are recognized as a decrease in Operating revenues within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. In the case of Antelope Valley, Constellation, CENG, Integrys and ConEdison, the fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the acquisition dates through either Operating revenues or Purchased power and fuel expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. 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.

Customer Relationships. The customer relationship intangibles were determined based on a "multi-period excess method" of the income approach. Under this method, the intangible asset's fair value is determined to be the estimated future cash flows that will be earned on the current customer base, taking into account expected contract renewals based on customer attrition rates and costs to retain those customers. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the customer attrition rate and the discount rate. The accounting guidance requires that customer-based intangibles be amortized over the period expected to be benefited using the pattern of economic benefit. The amortization of the customer relationships recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Service Contract Backlog. The service contract backlog intangibles were determined based on a "multi-period excess method" of the income approach. Under this method, the intangible asset's fair value is determined to be the estimated future cash flows that will be earned on the contracts. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include estimated revenues and expenses to complete the contracts as well as the discount rate. The accounting guidance requires that customer-based intangibles be amortized over the period expected to be benefited using the pattern of economic benefit. The amortization of the service contract backlog is recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Trade Name. The Constellation trade name intangible was determined based on the relief from royalty method of income approach whereby fair value is determined to be the present value of the license fees avoided by owning the assets. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the hypothetical royalty rate and the discount rate. The Constellation trade name intangible is amortized on a straight-line basis over a period of 10 years. The amortization of the trade name is recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Renewable Energy Credits and Alternative Energy Credits

Exelon's, Generation's, ComEd's, PECO's, PHI's, DPL's and ACE's other intangible assets, included in Other current assets and Other deferred debits and other assets on the Consolidated Balance Sheets, include RECs (Exelon, Generation, ComEd, PHI, DPL and ACE) and AECs (Exelon and PECO). Purchased RECs are recorded at cost on the date they are purchased. The cost of RECs purchased on a stand-alone basis is based on the transaction price, while the cost of RECs acquired through PPAs represents the difference between the total contract price and the market price of energy at contract inception. Generally, revenue for RECs that are part of a bundled power sale is recognized when the power is produced and delivered to the customer, otherwise, the revenue is recognized upon physical transfer of the REC.

The following table summarizes the current and noncurrent Renewable and Alternative Energy Credits for the years ended December 31, 2017 and 2016:

	As of December 31,	
	2017	2016
Current AEC's	$ 1	$ 1
Noncurrent AEC's	—	—
Current REC's	321	330
Noncurrent REC's	27	29

11. Fair Value of Financial Assets and Liabilities

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of Exelon's short-term liabilities, long-term debt, SNF obligation, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of December 31, 2017 and 2016:

	December 31, 2017				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 929	$—	$ 929	$ —	$ 929
Long-term debt (including amounts due within one year)[a]	34,264	—	34,735	1,970	36,705
Long-term debt to financing trusts[b]	389	—	—	431	431
SNF obligation	1,147	—	936	—	936

	December 31, 2016				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 1,267	$ —	$ 1,267	$ —	$ 1,267
Long-term debt (including amounts due within one year)[a]	34,005	1,113	31,741	1,959	34,813
Long-term debt to financing trusts[b]	641	—	—	667	667
SNF obligation	1,024	—	732	—	732

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of dividends payable (included in Other current liabilities) (Level 1) and short-term borrowings (Level 2). The Registrants' carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments.

Long-Term Debt. The fair value amounts of Exelon's taxable debt securities (Level 2) and private placement taxable debt securities (Level 3) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the utility sector with similar credit ratings in both the primary and secondary market, across the Registrants' debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note. Due to low trading volume of private placement debt, qualitative factors such as market conditions, low volume of investors and investor demand, this debt is classified as Level 3. The fair value of Exelon's equity units (Level 1) are valued based on publicly traded securities issued by Exelon.

The fair value of Generation's and Pepco's non-government-backed fixed rate nonrecourse debt (Level 3) is based on market and quoted prices for its own and other nonrecourse debt with similar risk profiles. Given the low trading volume in the nonrecourse debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project (e.g., political and regulatory environment). The fair value of Generation's government-backed fixed rate project financing debt (Level 3) is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate financing debt resets on a monthly or quarterly basis and the carrying value approximates fair value (Level 2). When trading data is available on variable rate financing debt, the fair value is based on market and quoted prices for its own and other nonrecourse debt with similar risk profiles (Level 2). Generation, Pepco, DPL and ACE also have tax-exempt debt (Level 2). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (e.g., conduit issuer political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above. Variable rate tax-exempt debt (Level 2) resets on a regular basis and the carrying value approximates fair value.

SNF Obligation. The carrying amount of Generation's SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2030. The carrying amount also includes $114 million as of December 31, 2017 for the one-time fee obligation associated with closing of the FitzPatrick acquisition on March 31, 2017. The fair value was determined using a similar methodology, however the New York Power Authority's (NYPA) discount rate is used in place of Generation's given the contractual right to reimbursement from NYPA for the obligation; see Note 4 - Mergers, Acquisitions and Dispositions for additional information on Generation's acquisition of FitzPatrick.

Long-Term Debt to Financing Trusts. Exelon's long-term debt to financing trusts is valued based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities, qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to liquidate as of the reporting date.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Transfers in and out of levels are recognized as of the end of the reporting period when the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Additionally, there were no material transfers between Level 1 and Level 2 during the years ended December 31, 2017 and 2016 for Cash equivalents, Nuclear decommissioning trust fund investments, Pledged assets for Zion Station decommissioning, Rabbi trust investments, and Deferred compensation obligations. For derivative contracts, transfers into Level 2 from Level 3 generally occur when the contract tenor becomes more observable and due to changes in market liquidity or assumptions for certain commodity contracts.

In accordance with the applicable guidance on fair value measurement, certain investments that are measured at fair value using the NAV per share as a practical expedient are no longer classified within the fair value hierarchy and are included under "Not subject to leveling" in the table below.

The following tables present assets and liabilities measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2017 and 2016:

As of December 31, 2017	Level 1	Level 2	Level 3	Not subject to leveling	Total
Assets					
Cash equivalents[(a)]	$ 656	$ —	$ —	$ —	$ 656
NDT fund investments					
Cash equivalents[(b)]	135	85	—	—	220
Equities	4,163	915	—	2,176	7,254
Fixed income					
Corporate debt	—	1,614	251	—	1,865
U.S. Treasury and agencies	1,917	52	—	—	1,969
Foreign governments	—	82	—	—	82
State and municipal debt	—	263	—	—	263
Other[(c)]	—	47	—	510	557
Fixed income subtotal	1,917	2,058	251	510	4,736
Middle market lending	—	—	397	131	528
Private equity	—	—	—	222	222
Real estate	—	—	—	471	471
NDT fund investments subtotal[(d)]	6,215	3,058	648	3,510	13,431
Pledged assets for Zion Station decommissioning					
Cash equivalents	2	—	—	—	2
Equities	—	1	—	—	1
Middle market lending	—	—	12	24	36
Pledged assets for Zion Station decommissioning subtotal	2	1	12	24	39
Rabbi trust investments					
Cash equivalents	77	—	—	—	77
Mutual funds	58	—	—	—	58
Fixed income	—	12	—	—	12
Life insurance contracts	—	71	22	—	93
Rabbi trust investments subtotal	135	83	22	—	240
Commodity derivative assets					
Economic hedges	557	2,378	1,290	—	4,225
Proprietary trading	2	31	35	—	68
Effect of netting and allocation of collateral[(e)(f)]	(585	(1,769)	(635)	—	(2,989)
Commodity derivative assets subtotal	(26	640	690	—	1,304
Interest rate and foreign currency derivative assets					
Derivatives designated as hedging instruments	—	6	—	—	6
Economic hedges	—	10	—	—	10
Effect of netting and allocation of collateral	(2	(5)	—	—	(7)
Interest rate and foreign currency derivative assets subtotal	(2	11	—	—	9
Other investments	—	—	37	—	37
Total assets	6,980	3,793	1,409	3,534	15,716
Liabilities					
Commodity derivative liabilities					
Economic hedges	(713	(2,226)	(1,101)	—	(4,040)
Proprietary trading	(2	(42)	(9)	—	(53)
Effect of netting and allocation of collateral[(e)(f)]	651	2,089	716	—	3,456
Commodity derivative liabilities subtotal	(64	(179)	(394)	—	(637)
Interest rate and foreign currency derivative liabilities					
Derivatives designated as hedging instruments	—	(2)	—	—	(2)
Economic hedges	(1	(8)	—	—	(9)
Effect of netting and allocation of collateral	2	5	—	—	7
Interest rate and foreign currency derivative liabilities subtotal	1	(5)	—	—	(4)
Deferred compensation obligation	—	(145)	—	—	(145)
Total liabilities	(63	(329)	(394)	—	(786)
Total net assets	$6,917	$ 3,464	$ 1,015	$ 3,534	$14,930

As of December 31, 2016	Level 1	Level 2	Level 3	Not subject to leveling	Total
Assets					
Cash equivalents[a]	$ 373	$ —	$ —	$ —	$ 373
NDT fund investments					
Cash equivalents[b]	110	19	—	—	129
Equities	3,551	452	—	2,011	6,014
Fixed income					
Corporate debt	—	1,554	250	—	1,804
U.S. Treasury and agencies	1,291	29	—	—	1,320
Foreign governments	—	37	—	—	37
State and municipal debt	—	264	—	—	264
Other[c]	—	59	—	493	552
Fixed income subtotal	1,291	1,943	250	493	3,977
Middle market lending	—	—	427	71	498
Private equity	—	—	—	148	148
Real estate	—	—	—	326	326
NDT fund investments subtotal[d]	4,952	2,414	677	3,049	11,092
Pledged assets for Zion Station decommissioning					
Cash equivalents	11	—	—	—	11
Equities	—	2	—	—	2
Fixed Income - U.S. Treasury and agencies	16	1	—	—	17
Middle market lending	—	—	19	64	83
Pledged assets for Zion Station decommissioning subtotal	27	3	19	64	113
Rabbi trust investments					
Cash equivalents	74	—	—	—	74
Mutual funds	50	—	—	—	50
Fixed income	—	16	—	—	16
Life insurance contracts	—	64	20	—	84
Rabbi trust investments subtotal	124	80	20	—	224
Commodity derivative assets					
Economic hedges	1,358	2,505	1,229	—	5,092
Proprietary trading	3	50	23	—	76
Effect of netting and allocation of collateral[e][f]	(1,164)	(2,142)	(481)	—	(3,787)
Commodity derivative assets subtotal	197	413	771	—	1,381
Interest rate and foreign currency derivative assets					
Derivatives designated as hedging instruments	—	16	—	—	16
Economic hedges	—	28	—	—	28
Proprietary trading	3	2	—	—	5
Effect of netting and allocation of collateral	(2)	(19)	—	—	(21)
Interest rate and foreign currency derivative assets subtotal	1	27	—	—	28
Other investments	—	—	42	—	42
Total assets	5,674	2,937	1,529	3,113	13,253
Liabilities					
Commodity derivative liabilities					
Economic hedges	(1,267)	(2,378)	(1,052)	—	(4,697)
Proprietary trading	(3)	(50)	(26)	—	(79)
Effect of netting and allocation of collateral[e][f]	1,233	2,339	542	—	4,114
Commodity derivative liabilities subtotal	(37)	(89)	(536)	—	(662)
Interest rate and foreign currency derivative liabilities					
Derivatives designated as hedging instruments	—	(10)	—	—	(10)
Economic hedges	—	(21)	—	—	(21)
Proprietary trading	(4)	—	—	—	(4)
Effect of netting and allocation of collateral	4	19	—	—	23
Interest rate and foreign currency derivative liabilities subtotal	—	(12)	—	—	(12)
Deferred compensation obligation	—	(136)	—	—	(136)
Total liabilities	(37)	(237)	(536)	—	(810)
Total net assets	$ 5,637	$ 2,700	$ 993	$3,113	$12,443

[a] Generation excludes cash of $259 million and $252 million at December 31, 2017 and 2016 and restricted cash of $127 million and $157 million at December 31, 2017 and 2016. Exelon excludes cash of $389 million and $360 million at December 31, 2017 and 2016 and restricted cash of $145 million and $180 million at December 31, 2017 and 2016 and includes long-term restricted cash of $85 million and $25 million at December 31, 2017 and 2016, which is reported in Other deferred debits on the Consolidated Balance Sheets.

[b] Includes $77 million and $29 million of cash received from outstanding repurchase agreements at December 31, 2017 and 2016, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (d) below.

[c] Includes derivative instruments of less than $1 million and $(2) million, which have a total notional amount of $811 million and $933 million at December 31, 2017 and 2016, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.

[d] Excludes net liabilities of $82 million and $31 million at December 31, 2017 and 2016, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.

[e] Collateral posted/(received) from counterparties totaled $65 million, $320 million and $81 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2017. Collateral posted/(received) from counterparties totaled $71 million, $197 million and $61 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2016.

[f] Of the collateral posted/(received), $(117) million and $(158) million represents variation margin on the exchanges as of December 31, 2017 and 2016, respectively.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2017 and 2016:

	Generation					ComEd	*Successor* PHI		Exelon
For the year ended December 31, 2017	**NDT Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total Generation**	**Mark-to-Market Derivatives**	**Life Insurance Contracts**	**Eliminated in Consolidation**	**Total**
Balance as of January 1, 2017	$ 677	$19	$493	$ 42	$1,231	$(258)	$20	$—	$ 993
Total realized / unrealized gains (losses)									
Included in net income	3	—	(90)[(a)]	3	(84)	—	3	—	(81)
Included in noncurrent payables to affiliates	6	—	—	—	6	—	—	(6)	—
Included in payable for Zion Station decommissioning	—	(8)	—	—	(8)	—	—	—	(8)
Included in regulatory assets/liabilities	—	—	—	—	—	2[(b)]	—	6	8
Change in collateral	—	—	20	—	20	—	—	—	20
Purchases, sales, issuances and settlements									
Purchases	64	1	178	5	248	—	—	—	248
Sales	—	—	(16)	—	(16)	—	—	—	(16)
Issuances	—	—	—	—	—	—	(1)	—	(1)
Settlements	(102)	—	(8)[(c)]	—	(110)	—	—	—	(110)
Transfers into Level 3	—	—	(6)	—	(6)	—	—	—	(6)
Transfers out of Level 3	—	—	(50)	(11)	(61)	—	—	—	(61)
Other miscellaneous	—	—	31[(d)]	(2)	29	—	—	—	29
Balance as of December 31, 2017	$ 648	$12	$552	$ 37	$1,249	$(256)	$22	$—	$1,015
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of December 31, 2017	$ 1	$—	$254	$ 3	$ 258	$ —	$ 3	$—	$ 261

For the year ended December 31, 2016	Generation					ComEd	*Successor* PHI[f]		Exelon
	NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation	Total
Balance as of January 1, 2016	$ 670	$22	$1,051	$33	$1,776	$(247)	$ —	$ —	$1,529
Included due to merger	—	—	—	—	—	—	20	—	20
Total realized / unrealized gains (losses)									
Included in net income	7	—	(568)[a]	1	(560)	—	3	—	(557)
Included in noncurrent payables to affiliates	16	—	—	—	16	—	—	(16)	—
Included in regulatory assets/liabilities	—	—	—	—	—	(11)[b]	—	16	5
Change in collateral	—	—	(141)	—	(141)	—	—	—	(141)
Purchases, sales, issuances and settlements									
Purchases	143	2	342[e]	7	494	—	—	—	494
Sales	(1)	(5)	(9)	—	(15)	—	—	—	(15)
Issuances	—	—	—	—	—	—	(3)	—	(3)
Settlements	(144)	—	—	—	(144)	—	—	—	(144)
Transfers into Level 3	—	—	1	1	2	—	—	—	2
Transfers out of Level 3	(14)	—	(183)	—	(197)	—	—	—	(197)
Balance as of December 31, 2016	$ 677	$19	$ 493	$42	$1,231	$(258)	$20	$ —	$ 993
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of December 31, 2016	$ 5	$ —	$ 109	$ —	$ 114	$ —	$ 2	$ —	$ 116

(a) Includes a reduction for the reclassification of $352 million and $677 million of realized gains due to the settlement of derivative contracts for the years ended December 31, 2017 and 2016, respectively.

(b) Includes $18 million of decreases in fair value and an increase for 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. Includes $29 million of decreases in fair value and an increase for realized losses due to settlements of $18 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2016.

(c) Exelon includes the settlement value for any open contracts that were net settled prior to their scheduled maturity within this line item.

(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's consolidated financial statements.

(e) Includes $168 million of fair value from contracts acquired as a result of portfolio acquisitions.

(f) Successor period represents activity from March 24, 2016 to December 31, 2016. See tables below for PHI's predecessor periods, as well as activity for Pepco for the years ended December 31, 2017 and 2016.

PHI	Predecessor January 1, 2016 to March 23, 2016 Preferred Stock	Life Insurance Contracts
Beginning Balance	$ 18	$19
Total realized / unrealized (losses) gains		
Included in net income	(18)	1
Ending Balance	$ —	$20
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	$ —	$ 1

	Life Insurance Contracts	
	For the year ended December 31,	
Pepco	2017	2016
Balance as of January 1	$20	$19
Total realized / unrealized gains (losses)		
Included in net income	3	3
Purchases, sales, issuances and settlements		
Issuances	(1)	(3)
Balance as of December 31	$22	$19
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	$ 3	$ 3

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2017 and 2016:

	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net[(a)]
Total gains (losses) included in net income for the year ended December 31, 2017	$ 28	$(126)	$3	$6
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2017	290	(36)	3	4

	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]
Total gains (losses) included in net income for the year ended December 31, 2016	$(477)	$(91)	$10
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2016	154	(45)	7

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation, accrued interest on a convertible promissory note at Generation and the life insurance contracts held by PHI and Pepco.

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents. The Registrants' cash equivalents include investments with original maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

Preferred Stock Derivative. In connection with entering into the PHI Merger Agreement, PHI entered into a Subscription Agreement with Exelon dated April 29, 2014, pursuant to which PHI issued to Exelon shares of preferred stock. The preferred stock contained embedded features requiring separate accounting consideration to reflect the potential value to PHI that any issued and outstanding preferred stock could be called and redeemed at a nominal par value upon a termination of the merger agreement under certain circumstances due to the failure to obtain required regulatory approvals. The embedded call and redemption features on the shares of the preferred stock in the event of such a termination were separately accounted for as derivatives. These preferred stock derivatives were valued quarterly using quantitative and qualitative factors, including management's assessment of the likelihood of a Regulatory Termination and therefore, were categorized in Level 3 in the fair value hierarchy. As a result of the PHI Merger, the PHI preferred stock derivative was reduced to zero as of March 23, 2016. The write-off was charged to Other, net on the PHI Consolidated Statement of Operations and Comprehensive Income.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning. The trust fund investments have been established to satisfy Generation's and CENG's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds and mutual funds, which are included in Equities and Fixed Income. Generation's and CENG's NDT fund investments policies outline investment guidelines for the trusts and limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are generally obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds which are based on quoted prices in active markets are categorized in Level 1. Certain equity securities have been categorized as Level 2 because they are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The fair values of private placement fixed income securities, which are included in Corporate debt, are determined using a third-party valuation that contains significant unobservable inputs and are categorized in Level 3.

Equity and fixed income commingled funds and mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives such as holding short-term fixed income securities or tracking the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For commingled funds and mutual funds, which are not publicly quoted, the funds are valued using NAV as a practical expedient for fair value, which is primarily derived from the quoted prices in active markets on the underlying securities, and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly with 30 or less days of notice and without further restrictions.

Derivative instruments consisting primarily of futures and interest rate swaps to manage risk are recorded at fair value. Over the counter derivatives are valued daily based on quoted prices in active markets and trade in open markets, and have been categorized as Level 1. Derivative instruments other than over the counter derivatives are valued based on external price data of comparable securities and have been categorized as Level 2.

Middle market lending are investments in loans or managed funds which lend to private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models, and income models. Investments in loans are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Managed funds are valued using NAV or its equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

Private equity and real estate investments include those in limited partnerships that invest in operating companies and real estate holding companies that are not publicly traded on a stock exchange, such as, leveraged buyouts, growth capital, venture capital, distressed investments, investments in natural resources, and direct investments in pools of real estate properties. The fair value of private equity and real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date. Private equity and real estate valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows, market based comparable data, and independent appraisals from sources with professional qualifications. These valuation inputs are unobservable.

As of December 31, 2017, Generation has outstanding commitments to invest in fixed income, middle market lending, private equity and real estate investments of approximately $65 million, $363 million, $220 million and $118 million, respectively. These commitments will be funded by Generation's existing nuclear decommissioning trust funds.

Concentrations of Credit Risk. Generation evaluated its NDT portfolios for the existence of significant concentrations of credit risk as of December 31, 2017. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2017, there were no significant concentrations (generally defined as greater than 10 percent) of risk in Generation's NDT assets.

See Note 15 — Asset Retirement Obligations for further discussion on the NDT fund investments.

Rabbi Trust Investments. The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The Rabbi trusts' assets are included in investments in the Registrants' Consolidated Balance Sheets and consist primarily of money market funds, mutual funds, fixed income securities and life insurance policies. The mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Money market funds and mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices. The fair values of fixed income securities are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The life insurance policies are valued using the cash surrender value of the policies, net of loans against those policies, which is provided by a third-party. Certain life insurance policies, which consist primarily of mutual funds that are priced based on observable market data, have been categorized as Level 2 because the life insurance policies can be liquidated at the reporting date for the value of the underlying assets. Life insurance policies that are valued using unobservable inputs have been categorized as Level 3.

Mark-to-Market Derivatives. Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants' derivatives are predominantly at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 12 — Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations. The Registrants' deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants' deferred compensation obligations is based on the market value of the participants' notional investment accounts. The underlying notional investments are comprised primarily of equities, mutual funds, commingled funds and fixed income securities which are based on directly and indirectly observable market prices. Since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

The value of certain employment agreement obligations (which are included with the Deferred Compensation Obligation in the tables above) are based on a known and certain stream of payments to be made over time and are categorized as Level 2 within the fair value hierarchy.

Additional Information Regarding Level 3 Fair Value Measurements

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning. For middle market lending and certain corporate debt securities investments, the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on discounting the forecasted cash flows, market-based comparable data, credit and liquidity factors, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied for factors such as size, marketability, credit risk and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers' inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations.

Rabbi Trust Investments - Life insurance contracts. For life insurance policies categorized as Level 3, the fair value is determined based on the cash surrender value of the policy, which contains unobservable inputs and assumptions. Because Exelon relies on its third-party insurance provider to develop the inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Exelon. Exelon gains an understanding of the types of inputs and assumptions used in preparing the valuations and performs procedures to assess the reasonableness of the valuations.

Mark-to-Market Derivatives. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief 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. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and other attributes. Generation's Level 3 balance generally consists of forward sales and purchases of power and natural gas and certain transmission congestion contracts. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price varies generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $2.99 and $0.42 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 12 — Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.

The following tables present the significant inputs to the forward curve used to value these positions:

Type of trade	Fair Value at December 31, 2017	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives—Economic hedges (Exelon and Generation)(a)(b)	$ 445	Discounted Cash Flow	Forward power price	$ 3 - $ 124
			Forward gas price	$1.27 - $12.80
		Option Model	Volatility percentage	11% - 139%
Mark-to-market derivatives—Proprietary trading (Exelon and Generation)(a)(b)	$ 26	Discounted Cash Flow	Forward power price	$ 14 - $ 94
Mark-to-market derivatives (Exelon and ComEd)	$(256)	Discounted Cash Flow	Forward heat rate(c)	9x - 10x
			Marketability reserve	4% - 8%
			Renewable factor	88% - 120%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.

(b) The fair values do not include cash collateral posted on level three positions of $81 million as of December 31, 2017.

(c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.

Type of trade	Fair Value at December 31, 2016	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives—Economic hedges (Exelon and Generation)(a)(b)	$ 435	Discounted Cash Flow	Forward power price	$ 11 - $ 130
			Forward gas price	$1.72 - $9.20
		Option Model	Volatility percentage	8% - 173%
Mark-to-market derivatives—Proprietary trading (Exelon and Generation)(a)(b)	$ (3)	Discounted Cash Flow	Forward power price	$ 19 - $ 79
Mark-to-market derivatives (Exelon and ComEd)	$(258)	Discounted Cash Flow	Forward heat rate(c)	8x - 9x
			Marketability reserve	3% - 8%
			Renewable factor	89% - 121%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.

(b) The fair values do not include cash collateral posted on level three positions of $61 million as of December 31, 2016

(c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

12. Derivative Financial Instruments

The Registrants use derivative instruments to manage commodity price risk, interest rate risk and foreign exchange risk related to ongoing business operations.

Commodity Price Risk

To the extent the total amount of power Generation produces and purchases differs from the amount of power it has contracted to sell, Exelon and Generation are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. Each of the Registrants employ established policies and procedures to manage their risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and commodity products. The Registrants believe these instruments, which are either determined to be non-derivative or classified as economic hedges, mitigate exposure to fluctuations in commodity prices.

Derivative authoritative guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings immediately. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchases and normal sales (NPNS), cash flow hedges and fair value hedges. For Generation, all derivative economic hedges related to commodities are recorded at fair value through earnings for the consolidated company, referred to as economic hedges in the following tables. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities.

Fair value authoritative guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. Generation's use of cash collateral is generally unrestricted unless Generation is downgraded below investment grade (i.e., to BB+ or Ba1). In the table below, Generation's energy related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral including initial margin on exchange positions, is aggregated in the collateral and netting column. As of December 31, 2017 and 2016, $4 million and $8 million of cash collateral held, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, were associated with accrual positions, or had no positions to offset as of the balance sheet date. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

ComEd's use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade (i.e., to BB+ or Ba1).

Cash collateral held by BGE and PECO must be deposited in a non-affiliate major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

In the table below, DPL's economic hedges are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting column.

The following table provides a summary of the derivative fair value balances related to commodity contracts recorded by the Registrants as of December 31, 2017:

Description	Generation: Economic Hedges	Generation: Proprietary Trading	Generation: Collateral and Netting[(a)(e)]	Generation: Subtotal[(b)]	ComEd: Economic Hedges[(c)]	DPL: Economic Hedges[(d)]	DPL: Collateral and Netting[(a)]	DPL: Subtotal	*Successor* PHI: Subtotal	Exelon: Total Derivatives
Mark-to-market derivative assets (current assets)	$ 3,061	$ 56	$(2,144)	$ 973	$ —	$—	$—	$—	$ —	$ 973
Mark-to-market derivative assets (noncurrent assets)	1,164	12	(845)	331	—	—	—	—	—	331
Total mark-to-market derivative assets	4,225	68	(2,989)	1,304	—	—	—	—	—	1,304
Mark-to-market derivative liabilities (current liabilities)	(2,646)	(43)	2,480	(209)	(21)	(1)	1	—	—	(230)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,137)	(10)	975	(172)	(235)	—	—	—	—	(407)
Total mark-to-market derivative liabilities	(3,783)	(53)	3,455	(381)	(256)	(1)	1	—	—	(637)
Total mark-to-market derivative net assets (liabilities)	$ 442	$ 15	$ 466	$ 923	$(256)	$ (1)	$ 1	$—	$ —	$ 667

(a) Exelon, Generation, PHI and DPL net all available amounts allowed under the derivative authoritative guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases, Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $169 million and $53 million, respectively, and current and noncurrent liabilities are shown net of collateral of $167 million and $77 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $466 million at December 31, 2017.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

(d) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

(e) Of the collateral posted/(received), $(117) million represents variation margin on the exchanges.

The following table provides a summary of the derivative fair value balances related to commodity contracts recorded by the Registrants as of December 31, 2016:

	Generation				ComEd	DPL			*Successor* PHI	Exelon
Description	Economic Hedges	Proprietary Trading	Collateral and Netting[(a)(e)]	Subtotal[(b)]	Economic Hedges[(c)]	Economic Hedges[(d)]	Collateral and Netting[(a)]	Subtotal	Subtotal	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 3,623	$ 55	$(2,769)	$ 909	$ —	$ 2	$(2)	$—	$—	$ 909
Mark-to-market derivative assets (noncurrent assets)	1,467	21	(1,016)	472	—	—	—	—	—	472
Total mark-to-market derivative assets	5,090	76	(3,785)	1,381	—	2	(2)	—	—	1,381
Mark-to-market derivative liabilities (current liabilities)	(3,165)	(54)	2,964	(255)	(19)	—	—	—	—	(274)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,274)	(25)	1,150	(149)	(239)	—	—	—	—	(388)
Total mark-to-market derivative liabilities	(4,439)	(79)	4,114	(404)	(258)	—	—	—	—	(662)
Total mark-to-market derivative net assets (liabilities)	$ 651	$ (3)	$ 329	$ 977	$(258)	$ 2	$(2)	$—	$—	$ 719

(a) Exelon, Generation, PHI and DPL net all available amounts allowed under the derivative authoritative guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases, Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, and letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $100 million and $72 million, respectively, and current and noncurrent liabilities are shown net of collateral of $95 million and $62 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $329 million at December 31, 2016.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

(d) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

(e) Of the collateral posted/(received), $(158) million represents variation margin on the exchanges.

Economic Hedges (Commodity Price Risk)

Within Exelon, Generation has the most exposure to commodity price risk. As such, Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power and gas sales, fuel and power purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. To manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from expected sales of power and gas and purchases of power and fuel. The objectives for executing such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis. For the years ended December 31, 2017, 2016 and 2015, Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses) which are also located in the "Net fair value changes related to derivatives" on the Consolidated Statements of Cash Flows.

	For the Years Ended December 31,		
	2017	2016	2015
Income Statement Location	Gain (Loss)		
Operating revenues	$(126)	$(490)	$196
Purchased power and fuel	(43)	459	54
Total Exelon and Generation	$(169)	$ (31)	$250

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Generation hedges commodity price risk 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, respectively.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 3 — Regulatory Matters for additional information.

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3 — Regulatory Matters. Based on Pennsylvania legislation and the DSP Programs permitting PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO's commodity price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts. PECO has certain full requirements contracts that are considered derivatives and qualify for the NPNS scope exception under current derivative authoritative guidance.

PECO's natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches to achieve system supply reliability at the least cost. PECO's reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO's natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2016 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2016 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 20% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's results of operations and financial position as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. BGE's commodity price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the MBR mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. BGE's natural gas supply and asset management agreements qualify for the NPNS scope exception and result in physical delivery.

Pepco has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and DCPSC. The SOS rates charged recover Pepco's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for residential and commercial rate classes. Pepco's commodity price risk related to electric supply procurement is limited. Pepco locks in fixed prices for its SOS requirements through full requirements contracts. Certain of Pepco's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other Pepco full requirements contracts are not derivatives.

DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and the DPSC. The SOS rates charged recover DPL's wholesale power supply costs. In Delaware, DPL is also entitled to recover a Reasonable Allowance for Retail Margin (RARM). The RARM includes a fixed annual margin of approximately $2.75 million, plus an incremental cost component and a cash working capital allowance. In Maryland, DPL charges an administrative fee intended to allow it to recover its administrative costs. DPL locks in fixed prices for its SOS requirements through full requirements contracts. DPL's commodity price risk related to electric supply procurement is limited. Certain of DPL's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

DPL provides natural gas to its customers under an Annual GCR mechanism approved by the DPSC. Under this mechanism, DPL's Annual GCR Filing establishes a future GCR for firm bundled sales customers by using a forecast of demand and commodity costs. The actual costs are trued up against forecast on a monthly basis and any shortfall or excess is carried forward as a recovery balance in the next GCR filing. The demand portion of the GCR is based upon DPL's firm transportation and storage contracts. DPL has firm deliverability of swing and seasonal storage; a liquefied natural gas facility and firm transportation capacity to meet customer demand and provide a reserve margin. The commodity portion of the GCR includes a commission approved hedging program which is intended to reduce gas commodity price volatility while limiting the firm natural gas customers' exposure to adverse changes in the market price of natural gas. The hedge program requires that DPL hedge, on a non-discretionary basis, an amount equal to 50% of estimated purchase requirements for each month, including estimated monthly purchases for storage injections. The 50% hedge monthly target is achieved by hedging 1/12th of the 50% target each month beginning 12-months prior to the month in which the physical gas is to be purchased. Currently, DPL uses only exchange traded futures for its gas hedging program, which are considered derivatives, however, it retains the capability to employ other physical and financial hedges if needed. DPL has not elected hedge accounting for these derivative financial instruments. Because of the DPSC-approved fuel adjustment clause for DPL's derivatives, the change in fair value of the derivatives each period, in addition to all premiums paid and other transaction costs incurred as part of the Gas Hedging Program, are fully recoverable and are recorded by DPL as regulatory assets or liabilities. DPL's physical gas purchases are currently all daily, monthly or intra-month transactions. From time to time, DPL will enter into seasonal purchase or sale arrangements, however, there are none currently in the portfolio. Certain of DPL's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

ACE has contracts to procure BGS electric supply that are executed through a competitive procurement process approved by the NJBPU. The BGS rates charged recover ACE's wholesale power supply costs. ACE does not make any profit or incur any loss on the supply component of the BGS it supplies to customers. ACE's commodity price risk related to electric supply procurement is limited. ACE locks in fixed prices for its BGS requirements through full requirements contracts. Certain of ACE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other ACE full requirements contracts are not derivatives.

Proprietary Trading (Commodity Price Risk)

Generation also executes commodity derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those executed with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Gains and losses associated with proprietary trading are reported as Operating revenues in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. For the years ended December 31, 2017, 2016 and 2015, Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses) which are also included in the "Net fair value changes related to derivatives" on the Consolidated Statements of Cash Flows. The Utility Registrants do not execute derivatives for proprietary trading purposes.

	For the Years Ended December 31,		
	2017	2016	2015
Income Statement Location	Gain (Loss)		
Operating revenues	$6	$2	$(6)

Interest Rate and Foreign Exchange Risk

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants 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 to manage interest rate risk.

To manage foreign exchange rate exposure associated with international commodity purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are treated as economic hedges. Below is a summary of the interest rate and foreign exchange hedge balances as of December 31, 2017:

	Generation					Exelon Corporate	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading	Collateral and Netting[(a)]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$—	$10	$—	$(7)	$ 3	$—	$ 3
Mark-to-market derivative assets (noncurrent assets)	3	—	—	—	3	3	6
Total mark-to-market derivative assets	3	10	—	(7)	6	3	9
Mark-to-market derivative liabilities (current liabilities)	(2)	(7)	—	7	(2)	—	(2)
Mark-to-market derivative liabilities (noncurrent liabilities)	—	(2)	—	—	(2)	—	(2)
Total mark-to-market derivative liabilities	(2)	(9)	—	7	(4)	—	(4)
Total mark-to-market derivative net assets (liabilities)	$ 1	$ 1	$—	$—	$ 2	$ 3	$ 5

(a) Exelon and Generation net all available amounts allowed under the derivative authoritative guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases, Exelon and Generation may have other offsetting counterparty exposures subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral, which are not reflected in the table above.

The following table provides a summary of the interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2016:

	Generation					Exelon Corporate	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading[(a)]	Collateral and Netting[(b)]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$ —	$ 17	$ 4	$(13)	$ 8	$—	$ 8
Mark-to-market derivative assets (noncurrent assets)	—	11	1	(8)	4	16	20
Total mark-to-market derivative assets	—	28	5	(21)	12	16	28
Mark-to-market derivative liabilities (current liabilities)	(7)	(13)	(2)	14	(8)	—	(8)
Mark-to-market derivative liabilities (noncurrent liabilities)	(3)	(8)	(2)	9	(4)	—	(4)
Total mark-to-market derivative liabilities	(10)	(21)	(4)	23	(12)	—	(12)
Total mark-to-market derivative net assets (liabilities)	$(10)	$ 7	$ 1	$ 2	$ —	$16	$ 16

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Exelon and Generation net all available amounts allowed under the derivative authoritative guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases, Exelon and Generation may have other offsetting counterparty exposures subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral, which are not reflected in the table above.

Fair Value Hedges (Interest Rate Risk)

For derivative instruments that qualify and are designated as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in earnings immediately. Exelon and Generation include the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps as follows:

		Year Ended December 31,					
		2017	2016	2015	2017	2016	2015
	Income Statement Location	Gain (Loss) on Swaps			Gain (Loss) on Borrowings		
Generation	Interest expense[a]	$ —	$—	$(1)	$ —	$ —	$ —
Exelon	Interest expense	(13)	(9)	3	28	23	14

(a) For the year ended December 31, 2015, the loss on Generation swaps included $(1) million realized in earnings with an immaterial amount excluded from hedge effectiveness testing.

The table below provides the notional amounts of fixed-to-floating hedges outstanding held by Exelon at December 31, 2017 and 2016.

	For the Years Ended December 31,	
	2017	2016
Fixed-to-floating hedges	$800	$800

During the years ended December 31, 2017, 2016 and 2015, the impact on the results of operations due to ineffectiveness from fair value hedges were gains of $15 million, $14 million and $17 million, respectively.

Cash Flow Hedges (Interest Rate Risk)

For derivative instruments that qualify and are designated as cash flow hedges, the gain or loss on the effective portion of the derivative will be deferred in AOCI and reclassified into earnings when the underlying transaction occurs. To mitigate interest rate risk, Exelon and Generation enter into floating-to-fixed interest rate swaps to manage a portion of interest rate exposure associated with debt issuances. The table below provides the notional amounts of floating-to-fixed hedges outstanding held by Exelon and Generation at December 31, 2017 and 2016.

	For the Years Ended December 31,	
	2017	2016
Floating-to-fixed hedges	$636	$659

The tables below provide the activity of OCI related to cash flow hedges for the years ended December 31, 2017 and 2016, containing information about the changes in the fair value of cash flow hedges and the reclassification from AOCI into results of operations. The amounts reclassified from AOCI, when combined with the impacts of the hedged transactions, result in the ultimate recognition of net revenues or expenses at the contractual price.

		Total Cash Flow Hedge AOCI Activity, Net of Income Tax	
		Generation	Exelon
For the Year Ended December 31, 2017	Income Statement Location	Total Cash Flow Hedges	Total Cash Flow Hedges
AOCI derivative loss at December 31, 2016		$(19)	$(17)
Effective portion of changes in fair value		(1)	(1)
Reclassifications from AOCI to net income	Interest expense	4[a]	4[a]
AOCI derivative loss at December 31, 2017		$(16)	$(14)

For the Year Ended December 31, 2016	Income Statement Location	Total Cash Flow Hedge AOCI Activity, Net of Income Tax	
		Generation	Exelon
		Total Cash Flow Hedges	Total Cash Flow Hedges
AOCI derivative loss at December 31, 2015		$(21)	$(19)
Effective portion of changes in fair value		(6)	(6)
Reclassifications from AOCI to net income	Interest expense	8[(b)]	8[(b)]
AOCI derivative loss at December 31, 2016		$(19)	$(17)

(a) Amount is net of related income tax expense of $1 million for the year ended December 31, 2017.
(b) Amount is net of related income tax expense of $5 million for the year ended December 31, 2016.

During the years ended December 31, 2017, 2016 and 2015, the impact on the results of operations due to the ineffectiveness from cash flow hedges that continue to be designated in hedging relationships was immaterial. The estimated amount of existing gains and losses that are reported in AOCI at the reporting date that are expected to be reclassified into earnings within the next twelve months is immaterial.

Economic Hedges (Interest Rate and Foreign Exchange Risk)

Exelon and Generation executes these instruments to mitigate exposure to fluctuations in interest rates or foreign exchange but for which the fair value or cash flow hedge elections were not made. Generation also enters into interest rate derivative contracts and foreign exchange currency swaps ("treasury") to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars.

At December 31, 2017 and 2016, Generation had immaterial notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The following table provides notional amounts outstanding held by Exelon and Generation at December 31, 2017 and 2016 related to foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

	For the Years Ended December 31,	
	2017	2016
Foreign currency exchange rate swaps	$94	$85

For the years ended December 31, 2017, 2016 and 2015, Exelon recognized the following net pre-tax mark-to-market gains (losses) in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows.

	Income Statement Location	For the Years Ended December 31,		
		2017	2016	2016
		Gain (Loss)		
Exelon	Operating Revenues	$(6)	$(10)	$ 7
Exelon	Interest Expense	(3)	—	100
Total Exelon		$(9)	$(10)	$107

Proprietary Trading (Interest Rate and Foreign Exchange Risk)

Generation also executes derivative contracts for proprietary trading purposes to hedge risk associated with the interest rate and foreign exchange components of underlying commodity positions. Gains and losses associated with proprietary trading are reported as Operating revenues in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. For the years ended December 31, 2017, 2016 and 2015, Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses).

Income Statement Location	For the Years Ended December 31,		
	2017	2016	2015
	Gain (Loss)		
Operating revenues	$(1)	$(1)	$(2)

Credit Risk, Collateral and Contingent-Related Features

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties on executed derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For commodity derivatives, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 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. The figures in the tables below exclude credit risk exposure from individual retail counterparties, nuclear fuel procurement contracts and exposure through RTOs, ISOs, NYMEX, ICE, NASDAQ, NGX and Nodal commodity exchanges. 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 as of December 31, 2017, respectively.

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

Net Credit Exposure by Type of Counterparty	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 credit collateral does not include non-liquid collateral.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on daily, updated forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price on a given day, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of December 31, 2017, ComEd's net credit exposure to suppliers was approximately $1 million.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 — Regulatory Matters for additional information.

PECO's unsecured credit used by the suppliers represents PECO's net credit exposure. As of December 31, 2017, PECO had no net credit exposure to suppliers.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2017, PECO had no material credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 — Regulatory Matters for additional information.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. As of December 31, 2017, BGE had no net credit exposure to suppliers.

BGE's regulated gas business is exposed to market-price risk. At December 31, 2017, BGE had credit exposure of $4 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Pepco's, DPL's and ACE's power procurement contracts provide suppliers with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents Pepco's, DPL's and ACE's net credit exposure. As of December 31, 2017, Pepco's, DPL's and ACE's net credit exposures to suppliers were immaterial.

Pepco is permitted to recover its costs of procuring energy through the MDPSC-approved and DCPSC-approved procurement tariffs. DPL is permitted to recover its costs of procuring energy through the MDPSC-approved and DPSC-approved procurement tariffs. ACE is permitted to recover its costs of procuring energy through the NJBPU-approved procurement tariffs. Pepco's, DPL's and ACE's counterparty credit risks are mitigated by their ability to recover realized energy costs through customer rates. See Note 3 — Regulatory Matters for additional information.

DPL's natural gas procurement plan is reviewed and approved annually on a prospective basis by the DPSC. DPL's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the GCR, which allows DPL to adjust rates annually to reflect realized natural gas prices. To the extent that the fair value of the transactions in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. Exchange-traded contracts are required to be fully collateralized without regard to the credit rating of the holder. As of December 31, 2017, DPL's credit exposure under its natural gas supply and asset management agreements was immaterial.

Collateral

As part of the normal course of business, Generation routinely enters into physically or financially settled contracts for the purchase and sale of electric capacity, electricity, fuels, emissions allowances and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges. The exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

Credit-Risk Related Contingent Feature	For the Years Ended December 31, 2017	2016
Gross fair value of derivative contracts containing this feature[(a)]	$(926)	$(960)
Offsetting fair value of in-the-money contracts under master netting arrangements[(b)]	577	627
Net fair value of derivative contracts containing this feature[(c)]	$(349)	$(333)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features ignoring the effects of master netting agreements.

(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.

(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

Generation had cash collateral posted of $497 million and letters of credit posted of $293 million, and cash collateral held of $35 million and letters of credit held of $33 million as of December 31, 2017 for external counterparties with derivative positions. Generation had cash collateral posted of $347 million and letters of credit posted of $284 million and cash collateral held of $24 million and letters of credit held of $28 million at December 31, 2016 for external counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e., to BB+ by S&P or Ba1 by Moody's), Generation would have been required to post additional collateral of $1.8 billion and $1.9 billion as of December 31, 2017 and 2016, respectively. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if Generation's debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of December 31, 2017, Generation's and Exelon's swaps were in an asset position with a fair value of $2 million and $5 million, respectively.

See Note 25 — Segment Information for further information regarding the letters of credit supporting the cash collateral.

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of ComEd's standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of December 31, 2017, ComEd held approximately $10 million in collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's renewable energy certificate (REC) contracts, collateral postings are required to cover a percentage of the REC contract value. As of December 31, 2017, ComEd held approximately $2 million in collateral from suppliers for REC contract obligations. Under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of December 31, 2017, ComEd held approximately $19 million in collateral from suppliers for the long-term renewable energy contracts. If ComEd lost its investment grade credit rating as of December 31, 2017, it would have been required to post approximately $14 million of collateral to its counterparties. See Note 3 — Regulatory Matters for additional information.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2017, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of December 31, 2017, PECO could have been required to post approximately $34 million of collateral to its counterparties.

PECO's supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2017, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of December 31, 2017, BGE could have been required to post approximately $66 million of collateral to its counterparties.

DPL's natural gas procurement contracts contain provisions that could require DPL to post collateral. To the extent that the fair value of the natural gas derivative transaction in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. The DPL obligations are standalone, without the guaranty of PHI. If DPL lost its investment grade credit rating as of December 31, 2017, DPL could have been required to post an additional amount of approximately $11 million of collateral to its natural gas counterparties.

BGE's, Pepco's, DPL's and ACE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE, Pepco, DPL or ACE to post collateral.

13. Debt and Credit Agreements

Short-Term Borrowings

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool. 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.

Commercial Paper

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at December 31, 2017 and 2016:

	Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31,	
Commercial Paper Issuer	**2017[(a)(b)(c)]**	**2016[(a)(b)(c)]**	**2017**	**2016**	**2017**	**2016**
Exelon Corporate	$ 600	$ 600	$ —	$ —	1.16%	0.70%
Generation	5,300	5,300	—	620	1.23%	0.94%
ComEd	1,000	1,000	—	—	1.24%	0.77%
PECO	600	600	—	—	1.13%	N/A
BGE	600	600	77	45	1.28%	0.77%
Pepco	500	500	26	23	1.06%	0.71%
DPL	500	500	216	—	1.48%	0.68%
ACE	350	350	108	—	1.43%	0.65%
Total	$9,450	$9,450	$427	$688		

(a) Excludes $480 million and $500 million in bilateral credit facilities that do not back Generation's commercial paper program at December 31, 2017 and 2016, respectively.

(b) Excludes additional credit facility agreements for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE with aggregate commitments of $49 million, $34 million, $34 million, $5 million, $2 million, $2 million and $2 million, respectively, arranged with minority and community banks located primarily within utilities' service territories. These facilities expire on October 12, 2018. These facilities are solely utilized to issue letters of credit. As of December 31, 2017, letters of credit issued under these facilities totaled $5 million and $2 million for Generation and BGE, respectively.

(c) Pepco, DPL and ACE's revolving credit facility is subject to available borrowing capacity. The borrowing capacity may be increased or decreased during the term of the facility, except that (i) the sum of the borrowing capacity must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by each of Pepco, DPL or ACE may not exceed $900 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility.

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of outstanding commercial paper does not reduce available capacity under a Registrant's credit facility, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit facility.

At December 31, 2017, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit facilities:

					Available Capacity at December 31, 2017	
Borrower	**Facility Type**	**Aggregate Bank Commitment[(a)(b)]**	**Facility Draws**	**Outstanding Letters of Credit[(c)]**	**Actual**	**To Support Additional Commercial Paper[(b)(d)]**
Exelon Corporate	Syndicated Revolver	$ 600	$—	$ 45	$ 555	$ 555
Generation	Syndicated Revolver	5,300	—	868	4,432	4,432
Generation	Bilaterals	480	—	231	249	—
ComEd	Syndicated Revolver	1,000	—	2	998	998
PECO	Syndicated Revolver	600	—	1	599	599
BGE	Syndicated Revolver	600	—	—	600	523
Pepco	Syndicated Revolver	300	—	—	300	274
DPL	Syndicated Revolver	300	—	—	300	84
ACE	Syndicated Revolver	300	—	—	300	192
Total		$9,480	$—	$1,147	$ 8,333	$7,657

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE with aggregate commitments of $49 million, $34 million, $34 million, $5 million, $2 million, $2 million and $2 million, respectively, arranged with minority and community banks located primarily within utilities' service territories. These facilities expire on October 12, 2018. These facilities are solely utilized to issue letters of credit. As of December 31, 2017, letters of credit issued under these facilities totaled $5 million and $2 million for Generation and BGE, respectively.

(b) Pepco, DPL and ACE's revolving credit facility is subject to available borrowing capacity. The borrowing capacity may be increased or decreased during the term of the facility, except that (i) the sum of the borrowing capacity must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by each of Pepco, DPL or ACE may not exceed $900 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility.

(c) Excludes nonrecourse debt letters of credit, see discussion below on Antelope Valley Solar Ranch One and Continental Wind.

(d) Excludes $480 million in bilateral credit facilities that do not back Generation's commercial paper program.

The following tables present the short-term borrowings activity for Exelon during 2017, 2016 and 2015.

	2017	**2016**	**2015**
Average borrowings	$ 823	$ 1,125	$ 499
Maximum borrowings outstanding	2,147	3,076	739
Average interest rates, computed on a daily basis	1.32%	0.88%	0.53%
Average interest rates, at December 31	1.24%	1.12%	0.88%

Short-Term Loan Agreements

On July 30, 2015, PHI entered into a $300 million term loan agreement. The net proceeds of the loan were used to repay PHI's outstanding commercial paper and for general corporate purposes. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.95%, and all indebtedness thereunder is unsecured. On April 4, 2016, PHI repaid $300 million of its term loan in full.

On January 13, 2016, PHI entered into a $500 million term loan agreement, which was amended on March 28, 2016. The net proceeds of the loan were used to repay PHI's outstanding commercial paper, and for general corporate purposes. Pursuant to the loan agreement, as amended, loans made thereunder bear interest at a variable rate equal to LIBOR plus 1%, and all indebtedness thereunder is unsecured. On March 23, 2017, the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement was fully repaid and the loan terminated. On March 23, 2017, Exelon Corporate entered into a similar type term loan for $500 million which expires on March 22, 2018. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 1% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's Consolidated Balance Sheet within Short-Term borrowings.

On February 22, 2016, Generation and EDF entered into separate member revolving promissory notes with CENG to finance short-term working capital needs. The notes are scheduled to mature on January 31, 2017 and bear interest at a variable rate equal to LIBOR plus 1.75%. On July 25, 2016, CENG paid off the outstanding balances under each note.

Credit Agreement

On January 5, 2016, Generation entered into a credit agreement establishing a $150 million bilateral credit facility, scheduled to mature in January of 2019. This facility will solely be utilized by Generation to issue lines of credit. This facility does not back Generation's commercial paper program.

On April 1, 2016, the credit agreement for CENG's $100 million bilateral credit facility was amended to increase the overall facility size to $200 million. This facility is utilized by CENG to fund working capital and capital projects. The facility does not back Generation's commercial paper program.

On May 26, 2016, Exelon Corporate, Generation, ComEd, PECO and BGE entered into amendments to each of their respective syndicated revolving credit facilities, which extended the maturity of each of the facilities to May 26, 2021. Exelon Corporate also increased the size of its facility from $500 million to $600 million. On May 26, 2016, PHI, Pepco, DPL and ACE entered into an amendment to their Second Amended and Restated Credit Agreement dated as of August 1, 2011, which (i) extended the maturity date of the facility to May 26, 2021, (ii) removed PHI as a borrower under the facility, (iii) decreased the size of the facility from $1.5 billion to $900 million and (iv) aligned its financial covenant from debt to capitalization leverage ratio to interest coverage ratio. On May 26, 2017, each of the Registrants' respective syndicated revolving credit facilities had their maturity dates extended to May 26, 2022.

On January 9, 2017, the credit agreement for Generation's $75 million bilateral credit facility was amended and restated to increase the facility size to $100 million and extend the maturity to January 2019. This facility will solely be used by Generation to issue letters of credit.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's, BGE's, Pepco's, DPL's and ACE's revolving credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular Registrant's credit rating.

The adders for the prime based borrowings and LIBOR-based borrowings are presented in the following table:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Prime based borrowings	27.5	27.5	7.5	0.0	0.0	7.5	7.5	7.5
LIBOR-based borrowings	127.5	127.5	107.5	90.0	100.0	107.5	107.5	107.5

The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 90 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments. The fee varies depending upon the respective credit ratings of the borrower.

Each revolving credit agreement for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter.

The following table summarizes the minimum thresholds reflected in the credit agreements for the year ended December 31, 2017:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At December 31, 2017, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Interest coverage ratio	6.34	9.02	11.68	7.99	10.50	6.35	8.69	5.57

An event of default under Exelon, Generation, ComEd, PECO or BGE's indebtedness will not constitute an event of default under any of the others' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation will constitute an event of default under the Exelon Corporate credit facility. An event of default under Pepco, DPL or ACE's indebtedness will not constitute an event of default with respect to the other PHI Utilities under the PHI Utilities' combined credit facility.

The absence of a material adverse change in Exelon's or PHI's business, property, results of operations or financial condition is not a condition to the availability of credit under any of the borrowers' credit agreement. None of the credit agreements include any rating triggers.

Variable Rate Demand Bonds

DPL has outstanding obligations in respect of Variable Rate Demand Bonds (VRDB). VRDBs are subject to repayment on the demand of the holders and, for this reason, are accounted for as short-term debt in accordance with GAAP. However, bonds submitted for purchase are remarketed by a remarketing agent on a best efforts basis. PHI expects that any bonds submitted for purchase will be remarketed successfully due to the creditworthiness of the issuer and, as applicable, the credit support, and because the remarketing resets the interest rate to the then-current market rate. The bonds may be converted to a fixed-rate, fixed-term option to establish a maturity which corresponds to the date of final maturity of the bonds. On this basis, PHI views VRDBs as a source of long-term financing. As of December 31, 2017 and December 31, 2016, $79 million and $105 million, respectively, in variable rate demand bonds issued by DPL were outstanding and are included in the Long-term debt due within one year on Exelon's, PHI's and DPL's Consolidated Balance Sheet.

Long-Term Debt

The following table presents the outstanding long-term debt at Exelon as of December 31, 2017 and 2016:

			December 31,	
	Rates	Maturity Date	2017	2016
Long-term debt				
Rate stabilization bonds	5.82%	2017	$ —	$ 41
First mortgage bonds[a]	1.70% - 7.90%	2018 - 2047	15,197	14,123
Senior unsecured notes	2.45% - 7.60%	2019 - 2046	11,285	11,868
Unsecured notes	2.40% - 6.35%	2021 - 2047	2,600	2,300
Pollution control notes	2.50% - 2.70%	2025 - 2036	435	435
Nuclear fuel procurement contracts	3.15% - 3.35%	2018 - 2020	82	105
Notes payable and other[b][c]	2.61% - 8.88%	2018 - 2053	405	576
Junior subordinated notes	3.50%	2022	1,150	1,150
Contract payment - junior subordinated notes	2.50%	2017	—	19
Long-term software licensing agreement	3.95%	2024	79	103
Unsecured Tax-Exempt Bonds	5.40%	2031	112	112
Medium-Terms Notes (unsecured)	6.81% - 7.72%	2018 - 2027	26	40
Transition bonds	5.05% - 5.55%	2020 - 2023	90	124
Nonrecourse debt:				
Fixed rates	2.29% - 6.00%	2031 - 2037	1,331	1,400
Variable rates	3.18% - 4.00%	2019 - 2024	865	915
Total long-term debt			33,657	33,311
Unamortized debt discount and premium, net			(57)	(68)
Unamortized debt issuance costs			(201)	(200)
Fair value adjustment			865	962
Long-term debt due within one year			(2,088)	(2,430)
Long-term debt			$ 32,176	$ 31,575
Long-term debt to financing trusts[d]				
Subordinated debentures to ComEd Financing III	6.35%	2033	$ 206	$ 206
Subordinated debentures to PECO Trust III	7.38%	2028	81	81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Subordinated debentures to BGE Capital Trust II	6.20%	2043	—	258
Total long-term debt to financing trusts			390	648
Unamortized debt issuance costs			(1)	(7)
Long-term debt to financing trusts			$ 389	$ 641

(a) Substantially all of ComEd's assets other than expressly excepted property and substantially all of PECO's, Pepco's, DPL's and ACE's assets are subject to the liens of their respective mortgage indentures.

(b) Includes capital lease obligations of $53 million and $69 million at December 31, 2017 and 2016, respectively. Lease payments of $18 million, $20 million, $5 million, $1 million, $1 million and $8 million will be made in 2018, 2019, 2020, 2021, 2022 and thereafter, respectively.

(c) Includes financing related to Albany Green Energy, LLC (AGE). During the third quarter of 2017, Generation retired $228 million of its outstanding debt balance. As of December 31, 2016, $198 million was outstanding.

(d) Amounts owed to these financing trusts are recorded as Long-term debt to financing trusts within Exelon's Consolidated Balance Sheets.

Long-term debt maturities at Exelon in the periods 2018 through 2022 and thereafter are as follows:

Year	
2018	$ 2,075
2019	959
2020	3,564
2021	1,513
2022	3,084
Thereafter	22,852
Total	$34,047

(a) Includes $390 million due to ComEd and PECO financing trusts.

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 for further information on the issuance of common stock.

Nonrecourse Debt

Exelon and Generation have issued nonrecourse debt financing, in which approximately $3 billion of generating assets have been pledged as collateral at December 31, 2017. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon or Generation in the event of a default. If a specific project financing entity does not maintain compliance with its specific nonrecourse debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, the lenders or security holders would generally have rights to foreclose against the project-specific assets and related collateral. The potential requirement to satisfy its associated debt or other borrowings earlier than otherwise anticipated could lead to impairments due to a higher likelihood of disposing of the respective project-specific assets significantly before the end of their useful lives.

Denver Airport. In June 2011, Generation entered into a 20-year, $7 million solar loan agreement to finance a solar construction project in Denver, Colorado. The agreement is scheduled to mature on June 30, 2031. The agreement bears interest at a fixed rate of 5.50% annually with interest payable annually. As of December 31, 2017, $6 million was outstanding.

CEU Upstream. In July 2011, CEU Holdings, LLC, a wholly owned subsidiary of Generation, entered into a 5-year reserve based lending agreement (RBL) associated with certain Upstream oil and gas properties. The lenders do not have recourse against Exelon or Generation in the event of default pursuant to the RBL. Borrowings under this arrangement are secured by the assets and equity of CEU Holdings.

In December 2016, substantially all of the Upstream natural gas and oil exploration and production assets were sold for $37 million. The proceeds were used to reduce the debt balance by $31 million. The remaining proceeds of $6 million were being held in escrow. In addition, during 2016, $15 million of the debt was repaid using CEU Holding's cash, resulting in an outstanding debt balance of $22 million at December 31, 2016. During 2017, additional assets were sold for $1 million and the remaining $6 million in escrow was released and applied to the debt balance resulting in an outstanding amount of $15 million at December 31, 2017. Upon final resolution, CEU Holdings will be released of its obligations regardless of the amount of asset sale proceeds received. The ultimate resolution of this matter has no direct effect on any Exelon or Generation credit facilities or other debt of an Exelon entity. At December 31, 2017, the outstanding debt balance of $15 million was classified within Long term debt due within one year on Exelon's and Generation's Consolidated Balance Sheets. See Note 4 — Mergers, Acquisitions and Dispositions and Note 7 — Impairment of Long-Lived Assets and Intangibles for additional information.

Holyoke Solar Cooperative. In October 2011, Generation entered into a 20-year, $11 million solar loan agreement related to a solar construction project in Holyoke, Massachusetts. The agreement is scheduled to mature on December 2031. The agreement bears interest at a fixed rate of 5.25% annually with interest payable monthly. As of December 31, 2017, $9 million was outstanding.

Antelope Valley Solar Ranch One. In December 2011, the DOE Loan Programs Office issued a guarantee for up to $646 million for a nonrecourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project became fully operational in the first half of 2014. The loan will mature on January 5, 2037. Interest rates on the loan were fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity. The advances were completed as of December 31, 2015 and the outstanding loan balance will bear interest at an average blended interest rate of 2.82%. As of December 31, 2017, $530 million was outstanding. In addition, Generation has issued letters of credit to support its equity investment in the project. As of December 31, 2017, Generation had $105 million in letters of credit outstanding related to the project.

Continental Wind. In September 2013, Continental Wind, LLC (Continental Wind), an indirect subsidiary of Exelon and Generation, completed the issuance and sale of $613 million senior secured notes. Continental Wind owns and operates a portfolio of wind farms in Idaho, Kansas, Michigan, Oregon, New Mexico and Texas with a total net capacity of 667MW. The net proceeds were distributed to Generation for its general business purposes. The notes are scheduled to mature on February 28, 2033. The notes bear interest at a fixed rate of 6.00% with interest payable semi-annually. As of December 31, 2017, $512 million was outstanding.

In addition, Continental Wind entered into a $131 million letter of credit facility and $10 million working capital revolver facility. Continental Wind has issued letters of credit to satisfy certain of its credit support and security obligations. As of December 31, 2017, the Continental Wind letter of credit facility had $114 million in letters of credit outstanding related to the project.

ExGen Texas Power. In September 2014, EGTP, an indirect subsidiary of Exelon and Generation, issued $675 million aggregate principal amount of a nonrecourse senior secured term loan. The net proceeds were distributed to Generation for general business purposes. The loan was scheduled to mature on September 18, 2021. In addition to the financing, EGTP entered into various interest rate swaps with an initial notional amount of approximately $505 million at an interest rate of 2.34% to hedge a portion of the interest rate exposure in connection with this financing, as required by the debt covenants.

On May 2, 2017, as a result of the negative impacts of certain market conditions and the seasonality of its cash flows, EGTP entered into a consent agreement with its lenders, which permitted EGTP to draw on its revolving credit facility and initiate an orderly sales process of its assets. On November 7, 2017, the debtors 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 the nonrecourse senior secured term loan, the revolving credit facility, and the interest rate swaps from their consolidated financial statements as of December 31, 2017. Due to their nonrecourse nature, these borrowings are secured solely by the assets of EGTP and its subsidiaries.

Renewable Power Generation. In March 2016, RPG, an indirect subsidiary of Exelon and Generation, issued $150 million aggregate principal amount of a nonrecourse senior secured notes. The net proceeds were distributed to Generation for paydown of long term debt obligations at Sacramento PV Energy and Constellation Solar Horizons and for general business purposes. The loan is scheduled to mature on March 31, 2035. The term loan bears interest at a fixed rate of 4.11% payable semi-annually. As of December 31, 2017, $127 million was outstanding.

SolGen. In September 2016, SolGen, LLC (SolGen), an indirect subsidiary of Exelon and Generation, issued $150 million aggregate principal amount of a nonrecourse senior secured notes. The net proceeds were distributed to Generation for general business purposes. The loan is scheduled to mature on September 30, 2036. The term loan bears interest at a fixed rate of 3.93% payable semi-annually. As of December 31, 2017, $147 million was outstanding.

ExGen Renewables IV. In November 2017, EGR IV, an indirect subsidiary of Exelon and Generation, entered into an $850 million nonrecourse senior secured term loan credit facility agreement. The net proceeds of $785 million, after the initial funding of $50 million for debt service and liquidity reserves as well as deductions for original discount and estimated costs, fees and expenses incurred in connection with the execution and delivery of the credit facility agreement, were distributed to Generation for general corporate purposes. The $50 million of debt service and liquidity reserves was treated as restricted cash on Exelon's and Generation's Consolidated Balance Sheets and Consolidated Statements of Cash Flows. The loan is scheduled to mature on November 28, 2024. The term loan bears interest at a variable rate equal to LIBOR + 3%, subject to a 1% LIBOR floor with interest payable quarterly. As of December 31, 2017, $850 million was outstanding. In addition to the financing, EGR IV entered into interest rate swaps with an initial notional amount of $636 million at an interest rate of 2.32% to manage a portion of the interest rate exposure in connection with the financing.

14. Income Taxes

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.

Pursuant to the enactment of the TCJA, the Registrants remeasured their existing deferred income tax balances as of December 31, 2017 to reflect the decrease in the corporate income tax rate from 35% to 21%, which resulted in a material decrease to their net deferred income tax liability balances as shown in the table below. Generation recorded a corresponding net decrease to income tax expense, while the Utility Registrants recorded corresponding regulatory liabilities or assets to the extent such amounts are probable of settlement or recovery through customer rates and an adjustment to income tax expense for all other amounts. The amount and timing of potential settlements of the established net regulatory liabilities will be determined by the Utility Registrants' respective rate regulators, subject to certain IRS "normalization" rules. See Note 3 — Regulatory Matters for further information.

The Registrants have completed their assessment of the majority of the applicable provisions in the TCJA and have recorded the associated impacts as of December 31, 2017. As discussed further below, under SAB 118 issued by the SEC in December 2017, 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 for which reasonable estimates could be determined.

For property acquired and placed-in-service after September 27, 2017, the TCJA repeals 50% bonus depreciation for all taxpayers and in addition provides for 100% expensing for taxpayers other than regulated utilities. As a result, Generation will be required to evaluate the contractual terms of its fourth quarter 2017 capital additions and determine if they qualify for 100% expensing under the TCJA as compared to 50% bonus depreciation under prior tax law. Similarly, the Utility Registrants will be required to evaluate the contractual terms of their fourth quarter 2017 capital additions to determine whether they still qualify for the prior tax law's 50% bonus depreciation as compared to no bonus depreciation pursuant to the TCJA. As of December 31, 2017, the Registrants have not completed this analysis but were able to record a reasonable estimate of the effects of these changes based on capital costs incurred at each of the Registrants prior to and after the beginning of the fourth quarter of 2017.

At Generation, any required changes to the provisional estimates during the measurement period related to the above item would result in an adjustment to current income tax expense at 35% and a corresponding adjustment to deferred income tax expense at 21% and such changes could be material to Generation's future results of operations. At the Utility Registrants, any required changes to the provisional estimates would result in the recording of regulatory assets or liabilities to the extent such amounts are probable of settlement or recovery through customer rates and a net change to income tax expense for any other amounts.

The Registrants expect any final adjustments to the provisional amounts to be recorded by the third quarter of 2018, which could be material to the Registrants' future results of operations or financial positions. The accounting for all other applicable provisions of the TCJA is considered complete based on our current interpretation of the provisions of the TCJA as enacted as of December 31, 2017.

While the Registrants have recorded the impacts of the TCJA based on their interpretation of the provisions as enacted, it is expected that technical corrections or other forms of guidance will be issued during 2018, which could result in material changes to previously finalized provisions. At this time, most states have not provided guidance regarding TCJA impacts and may issue guidance in 2018 which may impact estimates.

The one-time impacts recorded by the Registrants to remeasure their deferred income tax balances at the 21% corporate federal income tax rate as of December 31, 2017 are presented below:

						Successor			
	Exelon[(b)]	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net Decrease to Deferred Income Tax Liability Balances	$8,624	$1,895	$2,819	$1,407	$1,120	$1,944	$968	$540	$456

						Successor			
	Exelon	Generation	ComEd	PECO[(c)]	BGE	PHI	Pepco	DPL	ACE
Net Regulatory Liability Recorded[(a)]	$7,315	N/A	$2,818	$1,394	$1,124	$1,979	$976	$545	$458

						Successor			
	Exelon[(b)]	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net Deferred Income Tax Benefit/ (Expense) Recorded	$1,309	$1,895	$1	$13	$(4)	$(35)	$(8)	$(5)	$(2)

(a) Reflects the net regulatory liabilities recorded on a pre-tax basis before taking into consideration the income tax benefits associated with the ultimate settlement with customers.

(b) Amounts do not sum across due to deferred tax adjustments recorded at the Exelon Corporation parent company, primarily related to certain employee compensation plans.

(c) 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. Refer to Note 3 - Regulatory Matters for additional information.

The net regulatory liabilities above include (1) amounts subject to IRS "normalization" rules that are required to be passed back to customers generally over the remaining useful life of the underlying assets giving rise to the associated deferred income taxes, and (2) amounts for which the timing of settlement with customers is subject to determinations by the rate regulators.

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.

					Successor			
	Exelon	ComEd	PECO[(a)]	BGE	PHI	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

(a) 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. 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.

The net regulatory liability amounts subject to the IRS normalization rules generally relate to property, plant and equipment with remaining useful lives ranging from 30 to 40 years across the Utility Registrants. For the other amounts, rate regulators could require the passing back of amounts to customers over shorter time frames.

Components of Income Tax Expense or Benefit

Income tax expense (benefit) from continuing operations is comprised of the following components:

	For the Years Ended December 31,		
	2017	2016	2015
Included in operations:			
Federal			
Current	$ 194	$ 60	$ 407
Deferred	(469)	607	566
Investment tax credit amortization	(25)	(24)	(22)
State			
Current	14	39	(86)
Deferred	161	79	208
Total	$(125)	$761	$1,073

Rate Reconciliation

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

	For the Years Ended December 31,		
	2017	2016	2015
U.S. Federal statutory rate	35.0%	35.0%	35.0%
Increase (decrease) due to:			
State income taxes, net of Federal income tax benefit[c]	2.3	3.3	3.7
Qualified nuclear decommissioning trust fund income (loss)	3.8	3.4	(0.4)
Amortization of investment tax credit, including deferred taxes on basis difference	(0.9)	(1.2)	(0.9)
Plant basis differences[a]	(1.7)	(4.8)	(1.5)
Production tax credits and other credits	(1.8)	(3.6)	(1.9)
Noncontrolling interests	0.1	(0.2)	0.3
Like-kind exchange	(1.2)	—	—
Merger expenses	(3.7)	5.5	—
FitzPatrick bargain purchase gain	(2.2)	—	—
Tax Cut and Jobs Act of 2017[b]	(33.1)	—	—
Statute of limitations expiration	—	(0.4)	(1.4)
Penalties	—	1.9	—
Domestic production activities deduction	—	—	(0.7)
Other[d][e]	0.1	(0.6)	—
Effective income tax rate	(3.3)%	38.3%	32.2%

(a) Includes the charges related to the transmission-related income tax regulatory asset for Exelon, ComEd, BGE, PHI, Pepco, DPL, and ACE of $35 million, $3 million, $5 million, $27 million, $14 million, $6 million, and $7 million, respectively (See Footnote 3 - Regulatory Matters).

(b) Included are impacts for TJCA other than the corporate rate change, including revisions further limiting tax deductions for compensation of certain highest paid executives, the write-off of foreign tax credit carryforwards, and loss of a 2015 domestic production activities deduction due to an NOL carryback.

(c) In 2016, includes a remeasurement of uncertain state income tax positions for Pepco and DPL.

(d) At PECO in 2016, includes a cumulative adjustment related to an anticipated gas repairs tax return accounting method change. The method change request was filed and accepted in 2017. No change to the results recorded as of December 31, 2016.

(e) In 2015, includes impacts of the PHI Global Settlement for Pepco, DPL, ACE and PHI.

Tax Differences and Carryforwards

The tax effects of temporary differences and carryforwards, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2017 and 2016 are presented below:

	As of December 31,	
	2017[a]	2016
Plant basis differences	$(12,490)	$(17,966)
Accrual based contracts	150	434
Derivatives and other financial instruments	(85)	(179)
Deferred pension and postretirement obligation	1,463	2,287
Nuclear decommissioning activities	(553)	(509)
Deferred debt refinancing costs	217	325
Regulatory assets and liabilities	(688)	(3,319)
Tax loss carryforward	344	189
Tax credit carryforward	861	446
Investment in partnerships	(434)	(650)
Other, net	746	1,485
Deferred income tax liabilities (net)	$(10,469)	$(17,457)
Unamortized investment tax credits	(732)	(658)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(11,201)	$(18,115)

(a) Includes remeasurement impacts related to the TCJA.

The following table provides Exelon's carryforwards and any corresponding valuation allowances as of December 31, 2017:

Federal	
Federal net operating loss	$ 624[a]
Deferred taxes on Federal net operating loss	131
Federal general business credits carryforwards	861[b]
State	
State net operating losses	3,555[c]
Deferred taxes on state tax attributes (net)	233
Valuation allowance on state tax attributes	29

(a) Exelon's federal net operating loss will begin expiring in 2034.
(b) Exelon's federal general business credit carryforwards will begin expiring in 2033.
(c) Exelon's state net operating losses and credit carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2018.

Tabular Reconciliation of Unrecognized Tax Benefits

The following tables provide a reconciliation of Exelon's unrecognized tax benefits as of December 31, 2017, 2016 and 2015:

Unrecognized tax benefits at January 1, 2017	$ 916
Increases based on tax positions related to 2017	—
Decreases based on tax positions related to 2017	—
Change to positions that only affect timing	—
Increases based on tax positions prior to 2017	28
Decreases based on tax positions prior to 2017	(196)
Decrease from settlements with taxing authorities	(5)
Decreases from expiration of statute of limitations	—
Unrecognized tax benefits at December 31, 2017	$ 743

Unrecognized tax benefits at January 1, 2016	$1,078
Merger balance transfer	22
Increases based on tax positions related to 2016	108
Decreases based on tax positions related to 2016	—
Change to positions that only affect timing	(332)
Increases based on tax positions prior to 2016	88
Decreases based on tax positions prior to 2016	(21)
Decrease from settlements with taxing authorities	(27)
Decreases from expiration of statute of limitations	—
Unrecognized tax benefits at December 31, 2016	$ 916

Unrecognized tax benefits at January 1, 2015	$1,829
Increases based on tax positions related to 2015	108
Decreases based on tax positions related to 2015	—
Change to positions that only affect timing	(705)
Increases based on tax positions prior to 2015	79
Decreases based on tax positions prior to 2015	(116)
Decreases from settlements with taxing authorities	(31)
Decreases from expiration of statute of limitations	(86)
Unrecognized tax benefits at December 31, 2015	$1,078

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 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, in the first quarter of 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.

Exelon reduced the liability related to the uncertain tax position associated with the like-kind exchange in the second quarter of 2017. Please see the Other Income Tax Matters section below for additional details related to the like-kind exchange adjustments made in the second quarter of 2017.

Exelon and Generation have $7 million of unrecognized tax benefits at December 31, 2017 for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits.

Exelon, Generation, and ComEd had $83 million, $7 million, and $(12) million of unrecognized tax benefits at December 31, 2016 for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits.

Exelon, Generation, and ComEd had $415 million, $20 million and $142 million of unrecognized tax benefits at December 31, 2015 for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits.

The disallowance of such positions would not materially affect the annual effective tax rate but would accelerate the payment of cash to, or defer the receipt of the cash tax benefit from, the taxing authority to an earlier or later period respectively.

Unrecognized Tax Benefits that if Recognized would Affect the Effective Tax Rate

Exelon, Generation, ComEd and PHI have $523 million, $461 million, $2 million, and $32 million, respectively, of unrecognized tax benefits at December 31, 2017 that, if recognized, would decrease the effective tax rate. BGE, PHI, Pepco, DPL, and ACE have $120 million, $94 million, $59 million, $21 million, and $14 million of unrecognized tax benefits at December 31, 2017 that, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Exelon, Generation, PHI, Pepco, DPL, and ACE had $633 million, $483 million, $93 million, $21 million, $16 million, and $22 million, respectively, of unrecognized tax benefits at December 31, 2016 that, if recognized, would decrease the effective tax rate. BGE, PHI, Pepco and DPL had $120 million, $80 million, $59 million, and $21 million of unrecognized tax benefits at December 31, 2016 that, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Exelon, Generation, and PHI had $538 million, $509 million, and $11 million, respectively, of unrecognized tax benefits at December 31, 2015 that, if recognized, would decrease the effective tax rate. BGE, PHI, Pepco and DPL had $120 million, $11 million, $8 million and $3 million of unrecognized tax benefits at December 31, 2015 that, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Reasonably Possible the Total Amount of Unrecognized Tax Benefits could Significantly Increase or Decrease within 12 Months after the Reporting Date

Like-Kind Exchange

As of December 31, 2017, Exelon and ComEd have approximately $39 million and $2 million, respectively, of unrecognized federal and state income tax benefits that could significantly decrease within the 12 months after the reporting date due to a final resolution of the like-kind exchange litigation described below. The recognition of these unrecognized tax benefits would decrease Exelon and ComEd's effective tax rate.

Settlement of Income Tax Audits, Refund Claims, and Litigation

As of December 31, 2017, Exelon, Generation, BGE, PHI, Pepco, DPL, and ACE have approximately $683 million, $469 million, $120 million, $94 million, $59 million, $21 million, $14 million respectively, of unrecognized federal and state tax benefits that could significantly decrease within the 12 months after the reporting date as a result of completing audits, potential settlements, refund claims, and the outcomes of pending court cases. Of the above unrecognized tax benefits, Exelon and Generation have $462 million that, if recognized, would decrease the effective tax rate. The unrecognized tax benefit related to BGE, Pepco, DPL and ACE, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Total Amounts of Interest and Penalties Recognized

The following table represents the net interest and penalties receivable (payable), including interest and penalties related to tax positions reflected in Exelon's Consolidated Balance Sheets.

	As of December 31,	
	2017	2016
Net interest receivable (payable)[(a)]	$ 233	(507)
Net penalties receivable (payable)	$ (17)	(106)

(a) Change in balance attributable to Like-Kind Exchange interest payments, see Other Tax Matters for further discussion.

The following tables set forth the net interest and penalty expense, including interest and penalties related to tax positions, recognized in Interest expense, net and Other, net in Other income and deductions in Exelon's Consolidated Statements of Operations and Comprehensive Income.

	For the Years Ended December 31,		
	2017	2016	2015
Net interest expense (income)	$37	$165	$(13)
Net penalty expense (income)	(2)	106	—

Description of Tax Years Open to Assessment by Major Jurisdiction

Taxpayer	Open Years
Exelon (and predecessors) and subsidiaries consolidated Federal income tax returns	1999, 2001-2016
PHI Holdings and subsidiaries consolidated Federal income tax returns	2013-2016
Exelon and subsidiaries Illinois unitary income tax returns	2013-2016
Constellation Illinois unitary income tax returns	2011-March 2012
Constellation combined New York corporate income tax returns	2010-March 2012
Exelon combined New York corporate income tax returns	2011-2016
Exelon New Jersey corporate income tax returns	2013-2015
Various separate company (excluding PECO) Pennsylvania corporate net income tax returns	2011-2016
PECO Pennsylvania separate company returns	2010-2016
DPL Delaware separate company returns	Same as Federal
ACE New Jersey separate company returns	2013-2016
Exelon and subsidiaries District of Columbia corporate income tax returns	2014-2016
PHI Holdings and subsidiaries District of Columbia corporate income tax returns	2014-2016
Various separate company Maryland corporate net income tax returns	Same as Federal

Other Tax Matters

Like-Kind Exchange

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately $1.2 billion of tax gain on the sale of ComEd's fossil generating assets. The gain was deferred by reinvesting a portion of the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities.

The IRS disagreed with this position and asserted that the entire gain of approximately $1.2 billion was taxable in 1999. Exelon was unable to reach agreement with the IRS regarding the dispute over the like-kind exchange position. The IRS asserted that the Exelon purchase and leaseback transaction was substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a "listed transaction" that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities did not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS also asserted a penalty of approximately $90 million for a substantial understatement of tax.

On September 30, 2013, the IRS issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court (Tax Court) and the trial took place in August of 2015. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the issue.

On September 19, 2016, the Tax Court rejected Exelon's position in the case and ruled that Exelon was not entitled to defer gain on the transaction. In addition, contrary to Exelon's evaluation that the penalty was unwarranted, the Tax Court ruled that Exelon is liable for the penalty and interest due on the asserted penalty. In June of 2017, the IRS finalized its computation of tax, penalties and interest owed by Exelon pursuant to the Tax Court's decision. In September of 2017, Exelon appealed this decision to the U.S. Court of Appeals for the Seventh Circuit.

In the first quarter of 2013, Exelon concluded that it was no longer more likely than not that the like-kind exchange position would be sustained and recorded charges to earnings representing the amount of interest expense (after-tax) and incremental state income tax expense that would be payable in the event Exelon is unsuccessful in litigation. Exelon agreed to hold ComEd harmless from any unfavorable impacts on ComEd's equity of the after-tax interest and penalty amounts.

Prior to the Tax Court's decision, however, Exelon did not believe it was likely a penalty would be assessed based on applicable case law and the facts of the transaction. As a result, no charge had been recorded for the penalty or for after-tax interest on the penalty. While it has strong arguments on appeal with respect to both the merits and the penalty, Exelon has determined that, pursuant to the applicable authoritative guidance, it is no longer more likely than not to avoid ultimate imposition of the penalty. As a result, in the third quarter of 2016, Exelon and ComEd recorded a charge to earnings of approximately $106 million and $86 million, respectively, of penalty and approximately $94 million and $64 million, respectively, of after-tax interest. Exelon and ComEd recorded the penalty and pre-tax interest due on the asserted penalty to Other, net and Interest expense, net, respectively, on their Consolidated Statements of Operations. Consistent with Exelon's agreement to continue to hold ComEd harmless from any unfavorable impact on its equity from the like-kind exchange position, ComEd recorded on its Consolidated Balance Sheets as of September 30, 2016, an additional $150 million receivable and non-cash equity contributions from Exelon.

As a result of the IRS's finalization of its computation in the second quarter of 2017, Exelon recorded a benefit to earnings of approximately $26 million, consisting of an income tax benefit of $50 million and a reduction of penalties of $2 million, partially offset by after-tax interest expense of $26 million, while ComEd recorded a charge to earnings of approximately $23 million, consisting of income tax expense of $15 million and after-tax interest expense of $8 million.

In the second quarter of 2017, Exelon amended its agreement with ComEd to also hold ComEd harmless for the unfavorable impacts on its equity from the additional income tax amounts owed by ComEd as a result of the IRS's finalization of its computation related to the like-kind exchange position. Accordingly, in the second quarter of 2017, ComEd recorded an additional receivable and non-cash equity contribution from Exelon for the total $23 million. As of June 30, 2017, ComEd had a total receivable from Exelon pursuant to the hold harmless agreement of $369 million, which was included in Current Receivables from Affiliates on ComEd's Consolidated Balance Sheet.

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 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. Following a final appellate decision, which is expected in 2018, Exelon expects to receive approximately $60 million related to final interest computations.

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. The $300 million payable discussed above attributable to ComEd, net of ComEd's receivable pursuant to the hold harmless agreement, was settled with Exelon in the third quarter of 2017. No recovery will be sought from ComEd customers for any interest, penalty, or additional income tax payment amounts resulting from the like-kind exchange tax position.

As previously disclosed, in the first quarter of 2014, Exelon entered into an agreement to terminate its investment in one of the three municipal-owned electric generation properties in exchange for a net early termination amount of $335 million. In the first quarter of 2016, Exelon terminated its interests in the remaining two municipal-owned electric generation properties in exchange for $360 million.

Long-Term State Tax Apportionment

Exelon, Generation and PHI periodically review events that may significantly impact how income is apportioned among the states and, therefore, the calculation of their respective deferred state income taxes. Events that may require Exelon, Generation and PHI to update their long-term state tax apportionment include significant changes in tax law and/or significant operational changes. Exelon's, PHI's and Pepco's long-term marginal state income tax rate were revised in the first quarter of 2017 as a result of a statutory rate change in Washington, D.C. As a result, Exelon, PHI and Pepco recorded a one-time decrease to Deferred income tax liability of $28 million, $8 million and $8 million, respectively, on their Consolidated Balance Sheets. Because income taxes are recovered through customer rates, Exelon, PHI and Pepco recorded a corresponding regulatory liability of $8 million, in the Consolidated Balance Sheets. In addition, Exelon recorded a decrease to Income tax expense of $20 million, net of federal taxes, in the Consolidated Statements of Operations and Comprehensive Income for the three months ended March 31, 2017.

In the third quarter of 2017, Exelon reviewed and updated its marginal state income tax rates based on 2016 state apportionment rates. In addition, Exelon, Generation and ComEd recorded the impacts of Illinois' statutory rate change, which increased the total corporate income tax rate from 7.75% to 9.5% effective July 1, 2017. As a result of the rate changes, in the third quarter of 2017, Exelon, Generation and ComEd recorded a one-time increase to Deferred income taxes of approximately $250 million, $20 million and $270 million, respectively, on their Consolidated Balance Sheets. Because income taxes are recovered through customer rates, each of Exelon and ComEd recorded a corresponding regulatory asset of $272 million. Further, Exelon recorded a decrease to Income tax expense of approximately $20 million and Generation recorded an increase to Income tax expense of approximately $20 million (each net of federal taxes) in their Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2017. The Illinois statutory rate increase is not expected to have a material ongoing impact to Exelon's, Generation's or ComEd's future results of operations.

Allocation of Tax Benefits

Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE are all party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. During 2017, Generation, PECO, BGE, and PHI recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $102 million, $16 million, $10 million and $7 million respectively. ComEd, Pepco, DPL, and ACE did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of a tax net operating loss.

During 2016, Generation, PECO and BGE recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $94 million, $18 million and $8 million respectively. ComEd did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of a tax net operating loss. PHI, Pepco, DPL and ACE did not record an allocation of Federal tax benefits from Exelon as they were not a part of Exelon's 2015 consolidated tax return.

During 2015, Generation, PECO and BGE recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $57 million, $16 million and $7 million respectively. ComEd did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of a tax net operating loss.

15. Asset Retirement Obligations

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations for financial accounting and reporting purposes, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation 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 scenarios.

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's Consolidated Balance Sheets, from January 1, 2016 to December 31, 2017:

Nuclear decommissioning ARO at January 1, 2016	$8,246
Accretion expense	436
Net increase for changes in and timing of estimated future cash flows	61
Costs incurred related to decommissioning plants	(9)
Nuclear decommissioning ARO at December 31, 2016[(a)]	8,734
Accretion Expense	458
Acquisition of FitzPatrick	444
Net increase for changes in and timing of estimated future cash flows	34
Costs incurred related to decommissioning plants	(8)
Nuclear decommissioning ARO at December 31, 2017[(a)]	9,662

(a) Includes $13 million and $10 million as the current portion of the ARO at December 31, 2017 and 2016, respectively, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

During 2017, Generation's total nuclear ARO increased by approximately $928 million, primarily reflecting year-to-date accretion of the ARO liability due to the passage of time, the recording of the fair value of the ARO, including subsequent purchase accounting adjustments, for the acquisition of FitzPatrick (see Note 4—Mergers, Acquisitions and Dispositions), the announced early retirement of TMI, and impacts of ARO updates completed during 2017 to reflect changes in amounts and timing of estimated decommissioning cash flows.

The net $34 million increase in the ARO during 2017 for changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments throughout the year, some with offsetting impacts. These adjustments include a $178 million increase due to higher assumed probabilities of early retirement of Salem and a $138 million increase in TMI's ARO liability associated with the May 30, 2017 announcement to early retire the unit on September 30, 2019. The increase in the ARO liability for TMI incorporates the early shutdown date, increases the probabilities of longer term decommissioning scenarios, and reflects an increase in the estimated costs to decommission based on an updated decommissioning cost study. See Note 8—Early Nuclear Plant Retirements for additional information regarding Salem and TMI. These increases in the ARO were partially offset by a $180 million decrease for refinements in estimated fleet wide labor costs expected to be incurred for certain on-site personnel during decommissioning as well as net decreases resulting from updates to the cost studies of Clinton, Quad Cities and Dresden.

During 2016, Generation's ARO increased by approximately $488 million, primarily reflecting year-to-date accretion of the ARO liability of approximately $436 million due to the passage of time and impacts of ARO updates completed during 2016 to reflect changes in amounts and timing of estimated decommissioning cash flows. The $61 million increase in the ARO during 2016 for changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments throughout the year, some with offsetting impacts. These adjustments include increases of $288 million resulting from the change in the assumed DOE spent fuel acceptance date for disposal from 2025 to 2030 as well as increases resulting from updates to the cost studies of Oyster Creek, Zion, Calvert Cliffs, Ginna and Nine Mile Point. These increases were partially offset by a decrease of $165 million resulting from changes to the decommissioning scenarios and their probabilities as well as reductions in estimated cost escalation rates, primarily for labor, energy and waste burial costs. Most of the increase to the ARO resulting from the June 2, 2016, announcement to early retire Clinton and Quad Cities was reversed pursuant to the December 7, 2016, enactment of the Illinois FEJA. See Note 8—Early Nuclear Plant Retirements for additional information.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generation station unit to satisfy Generation's nuclear decommissioning obligations. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with Generation's nuclear units have been funded with amounts collected from the previous owners and their respective utility customers. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the former PECO plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. On March 31, 2017, PECO filed its Nuclear Decommissioning Cost Adjustment (NDCA) with the PAPUC proposing an annual recovery from customers of approximately $4 million. This amount reflects a decrease from the current approved annual collection of approximately $24 million primarily due to the removal of the collections for Limerick Units 1 and 2 as a result of the NRC approving the extension of the operating licenses for an additional 20 years. On August 8, 2017, the PAPUC approved the filing and the new rates became effective January 1, 2018.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third-party (see Zion Station Decommissioning below) and the CENG units, where any shortfall is required to be funded by both Generation and EDF. Generation, through PECO, has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO, and likewise Generation will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds compared to decommissioning costs, as well as 5% of any additional shortfalls, on an aggregate basis for all former PECO units. The initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from utility customers for any of Generation's other nuclear units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after all decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to Generation's other nuclear units, Generation retains any funds remaining after decommissioning. However, in connection with CENG's acquisition of the Nine Mile Point and Ginna plants and settlements with certain regulatory agencies, CENG is subject to certain conditions pertaining to nuclear decommissioning trust funds that, if met, could possibly result in obligations to make payments to certain third parties (clawbacks). For Nine Mile Point and Ginna, the clawback provisions are triggered only in the event that the required decommissioning activities are discontinued or not started or completed in a timely manner. In the event that the clawback provisions are triggered for Nine Mile Point, then, depending upon the triggering event, an amount equal to 50% of the total amount withdrawn from the funds for non-decommissioning activities or 50% of any excess funds in the trust funds above the amounts required for decommissioning (including spent fuel management and decommissioning) is to be paid to the Nine Mile Point sellers. In the event that the clawback provisions are triggered for Ginna, then an amount equal to any estimated cost savings realized by not completing any of the required decommissioning activities is to be paid to the Ginna sellers. Generation expects to comply with applicable regulations and timely commence and complete all required decommissioning activities.

At December 31, 2017 and 2016, Exelon and Generation had NDT fund investments totaling $13,349 million and $11,061 million, respectively. The increase is primarily driven by improved market performance and the acquisition of FitzPatrick. For additional information related to the NDT fund investments, refer to Note 11—Fair Value of Financial Assets and Liabilities.

The following table provides unrealized gains on NDT funds for 2017, 2016 and 2015:

	For the Years Ended December 31,		
	2017	2016	2015
Net unrealized gains (losses) on decommissioning trust funds—Regulatory Agreement Units[(a)]	$455	$216	$(282)
Net unrealized gains (losses) on decommissioning trust funds—Non-Regulatory Agreement Units[(b)(c)]	521	194	(197)

(a) Net unrealized gains (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.

(b) Excludes $(10) million, $(1) million and $7 million of net unrealized gains (losses) related to the Zion Station pledged assets in 2017, 2016 and 2015, respectively. Net unrealized gains related to Zion Station pledged assets are included in the Other current liabilities and Payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets in 2017 and 2016, respectively.

(c) Net unrealized gains (losses) related to Generation's NDT funds with Non-Regulatory Agreement Units are included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units are eliminated within Other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

Accounting Implications of the Regulatory Agreements with ComEd and PECO

Based on the regulatory agreement with the ICC that dictates Generation's obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis, as long as funds held in the NDT funds are expected to exceed the total estimated decommissioning obligation, decommissioning-related activities, including realized and unrealized gains and losses on the NDT funds and accretion of the decommissioning obligation, are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability. Should the expected value of the NDT fund for any former ComEd unit fall below the amount of the expected decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income and the adverse impact to Exelon's and Generation's results of operations and financial positions could be material. As of December 31, 2017, the NDT funds of each of the former ComEd units, except for Zion (see Zion Station Decommissioning below), are expected to exceed the related decommissioning obligation for each of the units. For the purposes of making this determination, the decommissioning obligation referred to is different, as described below, from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

Based on the regulatory agreement supported by the PAPUC that dictates Generation's rights and obligations related to the shortfall or excess of trust funds necessary for decommissioning the former PECO units, regardless of whether the funds held in the NDT funds are expected to exceed or fall short of the total estimated decommissioning obligation, decommissioning-related activities are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, PECO has recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability. Any changes to the PECO regulatory agreements could impact Exelon's and Generation's ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon's and Generation's results of operations and financial positions could be material.

The decommissioning-related activities related to the Non-Regulatory Agreement Units are reflected in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Refer to Note 3—Regulatory Matters and Note 26—Related Party Transactions for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning

On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions, under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to dispose of SNF and decommission the SNF dry storage facility, 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 its decommissioning efforts at Zion Station. During 2013, EnergySolutions entered a definitive acquisition agreement and was acquired by another company. Generation reviewed the acquisition as it relates to the ASA to decommission Zion Station. Based on that review, Generation determined that the acquisition will not adversely impact decommissioning activities under the ASA.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to Pledged assets for Zion Station decommissioning within Generation's and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a Payable for Zion Station decommissioning in Generation's and Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the Payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation for the SNF. Following ZionSolutions' completion of its contractual obligations and transfer of the NRC license to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal, and will complete all remaining decommissioning activities associated with the SNF dry storage facility. Generation has a liability of approximately $114 million, which is included within the nuclear decommissioning ARO at December 31, 2017. Generation also has retained NDT assets to fund its obligation to maintain the SNF at Zion Station until transfer to the DOE and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payables to ZionSolutions, and withdrawals by ZionSolutions at December 31, 2017 and 2016:

	2017	2016
Carrying value of Zion Station pledged assets[(a)]	$ 39	$ 113
Payable to Zion Solutions[(b)]	37	104
Current portion of payable to Zion Solutions[(c)]	37	90
Cumulative withdrawals by Zion Solutions to pay decommissioning costs[(d)]	942	878

(a) Included in Other current assets within Exelon's and Generation's Consolidated Balance Sheets in 2017.

(b) Excludes a liability recorded within Exelon's and Generation's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.

(c) Included in Other current liabilities within Exelon's and Generation's Consolidated Balance Sheets.

(d) Includes project expenses to decommission Zion Station and estimated tax payments on Zion Station NDT fund earnings.

ZionSolutions leased the land associated with Zion Station from Generation pursuant to a Lease Agreement. Under the Lease Agreement, ZionSolutions has committed to complete the required decommissioning work according to an established schedule and constructed a dry cask storage facility on the land and has loaded the SNF from the SNF pools onto the dry cask storage facility at Zion Station. Rent payable under the Lease Agreement is $1.00 per year, although the Lease Agreement requires ZionSolutions to pay property taxes associated with Zion Station and penalty rents may accrue if there are unexcused delays in the progress of decommissioning work at Zion Station or the construction of the dry cask SNF storage facility. To reduce the risk of default by ZionSolutions, EnergySolutions provided a $200 million letter of credit to be used to fund decommissioning costs in the event the NDT assets are insufficient. In accordance with the terms of the ASA, the letter of credit was reduced to $98 million in August 2017 due to the completion of key decommissioning milestones. EnergySolutions and its parent company have also provided a performance guarantee and EnergySolutions has entered into other agreements that will provide rights and remedies for Generation and the NRC in the case of other specified events of default, including a special purpose easement for disposal capacity at the EnergySolutions site in Clive, Utah, for all LLRW volume of Zion Station.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded on Generation's and Exelon's Consolidated Balance Sheets primarily due to differences in the type of costs included in the estimates, the basis for estimating such costs, and assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements calculated under the NRC methodology are less than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires either further funding or other financial guarantees.

Key assumptions used in the minimum funding calculation using the NRC methodology at December 31, 2017 include: (1) consideration of costs only for the removal of radiological contamination at each unit; (2) the option on a unit-by-unit basis to use generic, non-site specific cost estimates; (3) consideration of only one decommissioning scenario for each unit; (4) the plants cease operation at the end of their current license lives (with no assumed license renewals for those units that have not already received renewals and with an assumed end-of-operations date of 2018 for Oyster Creek and 2019 for TMI); (5) the assumption of current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (6) assumed annual after-tax returns on the NDT funds of 2% (3% for the former PECO units, as specified by the PAPUC).

In contrast, the key criteria and assumptions used by Generation to determine the ARO and to forecast the target growth in the NDT funds at December 31, 2017 include: (1) the use of site specific cost estimates that are updated at least once every five years; (2) the inclusion in the ARO estimate of all legally unavoidable costs required to decommission the unit (e.g., radiological decommissioning and full site restoration for certain units, on-site spent fuel maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain low-level radioactive waste); (3) the consideration of multiple scenarios where decommissioning and site restoration activities, as applicable, are completed under four possible scenarios ranging from 10 to 70 years after the cessation of plant operations; (4) the consideration of multiple end of life scenarios; (5) the measurement of the obligation at the present value of the future estimated costs and an annual average accretion of the ARO of approximately 5% through a period of approximately 30 years after the end of the extended lives of the units; and (6) an estimated targeted annual pre-tax return on the NDT funds of 4.8% to 6.4% (as compared to a historical 5-year annual average pre-tax return of approximately 8%).

Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired or are within five years of the current approved license life), based on values as of December 31, addressing Generation's ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. As a result, Exelon's and Generation's cash flows and financial positions may be significantly adversely affected.

Generation filed its biennial decommissioning funding status report with the NRC on March 31, 2017 for all units except for Zion Station which is included in a separate report to the NRC submitted by ZionSolutions (see Zion Station Decommissioning above) and FitzPatrick which is still owned by Entergy as of the NRC reporting period. This status report demonstrated adequate decommissioning funding assurance for all units except for Peach Bottom Unit 1. As a former PECO plant, financial assurance for decommissioning Peach Bottom Unit 1 is provided by the NDT fund in addition to collections from PECO ratepayers. As discussed under Nuclear Decommissioning Trust Fund Investments above, the amount collected from PECO ratepayers has been adjusted in the March 31, 2017 filing to the PAPUC which was approved on August 8, 2017 and effective on January 1, 2018.

Generation will file its next decommissioning funding status report with the NRC by March 31, 2018 for shutdown reactors and reactors within five years of shutdown. This report will reflect the status of decommissioning funding assurance as of December 31, 2017 and will include the early retirement of TMI announced on May 30, 2017, in addition to an adjustment for the February 2, 2018 announced retirement date for Oyster Creek. A shortfall at any unit could necessitate that Exelon post a parental guarantee for Generation's share of the funding assurance. However, the amount of any required guarantee will ultimately depend on the decommissioning approach adopted, the associated level of costs, and the decommissioning trust fund investment performance going forward.

As the future values of trust funds change due to market conditions, the NRC minimum funding status of Generation's units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO customers for decommissioning the former PECO units, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

Non-Nuclear Asset Retirement Obligations

Generation has AROs for plant closure costs associated with its fossil and renewable generating facilities, including asbestos abatement, removal of certain storage tanks, restoring leased land to the condition it was in prior to construction of renewable generating stations and other decommissioning-related activities. PHI and the Utility Registrants have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1—Significant Accounting Policies for additional information on the Registrants' accounting policy for AROs.

The following table provides a rollforward of the non-nuclear AROs reflected on Exelon's Consolidated Balance Sheets from January 1, 2016 to December 31, 2017:

Non-nuclear AROs at January 1, 2016	$ 355
Merger with PHI[a]	8
Net increase due to changes in, and timing of, estimated future cash flows[b]	34
Development projects[c]	11
Accretion expense[d]	18
Sale of generating assets[e]	(22)
Payments	(11)
Non-nuclear AROs at December 31, 2016[f]	393
Net increase (decrease) due to changes in, and timing of, estimated future cash flows[b]	(11)
Development projects[c]	1
Accretion expense[d]	18
Deconsolidation of EGTP[g]	(7)
Payments	(10)
Non-nuclear AROs at December 31, 2017[f]	$ 384

(a) Following the completion of the PHI merger on March 23, 2016, PHI's AROs related to its unregulated business interests were transferred to Exelon and Generation.

(b) During the year ended December 31, 2017, ComEd recorded a decrease of $1 million in Operating and maintenance expense. Generation, PECO, BGE, Pepco, DPL and ACE did not record any adjustments in Operating and maintenance expense for the year ended December 31, 2017. During the year ended December 31, 2016, Generation recorded a increase of $1 million in Operating and maintenance expense. ComEd, PECO, BGE, Pepco, DPL and ACE did not record any adjustments in Operating and maintenance expense for the year ended December 31, 2016.

(c) Relates to new AROs recorded due to the construction of solar, wind and other non-nuclear generating sites.

(d) For ComEd, PECO and BGE, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.

(e) Reflects a reduction to the ARO resulting primarily from the sales of the New Boston generating site and Upstream business in 2016. See Note 4—Mergers, Acquisitions and Dispositions for further information.

(f) Excludes the current portion of the ARO at December 31, 2017 for Generation, ComEd and BGE of $1 million, $2 million and $2 million, respectively. Excludes the current portion of the ARO at December 31, 2016 for Generation, ComEd and BGE of $1 million, $2 million and $3 million, respectively. This is included in Other current liabilities on the Registrants' respective Consolidated Balance Sheets.

(g) See Note 4—Mergers, Acquisitions and Dispositions for additional information.

16. Retirement Benefits

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all current employees. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Effective February 1, 2018, most newly-hired Generation and BSC non-represented employees are not eligible for pension benefits, and will instead be eligible to receive an enhanced non-discretionary employer contribution in an Exelon defined contribution savings plan. Effective January 1, 2018, most newly-hired non-represented employees are not eligible for OPEB benefits and employees represented by Local 614 are not eligible for retiree health care benefits.

Effective March 23, 2016, Exelon became the sponsor of all of PHI's defined benefit pension and other postretirement benefit plans, and assumed PHI's benefit plan obligations and related assets. As a result, PHI's benefit plan net obligation and related regulatory assets were transferred to Exelon.

The table below shows the pension and other postretirement benefit plans in which employees of each operating company participated at December 31, 2017:

	Operating Company[e]								
Name of Plan:	**Generation**	**ComEd**	**PECO**	**BGE**	**BSC**	**PHI**	**Pepco**	**DPL**	**ACE**
Qualified Pension Plans:									
Exelon Corporation Retirement Program[a]	X	X	X	X	X				
Exelon Corporation Cash Balance Pension Plan[a]	X	X	X	X	X				
Exelon Corporation Pension Plan for Bargaining Unit Employees[a]	X	X			X				
Exelon New England Union Employees Pension Plan[a]	X								
Exelon Employee Pension Plan for Clinton, TMI and Oyster Creek[a]	X	X	X		X				
Pension Plan of Constellation Energy Group, Inc.[b]	X	X	X	X	X				
Pension Plan of Constellation Energy Nuclear Group, LLC[c]	X	X		X	X				
Nine Mile Point Pension Plan[c]	X				X				
Constellation Mystic Power, LLC Union Employees Pension Plan Including Plan A and Plan B[b]	X								
Pepco Holdings LLC Retirement Plan[d]	X					X	X	X	X
Non-Qualified Pension Plans:									
Exelon Corporation Supplemental Pension Benefit Plan and 2000 Excess Benefit Plan[a]	X	X	X		X				
Exelon Corporation Supplemental Management Retirement Plan[a]	X	X	X	X	X				
Constellation Energy Group, Inc. Senior Executive Supplemental Plan[b]	X			X	X				
Constellation Energy Group, Inc. Supplemental Pension Plan[b]	X			X	X				
Constellation Energy Group, Inc. Benefits Restoration Plan[b]	X	X		X	X				
Constellation Energy Nuclear Plan, LLC Executive Retirement Plan[c]	X				X				
Constellation Energy Nuclear Plan, LLC Benefits Restoration Plan[c]	X				X				
Baltimore Gas & Electric Company Executive Benefit Plan[b]	X			X	X				
Baltimore Gas & Electric Company Manager Benefit Plan[b]	X	X		X	X				
Pepco Holdings LLC 2011 Supplemental Executive Retirement Plan[d]	X					X	X	X	X
Conectiv Supplemental Executive Retirement Plan[d]	X					X		X	X
Pepco Holdings LLC Combined Executive Retirement Plan[d]	X					X	X		
Atlantic City Electric Director Retirement Plan[d]									X

	Operating Company[e]								
Name of Plan:	**Generation**	**ComEd**	**PECO**	**BGE**	**BSC**	**PHI**	**Pepco**	**DPL**	**ACE**
Other Postretirement Benefit Plans:									
PECO Energy Company Retiree Medical Plan[a]	X	X	X	X	X				
Exelon Corporation Health Care Program[a]	X	X	X	X	X				
Exelon Corporation Employees' Life Insurance Plan[a]	X	X	X	X	X				
Exelon Corporation Health Reimbursement Arrangement Plan[a]	X	X	X	X	X				
Constellation Energy Group, Inc. Retiree Medical Plan[b]	X	X	X	X	X				
Constellation Energy Group, Inc. Retiree Dental Plan[b]	X			X	X				
Constellation Energy Group, Inc. Employee Life Insurance Plan and Family Life Insurance Plan[b]	X	X	X	X	X				
Constellation Mystic Power, LLC Post-Employment Medical Account Savings Plan[b]	X								
Exelon New England Union Post-Employment Medical Savings Account Plan[a]	X								
Retiree Medical Plan of Constellation Energy Nuclear Group LLC[c]	X			X	X				
Retiree Dental Plan of Constellation Energy Nuclear Group LLC[c]	X			X	X				
Nine Mile Point Nuclear Station, LLC Medical Care and Prescription Drug Plan for Retired Employees[c]	X				X				
Pepco Holdings LLC Welfare Plan for Retirees[d]	X					X	X	X	X

(a) These plans are collectively referred to as the legacy Exelon plans.
(b) These plans are collectively referred to as the legacy Constellation Energy Group (CEG) Plans.
(c) These plans are collectively referred to as the legacy CENG plans.
(d) These plans are collectively referred to as the legacy PHI plans.
(e) Employees generally remain in their legacy benefit plans when transferring between operating companies.

Exelon's traditional and cash balance pension plans are intended to be tax-qualified defined benefit plans. Exelon has elected that the trusts underlying these plans be treated as qualified trusts under the IRC. If certain conditions are met, Exelon can deduct payments made to the qualified trusts, subject to certain IRC limitations.

Benefit Obligations, Plan Assets and Funded Status

Exelon recognizes the overfunded or underfunded status of defined benefit pension and OPEB plans as an asset or liability on its balance sheet, with offsetting entries to AOCI and regulatory assets (liabilities), in accordance with the applicable authoritative guidance. The measurement date for the plans is December 31.

During the first quarter of 2017, Exelon received an updated valuation of its pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2017. This valuation resulted in an increase to the pension obligation of $92 million and an increase to the other postretirement benefit obligation of $57 million. Additionally, accumulated other comprehensive loss increased by approximately $59 million (after tax), regulatory assets increased by approximately $57 million and regulatory liabilities increased by approximately $4 million.

In connection with the acquisition of FitzPatrick in the first quarter of 2017, Exelon recorded pension and OPEB obligations for FitzPatrick employees of $16 million and $17 million, respectively. Refer to Note 4 — Mergers, Acquisitions and Dispositions for additional discussion of the acquisition of FitzPatrick.

The following tables provide a rollforward of the changes in the benefit obligations and plan assets for the most recent two years for all plans combined:

Exelon	Pension Benefits		Other Postretirement Benefits	
	2017	2016[(a)]	2017	2016[(a)]
Change in benefit obligation:				
Net benefit obligation at beginning of year	$21,060	$17,753	$4,457	$3,938
Service cost	387	354	106	107
Interest cost	842	830	182	185
Plan participants' contributions	—	—	53	54
Actuarial loss (gain)	1,182	567	350	(136)
Plan amendments	9	(60)	—	—
Acquisitions/divestitures[(b)]	16	2,667	17	589
Settlements	(34)	—	—	—
Gross benefits paid	(1,125)	(1,051)	(309)	(280)
Net benefit obligation at end of year	$22,337	$21,060	$4,856	$4,457

Exelon	Pension Benefits		Other Postretirement Benefits	
	2017	2016[(a)]	2017	2016[(a)]
Change in plan assets:				
Fair value of net plan assets at beginning of year	$16,791	$14,347	$2,578	$2,293
Actual return on plan assets	2,600	1,061	346	128
Employer contributions	341	347	64	50
Plan participants' contributions	—	—	53	54
Gross benefits paid	(1,125)	(1,051)	(309)	(280)
Acquisitions/divestitures[(b)]	—	2,087	—	333
Settlements	(34)	—	—	—
Fair value of net plan assets at end of year	$18,573	$16,791	$2,732	$2,578

	Predecessor	
	Pension Benefits	Other Postretirement Benefits
PHI	January 1, 2016 to March 23, 2016	January 1, 2016 to March 23, 2016
Change in benefit obligation:		
Net benefit obligation at beginning of the period	$2,490	$ 563
Service cost	12	1
Interest cost	26	6
Actuarial (gain) loss	(30)	(5)
Gross benefits paid	(2)	(1)
Net benefit obligation at end of the period	$2,496	$ 564

	Predecessor	
	Pension Benefits	Other Postretirement Benefits
PHI	January 1, 2016 to March 23, 2016	January 1, 2016 to March 23, 2016
Change in plan assets:		
Fair value of net plan assets at beginning of the period	$2,018	$ 348
Employer and plan participant contributions	4	1
Gross benefits paid by plan	(2)	(1)
Fair value of net plan assets at end of the period	$2,020	$ 348

(a) 2016 amounts include PHI for the period of March 24, 2016 through December 31, 2016.

(b) Exelon recorded pension and OPEB obligations associated with its acquisition of Fitzpatrick on March 31, 2017. Effective March 23, 2016, Exelon became the sponsor of PHI's defined benefit pension and other postretirement benefit plans.

Exelon presents its benefit obligations and plan assets net on its balance sheet within the following line items:

Exelon	Pension Benefits 2017	Pension Benefits 2016[(a)]	Other Postretirement Benefits 2017	Other Postretirement Benefits 2016[(a)]
Other current liabilities	$ 28	$ 21	$ 31	$ 31
Pension obligations	3,736	4,248	—	—
Non-pension postretirement benefit obligations	—	—	2,093	1,848
Unfunded status (net benefit obligation less plan assets)	$3,764	$4,269	$2,124	$1,879

(a) Effective March 23, 2016, Exelon became the sponsor of PHI's defined benefit pension and other postretirement benefit plans, and assumed PHI's benefit plan obligations and related assets.

The funded status of the pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations of the plan. The funded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following tables provide the projected benefit obligations (PBO), accumulated benefit obligation (ABO), and fair value of plan assets for all pension plans with a PBO or ABO in excess of plan assets.

PBO IN EXCESS OF PLAN ASSETS

	Exelon 2017	Exelon 2016
Projected benefit obligation	$ 22,337	$ 21,060
Fair value of net plan assets	18,573	16,791

ABO IN EXCESS OF PLAN ASSETS

	Exelon 2017	Exelon 2016
Projected benefit obligation	$ 22,337	$ 21,060
Accumulated benefit obligation	21,153	19,930
Fair value of net plan assets	18,573	16,791

On a PBO basis, the Exelon plans were funded at 83% and 80% at December 31, 2017 and 2016, respectively. On an ABO basis, the Exelon plans were funded at 88% and 84% at December 31, 2017 and 2016, respectively. The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The majority of the 2017 pension benefit cost for the Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 4.04%. The majority of the 2017 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.58% for funded plans and a discount rate of 4.04%.

A portion of the net periodic benefit cost for all plans is capitalized within the Consolidated Balance Sheets. The following tables present the components of Exelon's net periodic benefit costs, prior to capitalization, for the years ended December 31, 2017, 2016 and 2015 and PHI's net periodic benefit costs, prior to capitalization, for the predecessor period of January 1, 2016 to March 23, 2016.

Exelon	Pension Benefits 2017[(a)]	Pension Benefits 2016[(b)]	Pension Benefits 2015	Other Postretirement Benefits 2017[(a)]	Other Postretirement Benefits 2016[(b)]	Other Postretirement Benefits 2015
Components of net periodic benefit cost:						
Service cost	$ 387	$ 354	$ 326	$ 106	$ 107	$ 119
Interest cost	842	830	710	182	185	167
Expected return on assets	(1,196)	(1,141)	(1,026)	(162)	(162)	(151)
Amortization of:						
Prior service cost (credit)	1	14	13	(188)	(185)	(174)
Actuarial loss	607	554	571	61	63	80
Settlement and other charges[(c)]	3	2	2	—	—	—
Net periodic benefit cost	$ 644	$ 613	$ 596	$ (1)	$ 8	$ 41

(a) FitzPatrick net benefit costs are included for the period after acquisition.
(b) PHI net periodic benefit costs for the period prior to the merger are not included in the table above.
(c) 2016 amount includes an additional termination benefit for PHI.

PHI	Predecessor			
	Pension Benefits		Other Postretirement Benefits	
	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
Components of net periodic benefit cost:				
Service cost	$ 12	$ 57	$ 1	$ 7
Interest cost	26	109	6	24
Expected return on assets	(30)	(140)	(5)	(22)
Amortization of:				
Prior service cost (credit)	—	2	(3)	(13)
Actuarial loss	14	65	2	8
Net periodic benefit cost	$ 22	$ 93	$ 1	$ 4

Components of AOCI and Regulatory Assets

Under the authoritative guidance for regulatory accounting, a portion of current year actuarial gains and losses and prior service costs (credits) is capitalized within Exelon's Consolidated Balance Sheets to reflect the expected regulatory recovery of these amounts, which would otherwise be recorded to AOCI. The following tables provide the components of AOCI and regulatory assets (liabilities) for the years ended December 31, 2017, 2016 and 2015 for all plans combined and the components of PHI's predecessor AOCI and regulatory assets (liabilities) for the period January 1, 2016 to March 23, 2016.

	Pension Benefits			Other Postretirement Benefits		
Exelon	2017	2016[a]	2015	2017	2016[a]	2015
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):						
Current year actuarial (gain) loss	$(222)	$ 644	$ 476	$166	$(101)	$(194)
Amortization of actuarial loss	(607)	(554)	(571)	(61)	(63)	(80)
Current year prior service cost (credit)	9	(60)	—	—	—	(23)
Amortization of prior service (cost) credit	(1)	(14)	(13)	188	185	174
Settlements	(3)	—	(2)	—	—	—
Acquisitions	—	994	—	—	94	—
Total recognized in AOCI and regulatory assets (liabilities)	$(824)	$1,010	$(110)	$293	$ 115	$(123)
Total recognized in AOCI	$(401)	$ 51	$ (64)	$168	$ 20	$ (63)
Total recognized in regulatory assets (liabilities)	$(423)	$ 959	$ (46)	$125	$ 95	$ (60)

PHI	Predecessor			
	Pension Benefits		Other Postretirement Benefits	
	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):				
Current year actuarial loss (gain)	$ —	$ 50	$—	$(39)
Amortization of actuarial loss	(14)	(65)	(2)	(8)
Amortization of prior service (cost) credit	—	(2)	3	13
Total recognized in AOCI and regulatory assets (liabilities)	$(14)	$(17)	$ 1	$(34)
Total recognized in AOCI	$ (1)	$(11)	$—	$ —
Total recognized in regulatory assets (liabilities)	$(13)	$ (6)	$ 1	$(34)

[a] 2016 amounts include PHI for the period of March 24, 2016 through December 31, 2016.

The following table provides the components of gross accumulated other comprehensive loss and regulatory assets (liabilities) that have not been recognized as components of periodic benefit cost at December 31, 2017 and 2016, respectively, for all plans combined:

	Exelon		Exelon	
	Pension Benefits		Other Postretirement Benefits	
	2017	2016[(a)]	2017	2016[(a)]
Prior service (credit) cost	$ (24)	$ (31)	$(522)	$(710)
Actuarial loss	7,556	8,387	829	724
Total[(a)]	$7,532	$8,356	$ 307	$ 14
Total included in AOCI	$3,896	$4,297	$ 125	$ (42)
Total included in regulatory assets (liabilities)	$3,636	$4,059	$ 182	$ 56

(a) Effective March 23, 2016, Exelon became the sponsor of PHI's defined benefit pension and other postretirement benefit plans, and assumed PHI's benefit plan obligations and related assets.

The following table provides the impact to Exelon's AOCI and regulatory assets (liabilities) at December 31, 2017 as a result of the components of periodic benefit costs that are expected to be amortized in 2018. These estimates are subject to the completion of an actuarial valuation of Exelon's pension and other postretirement benefit obligations, which will reflect actual census data as of January 1, 2018 and actual claims activity as of December 31, 2017. The valuation is expected to be completed in the first quarter of 2018 for the majority of the benefit plans.

	Pension Benefits	Other Postretirement Benefits
Prior service cost (credit)	$ 2	$(186)
Actuarial loss	640	66
Total[(a)]	$642	$(120)

(a) Of the $642 million related to pension benefits at December 31, 2017, $317 million and $325 million are expected to be amortized from AOCI and regulatory assets in 2018, respectively. Of the $(120) million related to other postretirement benefits at December 31, 2017, $(65) million and $(55) million are expected to be amortized from AOCI and regulatory assets (liabilities) in 2018, respectively.

Average Remaining Service Period

For pension benefits, Exelon amortizes its unrecognized prior service costs and certain actuarial gains and losses, as applicable, based on participants' average remaining service periods. The average remaining service period of Exelon's defined benefit pension plan participants was 11.8 years, 11.9 years and 11.9 years for the years ended December 31, 2017, 2016 and 2015, respectively. For the predecessor period, the average remaining service period of PHI's defined benefit plans was approximately 11 years for the year ended December 31, 2015.

For other postretirement benefits, Exelon amortizes its unrecognized prior service costs over participants' average remaining service period to benefit eligibility age and amortizes certain actuarial gains and losses over participants' average remaining service period to expected retirement. The average remaining service period of postretirement benefit plan participants related to benefit eligibility age was 8.2 years, 9.0 years and 10.8 years for the years ended December 31, 2017, 2016 and 2015, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 9.6 years, 9.7 years and 9.7 years for the years ended December 31, 2017, 2016 and 2015, respectively. For the predecessor period, the average remaining service period of PHI's other postretirement benefit plans was approximately 11 years for the year ended December 31, 2015.

Assumptions

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit and other postretirement plans involves various factors, including the development of valuation assumptions and inputs and accounting policy elections. The measurement of benefit obligations and costs is impacted by several assumptions and inputs, including the discount rate applied to benefit obligations, the long-term EROA, Exelon's expected level of contributions to the plans, the long-term expected investment rate credited to employees participating in cash balance plans and the anticipated rate of increase of health care costs. Additionally, assumptions related to plan participants include the incidence of mortality, the expected remaining service period, the level of compensation and rate of compensation increases, employee age and length of service, among other factors. When developing the required assumptions, Exelon considers historical information as well as future expectations.

Expected Rate of Return. In selecting the EROA, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by Exelon's target asset class allocations.

Mortality. For the December 31, 2014 actuarial valuation, Exelon changed its assumption of mortality to reflect more recent expectations of future improvements in life expectancy. The change was supported through completion of an experience study and supplemental analyses performed by Exelon's actuaries. There were no changes to the mortality assumption in 2015, 2016 or 2017.

The following assumptions were used to determine the benefit obligations for the plans at December 31, 2017, 2016 and 2015. Assumptions used to determine year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits			Other Postretirement Benefits		
Exelon	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Discount rate	3.62%[a]	4.04%[b]	4.29%[c]	3.61%[a]	4.04%[b]	4.29%[c]
Rate of compensation increase	[d]	[e]	[e]	[d]	[e]	[e]
Mortality table	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)
Health care cost trend on covered charges	N/A	N/A	N/A	5.00% with ultimate trend of 5.00% in 2017	5.00% with ultimate trend of 5.00% in 2017	5.50% decreasing to ultimate trend of 5.00% in 2017

	Predecessor		Predecessor	
	Pension Benefits		Other Postretirement Benefits	
PHI	**January 1, 2016 to March 23, 2016[f]**	**2015**	**January 1, 2016 to March 23, 2016[e]**	**2015**
Discount rate		4.65%/4.55%[g]		4.55%
Rate of compensation increase		5.00%		5.00%
Mortality table		RP-2014 table with improvement scale MP-2015		RP-2014 table with improvement scale MP-2015
Health care cost trend on covered charges		N/A		6.33% pre-65 and 5.40% post-65 decreasing to ultimate trend of 5.00% in 2020

(a) The discount rates above represent the blended rates used to determine the majority of Exelon's pension and other postretirement benefits obligations as of December 31, 2017. Certain benefit plans used individual rates ranging from 3.49% - 3.65% and 3.57% - 3.68% for pension and other postretirement plans, respectively.

(b) The discount rates above represent the blended rates used to determine the majority of Exelon's pension and other postretirement benefits obligations as of December 31, 2016. Certain benefit plans used individual rates ranging from 3.66% - 4.11% and 4.00% - 4.17% for pension and other postretirement plans, respectively.

(c) The discount rates above represent the blended rates used to determine the majority of Exelon's pension and other postretirement benefits obligations as of December 31, 2015. Certain benefit plans used individual rates ranging from 3.68% - 4.14% and 4.32% - 4.43% for pension and other postretirement plans, respectively.

(d) 3.25% through 2019 and 3.75% thereafter.

(e) The legacy Exelon, CEG and CENG pension and other postretirement plans used a rate of compensation increase of 3.25% through 2019 and 3.75% thereafter, while the legacy PHI pension and other postretirement plans used a weighted-average rate of compensation increase of 5% for all periods.

(f) Obligation was not remeasured during this period.

(g) The discount rate for the qualified and non-qualified pension plans was 4.65% and 4.55%, respectively.

The following assumptions were used to determine the net periodic benefit costs for the plans for the years ended December 31, 2017, 2016 and 2015, as well as for the PHI predecessor period January 1, 2016 to March 23, 2016:

	Pension Benefits			Other Postretirement Benefits		
Exelon	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Discount rate	4.04%[a]	4.29%[b]	3.94%[c]	4.04%[a]	4.29%[b]	3.92%[c]
Expected return on plan assets	7.00%[d]	7.00%[d]	7.00%[d]	6.58%[d]	6.71%[d]	6.50%[d]
Rate of compensation increase	[e]	[e]	[e]	[e]	[e]	[e]
Mortality table	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)
Health care cost trend on covered charges	N/A	N/A	N/A	5.00% decreasing to ultimate trend of 5.00% in 2017	5.50% decreasing to ultimate trend of 5.00% in 2017	6.00% decreasing to ultimate trend of 5.00% in 2017

	Predecessor Pension Benefits		Predecessor Other Postretirement Benefits	
PHI	**January 1, 2016 to March 23, 2016**	**2015**	**January 1, 2016 to March 23, 2016**	**2015**
Discount rate	4.65%/4.55%[f]	4.20%	4.55%	4.15%
Expected return on plan assets[g]	6.50%	6.50%	6.75%	6.75%
Rate of compensation increase	5.00%	5.00%	5.00%	5.00%
Mortality table	RP-2014 table with improvement scale MP-2015	RP-2014 table with improvement scale MP-2014	RP-2014 table with improvement scale MP-2015	RP-2014 table with improvement scale MP-2014
Health care cost trend on covered charges	N/A	N/A	6.33% pre-65 and 5.40% post-65 decreasing to ultimate trend of 5.00% in 2020	6.67% pre-65 and 5.50% post-65 decreasing to ultimate trend of 5.00% in 2020

(a) The discount rates above represent the blended rates used to establish the majority of Exelon's pension and other postretirement benefits costs for the year ended December 31, 2017. Certain benefit plans used individual rates ranging from 3.66%-4.11% and 4.00%-4.17% for pension and other postretirement plans, respectively.

(b) The discount rates above represent the blended rates used to establish the majority of Exelon's pension and other postretirement benefits costs for the year ended December 31, 2016. Certain benefit plans used individual rates ranging from 3.68%-4.14% and 4.32%-4.43% for pension and other postretirement plans, respectively.

(c) The discount rates above represent the blended rates used to establish the majority of Exelon's pension and other postretirement benefits costs for the year ended December 31, 2015. Certain benefit plans used the individual rates ranging from 3.29%-3.82% and 3.99%-4.06% for pension and other postretirement plans, respectively.

(d) Not applicable to pension and other postretirement benefit plans that do not have plan assets.

(e) The legacy Exelon, CEG and CENG pension and other postretirement plans used a rate of compensation increase of 3.25% through 2019 and 3.75% thereafter, while the legacy PHI pension and other postretirement plans used a weighted-average rate of compensation increase of 5% for all periods.

(f) The discount rate for the qualified and non-qualified pension plans was 4.65% and 4.55%, respectively.

(g) Expected return on other postretirement benefit plan assets is pre-tax.

Assumed health care cost trend rates impact the other postretirement benefit plan costs reported for Exelon's participant populations with plan designs that do not have a cap on cost growth. A one percentage point change in assumed health care cost trend rates would have the following effects:

Effect of a one percentage point increase in assumed health care cost trend:	
on 2017 total service and interest cost components	$ 9
on postretirement benefit obligation at December 31, 2017	125
Effect of a one percentage point decrease in assumed health care cost trend:	
on 2017 total service and interest cost components	(8)
on postretirement benefit obligation at December 31, 2017	(113)

Contributions

The following tables provide contributions to the pension and other postretirement benefit plans:

	Pension Benefits			Other Postretirement Benefits		
	2017(a)	2016(a)	2015(a)	2017	2016	2015
Exelon	$341	$347	$462	$64	$50	$40
Generation	137	140	231	11	12	14
ComEd	36	33	143	5	5	7
PECO	24	30	40	—	—	—
BGE	39	31	1	14	18	16
BSC(b)	38	39	47	2	3	3
Pepco	62	24	—	10	8	2
DPL	—	22	—	2	—	—
ACE	—	15	—	20	2	3
PHISCO(c)	5	17	—	—	2	—

	Pension Benefits				Other Postretirement Benefits			
	Successor		Predecessor		Successor		Predecessor	
	2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI	$67	$74	$4	$—	$32	$12	$—	$5

(a) Exelon's and Generation's pension contributions include $21 million, $25 million and $36 million related to the legacy CENG plans that was funded by CENG as provided in an Employee Matters Agreement (EMA) between Exelon and CENG for the years ended December 31, 2017, 2016 and 2015, respectively.

(b) Includes $4 million, $6 million, and $5 million of pension contributions funded by Exelon Corporate, for the years ended December 31, 2017, 2016, and 2015, respectively.

(c) PHISCO's pension contributions for the year ended December 31, 2016 include $4 million of contributions made prior to the closing of Exelon's merger with PHI on March 23, 2016.

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 (which has been 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 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

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans at December 31, 2017 were:

	Pension Benefits	Other Postretirement Benefits
2018	$ 1,166	$ 256
2019	1,165	262
2020	1,210	270
2021	1,236	276
2022	1,265	284
2023 through 2027	6,671	1,509
Total estimated future benefit payments through 2027	$12,713	$ 2,857

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

Exelon has developed and implemented a liability hedging investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. Trust assets for Exelon's other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and other postretirement benefit plans. The actual asset returns across Exelon's pension and other postretirement benefit plans for the year ended December 31, 2017 were 16.10% and 14.70%, respectively, compared to an expected long-term return assumption of 7.00% and 6.58%, respectively.

Exelon used an EROA of 7.00% and 6.60% to estimate its 2018 pension and other postretirement benefit costs, respectively.

Exelon's pension and other postretirement benefit plan target asset allocations at December 31, 2017 and 2016 asset allocations were as follows:

Pension Plans

		Percentage of Plan Assets at December 31,	
Asset Category	**Target Allocation**	**2017**	**2016**
Equity securities	35%	35%	33%
Fixed income securities	38%	39	39
Alternative investments[a]	27%	26	28
Total		100%	100%

Other Postretirement Benefit Plans

		Percentage of Plan Assets at December 31,	
Asset Category	**Target Allocation**	**2017**	**2016**
Equity securities	46%	47%	47%
Fixed income securities	28%	28	29
Alternative investments[a]	26%	25	24
Total		100%	100%

(a) Alternative investments include private equity, hedge funds, real estate, and private credit.

Concentrations of Credit Risk. Exelon evaluated its pension and other postretirement benefit plans' asset portfolios for the existence of significant concentrations of credit risk as of December 31, 2017. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2017, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in Exelon's pension and other postretirement benefit plan assets.

Fair Value Measurements

The following tables present pension and other postretirement benefit plan assets measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy at December 31, 2017 and 2016:

December 31, 2017[a][b]	Level 1	Level 2	Level 3	Not subject to leveling	Total
Pension plan assets					
Cash equivalents	$ 585	$ —	$ —	$ —	$ 585
Equities[c]	3,565	—	2	3,077	6,644
Fixed income:					
U.S. Treasury and agencies	1,150	159	—	—	1,309
State and municipal debt	—	64	—	—	64
Corporate debt	—	3,931	232	—	4,163
Other[c]	—	447	—	756	1,203
Fixed income subtotal	1,150	4,601	232	756	6,739
Private equity	—	—	—	1,034	1,034
Hedge funds	—	—	—	1,770	1,770
Real estate	—	—	—	884	884
Private credit	—	—	—	919	919
Pension plan assets subtotal	$5,300	$4,601	$ 234	$ 8,440	$18,575
Other postretirement benefit plan assets					
Cash equivalents	$ 29	$ —	$ —	$ —	$ 29
Equities	523	2	—	764	1,289
Fixed income:					
U.S. Treasury and agencies	13	56	—	—	69
State and municipal debt	—	136	—	—	136
Corporate debt	—	47	—	—	47
Other	225	71	—	185	481
Fixed income subtotal	238	310	—	185	733
Hedge funds	—	—	—	430	430
Real estate	—	—	—	124	124
Private credit	—	—	—	123	123
Other postretirement benefit plan assets subtotal	$ 790	$ 312	$ —	$ 1,626	$ 2,728
Total pension and other postretirement benefit plan assets[d]	$6,090	$4,913	$ 234	$10,066	$21,303

December 31, 2016[a][e]	Level 1	Level 2	Level 3	Not subject to leveling	Total
Pension plan assets					
Cash equivalents	$ 325	$ —	$ —	$ —	$ 325
Equities[c]	3,144	—	2	2,535	5,681
Fixed income:					
U.S. Treasury and agencies	1,008	192	—	—	1,200
State and municipal debt	—	64	—	—	64
Corporate debt	—	3,641	206	—	3,847
Other[c]	—	340	—	748	1,088
Fixed income subtotal	1,008	4,237	206	748	6,199
Private equity	—	—	—	991	991
Hedge funds	—	—	—	1,962	1,962
Real estate	—	—	—	828	828
Private credit	—	—	—	833	833
Pension plan assets subtotal	$4,477	$4,237	$208	$7,897	$16,819
Other postretirement benefit plan assets					
Cash equivalents	$ 24	$ —	$ —	$ —	$ 24
Equities	547	2	—	644	1,193
Fixed income:					
U.S. Treasury and agencies	9	59	—	—	68
State and municipal debt	—	134	—	—	134
Corporate debt	—	43	—	—	43
Other	256	60	—	131	447
Fixed income subtotal	265	296	—	131	692
Hedge funds	—	—	—	445	445
Real estate	—	—	—	117	117
Private credit	—	—	—	107	107
Other postretirement benefit plan assets subtotal	$ 836	$ 298	$ —	$1,444	$ 2,578
Total pension and other postretirement benefit plan assets[d]	$5,313	$4,535	$208	$9,341	$19,397

(a) See Note 11—Fair Value of Financial Assets and Liabilities for a description of levels within the fair value hierarchy.

(b) Effective March 31, 2017, Exelon became sponsor of FitzPatrick's defined benefit pension and other postretirement benefit plans, and assumed FitzPatrick's benefit plan obligations.

(c) Includes derivative instruments of $6 million and $1 million, which have a total notional amount of $3,606 million and $2,918 million at December 31, 2017 and 2016, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.

(d) Excludes net assets of $2 million and net liabilities of $28 million at December 31, 2017 and 2016, respectively, which are required to reconcile to the fair value of net plan assets. These items consist primarily of receivables related to pending securities sales, interest and dividends receivable, and payables related to pending securities purchases.

(e) Effective March 23, 2016, Exelon became sponsor of PHI's defined benefit pension and other postretirement benefit plans, and assumed PHI's benefit plan obligations and related assets.

The following table presents the reconciliation of Level 3 assets and liabilities measured at fair value for pension and other postretirement benefit plans for the years ended December 31, 2017 and 2016:

Pension Assets	Fixed Income	Equities	Total
Balance as of January 1, 2017	$206	$ 2	$ 208
Actual return on plan assets:			
Relating to assets sold during the period	11	—	11
Purchases, sales and settlements:			
Purchases	31	—	31
Sales	(16)	—	(16)
Settlements[(a)]	—	—	—
Balance as of December 31, 2017	$232	$ 2	$ 234

Pension Assets	Fixed Income	Equities	Total
Balance as of January 1, 2016	$165	$ 2	$ 167
Actual return on plan assets:			
Relating to assets still held at the reporting date	(2)	—	(2)
Purchases, sales and settlements:			
Purchases	69	—	69
Sales	(14)	—	(14)
Settlements[(a)]	(12)	—	(12)
Balance as of December 31, 2016	$206	$ 2	$ 208

(a) Represents cash settlements only.

There were no significant transfers between Level 1 and Level 2 during the year ended December 31, 2017 for the pension and other postretirement benefit plan assets.

Valuation Techniques Used to Determine Fair Value

Cash equivalents. Investments with original maturities of three months or less when purchased, including certain short-term fixed income securities and money market funds, are considered cash equivalents. The fair values are based on observable market prices and, therefore, are included in the recurring fair value measurements hierarchy as Level 1.

Equities. Equities consist of individually held equity securities, equity mutual funds and equity commingled funds in domestic and foreign markets. With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are generally obtained from direct feeds from market exchanges, which Exelon is able to independently corroborate. Equity securities held individually, including real estate investment trusts, rights and warrants, are primarily traded on exchanges that contain only actively traded securities due to the volume trading requirements imposed by these exchanges. Equity securities are valued based on quoted prices in active markets and are categorized as Level 1. Certain private placement equity securities are categorized as Level 3 because they are not publicly traded and are priced using significant unobservable inputs.

Equity commingled funds and mutual funds are maintained by investment companies, and certain investments are held in accordance with a stated set of fund objectives, which are consistent with the plans' overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For equity commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly with 30 or less days of notice and without further restrictions.

Fixed income. For fixed income securities, which consist primarily of corporate debt securities, foreign government securities, municipal bonds, asset and mortgage-backed securities, commingled funds, mutual funds and derivative instruments, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Exelon has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Exelon selectively corroborates the fair values of securities by comparison to other market-based price sources. Investments in U.S. Treasury securities have been categorized as Level 1 because they trade in highly-liquid and transparent markets. Certain private placement fixed income securities have been categorized as Level 3 because they are priced using certain significant unobservable inputs and are typically illiquid. The remaining fixed income securities, including certain other fixed income investments, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2.

Other fixed income investments primarily consist of fixed income commingled funds and mutual funds, which are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For fixed income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly with 30 or less days of notice and without further restrictions.

Derivative instruments consisting primarily of futures and swaps to manage risk are recorded at fair value. Over-the-counter derivatives are valued daily based on quoted prices in active markets and trade in open markets, and have been categorized as Level 1. Derivative instruments other than over-the-counter derivatives are valued based on external price data of comparable securities and have been categorized as Level 2.

Private equity. Private equity investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange such as leveraged buyouts, growth capital, venture capital, distressed investments and investments in natural resources. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include unobservable inputs such as cost, operating results, discounted future cash flows and market based comparable data. The fair value of private equity investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Hedge funds. Hedge fund investments include those seeking to maximize absolute returns using a broad range of strategies to enhance returns and provide additional diversification. The fair value of hedge funds is determined using NAV or its equivalent as a practical expedient, and therefore, hedge funds are not classified within the fair value hierarchy. Exelon has the ability to redeem these investments at NAV or its equivalent subject to certain restrictions which may include a lock-up period or a gate.

Real estate. Real estate funds are funds with a direct investment in pools of real estate properties. These funds are valued by investment managers on a periodic basis using pricing models that use independent appraisals from sources with professional qualifications. These valuation inputs are not highly observable. The fair value of real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Private credit. Private credit investments primarily consist of limited partnerships that invest in private debt strategies. These investments are generally less liquid assets with an underlying term of 3 to 5 years and are intended to be held to maturity. The fair value of these investments is determined by the fund manager or administrator and include unobservable inputs such as cost, operating results, and discounted cash flows. The fair value of private credit investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Defined Contribution Savings Plan

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents matching contributions to the savings plan for the years ended December 31, 2017, 2016 and 2015:

For the Year Ended December 31,	Exelon[(a)]	Generation[(a)]	ComEd	PECO	BGE	BSC[(b)]	Pepco[(c)]	DPL[(c)]	ACE	PHISCO[(c)(d)]
2017	$128	$55	$31	$10	$10	$ 9	$3	$2	$2	$6
2016	164	79	34	10	12	19	3	2	2	6
2015	148	80	32	11	14	11	3	2	2	6

	Successor		*Predecessor*	
PHI	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
Saving Plan Matching Contributions	$13	$10	$3	$14

(a) Includes $13 million and $9 million related to CENG for the years ended December 31, 2016 and December 31, 2015.

(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO, BGE, PHI, Pepco, DPL or ACE amounts above.

(c) Pepco's, DPL's and PHISCO's matching contributions include $1 million, $1 million and $1 million, respectively, of costs incurred prior to the closing of Exelon's merger with PHI on March 23, 2016, which is not included in Exelon's matching contributions for the year ended December 31, 2016.

(d) These amounts primarily represent amounts billed to Pepco, DPL, and ACE through intercompany allocations. These amounts are not included in Pepco, DPL or ACE amounts above.

17. Severance

The Registrants have an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. The Registrants record a liability and expense or regulatory asset for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan ("one-time termination benefits"), the Registrants measure the obligation and record the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

Ongoing Severance Plans

The Registrants provide severance and health and welfare benefits under Exelon's ongoing severance benefit plans to terminated employees in the normal course of business. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

For the years ended December 31, 2017 and 2016, the Registrants recorded the following severance costs associated with ongoing severance benefits within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income:

						Successor			
Year ended December 31,	**Exelon**	**Generation[(a)]**	**ComEd[(a)]**	**PECO[(a)]**	**BGE[(a)]**	**PHI[(a)]**	**Pepco[(a)]**	**DPL[(a)]**	**ACE[(a)]**
2017	$14	$ 6	$3	$1	$—	$4	$ 2	$ 1	$ 1
2016	19	13	3	1	1	1	—	—	—

(a) The amounts above for Generation, ComEd, PECO, BGE, and PHI include immaterial amounts billed by BSC for the years ended December 31, 2017 and 2016. Pepco, DPL, and ACE include immaterial amounts billed by PHISCO for the year ended December 31, 2017. Pepco, DPL, and ACE did not have any ongoing severance plans for the year ended December 31, 2016.

Cost Management Program-Related Severance

In August 2015, Exelon announced a cost management program focused on cost savings of approximately $400 million at BSC and Generation. 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. In connection with the program, certain positions have been identified for elimination and severance costs were recognized as both probable and estimable.

While there may be additional position eliminations identified leading to potential severance or other termination benefit changes, Exelon, Generation and BSC intend to manage any staff reductions through natural attrition to the extent possible to minimize impacts on employees. Any additional severance or other termination benefit charges related to this commitment will be recognized when such amounts are considered probable and can be reasonably estimated.

For the years ended December 31, 2017 and 2016, Exelon recorded the following severance costs related to the cost management program within Operating and maintenance expense in their Consolidated Statements of Operations:

2017	$ 6
2016	23

Early Plant Retirement-Related Severance

As a result of the Three Mile Island plant retirement decision, Exelon and Generation will incur certain employee-related costs, including severance benefit costs. Severance costs will be provided to management employees that are eligible under the Company's severance policy, to the extent that those employees are not redeployed to other locations. In June 2017, Exelon and Generation recognized severance costs of $17 million related to expected management employee severances resulting from the plant retirements within Operating and maintenance expense in their Consolidated Statements of Operation and Comprehensive Income. Approximately half of the employees at this location fall under a collective bargaining union agreement and are not eligible for severance benefits under an existing plan. The union and Exelon will negotiate terms of any severance benefits. If severance benefits are successfully negotiated, the amounts will be accrued as a one-time employee termination benefit once the established plan is communicated to employees. The final amount of the severance cost will ultimately depend on the specific employees severed. See Note 8 - Early Nuclear Plant Retirements for additional information regarding the announced early retirement of TMI. See Note 28 - Subsequent Events for additional information regarding the early retirement of Oyster Creek.

Severance Costs Related to the PHI Merger

Upon closing the PHI Merger, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. Cash payments under the plan began in May 2016 and will continue through 2020.

For the year ended December 31, 2017, the PHI Merger severance costs were immaterial. For the year ended December 31, 2016, the Registrants recorded the following severance costs associated with the identified job reductions within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income, pursuant to the authoritative guidance for ongoing severance plans:

						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Severance Benefits									
Severance costs[(a)]	$57	$9	$2	$1	$1	$44	$21	$13	$10

(a) The amounts above for Generation, ComEd, PECO, BGE, Pepco, DPL, and ACE include $8 million, $2 million, $1 million, $1 million, $20 million, $12 million and $10 million, respectively, for amounts billed by BSC and/or PHISCO through intercompany allocations for the year ended December 31, 2016.

PHI, Pepco, DPL and ACE record regulatory assets for merger related integration costs which include a portion of the severance costs in the table above related to the PHI Merger. These regulatory assets are either currently being recovered in rates or are deemed probable of recovery in future rates. See Note 3 — Regulatory Matters for further information.

Severance Liability

Amounts included in the table below represent the severance liability recorded for employees of each Registrant and exclude amounts included at Exelon and billed through intercompany allocations:

Severance Liability	
Balance at December 31, 2015	$ 35
Severance charges[(a)]	99
Payments	(46)
Balance at December 31, 2016	$ 88
Severance charges[(a)]	35
Payments	(29)
Balance at December 31, 2017	$ 94

(a) Includes salary continuance and health and welfare severance benefits.

18. Mezzanine Equity

Contingently Redeemable Noncontrolling Interests

In November 2015, 2015 ESA Investco, LLC, a wholly owned subsidiary of Generation, entered into an arrangement to sell a portion of its equity to a tax equity investor. Pursuant to the operating agreement, in certain circumstances the equity contributed by the noncontrolling interests holder could be contingently redeemable. These circumstances were outside of the control of Generation and the noncontrolling interests holder resulting in a portion of the noncontrolling interests being considered contingently redeemable and thus was presented in mezzanine equity on the consolidated balance sheet.

There were no changes in the contingently redeemable noncontrolling interests for the year ended December 31, 2017. The following table summarizes the changes in the contingently redeemable noncontrolling interests for the year ended December 31, 2016:

	Contingently Redeemable NCI
Balance at December 31, 2015	$ 28
Cash received from noncontrolling interests	129
Release of contingency	(157)
Balance at December 31, 2016	$ —

Preferred Stock

In connection with the PHI Merger Agreement, Exelon purchased 18,000 originally issued shares of PHI preferred stock for a purchase price of $180 million. PHI excluded the preferred stock from equity at December 31, 2015 since the preferred stock contained conditions for redemption that were not solely within the control of PHI. Management determined that the preferred stock contained embedded features requiring separate accounting consideration to reflect the potential value to PHI that any issued and outstanding preferred stock could be called and redeemed at a nominal par value upon a termination of the merger agreement under certain circumstances due to the failure to obtain required regulatory approvals. The embedded call and redemption features on the shares of the preferred stock in the event of such a termination were separately accounted for as derivatives. As of December 31, 2015, the fair value of the derivative related to the preferred stock was estimated to be $18 million based on PHI's updated assessment and was included in current assets with a corresponding increase in preferred stock on the Consolidated Balance Sheet. Immediately prior to the merger date, PHI updated its assessment of the fair value of the derivative and reduced the fair value to zero, recording the $18 million decrease in fair value as a reduction of Other, net within PHI's predecessor period, January 1, 2016 to March 23, 2016, Statements of Operations and Comprehensive Income.

On March 23, 2016, the preferred stock was cancelled and the $180 million cash consideration previously received by PHI to issue the preferred stock was treated as additional merger purchase price consideration.

19. Shareholders' Equity

The following table presents common stock authorized and outstanding as of December 31, 2017 and 2016:

			December 31,	
			2017	2016
	Par Value	Shares Authorized	Shares Outstanding	
Common Stock				
Exelon	no par value	2,000,000,000	963,335,888	924,035,059
ComEd	$12.50	250,000,000	127,021,246	127,017,157
PECO	no par value	500,000,000	170,478,507	170,478,507
BGE	no par value	1,500	1,000	1,000
Pepco	$ 0.01	200,000,000	100	100
DPL	$ 2.25	1,000	1,000	1,000
ACE	$ 3.00	25,000,000	8,546,017	8,546,017

ComEd had 60,584 and 72,859 warrants outstanding to purchase ComEd common stock at December 31, 2017 and 2016, respectively. The warrants entitle the holders to convert such warrants into common stock of ComEd at a conversion rate of one share of common stock for three warrants. At December 31, 2017 and 2016, 20,195 and 24,286 shares of common stock, respectively, were reserved for the conversion of warrants.

Equity Securities Offering

In June 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share. In connection with such offering, Exelon entered into forward sale agreements with two counterparties. In July 2015, Exelon settled the forward sale agreement by the issuance of 57.5 million shares of Exelon common stock. Exelon received net cash proceeds of $1.87 billion, which was calculated based on a forward price of $32.48 per share as specified in the forward sale agreements. The net proceeds were used to fund the merger with PHI and related costs and expenses, and for general corporate purposes. The forward sale agreements are classified as equity transactions. As a result, no amounts were recorded in the consolidated financial statements until the July 2015 settlement of the forward sale agreements. However, prior to the July 2015 settlement, incremental shares, if any, were included within the calculation of diluted EPS using the treasury stock method.

Concurrent with the forward equity transaction, Exelon also issued $1.15 billion of junior subordinated notes in the form of 23 million equity units. On June 1, 2017, Exelon settled the forward purchase contract, which was a component of the June 2014 equity units, through the issuance of Exelon common stock from treasury stock. See Note 13 — Debt and Credit Agreements for further information on the equity units.

Share Repurchases

Share Repurchase Programs

There currently is no Exelon Board of Director authority to repurchase shares. Any previous shares repurchased are held as treasury shares, at cost, unless cancelled or reissued at the discretion of Exelon's management. Under the previous share repurchase programs, 2 million and 35 million shares of common stock were held as treasury stock with a historical cost of $123 million and $2.3 billion at December 31, 2017 and 2016, respectively. During 2017, Exelon issued approximately 33 million shares of Exelon common stock from treasury stock in order to settle the forward purchase contract, which was a component of the June 2014 equity units discussed above. During 2016 and 2015, Exelon had no common stock repurchases.

Preferred and Preference Securities of Subsidiaries

At December 31, 2017 and 2016, Exelon was authorized to issue up to 100,000,000 shares of preferred securities, none of which were outstanding.

At December 31, 2017 and 2016, ComEd prior preferred securities and ComEd cumulative preference securities consisted of 850,000 shares and 6,810,451 shares authorized, respectively, none of which were outstanding.

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.

20. Stock-Based Compensation Plans

Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes stock options, restricted stock units and performance share awards. At December 31, 2017, there were approximately 13 million shares authorized for issuance under the LTIP. For the years ended December 31, 2017, 2016 and 2015, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

ComEd, PECO, BGE and PHI grant cash awards. The following tables do not include expense related to these plans as they are not considered stock-based compensation plans under the applicable authoritative guidance.

In connection with the acquisition of PHI in March 2016, PHI's unvested time-based restricted stock units and performance-based restricted stock units issued prior to April 29, 2014 were immediately vested and paid in cash upon the close of the merger. PHI's remaining unvested time-based restricted stock units as of the close of the merger were cancelled. There were no remaining unvested performance-based restricted stock units as of the close of the merger.

For the years ended December 31, 2017, 2016 and 2015, there were no significant modifications to the granted stock based awards.

The following tables present the stock-based compensation expense included in Exelon's and PHI's Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2017, 2016 and 2015 and PHI's predecessor periods January 1, 2016 to March 23, 2016 and the year ended December 31, 2015:

EXELON

	Year Ended December 31,		
Components of Stock-Based Compensation Expense	**2017**	**2016[(a)]**	**2015**
Performance share awards	$107	$ 93	$ 41
Restricted stock units	77	75	71
Stock options	—	—	1
Other stock-based awards	7	7	6
Total stock-based compensation expense included in operating and maintenance expense	191	175	119
Income tax benefit	(74)	(68)	(46)
Total after-tax stock-based compensation expense	$117	$107	$ 73

(a) 2016 amounts include expense related to stock-based compensation granted to eligible PHI employees since the merger date of March 23, 2016.

PHI

	Predecessor	
	January 1 to March 23,	Year Ended December 31,
Components of Stock-Based Compensation Expense	**2016**	**2015**
Time-based restricted stock units	$ 2	$ 7
Performance-based restricted stock units	1	5
Time-based restricted stock awards	—	1
Total stock-based compensation expense included in operating and maintenance expense	3	13
Income tax benefit	(1)	(5)
Total after-tax stock-based compensation expense	$ 2	$ 8

The following tables present the Registrants' stock-based compensation expense (pre-tax) for the years ended December 31, 2017, 2016 and 2015, as well as for the PHI predecessor periods January 1, 2016 to March 23, 2016 and the year ended December 31, 2015:

	Year Ended December 31,		
Subsidiaries	**2017**	**2016**	**2015**
Exelon	$191	$175	$119
Generation	88	78	64
ComEd	7	8	6
PECO	3	3	3
BGE	1	1	3
BSC[(a)]	88	81	43
PHI Successor[(b)(c)]	4	4	—

	Predecessor	
	January 1 to March 23,	For the Year Ended December 31,
	2016	**2015**
PHI	$3	$13

(a) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO, BGE or PHI amounts above.

(b) Pepco's, DPL's and ACE's stock-based compensation expense for the years ended December 31, 2017 and 2016 was not material.

(c) These amounts primarily represent amounts billed to PHI's subsidiaries through PHISCO intercompany allocations.

There were no significant stock-based compensation costs capitalized during the years ended December 31, 2017, 2016 and 2015 for Exelon or PHI, or for PHI during the predecessor period January 1, 2016 to March 23, 2016.

Exelon and PHI receive a tax deduction based on the intrinsic value of the award on the exercise date for stock options and the distribution date for performance share awards and restricted stock units. For each award, throughout the requisite service period, Exelon and PHI recognize the tax benefit related to compensation costs. The following tables present information regarding Exelon's and PHI's tax benefits for the years ended December 31, 2017, 2016 and 2015 and PHI's predecessor periods January 1, 2016 to March 23, 2016 and the year ended December 31, 2015:

EXELON

	Year Ended December 31,		
	2017	2016	2015
Realized tax benefit when exercised/distributed:			
Restricted stock units	35	27	30
Performance share awards	29	18	18

PHI

	Predecessor	
	January 1 to March 23, 2016	For the Year Ended December 31, 2015
Realized tax benefit when exercised/distributed:		
Time-based restricted stock units	$—	$2
Performance-based restricted stock units	—	5

Stock Options

Non-qualified stock options to purchase shares of Exelon's common stock were granted under the LTIP through 2012. Due to changes in the LTIP, there were no stock options granted in 2017, 2016 or 2015. For all stock options granted through 2012, the exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. The vesting period of stock options is generally four years and all stock options will expire no later than ten years from the date of grant.

The value of stock options at the date of grant is expensed over the requisite service period using the straight-line method. The requisite service period for stock options is generally four years. However, certain stock options become fully vested upon the employee reaching retirement-eligibility. The value of the stock options granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility.

The following table presents information with respect to stock option activity for the year ended December 31, 2017:

	Shares	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
Balance of shares outstanding at December 31, 2016	12,531,591	$ 46.23	3.50	$ 13
Options exercised	(3,093,156)	34.69		
Options forfeited	—	—		
Options expired	(2,714,824)	55.78		
Balance of shares outstanding at December 31, 2017	6,723,611	$ 47.69	2.65	$ 7
Exercisable at December 31, 2017[(a)]	6,723,611	$ 47.69	2.65	$ 7

(a) Includes stock options issued to retirement eligible employees.

The following table summarizes additional information regarding stock options exercised for the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
Intrinsic value[a]	$ 15	$11	$ —
Cash received for exercise price	107	19	—

[a] The difference between the market value on the date of exercise and the option exercise price.

At December 31, 2016, all stock options were vested and at December 31, 2017 there were no unrecognized compensation costs related to nonvested stock options.

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued.

The value of the restricted stock units is expensed over the requisite service period using the straight-line method. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility. The value of the restricted stock units granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility. Exelon processes forfeitures as they occur for employees who do not complete the requisite service period.

The following table summarizes Exelon's nonvested restricted stock unit activity for the year ended December 31, 2017:

EXELON

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2016[a][c]	3,824,416	$ 30.49
Granted	2,266,199	34.98
Vested	(1,736,965)	30.98
Forfeited	(92,938)	33.12
Undistributed vested awards[b]	(871,209)	34.09
Nonvested at December 31, 2017[a]	3,389,503	$ 32.24

[a] Excludes 1,488,383 and 1,319,372 of restricted stock units issued to retirement-eligible employees as of December 31, 2017 and 2016, respectively, as they are fully vested.

[b] Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2017.

[c] 2016 amounts include activity related to stock-based compensation granted to eligible PHI employees since the merger date of March 23, 2016.

For Exelon, the weighted average grant date fair value (per share) of restricted stock units granted for the years ended December 31, 2017, 2016 and 2015 was $34.98, $28.14 and $36.55, respectively. At December 31, 2017 and 2016, Exelon had obligations related to outstanding restricted stock units not yet settled of $108 million and $101 million, respectively, which are included in common stock in Exelon's Consolidated Balance Sheets. For the years ended December 31, 2017, 2016 and 2015, Exelon settled restricted stock units with fair value totaling $88 million, $68 million and $75 million, respectively. At December 31, 2017, $51 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 1.7 years.

For PHI, the weighted average grant date fair value (per share) of time-based restricted stock units granted for the year ended December 31, 2015 was $27.40 and for performance-based restricted stock units was $26.08 for the same period. For the year ended December 31, 2015, PHI settled time-based restricted stock units with fair value totaling $6 million and settled performance-based restricted stock units with fair value totaling $15 million, for the same period. There were no settled restricted stock units for the predecessor period January 1, 2016 to March 23, 2016.

Performance Share Awards

Performance share awards are granted under the LTIP. The performance share awards are settled 50% in common stock and 50% in cash at the end of the three-year performance period, except for awards granted to vice presidents and higher officers that are settled 100% in cash if certain ownership requirements are satisfied.

The common stock portion of the performance share awards is considered an equity award and is valued based on Exelon's stock price on the grant date. The cash portion of the performance share awards is considered a liability award which is remeasured each reporting period based on Exelon's current stock price. As the value of the common stock and cash portions of the awards are based on Exelon's stock price during the performance period, coupled with changes in the total shareholder return modifier and expected payout of the award, the compensation costs are subject to volatility until payout is established.

Effective January 2017 for nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the straight-line method. For performance share awards granted to retirement-eligible employees, the value of the performance shares is recognized ratably over the vesting period, which is the year of grant.

In 2016 and prior, for nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method. For performance share awards granted to retirement-eligible employees, the value of the performance shares is recognized ratably over the vesting period, which is the year of grant.

Exelon processes forfeitures as they occur for employees who do not complete the requisite service period.

The following table summarizes Exelon's nonvested performance share awards activity for the year ended December 31, 2017:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2016[a][c]	3,116,261	$ 30.77
Granted	1,632,186	35.00
Change in performance	545,793	30.97
Vested	(1,111,751)	29.11
Forfeited	(18,034)	33.74
Undistributed vested awards[b]	(1,207,489)	33.46
Nonvested at December 31, 2017[a]	2,956,966	$ 32.65

(a) Excludes 2,723,440 and 2,443,409 of performance share awards issued to retirement-eligible employees as of December 31, 2017 and 2016, respectively, as they are fully vested.

(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2017.

(c) 2016 amounts include activity related to stock-based compensation granted to eligible PHI employees since the merger date of March 23, 2016.

The following table summarizes the weighted average grant date fair value and the fair value of performance share awards granted and settled for the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017[a]	2016	2015
Weighted average grant date fair value (per share)	$35.00	$28.85	$35.88
Fair value of performance shares settled	72	45	46
Fair value of performance shares settled in cash	56	28	29

(a) As of December 31, 2017, $41 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 1.5 years.

For PHI, the weighted average grant date fair value (per share) of performance-based restricted stock awards was $26.10 for the year ended December 31, 2015. There were no time-based restricted stock awards granted for the year ended December 31, 2015. There were no time-based share settlements or performance-based share settlements for the year-ended December 31, 2015 or the predecessor period January 1, 2016 to March 23, 2016.

The following table presents the balance sheet classification of obligations related to outstanding performance share awards not yet settled:

	December 31,	
	2017	2016
Current liabilities[(a)]	$ 57	$ 49
Deferred credits and other liabilities[(b)]	100	52
Common stock	26	40
Total	$ 183	$ 141

(a) Represents the current liability related to performance share awards expected to be settled in cash.

(b) Represents the long-term liability related to performance share awards expected to be settled in cash.

21. Earnings Per Share

Basic earnings per share is computed by dividing net income attributable to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed by dividing net income attributable to common shareholders by the weighted average number of common shares outstanding, including the effect of issuing common stock assuming (i) stock options are exercised, and (ii) performance share awards and restricted stock awards are fully vested under the treasury stock method.

The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock awards on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	Year Ended December 31,		
	2017	2016	2015
Net income attributable to common shareholders	$3,770	$1,134	$2,269
Weighted average common shares outstanding — basic	947	924	890
Assumed exercise and/or distributions of stock-based awards	2	3	3
Weighted average common shares outstanding — diluted	949	927	893

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 8 million in 2017, 12 million in 2016, and 16 million in 2015. There were no equity units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect for the years ended December 31, 2017 and 2016. The number of equity units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect was 3 million for the year ended 2015. Refer to Note 19 —Shareholders' Equity for further information regarding the equity units and equity forward units.

On June 1, 2017, Exelon settled the forward purchase contract, which was a component of the June 2014 equity units, through the issuance of approximately 33 million shares of Exelon common stock from treasury stock. The issuance of shares on June 1, 2017 triggered full dilution in the EPS calculation, which prior to settlement were included in the calculation of diluted EPS using the treasury stock method. Refer to Note 19 — Shareholders' Equity for further information regarding share repurchases.

22. Changes in Accumulated Other Comprehensive Income

The following tables present changes in accumulated other comprehensive income (loss) (AOCI) by component for the years ended December 31, 2017 and 2016:

For the Year Ended December 31, 2017	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon[(a)]						
Beginning balance	$(17)	$ 4	$(2,610)	$(30)	$(7)	$(2,660)
OCI before reclassifications	(1)	6	11	7	6	29
Amounts reclassified from AOCI[(b)]	4	—	140	—	—	144
Net current-period OCI	3	6	151	7	6	173
Ending balance	$(14)	$10	$(2,459)	$(23)	$(1)	$(2,487)

For the Year Ended December 31, 2016	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon[(a)]						
Beginning balance	$(19)	$ 3	$(2,565)	$(40)	$(3)	$(2,624)
OCI before reclassifications	(6)	1	(182)	5	(4)	(186)
Amounts reclassified from AOCI[(b)]	8	—	137	5	—	150
Net current-period OCI	2	1	(45)	10	(4)	(36)
Ending balance	$(17)	$ 4	$(2,610)	$(30)	$(7)	$(2,660)

(a) All amounts are net of tax and noncontrolling interests. Amounts in parenthesis represent a decrease in AOCI.

(b) See next tables for details about these reclassifications.

(c) As a result of the PHI Merger, the PHI predecessor balances at March 23, 2016 were reduced to zero on March 24, 2016 due to purchase accounting adjustments applied to PHI.

ComEd, PECO, BGE, Pepco, DPL and ACE did not have any reclassifications out of AOCI to Net income during the years ended December 31, 2017 and 2016. The following tables present amounts reclassified out of AOCI to Net income for Exelon, Generation and PHI during the years ended December 31, 2017 and 2016:

FOR THE YEAR ENDED DECEMBER 31, 2017

Details about AOCI components	Items reclassified out of AOCI[a]	Affected line item in the Statement of Operations and Comprehensive Income
Gains and (losses) on cash flow hedges		
Other cash flow hedges	$ (5)	Interest expense
Total before tax	(5)	
Tax benefit	1	
Net of tax	$ (4)	Comprehensive income
Amortization of pension and other postretirement benefit plan items		
Prior service costs[b]	$ 92	
Actuarial losses[b]	(324)	
Total before tax	(232)	
Tax benefit	92	
Net of tax	$(140)	Comprehensive Income
Total Reclassifications	$(144)	Comprehensive income

FOR THE YEAR ENDED DECEMBER 31, 2016

Details about AOCI components	Items reclassified out of AOCI[a]	Affected line item in the Statement of Operations and Comprehensive Income
Loss on cash flow hedges		
Other cash flow hedges	$ (13)	Interest expense
Total before tax	(13)	
Tax benefit	5	
Net of tax	$ (8)	Comprehensive income
Amortization of pension and other postretirement benefit plan items		
Prior service costs[b]	$ 78	
Actuarial losses[b]	(302)	
Total before tax	(224)	
Tax benefit	87	
Net of tax	$(137)	Comprehensive Income
Losses on foreign currency translation		
Loss	$ (5)	Other income and (deductions)
Total before tax	(5)	
Tax benefit	—	
Net of tax	$ (5)	
Total Reclassifications	$(150)	Comprehensive income

(a) Amounts in parenthesis represent a decrease in net income.

(b) This AOCI component is included in the computation of net periodic pension and OPEB cost (see Note 16 — Retirement Benefits for additional details).

The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the years ended December 31, 2017 and 2016:

	For the Year Ended December 31,		
	2017	2016	2015
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	$ 36	$ 30	$ 30
Actuarial loss reclassified to periodic benefit cost	(128)	(118)	(140)
Pension and non-pension postretirement benefit plans valuation adjustment	13	115	62
Change in unrealized loss on cash flow hedges	(7)	—	(6)
Change in unrealized (loss)/gain on equity investments	(3)	3	1
Change in unrealized loss on marketable securities	(1)	—	—
Total	$ (90)	$ 30	$ (53)

23. Commitments and Contingencies

Commitments

Constellation Merger Commitments

In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion.

The direct investment includes the construction of a new 21-story headquarters building in Baltimore for Generation's competitive energy business that was substantially complete in November 2016 and is now occupied by approximately 1,500 Exelon employees. Generation's investment includes leasehold improvements that are not expected to exceed $110 million. In addition, Generation entered into a 20-year operating lease as the primary lessee of the building.

The direct investment commitment also includes $450 million to $500 million relating to Exelon and Generation's development or assistance in the development of 285 - 300 MWs of new generation in Maryland, which is expected to be completed within a period of 10 years. The MDPSC order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed or certain specified provisions are elected, making liquidated damages payments. Exelon and Generation have incurred $457 million towards satisfying the commitment for new generation development in the state of Maryland, with approximately 220 MW of the new generation commencing with commercial operations to date and an additional 10 MW commitment satisfied through a liquidated damages payment made in the fourth quarter of 2016. Additionally, during the fourth quarter of 2016, given continued declines in projected energy and capacity prices, Generation terminated rights to certain development projects originally intended to meet its remaining 55 MW commitment amount. The commitment will now most likely be satisfied via payment of liquidated damages or execution of a third party PPA, rather than by Generation constructing renewable generating assets. As a result, Exelon and Generation recorded a pre-tax $50 million loss contingency in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2016.

Commercial Commitments

Exelon's commercial commitments as of December 31, 2017, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2018	2019	2020	2021	2022	2023 and beyond
Letters of credit (non-debt)[(a)]	$1,226	$1,056	$ 154	$ 16	$—	$—	$ —
Surety bonds[(b)]	1,381	1,293	66	16	6	—	—
Financing trust guarantees	378	—	—	—	—	—	378
Guaranteed lease residual values[(c)]	21	—	—	—	—	—	21
Total commercial commitments	$3,006	$2,349	$ 220	$ 32	$ 6	$—	$ 399

(a) Letters of credit (non-debt)—Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.

(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $56 million, $16 million of which is a guarantee by Pepco, $23 million by DPL and $15 million by ACE. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

Leases

Minimum future operating lease payments, including lease payments for contracted generation, vehicles, real estate, computers, rail cars, operating equipment and office equipment, as of December 31, 2017 were:

	Exelon[(a)]
2018	$ 188
2019	129
2020	147
2021	142
2022	119
Remaining years	787
Total minimum future lease payments	$ 1,512

(a) Includes amounts related to shared use land arrangements.

The following table presents Exelon's rental expense under operating leases for the years ended December 31, 2017, 2016 and 2015:

For the Year Ended December 31,	
2017	$ 709
2016	777
2015	922

For information regarding capital lease obligations, see Note 13—Debt and Credit Agreements.

Nuclear Insurance

Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations. Generation has mitigated its financial exposure to these risks through insurance and other industry risk-sharing provisions.

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and to limit the liability of nuclear reactor owners for such claims from any single incident. As of December 31, 2017, the current liability limit per incident is $13.4 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors at least once every five years with the last adjustment effective September 10, 2013. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. Effective January 1, 2017, the required amount of nuclear energy liability insurance purchased is $450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool, as required by the Price Anderson-Act, which provides the additional $13.0 billion per incident in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Exelon's share of this secondary layer would be approximately $2.8 billion, however any amounts payable under this secondary layer would be capped at $420 million per year.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.4 billion limit for a single incident.

As part of the execution of the NOSA on April 1, 2014, Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this indemnity. See Note 2 — Variable Interest Entities for additional information on Generation's operations relating to CENG.

Generation is required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years NEIL has made distributions to its members, but Generation cannot predict the level of future distributions or if they will continue at all. Generation's portion of the distribution declared by NEIL is estimated to be $60 million for 2017, and was $21 million for 2016 and 2015. The distributions were recorded as a reduction to Operating and maintenance expense within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income.

Premiums paid to NEIL by its members are also subject to a potential assessment for adverse loss experience in the form of a retrospective premium obligation. NEIL has never assessed this retrospective premium since its formation in 1973, and Generation cannot predict the level of future assessments if any. The current maximum aggregate annual retrospective premium obligation for Generation is approximately $360 million. NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

NEIL provides "all risk" property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, Generation is unable to predict the timing of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery by Exelon will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon's and Generation's financial conditions, results of operations and cash flows.

Spent Nuclear Fuel Obligation

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, Generation is a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from Generation's nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation historically had paid the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. On November 19, 2013, the D.C. Circuit Court ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. On May 9, 2014, the DOE notified Generation that the SNF disposal fee remained in effect through May 15, 2014, after which time the fee was set to zero. As a result, for the year ended December 31, 2017, 2016 and 2015, Generation did not incur any expense in SNF disposal fees. Until a new fee structure is in effect, Exelon and Generation will not accrue any further costs related to SNF disposal fees. This fee may be adjusted prospectively to ensure full cost recovery. The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance has been, and is expected to be, delayed significantly.

The 2010 Federal budget (which became effective October 1, 2009) eliminated almost all funding for the creation of the Yucca Mountain repository while the Obama Administration devised a new strategy for long-term SNF management. The Blue Ribbon Commission (BRC) on America's Nuclear Future, appointed by the U.S. Energy Secretary, released a report on January 26, 2012, detailing comprehensive recommendations for creating a safe, long-term solution for managing and disposing of the nation's SNF and high-level radioactive waste.

In early 2013, the DOE issued an updated "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste" in response to the BRC recommendations. This strategy included a consolidated interim storage facility that was planned to be operational in 2025. However, due to continued delays on the part of the DOE, Generation currently assumes the DOE will begin accepting SNF in 2030 and uses that date for purposes of estimating the nuclear decommissioning asset retirement obligations. 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.

In August 2004, Generation and the DOJ, in close consultation with the DOE, reached a settlement under which the government agreed to reimburse Generation, subject to certain damage limitations based on the extent of the government's breach, for costs associated with storage of SNF at Generation's nuclear stations pending the DOE's fulfillment of its obligations. Generation's settlement agreement does not include FitzPatrick and FitzPatrick does not currently have a settlement agreement in place. Calvert Cliffs, Ginna and Nine Mile Point each have separate settlement agreements in place with the DOE which were extended during 2017 to provide for the reimbursement of SNF storage costs through December 31, 2019. Generation submits annual reimbursement requests to the DOE for costs associated with the storage of SNF. In all cases, reimbursement requests are made only after costs are incurred and only for costs resulting from DOE delays in accepting the SNF.

Under the settlement agreements, Generation has received cumulative cash reimbursements for costs incurred as follows:

	Total	Net[(a)]
Cumulative cash reimbursements[(b)]	$ 1,167	$ 1,006

(a) Total after considering amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek.
(b) Includes $53 and $49, respectively, for amounts received since April 1, 2014, for costs incurred under the CENG DOE Settlement Agreements prior to the consolidation of CENG.

As of December 31, 2017 and 2016, the amount of SNF storage costs for which reimbursement has been or will be requested from the DOE under the DOE settlement agreements is as follows:

	December 31, 2017	December 31, 2016
DOE receivable - current[(a)]	$ 94	$ 109
DOE receivable - noncurrent[(b)]	15	15
Amounts owed to co-owners[(a)(c)]	(11)	(13)

(a) Recorded in Accounts receivable, other.
(b) Recorded in Deferred debits and other assets, other
(c) Non-CENG amounts owed to co-owners are recorded in Accounts receivable, other. CENG amounts owed to co-owners are recorded in Accounts payable. Represents amounts owed to the co-owners of Peach Bottom, Quad Cities, and Nine Mile Point Unit 2 generating facilities.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. The fee related to the former PECO units has been paid. Pursuant to the Standard Contracts, ComEd previously elected to defer payment of the one-time fee of $277 million for its units (which are now part of Generation), with interest to the date of payment, until just prior to the first delivery of SNF to the DOE. The unfunded liabilities for SNF disposal costs, including the one-time fee, were transferred to Generation as part of Exelon's 2001 corporate restructuring. A prior owner of FitzPatrick also elected to defer payment of the one-time fee of $34 million for the FitzPatrick unit. As part of the FitzPatrick acquisition on March 31, 2017, Generation assumed a SNF liability for the DOE one-time fee obligation with interest related to FitzPatrick along with an offsetting asset for the contractual right to reimbursement from NYPA, a prior owner of FitzPatrick, for amounts paid for the FitzPatrick DOE one-time fee obligation. The amounts were recorded at fair value. See Note 4 -Mergers, Acquisitions and Dispositions for additional information on the FitzPatrick acquisition. As of December 31, 2017 and 2016, the SNF liability for the one-time fee with interest was $1,147 million and $1,024 million, respectively, which is included in Exelon's and Generation's Consolidated Balance Sheets. Interest for Exelon's and Generation's SNF liabilities accrues at the 13-week Treasury Rate. The 13-week Treasury Rate in effect, for calculation of the interest accrual at December 31, 2017, was 1.149%. The outstanding one-time fee obligations for the Nine Mile Point, Ginna, Oyster Creek and TMI units remain with the former owners. The Clinton and Calvert Cliffs units have no outstanding obligation. See Note 11 — Fair Value of Financial Assets and Liabilities for additional information.

Environmental Remediation Matters

General. The Registrants' operations have in the past, and may in the future, require substantial expenditures 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, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future. Unless otherwise disclosed, the Registrants cannot reasonably estimate whether they will incur significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers. Additional costs could have a material, unfavorable impact on the Registrants' financial conditions, results of operations and cash flows.

MGP Sites

ComEd, PECO, BGE and DPL have identified sites where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

- ComEd has identified 42 sites, 19 of which have been remediated and approved by the Illinois EPA or the U.S. EPA and 23 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2022.
- PECO has identified 26 sites, 17 of which have been remediated in accordance with applicable PA DEP regulatory requirements and 9 that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2022.
- BGE has identified 13 former gas manufacturing or purification sites, 11 of which the remediation has been completed and approved by the MDE and 2 that require some level of remediation and/or ongoing monitoring. BGE has determined that a loss associated with these sites is probable and has recorded an estimated liability, which is included in the table below. However, it is reasonably possible that BGE's cost of remediation for one of its sites could be up to $13 million.
- DPL has identified 3 sites, 2 of which remediation has been completed and approved by the MDE or the Delaware Department of Natural Resources and Environmental Control. The remaining site is under study and the required cost at the site is not expected to be material.

The historical nature of the MGP sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs using all available information at the time of each study, including probabilistic and deterministic modeling for ComEd and PECO, and the remediation standards currently required by the applicable state environmental agency. Prior to completion of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. See Note 3 — Regulatory Matters for additional information regarding the associated regulatory assets. While BGE and DPL do not have riders for MGP clean-up costs, they have historically received recovery of actual clean-up costs in distribution rates.

As of December 31, 2017 and 2016, the Registrants had accrued the following undiscounted amounts for environmental liabilities in Other current liabilities and Other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

December 31, 2017	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 466	$ 315
Generation	117	—
ComEd	285	283
PECO	30	28
BGE	5	4
PHI	29	—
Pepco	27	—
DPL	1	—
ACE	1	—

December 31, 2016	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 429	$ 325
Generation	72	—
ComEd	292	291
PECO	33	31
BGE	2	2
PHI	30	1
Pepco	27	—
DPL	2	1
ACE	1	—

During the third quarter of 2017, ComEd, PECO, BGE and DPL completed an annual study of their future estimated MGP remediation requirements. The study resulted in a $13 million and $2 million increase to environmental liabilities and related regulatory assets for ComEd and PECO, respectively, and no change at BGE and DPL.

Solid and Hazardous Waste

Cotter Corporation. The EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. In 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the EPA issued a Record of Decision (ROD) approving a landfill cover remediation approach. By letter dated January 11, 2010, the EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the supplemental feasibility study to the EPA for review. Since June 2012, the EPA has requested that the PRPs perform a series of additional analyses and groundwater and soil sampling as part of the supplemental feasibility study. This further analysis was focused on a partial excavation remedial option. The PRPs provided the draft final Remedial Investigation and Feasibility Study (RI/FS) to the EPA in January 2018, which formed the basis for EPA's proposed remedy selection, as further discussed below. There are currently three PRPs participating in the West Lake Landfill remediation proceeding. Investigation by Generation has identified a number of other parties who also may be PRPs and could be liable to contribute to the final remedy. Further investigation is ongoing. As of December 31, 2016, Generation had previously recorded an estimated liability for its anticipated share of a landfill cover remedy, which at the time was estimated to cost approximately $90 million in total.

On February 1, 2018, the EPA announced its proposed remedy involving partial excavation of the site with an enhanced landfill cover. The proposed remedy will be open for public comment through March 22, 2018 and Generation currently expects that a ROD will be issued during the third quarter of 2018. Thereafter, the EPA will seek to enter into a Consent Decree with the PRPs to effectuate the remedy, which Generation currently expects will occur in late 2018 or early 2019. The estimated cost of the remedy, taking into account the current EPA technical requirements and the total costs expected to be incurred by the PRPs in fully executing the remedy, is approximately $340 million, including cost escalation on an undiscounted basis, which would be allocated among the final group of PRPs. Generation has determined that a loss associated with the EPA's partial excavation and enhanced landfill cover remedy is probable and has recorded a liability as of December 31, 2017, included in the table above, that reflects management's best estimate of Cotter's allocable share of the ultimate cost for the entire remediation effort. Given the joint and several nature of this liability, the magnitude of Generation's ultimate liability will depend on the actual costs incurred to implement the ultimate required remediation remedy as well as on the nature and terms of any cost-sharing arrangements with the final group of PRPs. Therefore, it is reasonably possible that the ultimate cost and Generation's associated allocable share recorded as of December 31, 2017, could differ significantly once these uncertainties are resolved, which could have a material impact on Exelon's and Generation's future financial conditions, results of operations and cash flows.

On January 16, 2018, the PRPs were advised by the EPA that it will begin an additional investigation and evaluation of groundwater conditions at the West Lake Landfill. The PRPs have been provided with a draft statement of work that will form the basis of an Administrative Settlement Agreement and Order on Consent for the performance by the PRPs of the groundwater RI/FS and reimbursement of EPA's oversight costs. The purposes of this new RI/FS are to define the nature and extent of any groundwater contamination from the West Lake Landfill site, determine the potential risk posed to human health and the environment, and evaluate remedial alternatives. Generation estimates the undiscounted cost for the groundwater RI/FS for West Lake to be approximately $20 million and Generation has recorded a liability as of December 31, 2017, included in the table above, that reflects management's best estimate of Cotter's allocable share of the cost among the PRPs. At this time Generation cannot predict the likelihood or the extent to which, if any, remediation activities will be required and cannot estimate a reasonably possible range of loss for response costs beyond those associated with the RI/FS component. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon's and Generation's future results of operations and cash flows.

During December 2015, the EPA took two actions related to the West Lake Landfill designed to abate what it termed as imminent and dangerous conditions at the landfill. The first involved installation by the PRPs of a non-combustible surface cover to protect against surface fires in areas where radiological materials are believed to have been disposed. Generation has accrued what it believes to be an adequate amount to cover its anticipated liability for this interim action, and the work is expected to be completed in 2018. The second action involved EPA's public statement that it will require the PRPs to construct a barrier wall in an adjacent landfill to prevent a subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, Generation believes that the requirement to build a barrier wall is remote in light of other technologies that have been employed by the adjacent landfill owner. Finally, one of the other PRPs, the landfill owner and operator of the adjacent landfill, has indicated that it will be making a contribution claim against Cotter for costs that it has incurred to prevent the subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, Exelon and Generation do not possess sufficient information to assess this claim and therefore are unable to estimate a range of loss, if any. As such, no liability has been recorded for the potential contribution claim. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon's and Generation's financial conditions, results of operations and cash flows.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. Government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under FUSRAP. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million from all PRPs. The DOJ and the PRPs agreed to toll the statute of limitations until August 2018 so that settlement discussions could proceed. Generation has determined that a loss associated with this matter is probable under its indemnification agreement with Cotter and has recorded an estimated liability, which is included in the table above.

Commencing in February 2012, a number of lawsuits have been filed in the U.S. District Court for the Eastern District of Missouri. Among the defendants were Exelon, Generation and ComEd, all of which were subsequently dismissed from the case, as well as Cotter, which remains a defendant. The suits allege that individuals living in the North St. Louis area developed some form of cancer or other serious illness due to Cotter's negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs are asserting public liability claims under the Price-Anderson Act. Their state law claims for negligence, strict liability, emotional distress, and medical monitoring have been dismissed. The complaints do not contain specific damage claims. In the event of a finding of liability against Cotter, it is reasonably possible that Generation would be financially responsible due to its indemnification responsibilities of Cotter described above. The court has dismissed a number of the lawsuits as untimely, and that ruling is currently on appeal. Pre-trial motions and discovery are proceeding in the remaining cases and a pre-trial scheduling order has been filed with the court. At this stage of the litigation, Generation cannot estimate a range of loss, if any. As such, no liability has been recorded for these lawsuits.

Benning Road Site. In September 2010, PHI received a letter from EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site was formerly the location of a Pepco Energy Services electric generating facility. That generating facility was deactivated in June 2012 and plant structure demolition was completed in July 2015. The remaining portion of the site consists of a Pepco transmission and distribution service center that remains in operation. In December 2011, the U.S. District Court for the District of Columbia approved a Consent Decree entered into by Pepco and Pepco Energy Services with the DOEE, which requires Pepco and Pepco Energy Services to conduct a Remediation Investigation (RI)/ Feasibility Study (FS) for the Benning Road site and an approximately 10 to 15-acre portion of the adjacent Anacostia River. The RI/FS will form the basis for the remedial actions for the Benning Road site and for the Anacostia River sediment associated with the site. The Consent Decree does not obligate Pepco or Pepco Energy Services to pay for or perform any remediation work, but it is anticipated that DOEE will look to Pepco and Pepco Energy Services to assume responsibility for cleanup of any conditions in the river that are determined to be attributable to past activities at the Benning Road site. Pursuant to Exelon's March 23, 2016 acquisition of PHI, Pepco Energy Services was transferred to Generation.

Since 2013, Pepco and Pepco Energy Services (now Generation) have been performing RI work and have submitted multiple draft RI reports to the DOEE. Once the RI work is completed, Pepco and Generation will issue a draft "final" RI report for review and comment by DOEE and the public. Pepco and Generation will then proceed to develop an FS to evaluate possible remedial alternatives for submission to DOEE. The Court has established a schedule for completion of the RI and FS, and approval by the DOEE, by May 6, 2019.

Upon DOEE's approval of the final RI and FS Reports, Pepco and Generation will have satisfied their obligations under the Consent Decree. At that point, DOEE will prepare a Proposed Plan regarding further response actions. After considering public comment on the Proposed Plan, DOEE will issue a Record of Decision identifying any further response actions determined to be necessary.

PHI, Pepco and Generation have determined that a loss associated with this matter is probable and have accrued an estimated liability, which is included in the table above.

Anacostia River Tidal Reach. Contemporaneous with the Benning RI/FS being performed by Pepco and Generation, DOEE and certain federal agencies have been conducting a separate RI/FS focused on the entire tidal reach of the Anacostia River extending from just north of the Maryland-D.C. boundary line to the confluence of the Anacostia and Potomac Rivers. In March 2016, DOEE released a draft of the river-wide RI Report for public review and comment. The river-wide RI incorporated the results of the river sampling performed by Pepco and Pepco Energy Services as part of the Benning RI/FS, as well as similar sampling efforts conducted by owners of other sites adjacent to this segment of the river and supplemental river sampling conducted by DOEE's contractor. DOEE asked Pepco, along with parties responsible for other sites along the river, to participate in a "Consultative Working Group" to provide input into the process for future remedial actions addressing the entire tidal reach of the river and to ensure proper coordination with the other river cleanup efforts currently underway, including cleanup of the river segment adjacent to the Benning Road site resulting from the Benning RI/FS. Pepco responded that it will participate in the Consultative Working Group but its participation is not an acceptance of any financial responsibility beyond the work that will be performed at the Benning Road site described above. DOEE has advised the Consultative Working Group that the federal and DOEE authorities are conducting the remedial investigation and that a feasibility study of potential remedies is being prepared. DOEE currently is working under a statutorily mandated date to complete the Record of Decision selecting the final remedy for the project by June 30, 2018. However, on January 11, 2018 the DOEE requested at a hearing of the District of Columbia Council Committee of the Environment that this statutory deadline be extended until December 31, 2019 to reflect the time necessary to complete the investigation. A recommendation by the Committee to the DC Council is expected in the near future. The District of Columbia Council will make the final determination to extend the deadline. An appropriate liability for Pepco's share of investigation costs has been accrued and is included in the table above. Although Pepco has determined that it is probable that costs for remediation will be incurred, Pepco cannot estimate the reasonably possible range of loss at this time and no liability has been accrued for those future costs.

Conectiv Energy Wholesale Power Generation Sites. In July 2010, PHI sold the wholesale power generation business of Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries (Conectiv Energy) to Calpine Corporation (Calpine). Under New Jersey's Industrial Site Recovery Act (ISRA), the transfer of ownership triggered an obligation on the part of Conectiv Energy to remediate any environmental contamination at each of the nine Conectiv Energy generating facility sites located in New Jersey. Under the terms of the sale, Calpine has assumed responsibility for performing the ISRA-required remediation and for the payment of all related ISRA compliance costs up to $10 million. Predecessor PHI was obligated to indemnify Calpine for any ISRA compliance remediation costs in excess of $10 million. According to PHI's estimates, the costs of ISRA-required remediation activities at the nine generating facility sites located in New Jersey are in the range of approximately $7 million to $18 million, and predecessor PHI recorded an estimated liability for its share of the estimated clean-up costs. Pursuant to Exelon's March 2016 acquisition of PHI, the Conectiv Energy legal entity was transferred to Generation and the liability for Predecessor PHI's share of the estimated clean-up costs was also transferred to Generation and is included in the table above as a liability of Generation. The responsibility to indemnify Calpine is shared by PHI and Generation.

Brandywine Fly Ash Disposal Site. In February 2013, Pepco received a letter from the MDE requesting that Pepco investigate the extent of waste on a Pepco right-of-way that traverses the Brandywine fly ash disposal site in Brandywine, Prince George's County, Maryland, owned by NRG Energy, Inc. (as successor to GenOn MD Ash Management, LLC) (NRG). In July 2013, while reserving its rights and related defenses under a 2000 agreement covering the sale of this site, Pepco indicated its willingness to investigate the extent of, and propose an appropriate closure plan to address, ash on the right-of-way. Pepco submitted a schedule for development of a closure plan to MDE on September 30, 2013 and, by letter dated October 18, 2013, MDE approved the schedule.

Pepco has determined that a loss associated with this matter is probable and has recorded an estimated liability, which is included in the table above. Pepco believes that the costs incurred in this matter may be recoverable from NRG under the 2000 sale agreement, but has not recorded an associated receivable for any potential recovery.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims

Generation maintains estimated liabilities for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The estimated liabilities are recorded on an undiscounted basis and exclude the estimated legal costs associated with handling these matters, which could be material.

At December 31, 2017 and 2016, Generation had recorded estimated liabilities of approximately $78 million and $83 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2017, approximately $21 million of this amount related to 230 open claims presented to Generation, while the remaining $57 million is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether adjustments to the estimated liabilities are necessary.

On November 22, 2013, the Supreme Court of Pennsylvania held that the Pennsylvania Workers Compensation Act does not apply to an employee's disability or death resulting from occupational disease, such as diseases related to asbestos exposure, which manifests more than 300 weeks after the employee's last employment-based exposure, and that therefore the exclusivity provision of the Act does not preclude such employee from suing his or her employer in court. The Supreme Court's ruling reverses previous rulings by the Pennsylvania Superior Court precluding current and former employees from suing their employers in court, despite the fact that the same employee was not eligible for workers compensation benefits for diseases that manifest more than 300 weeks after the employee's last employment-based exposure to asbestos. Since the Pennsylvania Supreme Court's ruling in November 2013, Exelon, Generation, and PECO have experienced an increase in asbestos-related personal injury claims brought by former PECO employees, all of which have been accrued for on a claim by claim basis. Those additional claims are taken into account in projecting estimated future asbestos-related bodily injury claims.

On November 4, 2015, the Illinois Supreme Court found that the provisions of the Illinois' Workers' Compensation Act and the Workers' Occupational Diseases Act barred an employee from bringing a direct civil action against an employer for latent diseases, including asbestos-related diseases that fall outside the 25-year limit of the statute of repose. The Illinois Supreme Court's ruling reversed previous rulings by the Illinois Court of Appeals, which initially ruled that the Illinois Worker's Compensation law should not apply in cases where the diagnosis of an asbestos related disease occurred after the 25-year maximum time period for filing a Worker's Compensation claim. As a result of this ruling, Exelon, Generation, and ComEd have not recorded an increase to the asbestos-related bodily injury liability as of December 31, 2017.

There is a reasonable possibility that Exelon may have additional exposure to estimated future asbestos-related bodily injury claims in excess of the amount accrued and the increases could have a material unfavorable impact on Exelon's, Generation's and PECO's financial conditions, results of operations and cash flows.

Fund Transfer Restrictions

Under applicable law, Exelon may borrow or receive an extension of credit from its subsidiaries. Under the terms of Exelon's intercompany money pool agreement, Exelon can lend to, but not borrow from the money pool.

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

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with financings arranged through ComEd Financing III that it will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued.

PECO's Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred securities. On May 1, 2013, PECO redeemed all outstanding preferred securities. As a result, the above ratio calculation is no longer applicable. Additionally, PECO may not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures, which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued.

BGE 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 is subject to certain dividend restrictions established by settlements approved in Maryland and the District of Columbia. Pepco is prohibited from paying a dividend on its common shares if (a) after the dividend payment, Pepco's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the commissions and the Board or (b) Pepco's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade.

DPL is subject to certain dividend restrictions established by settlements approved in Delaware and Maryland. DPL is prohibited from paying a dividend on its common shares if (a) after the dividend payment, DPL's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the commissions and the Board or (b) DPL's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade.

ACE is subject to certain dividend restrictions established by settlements approved in New Jersey. ACE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, ACE's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the commissions and the Board or (b) ACE's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade.

Conduit Lease with City of Baltimore

On September 23, 2015, the Baltimore City Board of Estimates approved an increase in annual rental fees for access to the Baltimore City underground conduit system effective November 1, 2015, from $12 million to $42 million, subject to an annual increase thereafter based on the Consumer Price Index. BGE subsequently entered into litigation with the City regarding the amount of and basis for establishing the conduit fee. On November 30, 2016, the Baltimore City Board of Estimates approved a settlement agreement entered into between BGE and the City to resolve the disputes and pending litigation related to BGE's use of and payment for the underground conduit system. As a result of the settlement, the parties have entered into a six-year lease that reduces the annual expense to $25 million in the first three years and caps the annual expense in the last three years to not more than $29 million. BGE recorded a decrease to Operating and maintenance expense in the fourth quarter of 2016 of approximately $28 million for the reversal of the previously higher fees accrued as well as the settlement of prior year disputed fee true-up amounts.

Deere Wind Energy Assets

In 2013, Deere & Company (Deere) filed a lawsuit against Generation in the Delaware Superior Court relating to Generation's acquisition of the Deere wind energy assets. Under the purchase agreement, Deere was entitled to receive earn-out payments if certain specific wind projects already under development in Michigan met certain development and construction milestones following the sale. In the complaint, Deere sought to recover a $14 million earn-out payment associated with one such project, which was never completed. On June 2, 2016, the Delaware Superior Court entered summary judgment in favor of Deere. As a result, in the second quarter of 2016, Generation increased its accrued liability to $14 million. On January 17, 2017, Generation filed an appeal with the Delaware Supreme Court. On December 18, 2017, the Delaware Supreme Court reversed the Superior Court decision and entered final judgment in favor of Generation. As a result, in the fourth quarter of 2017, Generation reversed its previously established liability of $14 million.

City of Everett Tax Increment Financing Agreement

On April 10, 2017, the City of Everett petitioned the Massachusetts Economic Assistance Coordinating Council (EACC) to revoke the 1999 tax increment financing agreement (TIF Agreement) relating to Mystic 8 & 9 on the grounds that the total investment in Mystic 8 & 9 materially deviates from the investment set forth in the TIF Agreement. On October 31, 2017, a three-member panel of the EACC conducted an administrative hearing on the City's petition. On November 30, 2017, the hearing panel issued a tentative decision denying the City's petition, finding that there was no material misrepresentation that would justify revocation of the TIF Agreement. On December 13, 2017, the tentative decision was adopted by the full EACC. On January 12, 2018, the City filed a complaint in Massachusetts Superior Court requesting, among other things, that the court set aside the EACC's decision, grant the City's request to decertify the Project and the TIF Agreement, and award the City damages for alleged underpaid taxes over the period of the TIF Agreement. Generation vigorously contested the City's claims before the EACC and will continue to do so in the Massachusetts Superior Court proceeding. Generation continues to believe that the City's claim lacks merit. Accordingly, Generation has not recorded a liability for payment resulting from such a revocation, nor can Generation estimate a reasonably possible range of loss, if any, associated with any such revocation. Further, it is reasonably possible that property taxes assessed in future periods, including those following the expiration of the current TIF Agreement in 2019, could be material to Generation's results of operations and cash flows.

General

The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Income Taxes

See Note 14 — Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil-generating assets.

24. Supplemental Financial Information

Supplemental Statement of Operations Information

The following tables provide additional information about Exelon's Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2017, 2016 and 2015.

	For the Years Ended December 31,		
	2017	2016	2015
Taxes other than income			
Utility[a]	$ 898	$ 753	$ 474
Property	545	483	407
Payroll	230	226	201
Other	58	114	118
Total taxes other than income	$1,731	$1,576	$1,200

	For the Years Ended December 31,		
	2017	2016	2015
Other, Net			
Decommissioning-related activities:			
Net realized income on decommissioning trust funds[a]			
Regulatory agreement units	$ 488	$ 237	$ 232
Non-regulatory agreement units	209	126	156
Net unrealized gains on decommissioning trust funds			
Regulatory agreement units	455	216	(282)
Non-regulatory agreement units	521	194	(197)
Net unrealized losses on pledged assets			
Zion Station decommissioning	(10)	(1)	7
Regulatory offset to decommissioning trust fund-related activities[b]	(724)	(372)	21
Total decommissioning-related activities	939	400	(63)
Investment income	8	17	8
Long-term lease income	—	4	15
Interest income (expense) related to uncertain income tax positions	3	13	1
Penalty related to uncertain income tax positions[c]	2	(106)	—
AFUDC—Equity	73	64	24
Loss on debt extinguishment	—	(3)	—
Terminated interest rate swaps[d]	—	—	(26)
PHI merger related debt exchange[e]	—	—	(22)
Other	31	24	17
Other, net	$1,056	$ 413	$ (46)

(a) Includes investment income and realized gains and losses on sales of investments within the nuclear decommissioning trust funds.

(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 15 — Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(c) See Note 14—Income Taxes for discussion of the penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position.

(d) In January 2015, in connection with Generation's $750 million issuance of five-year Senior Unsecured Notes, Exelon terminated certain floating-to-fixed interest rate swaps. As the original forecasted transactions were a series of future interest payments over a ten-year period, a portion of the anticipated interest payments are probable not to occur. As a result, $26 million of anticipated payments were reclassified from AOCI to Other, net in Exelon's Consolidated Statements of Operations and Comprehensive Income.

(e) See Note 13—Debt and Credit Agreements and Note 4—Mergers, Acquisitions and Dispositions for additional information on the PHI merger related debt exchange.

Supplemental Cash Flow Information

The following tables provide additional information regarding Exelon's Consolidated Statements of Cash Flows for the years ended December 31, 2017, 2016 and 2015.

	For the year ended December 31,		
	2017	2016	2015
Depreciation, amortization and accretion			
Property, plant and equipment	$3,293	$3,477	$2,227
Regulatory assets	478	407	170
Amortization of intangible assets, net	57	52	54
Amortization of energy contract assets and liabilities[a]	35	35	22
Nuclear fuel[b]	1,096	1,159	1,116
ARO accretion[c]	468	446	398
Total depreciation, amortization and accretion	$5,427	$5,576	$3,987

(a) Included in Operating revenues or Purchased power and fuel on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

(b) Included in Purchased power and fuel expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

(c) Included in Operating and maintenance expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

	For the year ended December 31,		
	2017	2016	2015
Cash paid (refunded) during the year:			
Interest (net of amount capitalized)	$2,430	$1,340	$ 930
Income taxes (net of refunds)	540	(441)	342
Other non-cash operating activities:			
Pension and non-pension postretirement benefit costs	$ 643	$ 619	$ 637
Loss from equity method investments	32	24	7
Provision for uncollectible accounts	125	155	120
Provision for excess and obsolete inventory	56	111	10
Stock-based compensation costs	88	(384)	97
Other decommissioning-related activity[a]	(313)	—	(82)
Energy-related options[b]	7	(11)	21
Amortization of regulatory asset related to debt costs	9	9	7
Amortization of rate stabilization deferral	(10)	76	73
Amortization of debt fair value adjustment	(18)	(11)	(17)
Merger-related commitments[c][d]	—	558	—
Severance costs	35	99	—
Amortization of debt costs	64	35	58
Provision for excess and obsolete inventory	—	12	—
Discrete impacts from EIMA and FEJA[e]	(52)	—	—
Discrete impacts from EIMA[f]	—	8	144
Lower of cost or market inventory adjustment	—	37	23
Baltimore City Conduit Lease Settlement	—	(28)	—
Cash Working Capital Order	—	(13)	—
Vacation accrual adjustment[g]	(68)	—	—
Asset Retirements Costs	—	2	—
Long-term incentive plan	109	70	24
Change in environmental liabilities	44	—	—
Other	(30)	(35)	(13)
Total other non-cash operating activities	$ 721	$1,333	$1,109

	For the year ended December 31,		
	2017	2016	2015
Non-cash investing and financing activities:			
Increase (decrease) in capital expenditures not paid	$ 42	$ (128)	$ 96
Change in PPE related to ARO update	29	191	885
Non-cash financing of capital projects	16	95	77
Indemnification of like-kind exchange position[h]	—	—	—
Dividends on stock compensation	7	6	6
Dissolution of financing trust due to long-term debt retirement	8	—	—
Fair value adjustment of long-term debt due to retirement	(5)	—	—
Fair value of pension and OPEB obligation transferred in connection with FitzPatrick	—	—	—
Sale of Upstream assets[c]	—	37	—
Pending FitzPatrick Acquisition[i]	—	(54)	—
Nuclear fuel procurement[j]	—	—	57
Long-term software licensing agreement[k]	—	—	95

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15 —Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.

(c) See Note 4 - Mergers, Acquisitions and Dispositions for more information.

(d) Excludes $5 million of forgiveness of Accounts receivable related to merger commitments recorded in connection with the PHI Merger, the balance is included within Provision for uncollectible accounts.

(e) Reflects the change in ComEd's distribution and energy efficiency formula rates. See Note 3 — Regulatory Matters for more information.

(f) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate. See Note 3 — Regulatory Matters for more information.

(g) On December 1, 2017, Exelon adopted a single, standard vacation accrual policy for all non-represented, non-craft (represented and craft policies remained unchanged) employees effective January 1, 2018. To reflect the new policy, Exelon recorded a one-time, $68 million pre-tax credit to expense to reverse 2018 vacation cost originally accrued throughout 2017 that will now be accrued ratably over the year in 2018.

(h) See Note 14 — Income Taxes for discussion of the like-kind exchange tax position.

(i) Reflects the transfer of nuclear fuel to Entergy under the cost reimbursement provisions of the FitzPatrick acquisition agreements. See Note 4 - Mergers, Acquisitions and Dispositions for more information.

(j) Relates to the nuclear fuel procurement contracts for the purchase of fixed quantities of uranium, which was delivered to Generation in 2015. Generation is required to make payments starting September 30, 2018, with the final payment being due no later than September 30, 2020.

(k) Relates to a long-term software license agreement entered into on May 30, 2015. Exelon is required to make payments starting August of 2015 through May of 2024. See Note 13 - Debt and Credit Agreements.

Supplemental Balance Sheet Information

The following tables provide additional information about Exelon's assets and liabilities at December 31, 2017 and 2016.

	As of December 31,	
	2017	2016
Investments		
Equity method investments:		
Financing trusts[a]	$ 14	$ 22
Bloom	206	216
Net Power	76	57
Other equity method investments	1	16
Total equity method investments	297	311
Other investments:		
Employee benefit trusts and investments[b]	244	232
Other cost method investments	62	52
Other available for sale investments	37	34
Total investments	$640	$629

(a) Includes investments in affiliated financing trusts, which were not consolidated within the financial statements of Exelon and are shown as investments on the Consolidated Balance Sheets. See Note 1 — Significant Accounting Policies for additional information.
(b) The Registrants' investments in these marketable securities are recorded at fair market value.

The following tables provide additional information about Exelon's liabilities at December 31, 2017 and 2016.

	As of December 31,	
	2017	2016
Accrued expenses		
Compensation-related accruals[a]	$ 978	$1,199
Taxes accrued	373	723
Interest accrued	328	1,234
Severance accrued	58	44
Other accrued expenses	98	260
Total accrued expenses	$1,835	$3,460

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.

25. Segment Information

Operating segments for each of the Registrants are determined based on information used by the chief operating decision maker(s) (CODM) in deciding how to evaluate performance and allocate resources at each of the Registrants.

In the first quarter of 2016, following the consummation of the PHI Merger, three new reportable segments were added: Pepco, DPL and ACE. As a result, Exelon has twelve reportable segments, which include ComEd, PECO, BGE, PHI's three reportable segments consisting of Pepco, DPL, and ACE, and Generation's six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other power regions referred to collectively as "Other Power Regions", which includes activities in the South, West and Canada. ComEd, PECO, BGE, Pepco, DPL and ACE each represent a single reportable segment, and as such, no separate segment information is provided for these Registrants. Exelon, ComEd, PECO, BGE, Pepco, DPL and ACE's CODMs evaluate the performance of and allocate resources to ComEd, PECO, BGE, Pepco, DPL and ACE based on net income and return on equity.

Effective with the consummation of the PHI Merger, PHI's reportable segments have changed based on the information used by the CODM to evaluate performance and allocate resources. PHI's reportable segments consist of Pepco, DPL and ACE. PHI's Predecessor periods' segment information was recast in 2016 to conform to the current Exelon presentation. The reclassification of the segment information did not impact PHI's reported consolidated revenues or net income. PHI's CODM evaluates the performance of and allocates resources to Pepco, DPL and ACE based on net income and return on equity.

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 to these same geographic regions. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of Pennsylvania and North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO, excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Power Regions:
    - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
    - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado and parts of New Mexico, Wyoming and South Dakota.
    - Canada represents operations across the entire country of Canada and includes AESO, OIESO and the Canadian portion of MISO.

The CODMs for Exelon and Generation evaluate the performance of Generation's electric business activities and allocate resources based on revenues net of purchased power and fuel expense (RNF). Generation believes that RNF is a useful measurement of operational performance. RNF 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. 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 Generation's owned generation and fuel costs associated with tolling agreements. The results of Generation's other business activities are not regularly reviewed by the CODM and are therefore not classified as operating segments or included in the regional reportable segment amounts. These activities include natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further, Generation's unrealized mark-to-market gains and losses on economic hedging activities and its amortization of certain intangible assets and liabilities relating to commodity contracts recorded at fair value from mergers and acquisitions are also excluded from the regional reportable segment amounts. Exelon and Generation do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the years ended December 31, 2017, 2016, and 2015 is as follows:

	Successor							
	Generation[(a)]	ComEd	PECO	BGE	PHI[(e)]	Other[(b)]	Intersegment Eliminations	Exelon
Operating revenues[(c)]:								
2017								
Competitive businesses electric revenues	$15,300	$ —	$ —	$ —	$ —	$ —	$ (1,105)	$ 14,195
Competitive businesses natural gas revenues	2,575	—	—	—	—	—	—	2,575
Competitive businesses other revenues	591	—	—	—	—	—	(1)	590
Rate-regulated electric revenues	—	5,536	2,375	2,489	4,469	—	(29)	14,840
Rate-regulated natural gas revenues	—	—	495	687	161	—	(10)	1,333
Shared service and other revenues	—	—	—	—	49	1,831	(1,880)	—
2016								
Competitive businesses electric revenues	$15,390	$ —	$ —	$ —	$ —	$ —	$ (1,430)	$ 13,960
Competitive businesses natural gas revenues	2,146	—	—	—	—	—	—	2,146
Competitive businesses other revenues	215	—	—	—	—	—	(4)	211
Rate-regulated electric revenues	—	5,254	2,531	2,609	3,506	—	(31)	13,869
Rate-regulated natural gas revenues	—	—	463	624	92	—	(13)	1,166
Shared service and other revenues	—	—	—	—	45	1,648	(1,686)	7
2015								
Competitive businesses electric revenues	$15,944	$ —	$ —	$ —	$ —	$ —	$ (744)	$ 15,200
Competitive businesses natural gas revenues	2,433	—	—	—	—	—	—	2,433
Competitive businesses other revenues	758	—	—	—	—	—	(1)	757
Rate-regulated electric revenues	—	4,905	2,486	2,490	—	—	(5)	9,876
Rate-regulated natural gas revenues	—	—	546	645	—	—	(15)	1,176
Shared service and other revenues	—	—	—	—	—	1,372	(1,367)	5

	Successor							
	Generation[(a)]	ComEd	PECO	BGE	PHI[(e)]	Other[(b)]	Intersegment Eliminations	Exelon
Intersegment revenues[(d)]:								
2017	$ 1,110	$ 15	$ 7	$ 16	$ 50	$ 1,824	$ (3,020)	$ 2
2016	1,428	15	8	21	45	1,647	(3,159)	5
2015	745	4	2	14	—	1,367	(2,127)	5
Depreciation and amortization:								
2017	$ 1,457	$ 850	$ 286	$ 473	$ 675	$ 87	$ —	$ 3,828
2016	1,879	775	270	423	515	74	—	3,936
2015	1,054	707	260	366	—	63	—	2,450
Operating expenses[(c)]:								
2017	$17,993	$ 4,214	$ 2,215	$2,562	$ 3,911	$ 1,851	$ (3,026)	$ 29,720
2016	16,856	4,056	2,292	2,683	3,549	1,928	(3,164)	28,200
2015	16,872	3,889	2,404	2,578	—	1,444	(2,131)	25,056
Equity in earnings (losses) of unconsolidated affiliates:								
2017	$ (33)	$ —	$ —	$ —	$ —	$ 1	$ —	$ (32)
2016	(25)	—	—	—	—	1	—	(24)
2015	(8)	—	—	—	—	1	—	(7)
Interest expense, net:								
2017	$ 440	$ 361	$ 126	$ 105	$ 245	$ 283	$ —	$ 1,560
2016	364	461	123	103	195	290	—	1,536
2015	365	332	114	99	—	123	—	1,033
Income (loss) before income taxes:								
2017	$ 1,429	$ 984	$ 538	$ 525	$ 578	$ (296)	$ (2)	$ 3,756
2016	873	679	587	468	(58)	(555)	(5)	1,989
2015	1,850	706	521	477	—	(219)	(5)	3,330
Income taxes:								
2017	$ (1,375)	$ 417	$ 104	$ 218	$ 217	$ 294	$ —	$ (125)
2016	290	301	149	174	3	(156)	—	761
2015	502	280	143	189	—	(41)	—	1,073
Net income (loss):								
2017	$ 2,771	$ 567	$ 434	$ 307	$ 362	$ (590)	$ (2)	$ 3,849
2016	558	378	438	294	(61)	(398)	(5)	1,204
2015	1,340	426	378	288	—	(177)	(5)	2,250
Capital expenditures:								
2017	$ 2,259	$ 2,250	$ 732	$ 882	$ 1,396	$ 65	$ —	$ 7,584
2016	3,078	2,734	686	934	1,008	113	—	8,553
2015	3,841	2,398	601	719	—	65	—	7,624
Total assets:								
2017	$48,387	$29,726	$10,170	$9,104	$21,247	$ 8,618	$(10,552)	$116,700
2016	46,974	28,335	10,831	8,704	21,025	10,369	(11,334)	114,904

(a) Generation includes the six reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. For the year ended December 31, 2017, intersegment revenues for Generation include revenue from sales to PECO of $138 million, sales to BGE of $388 million, sales to Pepco of $255 million, sales to DPL of $179 million and sales to ACE of $29 million in the Mid-Atlantic region, and sales to ComEd of $121 million in the Midwest region, which eliminate upon consolidation. For the year ended December 31, 2016, intersegment revenues for Generation include revenue from sales to PECO of $290 million and sales to BGE of $608 million in the Mid-Atlantic region, and sales to ComEd of $47 million in the Midwest region, which eliminate upon consolidation. For the Successor period of March 24, 2016 to December 31, 2016, intersegment revenues for Generation include revenue from sales to Pepco of $295 million, sales to DPL of $154 million and sales to ACE of $37 million in the Mid-Atlantic region, which eliminate upon consolidation. For the year ended December 31, 2015, intersegment revenues for Generation include revenue from sales to PECO of $224 million and sales to BGE of $502 million in the Mid-Atlantic region, and sales to ComEd of $18 million in the Midwest region, which eliminate upon consolidation.

(b) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.

(c) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 24 — Supplemental Financial Information for total utility taxes for the years ended December 31, 2017, 2016 and 2015.

(d) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

(e) Amounts included represent activity for PHI's successor period, March 24, 2016 through December 31, 2017. PHI includes the three reportable segments: Pepco, DPL and ACE. See tables below for PHI's predecessor periods, including Pepco, DPL and ACE, for January 1, 2016 to March 23, 2016 and for the year ended December 31, 2015.

SUCCESSOR AND PREDECESSOR PHI:

	Pepco	DPL	ACE	Other(b)	Intersegment Eliminations	PHI
Operating revenues(a):						
December 31, 2017 - Successor						
Rate-regulated electric revenues	$2,158	$1,139	$1,186	$ —	$ (14)	$ 4,469
Rate-regulated natural gas revenues	—	161	—	—	—	161
Shared service and other revenues	—	—	—	52	(3)	49
March 24, 2016 to December 31, 2016 - Successor						
Rate-regulated electric revenues	$1,675	$ 850	$ 989	$ 5	$ (13)	$ 3,506
Rate-regulated natural gas revenues	—	92	—	—	—	92
Shared service and other revenues	—	—	—	45	—	45
January 1, 2016 to March 23, 2016 - Predecessor						
Rate-regulated electric revenues	$ 511	$ 279	$ 268	$ 42	$ (4)	$ 1,096
Rate-regulated natural gas revenues	—	56	—	1	—	57
Shared service and other revenues	—	—	—	—	—	—
December 31, 2015 - Predecessor						
Rate-regulated electric revenues	$2,129	$1,138	$1,295	$ 210	$ (2)	$ 4,770
Rate-regulated natural gas revenues	—	164	—	1	—	165
Shared service and other revenues	—	—	—	—	—	—
Intersegment revenues:						
December 31, 2017 - Successor	$ 6	$ 8	$ 2	$ 53	$ (19)	$ 50
March 24, 2016 to December 31, 2016 - Successor	4	5	2	47	(13)	45
January 1, 2016 to March 23, 2016 - Predecessor	1	2	1	—	(4)	—
December 31, 2015 - Predecessor	5	6	4	—	(15)	—
Depreciation and amortization:						
December 31, 2017 - Successor	$ 321	$ 167	$ 146	$ 42	$ (1)	$ 675
March 24, 2016 to December 31, 2016 - Successor	224	120	128	43	—	$ 515
January 1, 2016 to March 23, 2016 - Predecessor	71	37	37	11	(4)	$ 152
December 31, 2015 - Predecessor	256	148	175	45	—	$ 624
Operating expenses:						
December 31, 2017 - Successor	$1,760	$1,071	$1,029	$ 68	$ (17)	$ 3,911
March 24, 2016 to December 31, 2016 - Successor	1,577	952	1,000	33	(13)	$ 3,549
January 1, 2016 to March 23, 2016 - Predecessor	443	284	251	73	(3)	$ 1,048
December 31, 2015 - Predecessor	1,790	1,137	1,161	220	—	$ 4,308
Interest expense, net:						
December 31, 2017 - Successor	$ 121	$ 51	$ 61	$ 13	$ (1)	$ 245
March 24, 2016 to December 31, 2016 - Successor	98	38	47	12	—	$ 195
January 1, 2016 to March 23, 2016 - Predecessor	29	12	15	11	(2)	$ 65
December 31, 2015 - Predecessor	124	50	64	43	(1)	$ 280
Income (loss) before income taxes:						
December 31, 2017 - Successor	$ 310	$ 192	$ 103	$ 377	$ (404)	$ 578
March 24, 2016 to December 31, 2016 - Successor	36	(30)	(51)	(84)	71	$ (58)
January 1, 2016 to March 23, 2016 - Predecessor	47	43	5	59	(118)	$ 36
December 31, 2015 - Predecessor	289	125	73	23	(29)	$ 481
Income taxes:						
December 31, 2017 - Successor	$ 105	$ 71	$ 26	$ 15	$ —	$ 217
March 24, 2016 to December 31, 2016 - Successor	26	5	(5)	(23)	—	$ 3
January 1, 2016 to March 23, 2016 - Predecessor	15	17	1	(16)	—	$ 17
December 31, 2015 - Predecessor	102	49	33	(48)	27	$ 163

	Pepco	DPL	ACE	Other[(b)]	Intersegment Eliminations	PHI
Operating revenues[(a)]:						
Net income (loss):						
December 31, 2017 - Successor	$ 205	$ 121	$ 77	$ (91)	$ 50	$ 362
March 24, 2016 to December 31, 2016 - Successor	10	(35)	(47)	(34)	45	$ (61)
January 1, 2016 to March 23, 2016 - Predecessor	32	26	5	(44)	—	$ 19
December 31, 2015 - Predecessor	187	76	40	25	(1)	$ 327
Capital expenditures:						
December 31, 2017 - Successor	$ 628	$ 428	$ 312	$ 28	$ —	$ 1,396
March 24, 2016 to December 31, 2016 - Successor	489	277	218	24	—	$ 1,008
January 1, 2016 to March 23, 2016 - Predecessor	97	72	93	11	—	273
December 31, 2015 - Predecessor	544	352	300	34	—	1,230
Total assets:						
December 31, 2017 - Successor	$7,832	$4,357	$3,445	$10,600	$(4,987)	$21,247
December 31, 2016 - Successor	7,335	4,153	3,457	10,804	(4,724)	21,025

(a) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 24 — Supplemental Financial Information for total utility taxes for the years ended December 31, 2017, 2016 and 2015.

(b) Other primarily includes PHI's corporate operations, shared service entities and other financing and investment activities. For the predecessor periods presented, Other includes the activity of PHI's unregulated businesses which were distributed to Exelon and Generation as a result of the PHI Merger.

GENERATION TOTAL REVENUES:

	2017			2016			2015		
	Revenues from external customers[(a)]	Intersegment revenues	Total revenues	Revenues from external customers[(a)]	Intersegment revenues	Total revenues	Revenues from external customers[(a)]	Intersegment revenues	Total revenues
Mid-Atlantic	$ 5,515	$ 25	$ 5,540	$ 6,212	$ (33)	$ 6,179	$ 5,974	$ (74)	$ 5,900
Midwest	4,206	(25)	4,181	4,402	10	4,412	4,712	(2)	4,710
New England	2,010	(8)	2,002	1,778	(9)	1,769	2,217	(5)	2,212
New York	1,535	(17)	1,518	1,198	(42)	1,156	996	(11)	985
ERCOT	958	4	962	831	6	837	863	(6)	857
Other Power Regions	1,076	(27)	1,049	969	(62)	907	1,182	(80)	1,102
Total Revenues for Reportable Segments	$15,300	$(48)	$15,252	$15,390	$(130)	$15,260	$15,944	$(178)	$15,766
Other[(b)]	3,166	48	3,214	2,361	130	2,491	3,191	178	3,369
Total Generation Consolidated Operating Revenues	$18,466	$ —	$18,466	$17,751	$ —	$17,751	$19,135	$ —	$19,135

(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to the Utility Registrants.

(b) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes a $38 million decrease to revenues, a $52 million decrease to revenues, and a $7 million increase to revenues for the amortization of intangible assets related to commodity contracts recorded at fair value for the years ended December 31, 2017, 2016, and 2015, respectively, unrealized mark-to-market losses of $131 million, losses of $500 million, and gains of $203 million for the years ended December 31, 2017, 2016, and 2015, respectively, and elimination of intersegment revenues.

GENERATION TOTAL REVENUES NET OF PURCHASED POWER AND FUEL EXPENSE:

	2017			2016			2015		
	RNF from external customers[(a)]	Intersegment RNF	Total RNF	RNF from external customers[(a)]	Intersegment RNF	Total RNF	RNF from external customers[(a)]	Intersegment RNF	Total RNF
Mid-Atlantic	$3,105	$ 109	$3,214	$3,282	$ 35	$3,317	$3,556	$ 15	$3,571
Midwest	2,810	10	2,820	2,969	2	2,971	2,912	(20)	2,892
New England	538	(24)	514	467	(29)	438	519	(58)	461
New York	975	1	976	761	(19)	742	584	50	634
ERCOT	575	(243)	332	412	(131)	281	425	(132)	293
Other Power Regions	476	(171)	305	483	(147)	336	440	(190)	250
Total Revenues net of purchased power and fuel expense for Reportable Segments	$8,479	$(318)	$8,161	$8,374	$(289)	$8,085	$8,436	$(335)	$8,101
Other[(b)]	297	318	615	547	289	836	678	335	1,013
Total Generation Revenues net of purchased power and fuel expense	$8,776	$ —	$8,776	$8,921	$ —	$8,921	$9,114	$ —	$9,114

(a) Includes purchases and sales from third parties and affiliated sales to the Utility Registrants.

(b) Other represents activities not allocated to a region. See text above for a description of included activities. Includes a $54 million decrease in RNF, a $57 million decrease in RNF, and a $8 million increase in RNF for the amortization of intangible assets and liabilities related to commodity contracts for the years ended December 31, 2017, 2016, and 2015, respectively, unrealized mark-to-market losses of $175 million, losses of $41 million, and gains of $257 million for the years ended December 31, 2017, 2016, and 2015, respectively, accelerated nuclear fuel amortization associated with the announced early retirement decision for Clinton and Quad Cities as discussed in Note 8 - Early Nuclear Plant Retirements of $12 million and $60 million for the year ended December 31, 2017 and 2016, and the elimination of intersegment revenues net of purchased power and fuel expense.

26. Related Party Transactions

The financial statements of Exelon include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2017	2016	2015
Operating revenues from affiliates:			
PECO[(a)]	$ 1	$ 1	$ 1
BGE[(a)]	4	4	4
Other	2	5	4
Total operating revenues from affiliates	$ 7	$ 10	$ 9
Interest expense to affiliates, net:			
ComEd Financing III	$ 14	$ 13	$13
PECO Trust III	6	6	6
PECO Trust IV	6	6	6
BGE Capital Trust II	10	16	16
Total interest expense to affiliates, net	$ 36	$ 41	$41
Earnings (losses) in equity method investments:			
Qualifying facilities and domestic power projects	$(33)	$(25)	$ (8)
Other	1	1	1
Total losses in equity method investments	$(32)	$(24)	$ (7)

	December 31, 2017	December 31, 2016
Payables to affiliates (current):		
ComEd Financing III	$ 4	$ 4
PECO Trust III	1	1
BGE Capital Trust II	—	3
Total payables to affiliates (current)	$ 5	$ 8
Long-term debt due to financing trusts:		
ComEd Financing III	$205	$205
PECO Trust III	81	81
PECO Trust IV	103	103
BGE Capital Trust II	—	252
Total long-term debt due to financing trusts	$389	$641

(a) The intersegment profit associated with the sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations. See Note 3—Regulatory Matters for additional information.

27. Quarterly Data

The data shown below, which may not equal the total for the year due to the effects of rounding and dilution, includes all adjustments that Exelon considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income Attributable to Common Shareholders	
	2017	2016	2017	2016	2017	2016
Quarter ended:						
March 31	$8,757	$7,573	$1,296	$ 483	$ 995	$173
June 30	7,623	6,910	232	647	80	267
September 30	8,769	9,002	1,475	1,267	824	490
December 31	8,381	7,875	1,258	714	1,871	204

	Average Basic Shares Outstanding (in millions)		Net Income per Basic Share	
	2017	2016	2017	2016
Quarter ended:				
March 31	928	923	$1.07	$0.19
June 30	934	924	0.09	0.29
September 30	962	925	0.86	0.53
December 31	964	925	1.94	0.22

	Average Diluted Shares Outstanding (in millions)		Net Income per Diluted Share	
	2017	2016	2017	2016
Quarter ended:				
March 31	930	925	$1.07	$0.19
June 30	936	926	0.09	0.29
September 30	965	927	0.85	0.53
December 31	967	928	1.93	0.22

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 Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First 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

28. Subsequent Events

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.

Early Retirement of Oyster Creek Generating Station

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 onetime 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.

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.

Income statement expense (pre-tax)	Projected[b] 2018
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.

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