UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2016

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number	Exact name of registrants as specified in their charters	I.R.S. Employer Identification Number
001-08489	**DOMINION RESOURCES, INC.**	**54-1229715**
000-55337	**VIRGINIA ELECTRIC AND POWER COMPANY**	**54-0418825**
001-37591	**DOMINION GAS HOLDINGS, LLC**	**46-3639580**

VIRGINIA
(State or other jurisdiction of incorporation or organization)
120 TREDEGAR STREET
RICHMOND, VIRGINIA **23219**
(Address of principal executive offices) *(Zip Code)*
(804) 819-2000
(Registrants' telephone number)

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

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
DOMINION RESOURCES, INC.	Common Stock, no par value	New York Stock Exchange
	2014 Series A 6.375% Corporate Units	New York Stock Exchange
	2016 Series A 6.75% Corporate Units	New York Stock Exchange
	2016 Series A 5.25% Enhanced Junior Subordinated Notes	New York Stock Exchange
DOMINION GAS HOLDINGS, LLC	2014 Series C 4.6% Senior Notes	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
VIRGINIA ELECTRIC AND POWER COMPANY
Common Stock, no par value
DOMINION GAS HOLDINGS, LLC
Limited Liability Company Membership Interests

Indicate by check mark whether the registrant is a well-known seasoned issuer as defined in Rule 405 of the Securities Act.
Dominion Resources, Inc. Yes ☒ No ☐ Virginia Electric and Power Company Yes ☒ No ☐ Dominion Gas Holdings, LLC Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Dominion Resources, Inc. Yes ☐ No ☒ Virginia Electric and Power Company Yes ☐ No ☒ Dominion Gas Holdings, LLC Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Dominion Resources, Inc. Yes ☒ No ☐ Virginia Electric and Power Company Yes ☒ No ☐ Dominion Gas Holdings, LLC Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Dominion Resources, Inc. Yes ☒ No ☐ Virginia Electric and Power Company Yes ☒ No ☐ Dominion Gas Holdings, LLC Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
Dominion Resources, Inc. ☐ Virginia Electric and Power Company ☒ Dominion Gas Holdings, LLC ☒

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

Dominion Resources, Inc.
Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Virginia Electric and Power Company
Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☐

Dominion Gas Holdings, LLC
Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Act).
Dominion Resources, Inc. Yes ☐ No ☒ Virginia Electric and Power Company Yes ☐ No ☒ Dominion Gas Holdings, LLC Yes ☐ No ☒

The aggregate market value of Dominion Resources, Inc. common stock held by non-affiliates of Dominion was approximately $47.9 billion based on the closing price of Dominion's common stock as reported on the New York Stock Exchange as of the last day of Dominion's most recently completed second fiscal quarter. Dominion is the sole holder of Virginia Electric and Power Company common stock. At February 15, 2017, Dominion had 628,115,398 shares of common stock outstanding and Virginia Power had 274,723 shares of common stock outstanding. Dominion Resources, Inc. holds all of the membership interests of Dominion Gas Holdings, LLC.

DOCUMENT INCORPORATED BY REFERENCE.

Portions of Dominion's 2017 Proxy Statement are incorporated by reference in Part III.

This combined Form 10-K represents separate filings by Dominion Resources, Inc., Virginia Electric and Power Company and Dominion Gas Holdings, LLC. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Virginia Electric and Power Company and Dominion Gas Holdings, LLC make no representations as to the information relating to Dominion Resources, Inc.'s other operations.
VIRGINIA ELECTRIC AND POWER COMPANY AND DOMINION GAS HOLDINGS, LLC MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTION I(1)(a) AND (b) OF FORM 10-K AND ARE FILING THIS FORM 10-K UNDER THE REDUCED DISCLOSURE FORMAT.

Dominion Resources, Inc., Virginia Electric and Power Company and Dominion Gas Holdings, LLC

Glossary of Terms

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition
2013 Biennial Review Order	Order issued by the Virginia Commission in November 2013 concluding the 2011—2012 biennial review of Virginia Power's base rates, terms and conditions
2013 Equity Units	Dominion's 2013 Series A Equity Units and 2013 Series B Equity Units issued in June 2013
2014 Equity Units	Dominion's 2014 Series A Equity Units issued in July 2014
2015 Biennial Review Order	Order issued by the Virginia Commission in November 2015 concluding the 2013—2014 biennial review of Virginia Power's base rates, terms and conditions
2016 Equity Units	Dominion's 2016 Series A Equity Units issued in August 2016
2017 Proxy Statement	Dominion 2017 Proxy Statement, File No. 001-08489
ABO	Accumulated benefit obligation
AFUDC	Allowance for funds used during construction
AMI	Advanced Metering Infrastructure
AMR	Automated meter reading program deployed by East Ohio
AOCI	Accumulated other comprehensive income (loss)
APCo	Appalachian Power Company
ARO	Asset retirement obligation
ARP	Acid Rain Program, a market-based initiative for emissions allowance trading, established pursuant to Title IV of the CAA
Atlantic Coast Pipeline	Atlantic Coast Pipeline, LLC, a limited liability company owned by Dominion, Duke and Southern Company Gas (formerly known as AGL Resources Inc.)
Atlantic Coast Pipeline Project	The approximately 600-mile natural gas pipeline running from West Virginia through Virginia to North Carolina which will be owned by Dominion, Duke and Southern Company Gas (formerly known as AGL Resources Inc.) and constructed and operated by DTI
BACT	Best available control technology
bcf	Billion cubic feet
bcfe	Billion cubic feet equivalent
Bear Garden	A 590 MW combined cycle, natural gas-fired power station in Buckingham County, Virginia
Blue Racer	Blue Racer Midstream, LLC, a joint venture between Dominion and Caiman
BP	BP Wind Energy North America Inc.
Brayton Point	Brayton Point power station
BREDL	Blue Ridge Environmental Defense League
Brunswick County	A 1,376 MW combined cycle, natural gas-fired power station in Brunswick County, Virginia
CAA	Clean Air Act
Caiman	Caiman Energy II, LLC
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAO	Chief Accounting Officer
CAP	IRS Compliance Assurance Process
CCR	Coal combustion residual
CEA	Commodity Exchange Act
CEO	Chief Executive Officer
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
CFO	Chief Financial Officer
CFTC	Commodity Futures Trading Commission
CGN Committee	Compensation, Governance and Nominating Committee of Dominion's Board of Directors
Clean Power Plan	Regulations issued by the EPA in August 2015 for states to follow in developing plans to reduce CO_2 emissions from existing fossil fuel-fired electric generating units, stayed by the U.S. Supreme Court in February 2016 pending resolution of court challenges by certain states
CNG	Consolidated Natural Gas Company
CNO	Chief Nuclear Officer
CO_2	Carbon dioxide
COL	Combined Construction Permit and Operating License
Companies	Dominion, Virginia Power and Dominion Gas, collectively
COO	Chief Operating Officer
Cooling degree days	Units measuring the extent to which the average daily temperature is greater than 65 degrees Fahrenheit, calculated as the difference between 65 degrees and the average temperature for that day
Corporate Unit	A stock purchase contract and 1/20 or 1/40 interest in a RSN issued by Dominion
Cove Point	Dominion Cove Point LNG, LP
Cove Point Holdings	Cove Point GP Holding Company, LLC
CPCN	Certificate of Public Convenience and Necessity
CSAPR	Cross State Air Pollution Rule
CWA	Clean Water Act

Abbreviation or Acronym	Definition
DCG	Dominion Carolina Gas Transmission, LLC (successor by statutory conversion to and formerly known as Carolina Gas Transmission Corporation)
DEI	Dominion Energy, Inc.
DGP	Dominion Gathering and Processing, Inc.
Dodd-Frank Act	The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010
DOE	Department of Energy
Dominion	The legal entity, Dominion Resources, Inc., one or more of its consolidated subsidiaries (other than Virginia Power and Dominion Gas) or operating segments, or the entirety of Dominion Resources, Inc. and its consolidated subsidiaries
Dominion Direct®	A dividend reinvestment and open enrollment direct stock purchase plan
Dominion Gas	The legal entity, Dominion Gas Holdings, LLC, one or more of its consolidated subsidiaries or operating segment, or the entirety of Dominion Gas Holdings, LLC and its consolidated subsidiaries
Dominion Iroquois	Dominion Iroquois, Inc., which, effective May 2016, holds a 24.07% noncontrolling partnership interest in Iroquois
Dominion Midstream	The legal entity, Dominion Midstream Partners, LP, one or more of its consolidated subsidiaries, Cove Point Holdings, Iroquois GP Holding Company, LLC, DCG (beginning April 1, 2015) and Questar Pipeline (beginning December 1, 2016) or operating segment, or the entirety of Dominion Midstream Partners, LP and its consolidated subsidiaries
Dominion Questar	The legal entity, Dominion Questar Corporation (formerly known as Questar Corporation), one or more of its consolidated subsidiaries or operating segment, or the entirety of Dominion Questar Corporation and its consolidated subsidiaries
Dominion Questar Combination	Dominion's acquisition of Dominion Questar completed on September 16, 2016 pursuant to the terms of the agreement and plan of merger entered on January 31, 2016
DRS	Dominion Resources Services, Inc.
DSM	Demand-side management
Dth	Dekatherm
DTI	Dominion Transmission, Inc.
Duke	The legal entity, Duke Energy Corporation, one or more of its consolidated subsidiaries or operating segments, or the entirety of Duke Energy Corporation and its consolidated subsidiaries
DVP	Dominion Virginia Power operating segment
EA	Environmental assessment
East Ohio	The East Ohio Gas Company, doing business as Dominion East Ohio
Eastern Market Access Project	Project to provide 294,000 Dths/day of firm transportation service to help meet demand for natural gas for Washington Gas Light Company, a local gas utility serving customers in D.C., Virginia and Maryland, and Mattawoman Energy, LLC for its new electric power generation facility to be built in Maryland
Elwood	Elwood power station
Energy Choice	Program authorized by the Ohio Commission which provides energy customers with the ability to shop for energy options from a group of suppliers certified by the Ohio Commission
EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 2005
EPS	Earnings per share
ERISA	The Employee Retirement Income Security Act of 1974
ERM	Enterprise Risk Management
ERO	Electric Reliability Organization
Excess Tax Benefits	Benefits of tax deductions in excess of the compensation cost recognized for stock-based compensation
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings Ltd.
Four Brothers	Four Brothers Solar, LLC, a limited liability company owned by Dominion and Four Brothers Holdings, LLC, a wholly-owned subsidiary of NRG effective November 2016
Fowler Ridge	Fowler I Holdings LLC, a wind-turbine facility joint venture with BP in Benton County, Indiana
FTA	Free Trade Agreement
FTRs	Financial transmission rights
GAAP	U.S. generally accepted accounting principles
Gal	Gallon
GHG	Greenhouse gas
Granite Mountain	Granite Mountain Holdings, LLC, a limited liability company owned by Dominion and Granite Mountain Renewables, LLC, a wholly-owned subsidiary of NRG effective November 2016
Green Mountain	Green Mountain Power Corporation
Greensville County	An approximately 1,588 MW natural gas-fired combined-cycle power station under construction in Greensville County, Virginia
Hastings	A natural gas processing and fractionation facility located near Pine Grove, West Virginia
HATFA of 2014	Highway and Transportation Funding Act of 2014

Abbreviation or Acronym	Definition
Heating degree days	Units measuring the extent to which the average daily temperature is less than 65 degrees Fahrenheit, calculated as the difference between 65 degrees and the average temperature for that day
Hope	Hope Gas, Inc., doing business as Dominion Hope
Idaho Commission	Idaho Public Utilities Commission
IRCA	Intercompany revolving credit agreement
Iron Springs	Iron Springs Holdings, LLC, a limited liability company owned by Dominion and Iron Springs Renewables, LLC, a wholly-owned subsidiary of NRG effective November 2016
Iroquois	Iroquois Gas Transmission System, L.P.
IRS	Internal Revenue Service
ISO	Independent system operator
ISO-NE	ISO New England
July 2016 hybrids	Dominion's 2016 Series A Enhanced Junior Subordinated Notes due 2076
June 2006 hybrids	Dominion's 2006 Series A Enhanced Junior Subordinated Notes due 2066
June 2009 hybrids	Dominion's 2009 Series A Enhanced Junior Subordinated Notes due 2064, subject to extensions no later than 2079
Kewaunee	Kewaunee nuclear power station
Keys Energy Project	Project to provide 107,000 Dths/day of firm transportation service from Cove Point's interconnect with Transco in Fairfax County, Virginia to Keys Energy Center, LLC's power generating facility in Prince George's County, Maryland
Kincaid	Kincaid power station
kV	Kilovolt
Leidy South Project	Project to provide 155,000 Dths/day of firm transportation service from Clinton County, Pennsylvania to Loudoun County, Virginia
Liability Management Exercise	Dominion exercise in 2014 to redeem certain debt and preferred securities
LIBOR	London Interbank Offered Rate
LIFO	Last-in-first-out inventory method
Line TL-388	A 37-mile, 24-inch gathering pipeline extending from Texas Eastern, LP in Noble County, Ohio to its terminus at Dominion's Gilmore Station in Tuscarawas County, Ohio
Liquefaction Project	A natural gas export/liquefaction facility currently under construction by Cove Point
LNG	Liquefied natural gas
Local 50	International Brotherhood of Electrical Workers Local 50
Local 69	Local 69, Utility Workers Union of America, United Gas Workers
Lordstown Project	Project to provide 129,000 Dths/day of firm transportation service to the Lordstown power station in northeast Ohio
LTIP	Long-term incentive program
MAP 21 Act	Moving Ahead for Progress in the 21st Century Act
Massachusetts Municipal	Massachusetts Municipal Wholesale Electric Company
MATS	Utility Mercury and Air Toxics Standard Rule
mcf	Thousand cubic feet
mcfe	Thousand cubic feet equivalent
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MGD	Million gallons a day
Millstone	Millstone nuclear power station
MISO	Midcontinent Independent System Operator, Inc.
MLP	Master limited partnership, also known as publicly traded partnership
Moody's	Moody's Investors Service
Morgans Corner	Morgans Corner Solar Energy, LLC
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
NAV	Net asset value
NedPower	NedPower Mount Storm LLC, a wind-turbine facility joint venture between Dominion and Shell in Grant County, West Virginia
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NG	Collectively, North East Transmission Co., Inc. and National Grid IGTS Corp.
NGL	Natural gas liquid
NJNR	NJNR Pipeline Company
NO_2	Nitrogen dioxide
North Anna	North Anna nuclear power station
North Carolina Commission	North Carolina Utilities Commission
Northern System	Collection of approximately 131 miles of various diameter natural gas pipelines in Ohio
NO_X	Nitrogen oxide
NRC	Nuclear Regulatory Commission

Abbreviation or Acronym	Definition
NRG	The legal entity, NRG Energy, Inc., one or more of its consolidated subsidiaries (including, effective November 2016, Four Brothers Holdings, LLC, Granite Mountain Renewables, LLC and Iron Springs Renewables, LLC) or operating segments, or the entirety of NRG Energy, Inc. and its consolidated subsidiaries
NSPS	New Source Performance Standards
NYSE	New York Stock Exchange
October 2014 hybrids	Dominion's 2014 Series A Enhanced Junior Subordinated Notes due 2054
ODEC	Old Dominion Electric Cooperative
Ohio Commission	Public Utilities Commission of Ohio
Order 1000	Order issued by FERC adopting new requirements for electric transmission planning, cost allocation and development
Philadelphia Utility Index	Philadelphia Stock Exchange Utility Index
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPP	Percentage of Income Payment Plan deployed by East Ohio
PIR	Pipeline Infrastructure Replacement program deployed by East Ohio
PJM	PJM Interconnection, L.L.C.
PREP	Pipeline Replacement and Expansion Program, a program of replacing, upgrading and expanding natural gas utility infrastructure deployed by Hope
PSMP	Pipeline Safety and Management Program deployed by East Ohio to ensure the continued safe and reliable operation of East Ohio's system and compliance with pipeline safety laws
ppb	Parts-per-billion
PSD	Prevention of significant deterioration
Questar Gas	Questar Gas Company
Questar Pipeline	Questar Pipeline, LLC (successor by statutory conversion to and formerly known as Questar Pipeline Company), one or more of its consolidated subsidiaries, or the entirety of Questar Pipeline, LLC and its consolidated subsidiaries
RCC	Replacement Capital Covenant
Regulation Act	Legislation effective July 1, 2007, that amended the Virginia Electric Utility Restructuring Act and fuel factor statute, which legislation is also known as the Virginia Electric Utility Regulation Act, as amended in 2015
Rider B	A rate adjustment clause associated with the recovery of costs related to the conversion of three of Virginia Power's coal-fired power stations to biomass
Rider BW	A rate adjustment clause associated with the recovery of costs related to Brunswick County
Rider GV	A rate adjustment clause associated with the recovery of costs related to Greensville County
Rider R	A rate adjustment clause associated with the recovery of costs related to Bear Garden
Rider S	A rate adjustment clause associated with the recovery of costs related to the Virginia City Hybrid Energy Center
Rider T1	A rate adjustment clause to recover the difference between revenues produced from transmission rates included in base rates, and the new total revenue requirement developed annually for the rate years effective September 1
Rider U	A rate adjustment clause associated with the recovery of costs of new underground distribution facilities
Rider US-2	A rate adjustment clause associated with Woodland, Scott Solar and Whitehouse
Rider W	A rate adjustment clause associated with the recovery of costs related to Warren County
Riders C1A and C2A	Rate adjustment clauses associated with the recovery of costs related to certain DSM programs approved in DSM cases
ROE	Return on equity
ROIC	Return on invested capital
RSN	Remarketable subordinated note
RTEP	Regional transmission expansion plan
RTO	Regional transmission organization
SAFSTOR	A method of nuclear decommissioning, as defined by the NRC, in which a nuclear facility is placed and maintained in a condition that allows the facility to be safely stored and subsequently decontaminated to levels that permit release for unrestricted use
SAIDI	System Average Interruption Duration Index, metric used to measure electric service reliability
SBL Holdco	SBL Holdco, LLC, a wholly-owned subsidiary of DEI
Scott Solar	A 17 MW utility-scale solar power station in Powhatan County, VA
SEC	Securities and Exchange Commission
September 2006 hybrids	Dominion's 2006 Series B Enhanced Junior Subordinated Notes due 2066
Shell	Shell WindEnergy, Inc.
SO_2	Sulfur dioxide
Standard & Poor's	Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies, Inc.
SunEdison	The legal entity, SunEdison, Inc., one or more of its consolidated subsidiaries (including, through November 2016, Four Brothers Holdings, LLC, Granite Mountain Renewables, LLC and Iron Springs Renewables, LLC) or operating segments, or the entirety of SunEdison, Inc. and its consolidated subsidiaries
Surry	Surry nuclear power station
Terra Nova Renewable Partners	A partnership comprised primarily of institutional investors advised by J.P. Morgan Asset Management—Global Real Assets

Abbreviation or Acronym	Definition
Three Cedars	Granite Mountain and Iron Springs, collectively
TransCanada	The legal entity, TransCanada Corporation, one or more of its consolidated subsidiaries or operating segments, or the entirety of TransCanada Corporation and its consolidated subsidiaries
TSR	Total shareholder return
UAO	Unilateral Administrative Order
UEX Rider	Uncollectible Expense Rider deployed by East Ohio
Utah Commission	Public Service Commission of Utah
VDEQ	Virginia Department of Environmental Quality
VEBA	Voluntary Employees' Beneficiary Association
VIE	Variable interest entity
Virginia City Hybrid Energy Center	A 610 MW baseload carbon-capture compatible, clean coal powered electric generation facility in Wise County, Virginia
Virginia Commission	Virginia State Corporation Commission
Virginia Power	The legal entity, Virginia Electric and Power Company, one or more of its consolidated subsidiaries or operating segments, or the entirety of Virginia Electric and Power Company and its consolidated subsidiaries
VOC	Volatile organic compounds
Warren County	A 1,342 MW combined-cycle, natural gas-fired power station in Warren County, Virginia
West Virginia Commission	Public Service Commission of West Virginia
Western System	Collection of approximately 212 miles of various diameter natural gas pipelines and three compressor stations in Ohio
Wexpro	The legal entity, Wexpro Company, one or more of its consolidated subsidiaries, or the entirety of Wexpro Company and its consolidated subsidiaries
Wexpro Agreement	An agreement effective August 1981, which sets forth the rights of Questar Gas to receive certain benefits from Wexpro's operations, including cost-of-service gas
Wexpro II Agreement	An agreement with the states of Utah and Wyoming modeled after the Wexpro Agreement that allows for the addition of properties under the cost-of-service methodology for the benefit of Questar Gas customers
Whitehouse	A 20 MW utility-scale solar power station in Louisa County, VA
Woodland	A 19 MW utility-scale solar power station in Isle of Wight County, VA
Wyoming Commission	Wyoming Public Service Commission

Item 1. Business

General

Dominion, headquartered in Richmond, Virginia and incorporated in Virginia in 1983, is one of the nation's largest producers and transporters of energy. Dominion's strategy is to be a leading provider of electricity, natural gas and related services to customers primarily in the eastern and Rocky Mountain regions of the U.S. As of December 31, 2016, Dominion's portfolio of assets includes approximately 26,400 MW of generating capacity, 6,600 miles of electric transmission lines, 57,600 miles of electric distribution lines, 14,900 miles of natural gas transmission, gathering and storage pipeline and 51,300 miles of gas distribution pipeline, exclusive of service lines. As of December 31, 2016, Dominion serves over 6 million utility and retail energy customers and operates one of the nation's largest underground natural gas storage systems, with approximately 1 trillion cubic feet of storage capacity.

In September 2016, Dominion completed the Dominion Questar Combination for total consideration of $4.4 billion and Dominion Questar became a wholly-owned subsidiary of Dominion. Dominion Questar is a Rockies-based integrated natural gas company. Questar Gas, a wholly-owned subsidiary of Dominion Questar, is consolidated by Dominion, and is a voluntary SEC filer. However, its Form 10-K is filed separately and is not combined herein.

In March 2014, Dominion formed Dominion Midstream, an MLP designed to grow a portfolio of natural gas terminaling, processing, storage, transportation and related assets. In October 2014, Dominion Midstream launched its initial public offering and issued 20,125,000 common units representing limited partner interests. Dominion has recently and may continue to investigate opportunities to acquire assets that meet its strategic objective for Dominion Midstream. At December 31, 2016, Dominion owns the general partner, 50.9% of the common and subordinated units and 37.5% of the convertible preferred interests in Dominion Midstream, which owns a preferred equity interest and the general partner interest in Cove Point, DCG, Questar Pipeline and a 25.93% noncontrolling partnership interest in Iroquois. Dominion Midstream is consolidated by Dominion, and is an SEC registrant. However, its Form 10-K is filed separately and is not combined herein.

Dominion is focused on expanding its investment in regulated electric generation, transmission and distribution and regulated natural gas transmission and distribution infrastructure. Dominion expects 80% to 90% of earnings from its primary operating segments to come from regulated and long-term contracted businesses.

Dominion continues to expand and improve its regulated and long-term contracted electric and natural gas businesses, in accordance with its existing five-year capital investment program. A major impetus for this program is to meet the anticipated increase in demand in its electric utility service territory. Other drivers for the capital investment program include the construction of infrastructure to handle the increase in natural gas production from the Marcellus and Utica Shale formations, to upgrade Dominion's gas and electric transmission and distribution networks, and to meet environmental requirements and standards set by various regulatory bodies. Investments in utility-scale solar generation are expected to be a focus in meeting such environmental requirements, particularly in Virginia. In September 2014, Dominion announced the formation of Atlantic Coast Pipeline. Atlantic Coast Pipeline is focused on constructing an approximately 600-mile natural gas pipeline running from West Virginia through Virginia to North Carolina, to increase natural gas supplies in the region.

Dominion has transitioned to a more regulated, less volatile earnings mix as evidenced by its capital investments in regulated infrastructure, including the Dominion Questar Combination, and in infrastructure whose output is sold under long-term purchase agreements as well as the sale of the electric retail energy marketing business in March 2014. Dominion's nonregulated operations include merchant generation, energy marketing and price risk management activities and natural gas retail energy marketing operations. Dominion's operations are conducted through various subsidiaries, including Virginia Power and Dominion Gas.

Virginia Power, headquartered in Richmond, Virginia and incorporated in Virginia in 1909 as a Virginia public service corporation, is a wholly-owned subsidiary of Dominion and a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and North Carolina. In Virginia, Virginia Power conducts business under the name "Dominion Virginia Power" and primarily serves retail customers. In North Carolina, it conducts business under the name "Dominion North Carolina Power" and serves retail customers located in the northeastern region of the state, excluding certain municipalities. In addition, Virginia Power sells electricity at wholesale prices to rural electric cooperatives, municipalities and into wholesale electricity markets. All of Virginia Power's stock is owned by Dominion.

Dominion Gas, a limited liability company formed in September 2013, is a wholly-owned subsidiary of Dominion and a holding company. It serves as the intermediate parent company for certain of Dominion's regulated natural gas operating subsidiaries, which conduct business activities through a regulated interstate natural gas transmission pipeline and underground storage system in the Northeast, mid-Atlantic and Midwest states, regulated gas transportation and distribution operations in Ohio, and gas gathering and processing activities primarily in West Virginia, Ohio and Pennsylvania. Dominion Gas' principal wholly-owned subsidiaries are DTI, East Ohio, DGP and Dominion Iroquois. DTI is an interstate natural gas transmission pipeline company serving a broad mix of customers such as local gas distribution companies, marketers, interstate and intrastate pipelines, electric power generators and natural gas producers. The DTI system links to other major pipelines and markets in the mid-Atlantic, Northeast, and Midwest including Dominion's Cove Point pipeline. DTI also operates one of the largest underground natural gas storage systems in the U.S. In August 2016, DTI transferred its gathering and processing facilities to DGP. East Ohio is a regulated natural gas distribution operation serving residential, commercial and industrial gas sales and transportation customers. Its service territory includes Cleveland, Akron, Canton, Youngstown and other eastern and western Ohio communities. In May 2016, Dominion Gas sold 0.65% of the noncontrolling partnership interest in Iroquois, a FERC-regulated interstate natural gas pipeline in New York and Connecticut, to TransCanada. At December 31, 2016, Dominion Gas holds a

24.07% noncontrolling partnership interest in Iroquois. All of Dominion Gas' membership interests are owned by Dominion.

Amounts and information disclosed for Dominion are inclusive of Virginia Power and/or Dominion Gas, where applicable.

Employees

At December 31, 2016, Dominion had approximately 16,200 full-time employees, of which approximately 5,200 employees are subject to collective bargaining agreements. At December 31, 2016, Virginia Power had approximately 6,800 full-time employees, of which approximately 3,100 employees are subject to collective bargaining agreements. At December 31, 2016, Dominion Gas had approximately 2,800 full-time employees, of which approximately 2,000 employees are subject to collective bargaining agreements.

Where You Can Find More Information About the Companies

The Companies file their annual, quarterly and current reports, proxy statements and other information with the SEC. Their SEC filings are available to the public over the Internet at the SEC's website at http://www.sec.gov. You may also read and copy any document they file at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room.

The Companies make their SEC filings available, free of charge, including the annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports, through Dominion's internet website, http://www.dom.com, as soon as reasonably practicable after filing or furnishing the material to the SEC. Information contained on Dominion's website is not incorporated by reference in this report.

Acquisitions and Dispositions

Following are significant acquisitions and divestitures by the Companies during the last five years.

Acquisition of Dominion Questar

In September 2016, Dominion completed the Dominion Questar Combination for total consideration of $4.4 billion and Dominion Questar became a wholly-owned subsidiary of Dominion. In December 2016, Dominion contributed Questar Pipeline to Dominion Midstream. See Note 3 to the Consolidated Financial Statements and *Liquidity and Capital Resources* in Item 7. MD&A for additional information.

Acquisition of Wholly- Owned Merchant Solar Projects

Throughout 2016, Dominion completed the acquisition of various wholly-owned merchant solar projects in Virginia, North Carolina and South Carolina for $32 million. The projects are expected to cost approximately $425 million to construct, including the initial acquisition cost, and are expected to generate approximately 221 MW.

Throughout 2015, Dominion completed the acquisition of various wholly-owned merchant solar projects in California and Virginia for $381 million. The projects cost $588 million to construct, including the initial acquisition cost, and generate 182 MW.

Throughout 2014, Dominion completed the acquisition of various wholly-owned solar development projects in California for $200 million. The projects cost $578 million to construct, including the initial acquisition cost, and generate 179 MW.

See Note 3 to the Consolidated Financial Statements for additional information.

Acquisition of Non-Wholly-Owned Merchant Solar Projects

In 2015, Dominion acquired 50% of the units in Four Brothers and Three Cedars from SunEdison for $107 million. In November 2016, NRG acquired the 50% of units in Four Brothers and Three Cedars previously held by SunEdison. The facilities began commercial operations in the third quarter of 2016, with generating capacity of 530 MW, at a cost of $1.1 billion. See Note 3 to the Consolidated Financial Statements for additional information.

Sale of Interest in Merchant Solar Projects

In September 2015, Dominion signed an agreement to sell a noncontrolling interest (consisting of 33% of the equity interests) in all of its then wholly-owned merchant solar projects, 24 solar projects totaling 425 MW, to SunEdison. In December 2015, the sale of interest in 15 of the solar projects closed for $184 million with the sale of interest in the remaining projects completed in January 2016 for $117 million. Upon closing, SunEdison sold its interest in these projects to Terra Nova Renewable Partners. See Note 3 to the Consolidated Financial Statements for additional information.

Dominion Midstream Acquisition of Interest in Iroquois

In September 2015, Dominion Midstream acquired from NG and NJNR a 25.93% noncontrolling partnership interest in Iroquois. The investment was recorded at $216 million based on the value of Dominion Midstream's common units at closing. The common units issued to NG and NJNR are reflected as noncontrolling interest in Dominion's Consolidated Financial Statements. See Note 3 to the Consolidated Financial Statements for additional information.

Acquisition of DCG

In January 2015, Dominion completed the acquisition of 100% of the equity interests of DCG from SCANA Corporation for $497 million in cash, as adjusted for working capital. In April 2015, Dominion contributed DCG to Dominion Midstream. See Note 3 to the Consolidated Financial Statements for additional information.

Sale of Electric Retail Energy Marketing Business

In March 2014, Dominion completed the sale of its electric retail energy marketing business. The proceeds were $187 million, net of transaction costs. The sale of the electric retail energy marketing business did not qualify for discontinued operations classification. See Note 3 to the Consolidated Financial Statements for additional information.

Sale of Pipelines and Pipeline Systems

In March 2014, Dominion Gas sold the Northern System to an affiliate that subsequently sold the Northern System to Blue Racer for consideration of $84 million. Dominion Gas' consideration consisted of $17 million in cash proceeds and the extinguishment of affiliated current borrowings of $67 million and Dominion's consideration consisted of cash proceeds of $84 million.

In September 2013, DTI sold Line TL-388 to Blue Racer for $75 million in cash proceeds.

In December 2012, East Ohio sold two pipeline systems to an affiliate for consideration of $248 million. East Ohio's consideration consisted of $61 million in cash proceeds and the extinguishment of affiliated long-term debt of $187 million and Dominion's consideration consisted of a 50% interest in Blue Racer and cash proceeds of $115 million.

See Note 9 to the Consolidated Financial Statements for additional information on sales of pipelines and pipeline systems.

Assignments of Shale Development Rights

In March 2015, Dominion Gas and a natural gas producer closed on an amendment to a December 2013 agreement, which included the immediate conveyance of approximately 9,000 acres of Marcellus Shale development rights and a two-year extension of the term of the original agreement. The conveyance of development rights resulted in the recognition of $43 million of previously deferred revenue. In April 2016, Dominion Gas and the natural gas producer closed on an amendment to the agreement, which included the immediate conveyance of a 32% partial interest in the remaining approximately 70,000 acres. This conveyance resulted in the recognition of the remaining $35 million of previously deferred revenue.

Also in March 2015, Dominion Gas conveyed to a natural gas producer approximately 11,000 acres of Marcellus Shale development rights underneath one of its natural gas storage fields and received proceeds of $27 million and an overriding royalty interest in gas produced from the acreage.

In September 2015, Dominion Gas closed on an agreement with a natural gas producer to convey approximately 16,000 acres of Utica and Point Pleasant Shale development rights underneath one of its natural gas storage fields. The agreement provided for a payment to Dominion Gas, subject to customary adjustments, of $52 million and an overriding royalty interest in gas produced from the acreage.

In November 2014, Dominion Gas closed on an agreement with a natural gas producer to convey over time approximately 24,000 acres of Marcellus Shale development rights underneath one of its natural gas storage fields. The agreement provides for payments to Dominion Gas, subject to customary adjustments, of approximately $120 million over a period of four years, and an overriding royalty interest in gas produced from the acreage.

In December 2013, Dominion Gas closed on agreements with two natural gas producers to convey over time approximately 100,000 acres of Marcellus Shale development rights underneath several natural gas storage fields. The agreements provide for payments to Dominion Gas, subject to customary adjustments, of approximately $200 million over a period of nine years, and an overriding royalty interest in gas produced from that acreage.

See Note 10 to the Consolidated Financial Statements for additional information on these sales of Marcellus acreage.

Sale of Brayton Point, Kincaid and Equity Method Investment in Elwood

In August 2013, Dominion completed the sale of Brayton Point, Kincaid and its equity method investment in Elwood to Energy Capital Partners and received proceeds of $465 million, net of transaction costs. The historical results of Brayton Point's and Kincaid's operations are presented in discontinued operations.

Operating Segments

Dominion manages its daily operations through three primary operating segments: DVP, Dominion Generation and Dominion Energy. Dominion also reports a Corporate and Other segment, which includes its corporate, service company and other functions (including unallocated debt). In addition, Corporate and Other includes specific items attributable to Dominion's other operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Virginia Power manages its daily operations through two primary operating segments: DVP and Dominion Generation. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Dominion Gas manages its daily operations through its primary operating segment: Dominion Energy. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segment that are not included in profit measures evaluated by executive management in assessing the segment's performance or in allocating resources and the effect of certain items recorded at Dominion Gas as a result of Dominion's basis in the net assets contributed.

While daily operations are managed through the operating segments previously discussed, assets remain wholly-owned by the Companies and their respective legal subsidiaries.

A description of the operations included in the Companies' primary operating segments is as follows:

Primary Operating Segment	Description of Operations	Dominion	Virginia Power	Dominion Gas
DVP	Regulated electric distribution	X	X	
	Regulated electric transmission	X	X	
Dominion Generation	Regulated electric fleet	X	X	
	Merchant electric fleet	X		
Dominion Energy	Gas transmission and storage	X(1)		X
	Gas distribution and storage	X		X
	Gas gathering and processing	X		X
	LNG import and storage	X		
	Nonregulated retail energy marketing	X		

(1) Includes remaining producer services activities.

For additional financial information on operating segments, including revenues from external customers, see Note 25 to the Consolidated Financial Statements. For additional information on operating revenue related to the Companies' principal products and services, see Notes 2 and 4 to the Consolidated Financial Statements, which information is incorporated herein by reference.

DVP

The DVP Operating Segment of Dominion and Virginia Power includes Virginia Power's regulated electric transmission and distribution (including customer service) operations, which serve approximately 2.6 million residential, commercial, industrial and governmental customers in Virginia and North Carolina.

DVP's existing five-year investment plan includes spending approximately $8.4 billion from 2017 through 2021 to upgrade or add new transmission and distribution lines, substations and other facilities to meet growing electricity demand within its service territory and maintain reliability and regulatory compliance. The proposed electric delivery infrastructure projects are intended to address both continued customer growth and increases in electricity consumption by the typical consumer. In addition, data centers continue to contribute to anticipated demand growth.

Revenue provided by electric distribution operations is based primarily on rates established by state regulatory authorities and state law. Variability in earnings is driven primarily by changes in rates, weather, customer growth and other factors impacting consumption such as the economy and energy conservation, in addition to operating and maintenance expenditures. Operationally, electric distribution continues to focus on improving service levels while striving to reduce costs and link investments to operational results. SAIDI performance results, excluding major events, were 137 minutes at the end of 2016, which is higher compared to the three-year average of 123 minutes, due to storm-related outages across all seasons. Virginia Power's overall customer satisfaction, however, improved year over year when compared to 2015 J.D. Power and Associates' scoring. In the future, safety, electric service reliability and customer service will remain key focus areas for electric distribution.

Revenue provided by Virginia Power's electric transmission operations is based primarily on rates approved by FERC. The profitability of this business is dependent on its ability, through the rates it is permitted to charge, to recover costs and earn a reasonable return on its capital investments. Variability in earnings primarily results from changes in rates and the timing of property additions, retirements and depreciation.

Virginia Power is a member of PJM, a RTO, and its electric transmission facilities are integrated into PJM wholesale electricity markets. Consistent with the increased authority given to NERC by EPACT, Virginia Power's electric transmission operations are committed to meeting NERC standards, modernizing its infrastructure and maintaining superior system reliability. Virginia Power's electric transmission operations will continue to focus on safety, operational performance, NERC compliance and execution of PJM's RTEP.

Competition

DVP Operating Segment—Dominion and Virginia Power

There is no competition for electric distribution service within Virginia Power's service territory in Virginia and North Carolina and no such competition is currently permitted. Historically, since its electric transmission facilities are integrated into PJM and electric transmission services are administered by PJM, there was no competition in relation to transmission service provided to customers within the PJM region. However, competition from non-incumbent PJM transmission owners for development, construction and ownership of certain transmission facilities in Virginia Power's service territory is now permitted pursuant to FERC Order 1000, subject to state and local siting and permitting approvals. This could result in additional competition to build and own transmission infrastructure in Virginia Power's service area in the future and could allow Dominion to seek opportunities to build and own facilities in other service territories.

Regulation

DVP Operating Segment—Dominion and Virginia Power

Virginia Power's electric distribution service, including the rates it may charge to jurisdictional customers, is subject to regulation by the Virginia and North Carolina Commissions. Virginia Power's wholesale electric transmission rates, tariffs and terms of service are subject to regulation by FERC. Electric transmission siting authority remains the jurisdiction of the Virginia and North Carolina Commissions. However, EPACT provides FERC with certain backstop authority for transmission siting. See *State Regulations and Federal Regulations* in *Regulation* and Note 13 to the Consolidated Financial Statements for additional information.

Properties

DVP Operating Segment—Dominion and Virginia Power

Virginia Power has approximately 6,600 miles of electric transmission lines of 69 kV or more located in North Carolina, Virginia and West Virginia. Portions of Virginia Power's electric transmission lines cross national parks and forests under permits entitling the federal government to use, at specified charges, any surplus capacity that may exist in these lines. While Virginia Power owns and maintains its electric transmission facilities, they are a part of PJM, which coordinates the planning, operation, emergency assistance and exchange of capacity and energy for such facilities.

As a part of PJM's RTEP process, PJM authorized the following material reliability projects (including Virginia Power's estimated cost):

- Surry-to-Skiffes Creek-to-Whealton ($280 million);
- Mt. Storm-to-Dooms ($240 million);
- Idylwood substation ($110 million);
- Dooms-to-Lexington ($130 million);
- Cunningham-to-Elmont ($110 million);
- Landstown voltage regulation ($70 million);
- Warrenton (including Remington CT-to-Warrenton, Vint Hill-to-Wheeler-to-Gainesville, and Vint Hill and Wheeler switching stations) ($110 million);
- Remington/Gordonsville/Pratts Area Improvement (including Remington-to-Gordonsville, and new Gordonsville substation transformer) ($110 million);
- Gainesville-to-Haymarket ($55 million);
- Kings Dominion-to-Fredericksburg ($50 million);
- Loudoun-Brambleton line-to-Poland Road Substation ($60 million);
- Cunningham-to-Dooms ($60 million);
- Carson-to-Rogers Road ($55 million);
- Dooms-Valley rebuild ($60 million); and
- Mt. Storm-Valley rebuild ($225 million).

Virginia Power plans to increase transmission substation physical security and expects to invest $300 million-$400 million through 2022 to strengthen its electrical system to better protect critical equipment, enhance its spare equipment process and create multiple levels of security.

In addition, Virginia Power's electric distribution network includes approximately 57,600 miles of distribution lines, exclusive of service level lines, in Virginia and North Carolina. The grants for most of its electric lines contain rights-of-way that have been obtained from the apparent owners of real estate, but underlying titles have not been examined. Where rights-of-way have not been obtained, they could be acquired from private owners by condemnation, if necessary. Many electric lines are on publicly-owned property, where permission to operate can be revoked.

Virginia legislation in 2014 provides for the recovery of costs, subject to approval by the Virginia Commission, for Virginia Power to move approximately 4,000 miles of electric distribution lines underground. The program is designed to reduce restoration outage time by moving its most outage-prone overhead distribution lines underground, has an annual investment cap of approximately $175 million and is expected to be implemented over the next decade. In August 2016, the Virginia Commission approved the first phase of the program encompassing approximately 400 miles of converted lines and $140 million in capital spending (with approximately $123 million recoverable through Rider U). In December 2016, Virginia Power filed its application with the Virginia Commission to recover costs associated with the first and second phases of this program. The second phase will convert an estimated 244 miles at a cost of $110 million.

Sources of Energy Supply

DVP Operating Segment—Dominion and Virginia Power

DVP's supply of electricity to serve Virginia Power customers is produced or procured by Dominion Generation. See *Dominion Generation* for additional information.

Seasonality

DVP Operating Segment—Dominion and Virginia Power

DVP's earnings vary seasonally as a result of the impact of changes in temperature, the impact of storms and other catastrophic weather events, and the availability of alternative sources for heating on demand by residential and commercial customers. Generally, the demand for electricity peaks during the summer and winter months to meet cooling and heating needs. An increase in heating degree days for DVP's electric utility-related operations does not produce the same increase in revenue as an increase in cooling degree days, due to seasonal pricing differentials and because alternative heating sources are more readily available.

Dominion Generation

The Dominion Generation Operating Segment of Virginia Power includes the generation operations of the Virginia Power regulated electric utility and its related energy supply operations. Virginia Power's utility generation operations primarily serve the supply requirements for the DVP segment's utility customers. *The Dominion Generation Operating Segment of Dominion* includes Virginia Power's generation facilities and its related energy supply operations as well as the generation operations of Dominion's merchant fleet and energy marketing and price risk management activities for these assets.

Dominion Generation's existing five-year investment plan includes spending approximately $8.0 billion from 2017 through 2021 to construct new generation capacity to meet growing electricity demand within its service territory and maintain reliability. The most significant project currently under construction is Greensville County, which is estimated to cost approximately $1.3 billion, excluding financing costs. See *Properties* and *Environmental Strategy* for additional information on this and other utility projects.

In addition, Dominion's merchant fleet includes numerous renewable generation facilities, which include a fuel cell generation facility in Connecticut and solar generation facilities in operation or development in nine states, including Virginia. The output of these facilities is sold under long-term power purchase agreements with terms generally ranging from 15 to 25 years. See Note 3 to the Consolidated Financial Statements for additional information regarding certain solar projects.

Earnings for the *Dominion Generation Operating Segment of Virginia Power* primarily result from the sale of electricity generated by its utility fleet. Revenue is based primarily on rates established by state regulatory authorities and state law. Approximately 82% of revenue comes from serving Virginia jurisdictional customers. Base rates for the Virginia jurisdiction are set using a modified cost-of-service rate model, and are generally designed to allow an opportunity to recover the cost of providing utility service and earn a reasonable return on investments used to provide that service. Earnings variability may arise when revenues are impacted by factors not reflected in current rates, such as the impact of weather on customers' demand for services. Likewise, earnings may reflect variations in the timing or nature of expenses as compared to those contemplated in current rates, such as labor and benefit costs, capacity expenses, and the timing, duration and costs of scheduled and unscheduled outages. The cost of fuel and purchased power is generally collected through fuel cost-recovery mechanisms established by regulators and does not materially impact net income. The cost of new generation facilities is generally recovered through rate adjustment clauses in Virginia. Variability in earnings from rate adjustment clauses reflects changes in the authorized ROE and the carrying amount of these facilities, which are largely driven by the timing and amount of capital investments, as well as depreciation. See Note 13 to the Consolidated Financial Statements for additional information.

The Dominion Generation Operating Segment of Dominion derives its earnings primarily from the sale of electricity generated by Virginia Power's utility and Dominion's merchant generation assets, as well as from associated capacity and ancillary services. Variability in earnings provided by Dominion's nonrenewable merchant fleet relates to changes in market-based prices received for electricity and capacity. Market-based prices for electricity are largely dependent on commodity prices, primarily natural gas, and the demand for electricity, which is primarily dependent upon weather. Capacity prices are dependent upon resource requirements in relation to the supply available (both existing and new) in the forward capacity auctions, which are held approximately three years in advance of the associated delivery year. Dominion manages the electric price volatility of its merchant fleet by hedging a substantial portion of its expected near-term energy sales with derivative instruments. Variability also results from changes in the cost of fuel consumed, labor and benefits and the timing, duration and costs of scheduled and unscheduled outages. Variability in earnings provided by Dominion's renewable merchant fleet is primarily driven by weather.

Competition

Dominion Generation Operating Segment—Dominion and Virginia Power

Virginia Power's generation operations are not subject to significant competition as only a limited number of its Virginia jurisdictional electric utility customers have retail choice. See *Electric* under *State Regulations* in *Regulation* for more information. Currently, North Carolina does not offer retail choice to electric customers.

Dominion Generation Operating Segment—Dominion

Dominion Generation's recently acquired and developed renewable generation projects are not currently subject to significant competition as the output from these facilities is primarily sold under long-term power purchase agreements with terms generally lasting between 15 and 25 years. Competition for the nonrenewable merchant fleet is impacted by electricity and fuel prices, new market entrants, construction by others of generating assets and transmission capacity, technological advances in power generation, the actions of environmental and other regulatory authorities and other factors. These competitive factors may negatively impact the merchant fleet's ability to profit from the sale of electricity and related products and services.

Unlike Dominion Generation's regulated generation fleet, its nonrenewable merchant generation fleet is dependent on its ability to operate in a competitive environment and does not have a predetermined rate structure that provides for a rate of return on its capital investments. Dominion Generation's nonrenewable merchant assets operate within functioning RTOs and primarily compete on the basis of price. Competitors include other generating assets bidding to operate within the RTOs. Dominion Generation's nonrenewable merchant units compete in the wholesale market with other generators to sell a variety of products including energy, capacity and ancillary services. It is difficult to compare various types of generation given the wide range of fuels, fuel procurement strategies, efficiencies and operating characteristics of the fleet within any given RTO. However, Dominion applies its expertise in operations, dispatch and risk management to maximize the degree to which its nonrenewable merchant fleet is competitive compared to similar assets within the region.

Regulation

Dominion Generation Operating Segment—Dominion and Virginia Power

Virginia Power's utility generation fleet and Dominion's merchant generation fleet are subject to regulation by FERC, the NRC, the EPA, the DOE, the Army Corps of Engineers and other federal, state and local authorities. Virginia Power's utility generation fleet is also subject to regulation by the Virginia and North Carolina Commissions. See *Regulation, Future Issues and Other Matters* in Item 7. MD&A and Notes 13 and 22 to the Consolidated Financial Statements for more information.

The Clean Power Plan and related proposed rules discussed represent a significant regulatory development affecting this segment. See *Future Issues and Other Matters* in Item 7. MD&A.

Properties

For a listing of Dominion's and Virginia Power's existing generation facilities, see Item 2. Properties.

Dominion Generation Operating Segment—Dominion and Virginia Power

The generation capacity of Virginia Power's electric utility fleet totals approximately 21,700 MW. The generation mix is diversified and includes gas, coal, nuclear, oil, renewables, biomass and power purchase agreements. Virginia Power's generation facilities are located in Virginia, West Virginia and North Carolina and serve load in Virginia and northeastern North Carolina.

Virginia Power is developing, financing and constructing new generation capacity to meet growing electricity demand within its service territory. Significant projects under construction or development are set forth below:

- Virginia Power plans to construct certain solar facilities in Virginia. See Note 13 to the Consolidated Financial Statements for more information.
- Virginia Power is considering the construction of a third nuclear unit at a site located at North Anna. See Note 13 to the Consolidated Financial Statements for more information on this project.
- In March 2016, the Virginia Commission authorized the construction of Greensville County and related transmission

interconnection facilities. Commercial operations are expected to commence in late 2018, at an estimated cost of approximately $1.3 billion, excluding financing costs.

Dominion Generation Operating Segment—Dominion

The generation capacity of Dominion's merchant fleet totals approximately 4,700 MW. The generation mix is diversified and includes nuclear, natural gas and renewables. Merchant non-renewable generation facilities are located in Connecticut, Pennsylvania and Rhode Island, with a majority of that capacity concentrated in New England. Dominion's merchant renewable generation facilities include a fuel cell generation facility in Connecticut, solar generation facilities in California, Connecticut, Georgia, Indiana, North Carolina, Tennessee, Utah and Virginia, and wind generation facilities in Indiana and West Virginia. Additional solar projects under construction are as set forth below:

- In August 2016, Dominion entered into an agreement to acquire 100% of the equity interests of two solar projects in California from Solar Frontier Americas Holding LLC for $128 million. The acquisition is expected to close prior to both projects commencing operations, which is expected by the end of 2017. The projects are expected to cost approximately $130 million once constructed, including the initial acquisition cost, and generate approximately 50 MW combined.
- In September 2016, Dominion entered into an agreement to acquire 100% of the equity interests of a solar project in Virginia from Community Energy Solar, LLC. The acquisition is expected to close during the first quarter of 2017, prior to the project commencing operations by the end of 2017, for an amount to be determined based on the costs incurred through closing. The project is expected to cost approximately $210 million once constructed, including the initial acquisition cost, and to generate approximately 100 MW.
- In November 2016, Dominion acquired 100% of the equity interest of four solar projects in Virginia and two solar projects in South Carolina for $21 million. The projects are expected to cost approximately $287 million once constructed, including the initial acquisition cost. The facilities are expected to begin commercial operations by the end of 2017 and generate approximately 161 MW.
- In January 2017, Dominion entered into an agreement to acquire 100% of the equity interests of a solar project in North Carolina from Cypress Creek Renewables, LLC for $154 million in cash. The acquisition is expected to close during the second quarter of 2017, prior to the project commencing commercial operations, which is expected by the end of the third quarter of 2017. The project is expected to cost $160 million once constructed, including the initial acquisition cost, and to generate approximately 79 MW.

Sources of Energy Supply

Dominion Generation Operating Segment—Dominion and Virginia Power

Dominion Generation uses a variety of fuels to power its electric generation and purchases power for utility system load requirements and to satisfy physical forward sale requirements, as described below. Some of these agreements have fixed commitments and are included as contractual obligations in *Future Cash Payments for Contractual Obligations and Planned Capital Expenditures* in Item 7. MD&A.

Nuclear Fuel—Dominion Generation primarily utilizes long-term contracts to support its nuclear fuel requirements. Worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices which are dependent on the market environment. Current agreements, inventories and spot market availability are expected to support current and planned fuel supply needs. Additional fuel is purchased as required to ensure optimal cost and inventory levels.

Fossil Fuel—Dominion Generation primarily utilizes natural gas and coal in its fossil fuel plants. All recent fossil fuel plant construction for Dominion Generation, with the exception of the Virginia City Hybrid Energy Center, involves natural gas generation.

Dominion Generation's natural gas and oil supply is obtained from various sources including purchases from major and independent producers in the Mid-Continent and Gulf Coast regions, purchases from local producers in the Appalachian area and Marcellus and Utica regions, purchases from gas marketers and withdrawals from underground storage fields owned by Dominion or third parties. Dominion Generation manages a portfolio of natural gas transportation contracts (capacity) that provides for reliable natural gas deliveries to its gas turbine fleet, while minimizing costs.

Dominion Generation's coal supply is obtained through long-term contracts and short-term spot agreements from domestic suppliers.

Biomass—Dominion Generation's biomass supply is obtained through long-term contracts and short-term spot agreements from local suppliers.

Purchased Power—Dominion Generation purchases electricity from the PJM spot market and through power purchase agreements with other suppliers to provide for utility system load requirements.

Dominion Generation also occasionally purchases electricity from the PJM and ISO-NE spot markets to satisfy physical forward sale requirements as part of its merchant generation operations.

Dominion Generation Operating Segment—Virginia Power

Presented below is a summary of Virginia Power's actual system output by energy source:

Source	**2016**	2015	2014
Nuclear(1)	**31%**	30%	33%
Natural gas	**31**	23	15
Coal(2)	**24**	26	30
Purchased power, net	**8**	15	19
Other(3)	**6**	6	3
Total	**100%**	100%	100%

(1) Excludes ODEC's 11.6% ownership interest in North Anna.
(2) Excludes ODEC's 50.0% ownership interest in the Clover power station.
(3) Includes oil, hydro, biomass and solar.

Seasonality

Dominion Generation Operating Segment—Dominion and Virginia Power

Sales of electricity for Dominion Generation typically vary seasonally as a result of the impact of changes in temperature and the availability of alternative sources for heating on demand by residential and commercial customers. See *DVP-Seasonality* above for additional considerations that also apply to Dominion Generation.

Nuclear Decommissioning

Dominion Generation Operating Segment—Dominion and Virginia Power

Virginia Power has a total of four licensed, operating nuclear reactors at Surry and North Anna in Virginia.

Decommissioning involves the decontamination and removal of radioactive contaminants from a nuclear power station once operations have ceased, in accordance with standards established by the NRC. Amounts collected from ratepayers are placed into trusts and are invested to fund the expected future costs of decommissioning the Surry and North Anna units.

Virginia Power believes that the decommissioning funds and their expected earnings for the Surry and North Anna units will be sufficient to cover expected decommissioning costs, particularly when combined with future ratepayer collections and contributions to these decommissioning trusts, if such future collections and contributions are required. This reflects the long-term investment horizon, since the units will not be decommissioned for decades, and a positive long-term outlook for trust fund investment returns. Virginia Power will continue to monitor these trusts to ensure they meet the NRC minimum financial assurance requirements, which may include, if needed, the use of parent company guarantees, surety bonding or other financial instruments recognized by the NRC.

The estimated cost to decommission Virginia Power's four nuclear units is reflected in the table below and is primarily based upon site-specific studies completed in 2014. These cost studies are generally completed every four to five years. The current cost estimates assume decommissioning activities will begin shortly after cessation of operations, which will occur when the operating licenses expire.

Under the current operating licenses, Virginia Power is scheduled to decommission the Surry and North Anna units during the period 2032 to 2078. NRC regulations allow licensees to apply for extension of an operating license in up to 20-year increments. Virginia Power has announced its intention to apply for an operating life extension for Surry, and may for North Anna as well.

Dominion Generation Operating Segment—Dominion

In addition to the four nuclear units discussed above, Dominion has two licensed, operating nuclear reactors at Millstone in Connecticut. A third Millstone unit ceased operations before Dominion acquired the power station. In May 2013, Dominion ceased operations at its single Kewaunee unit in Wisconsin and commenced decommissioning activities using the SAFSTOR methodology. The planned decommissioning completion date is 2073, which is within the NRC allowed 60-year window.

As part of Dominion's acquisition of both Millstone and Kewaunee, it acquired decommissioning funds for the related units. Any funds remaining in Kewaunee's trust after decommissioning is completed are required to be refunded to Wisconsin ratepayers. Dominion believes that the amounts currently available in the decommissioning trusts and their expected earnings will be sufficient to cover expected decommissioning costs for the Millstone and Kewaunee units. Dominion will continue to monitor these trusts to ensure they meet the NRC minimum financial assurance requirements, which may include, if needed, the use of parent company guarantees, surety bonding or other financial instruments recognized by the NRC. The estimated cost to decommission Dominion's eight units is reflected in the table below and is primarily based upon site-specific studies completed for Surry, North Anna and Millstone in 2014 and for Kewaunee in 2013.

The estimated decommissioning costs and license expiration dates for the nuclear units owned by Dominion and Virginia Power are shown in the following table:

	NRC license expiration year	Most recent cost estimate (2016 dollars)(1)	Funds in trusts at December 31, 2016	2016 contributions to trusts
(dollars in millions)				
Surry				
Unit 1	**2032**	**$ 600**	**$ 597**	**$ 0.6**
Unit 2	**2033**	**620**	**588**	**0.6**
North Anna				
Unit 1(2)	**2038**	**513**	**475**	**0.4**
Unit 2(2)	**2040**	**525**	**446**	**0.3**
Total (Virginia Power)		**2,258**	**2,106**	**1.9**
Millstone				
Unit 1(3)	**N/A**	**373**	**474**	**—**
Unit 2	**2035**	**563**	**614**	**—**
Unit 3(4)	**2045**	**684**	**604**	**—**
Kewaunee				
Unit 1(5)	**N/A**	**467**	**686**	**—**
Total (Dominion)		**$ 4,345**	**$ 4,484**	**$ 1.9**

(1) The cost estimates shown above reflect reductions for the expected future recovery of certain spent fuel costs based on Dominion's and Virginia Power's contracts with the DOE for disposal of spent nuclear fuel consistent with the reductions reflected in Dominion's and Virginia Power's nuclear decommissioning AROs.

(2) North Anna is jointly owned by Virginia Power (88.4%) and ODEC (11.6%). However, Virginia Power is responsible for 89.26% of the decommissioning obligation. Amounts reflect 89.26% of the decommissioning cost for both of North Anna's units.

(3) Unit 1 permanently ceased operations in 1998, before Dominion's acquisition of Millstone.

(4) Millstone Unit 3 is jointly owned by Dominion Nuclear Connecticut, Inc., with a 6.53% undivided interest in Unit 3 owned by Massachusetts Municipal and Green Mountain. Decommissioning cost is shown at Dominion's ownership percentage. At December 31, 2016, the minority owners held $37 million of trust funds related to Millstone Unit 3 that are not reflected in the table above.

(5) Permanently ceased operations in 2013.

Also see Notes 14 and 22 to the Consolidated Financial Statements for further information about AROs and nuclear decommissioning, respectively, and Note 9 for information about nuclear decommissioning trust investments.

Dominion Energy

The Dominion Energy Operating Segment of Dominion Gas includes certain of Dominion's regulated natural gas operations. DTI, the gas transmission pipeline and storage business, serves gas distribution businesses and other customers in the Northeast, mid-Atlantic and Midwest. DGP conducts gas gathering and processing activities, which include the sale of extracted products at market rates, primarily in West Virginia, Ohio and Pennsylvania. East Ohio, the primary gas distribution business of Dominion, serves residential, commercial and industrial gas sales, transportation and gathering service customers primarily in Ohio. Dominion Iroquois holds a 24.07% noncontrolling partnership interest in Iroquois, which provides service to local gas distribution companies, electric utilities and electric power generators, as well as marketers and other end users, through interconnecting pipelines and exchanges primarily in New York.

Earnings for the *Dominion Energy Operating Segment of Dominion Gas* primarily result from rates established by FERC and the Ohio Commission. The profitability of this business is dependent on Dominion Gas' ability, through the rates it is permitted to charge, to recover costs and earn a reasonable return on its capital investments. Variability in earnings results from changes in operating and maintenance expenditures, as well as changes in rates and the demand for services, which are dependent on weather, changes in commodity prices and the economy.

Approximately 96% of the transmission capacity under contract on DTI's pipeline is subscribed with long-term contracts (two years or greater). The remaining 4% is contracted on a year-to-year basis. Less than 1% of firm transportation capacity is currently unsubscribed. Less than 1% of storage services are unsubscribed. All contracted storage is subscribed with long-term contracts.

Revenue from processing and fractionation operations largely results from the sale of commodities at market prices. For DGP's processing plants, Dominion Gas receives the wet gas product from producers and may retain the extracted NGLs as compensation for its services. This exposes Dominion Gas to commodity price risk for the value of the spread between the NGL products and natural gas. In addition, Dominion Gas has volumetric risk as the majority of customers receiving these services are not required to deliver minimum quantities of gas.

East Ohio utilizes a straight-fixed-variable rate design for a majority of its customers. Under this rate design, East Ohio recovers a large portion of its fixed operating costs through a flat monthly charge accompanied by a reduced volumetric base delivery rate. Accordingly, East Ohio's revenue is less impacted by weather-related fluctuations in natural gas consumption than under the traditional rate design.

In addition to the operations of Dominion Gas, the *Dominion Energy Operating Segment of Dominion* also includes LNG operations, Dominion Questar operations, Hope's gas distribution operations in West Virginia, and nonregulated retail natural gas marketing, as well as Dominion's investments in the Blue Racer joint venture, Atlantic Coast Pipeline and Dominion Midstream. See *Properties and Investments* below for additional information regarding the Blue Racer and Atlantic Coast Pipeline investments. Dominion's LNG operations involve the import and storage of LNG at Cove Point and the transportation of regasified LNG to the interstate pipeline grid and mid-Atlantic and Northeast markets. Dominion has received DOE and FERC approval to export LNG from Cove Point and has begun construction on a bi-directional facility, which will be able to import LNG and regasify it as natural gas and liquefy natural gas and export it as LNG. See Note 22 to the Consolidated Financial Statements for more information.

In September 2016, Dominion completed the Dominion Questar Combination and Dominion Questar became a wholly-owned subsidiary of Dominion. Dominion Questar, a Rockies-based integrated natural gas company, included Questar Gas, Wexpro and Questar Pipeline at closing. Questar Gas' regulated gas distribution operations in Utah, southwestern Wyoming and southeastern Idaho includes 29,200 miles of gas distribution pipeline. Wexpro develops and produces natural gas from reserves supplied to Questar Gas under a cost-of-service framework. Questar Pipeline provides FERC-regulated interstate natural gas transportation and storage services in Utah, Wyoming and western Colorado through 2,200 miles of gas transmission pipeline and 56 bcf of working gas storage. See *Acquisitions and Dispositions* above and Note 3 to the Consolidated Financial Statements for a description of the Dominion Questar Combination.

In 2014, Dominion formed Dominion Midstream, an MLP initially consisting of a preferred equity interest in Cove Point. See *General* above for more information. Also see *Acquisitions and Dispositions* above and Note 3 to the Consolidated Financial Statements for a description of Dominion's contribution of Questar Pipeline to Dominion Midstream in December 2016 as well as Dominion's acquisition of DCG, which Dominion contributed to Dominion Midstream in April 2015, and Dominion Midstream's acquisition of a 25.93% noncontrolling partnership interest in Iroquois in September 2015. DCG provides FERC-regulated interstate natural gas transportation services in South Carolina and southeastern Georgia through 1,500 miles of gas transmission pipeline.

Dominion Energy's existing five-year investment plan includes spending approximately $8.0 billion from 2017 through 2021 to upgrade existing or add new infrastructure to meet growing energy needs within its service territory and maintain reliability. Demand for natural gas is expected to continue to grow as initiatives to transition to gas from more carbon-intensive fuels are implemented. This plan includes Dominion's portion of spending for the Atlantic Coast Pipeline Project.

In addition to the earnings drivers noted above for Dominion Gas, earnings for the *Dominion Energy Operating Segment of Dominion* primarily include the results of rates established by FERC and the West Virginia, Utah, Wyoming and Idaho Commissions. Additionally, Dominion Energy receives revenue from firm fee-based contractual arrangements, including negotiated rates, for certain LNG storage and regasification services. Questar Pipeline's and DCG's revenues are primarily derived from reservation charges for firm transportation and storage services as provided for in their FERC-approved tariffs. Revenue provided by Questar Gas' operations is based primarily on rates established by the Utah and Wyoming Commissions. The Idaho Commission has contracted with the Utah Commission for rate oversight of Questar Gas operations in a small area of southeastern Idaho. Hope's gas distribution operations in West Virginia serve residential, commercial, sale for resale and industrial gas sales, transportation and gathering service customers. Revenue provided by Hope's operations is based primarily on rates established by the West Virginia Commission. The profitability of these businesses is dependent on their ability, through the rates they are permitted to charge, to recover costs and earn a reasonable return on their capital investments. Variability in earnings results from changes in operating and maintenance expenditures, as well as changes in rates and the demand for services, which are dependent on weather, changes in commodity prices and the economy.

Dominion's retail energy marketing operations compete in nonregulated energy markets. In March 2014, Dominion completed the sale of its electric retail energy marketing business; however, it still participates in the retail natural gas and energy-related products and services businesses. The remaining customer base includes approximately 1.4 million customer accounts in 17 states. Dominion has a heavy concentration of natural gas customers in markets where utilities have a long-standing commitment to customer choice, primarily in the states of Ohio and Pennsylvania.

Competition

Dominion Energy Operating Segment—Dominion and Dominion Gas

Dominion Gas' natural gas transmission operations compete with domestic and Canadian pipeline companies. Dominion Gas also competes with gas marketers seeking to provide or arrange transportation, storage and other services. Alternative energy sources, such as oil or coal, provide another level of competition. Although competition is based primarily on price, the array of services that can be provided to customers is also an important factor. The combination of capacity rights held on certain long-line pipelines, a large storage capability and the availability of numerous receipt and delivery points along its own pipeline system enable Dominion to tailor its services to meet the needs of individual customers.

DGP's processing and fractionation operations face competition in obtaining natural gas supplies for its processing and related services. Numerous factors impact any given customer's choice of processing services provider, including the location of the facilities, efficiency and reliability of operations, and the pricing arrangements offered.

In Ohio, there has been no legislation enacted to require supplier choice for natural gas distribution consumers. However, East Ohio has offered an Energy Choice program to residential and commercial customers since October 2000. East Ohio has since taken various steps approved by the Ohio Commission toward exiting the merchant function, including restructuring its commodity service and placing Energy Choice-eligible customers in a direct retail relationship with participating suppliers. Further, in April 2013, East Ohio fully exited the merchant function for its nonresidential customers, which are now required to choose a retail supplier or be assigned to one at a monthly variable rate set by the supplier. At December 31, 2016, approximately 1 million of East Ohio's 1.2 million Ohio customers were participating in the Energy Choice program.

Dominion Energy Operating Segment—Dominion

Questar Gas and Hope do not currently face direct competition from other distributors of natural gas for residential and commercial customers in their service territories as state regulations in Utah, Wyoming and Idaho for Questar Gas, and West Virginia for Hope, do not allow customers to choose their provider at this time. See *State Regulations* in *Regulation* for additional information.

Cove Point's gas transportation, LNG import and storage operations, as well as the Liquefaction Project's capacity are contracted primarily under long-term fixed reservation fee agreements. However, in the future Cove Point may compete with other independent terminal operators as well as major oil and gas companies on the basis of terminal location, services provided and price. Competition from terminal operators primarily comes from refiners and distribution companies with marketing and trading arms.

Questar Pipeline's and DCG's pipeline systems generate a substantial portion of their revenue from long-term firm contracts for transportation services and are therefore insulated from competitive factors during the terms of the contracts. When these long-term contracts expire, Questar Pipeline's pipeline system faces competitive pressures from similar facilities that serve the Rocky Mountain region and DCG's pipeline system faces competitive pressures from similar facilities that serve the South Carolina and southeastern Georgia area in terms of location, rates, terms of service, and flexibility and reliability of service.

Dominion's retail energy marketing operations compete against incumbent utilities and other energy marketers in nonregulated energy markets for natural gas. Customers in these markets have the right to select a retail marketer and typically do so based upon price savings or price stability; however, incumbent utilities have the advantage of long-standing relationships with their customers and greater name recognition in their markets.

Regulation

Dominion Energy Operating Segment—Dominion and Dominion Gas

Dominion Gas' natural gas transmission and storage operations are regulated primarily by FERC. East Ohio's gas distribution operations, including the rates that it may charge to customers, are regulated by the Ohio Commission. See *State Regulations* and *Federal Regulations* in *Regulation* for more information.

Dominion Energy Operating Segment—Dominion

Cove Point's, Questar Pipeline's, and DCG's operations are regulated primarily by FERC. Questar Gas' distribution operations, including the rates it may charge customers, are regulated by the Utah, Wyoming and Idaho Commissions. Hope's gas distribution operations, including the rates that it may charge customers, are regulated by the West Virginia Commission. See *State Regulations* and *Federal Regulations* in *Regulation* for more information.

Properties and Investments

For a description of Dominion's and Dominion Gas' existing facilities see Item 2. Properties.

Dominion Energy Operating Segment—Dominion and Dominion Gas

Dominion Gas has the following significant projects under construction or development to better serve customers or expand its service offerings within its service territory.

In September 2014, DTI announced its intent to construct and operate the Supply Header project which is expected to cost approximately $500 million and provide 1,500,000 Dths per day of firm transportation service to various customers. In October 2014, DTI requested authorization to use FERC's pre-filing process. The application to request FERC authorization to construct and operate the project facilities was filed in September 2015, with the facilities expected to be in service in late 2019. In December 2014, DTI entered into a precedent agreement with Atlantic Coast Pipeline for the Supply Header project.

In June 2014, DTI executed binding precedent agreements with two power generators for the Leidy South Project. In November 2014, one of the power generators assigned a portion of its capacity to an affiliate, bringing the total number of project customers to three. The project is expected to cost approximately $210 million. In August 2016, DTI received FERC authorization to construct and operate the Leidy South Project facilities. Service under the 20-year contracts is expected to commence in late 2017.

In September 2013, DTI executed binding precedent agreements with several local distribution company customers for the New Market project. The project is expected to cost approximately $180 million and provide 112,000 Dths per day of firm transportation service from Leidy, Pennsylvania to interconnects with Iroquois and Niagara Mohawk Power Corporation's distribution system in the Albany, New York market. In April 2016, DTI received FERC authorization to construct, operate and maintain the project facilities, which are expected to be in service in late 2017.

In March 2016, East Ohio executed a binding precedent agreement with a power generator for the Lordstown Project. In January 2017, East Ohio commenced construction of the project, with an in-service date expected in the third quarter of 2017 at a total estimated cost of approximately $35 million.

In 2008, East Ohio began PIR, aimed at replacing approximately 4,100 miles of its pipeline system at a cost of $2.7 billion. In 2011, approval was obtained to include an additional 1,450 miles and to increase annual capital investment to meet the program goal. The program will replace approximately 25% of the pipeline system and is anticipated to take place over a total of 25 years. In March 2015, East Ohio filed an application with the Ohio Commission requesting approval to extend the PIR program for an additional five years and to increase the annual capital investment, with corresponding increases in the annual rate-increase caps. In September 2016, the Ohio Commission approved a stipulation filed jointly by East Ohio and the Staff of the Ohio Commission to settle East Ohio's pending application. As requested, the PIR Program and associated cost recovery will continue for another five-year term, calendar years 2017 through 2021, and East Ohio will be permitted to increase its annual capital expenditures to $200 million by 2018 and 3% per year thereafter subject to the cost recovery rate increase caps proposed by East Ohio. Costs associated with calendar year 2016 investment will be recovered under the existing terms.

Dominion Energy Operating Segment—Dominion

Dominion has the following significant projects under construction or development.

Cove Point—Dominion is pursuing the Liquefaction Project, which would enable Cove Point to liquefy domestically-produced natural gas for export as LNG. The DOE previously authorized Dominion to export LNG to countries with free trade agreements. In September 2013, the DOE authorized Dominion to export LNG from Cove Point to non-free trade agreement countries.

In May 2014, the FERC staff issued its EA for the Liquefaction Project. In the EA, the FERC staff addressed a variety of topics related to the proposed construction and development of the Liquefaction Project and its potential impact to the environment, and determined that with the implementation of appropriate mitigation measures, the Liquefaction Project can be built and operated safely with no significant impact to the environment. In September 2014, Cove Point received the FERC order authorizing the Liquefaction Project with certain conditions. The conditions regarding the Liquefaction Project set forth in the FERC order largely incorporate the mitigation measures proposed in the EA. In October 2014, Cove Point commenced construction of the Liquefaction Project, with an in-service date anticipated in late 2017 at a total estimated cost of approximately $4.0 billion, excluding financing costs. The Cove Point facility is authorized to export at a rate of 770 million cubic feet of natural gas per day for a period of 20 years.

In April 2013, Dominion announced it had fully subscribed the capacity of the project with 20-year terminal service agreements. ST Cove Point, LLC, a joint venture of Sumitomo Corporation, a Japanese corporation that is one of the world's leading trading companies, and Tokyo Gas Co., Ltd., a Japanese corporation that is the largest natural gas utility in Japan, and GAIL Global (USA) LNG LLC, a wholly-owned indirect U.S. subsidiary of GAIL (India) Ltd., have each contracted for half of the capacity. Following completion of the front-end engineering and design work, Dominion also announced it had awarded its engineering, procurement and construction contract for new liquefaction facilities to IHI/Kiewit Cove Point, a joint venture between IHI E&C International Corporation and Kiewit Energy Company.

Cove Point has historically operated as an LNG import facility under various long-term import contracts. Since 2010, Dominion has renegotiated certain existing LNG import contracts in a manner that will result in a significant reduction in pipeline and storage capacity utilization and associated anticipated revenues during the period from 2017 through 2028. Such amendments created the opportunity for Dominion to explore the Liquefaction Project, which, assuming it becomes operational, will extend the economic life of Cove Point and contribute to Dominion's overall growth plan. In total, these renegotiations reduced Cove Point's expected annual revenues from the import-related contracts by approximately $150 million from 2017 through 2028, partially offset by approximately $50 million of additional revenues in the years 2013 through 2017.

In October 2015, Cove Point received FERC authorization to construct the approximately $40 million Keys Energy Project. Construction on the project commenced in December 2015, and the project facilities are expected to be placed into service in March 2017.

In November 2016, Cove Point filed an application to request FERC authorization to construct the approximately $150 million Eastern Market Access Project. Construction on the project is expected to begin in the fourth quarter of 2017, and the project facilities are expected to be placed into service in late 2018.

DCG—In 2014, DCG executed binding precedent agreements with three customers for the Charleston project. The project is expected to cost approximately $120 million, and provide 80,000 Dths per day of firm transportation service from an existing interconnect with Transcontinental Gas Pipe Line, LLC in Spartanburg County, South Carolina to customers in Dillon, Marlboro, Sumter, Charleston, Lexington and Richland counties, South Carolina. In February 2017, DCG received FERC approval to construct and operate the project facilities, which are expected to be placed into service in the fourth quarter of 2017.

Questar Gas—In 2010, Questar Gas began replacing aging high pressure infrastructure under a cost-tracking mechanism that allows it to place into rate base and earn a return on capital expenditures associated with a multi-year natural gas infrastructure-replacement program upon the completion of each project. At that time, the commission-allowed annual spending in the replacement program was approximately $55 million.

In its 2014 Utah general rate case Questar Gas received approval to include intermediate high pressure infrastructure in the replacement program and increase the annual spending limit to approximately $65 million, adjusted annually using a gross domestic product inflation factor. At that time, 420 miles of high pressure pipe and 70 miles of intermediate high pressure pipe were identified to be replaced in the program over a 17-year period. Questar Gas has spent about $65 million each year through 2016 under this program. The program is evaluated in each Utah general rate case. The next Utah general rate case is anticipated to occur in 2019.

Dominion Energy Equity Method Investments—In September 2015, Dominion, through Dominion Midstream, acquired an additional 25.93% interest in Iroquois. Dominion Gas holds a 24.07% interest with TransCanada holding a 50% interest. Iroquois owns and operates a 416-mile FERC regulated interstate natural gas pipeline providing service to local gas distribution companies, electric utilities and electric power generators, as well as marketers and other end users, through interconnecting pipelines and exchanges. Iroquois' pipeline extends from the U.S.-Canadian border at Waddington, New York through the state of Connecticut to South Commack, Long Island, New York and continuing on from Northport, Long Island, New York through the Long Island Sound to Hunts Point, Bronx, New York. See Note 9 to the Consolidated Financial Statements for further information about Dominion's equity method investment in Iroquois.

In September 2014, Dominion, along with Duke and Southern Company Gas (formerly known as AGL Resources Inc.), announced the formation of Atlantic Coast Pipeline. The Atlantic Coast Pipeline partnership agreement includes provisions to allow Dominion an option to purchase additional ownership interest in Atlantic Coast Pipeline to maintain a leading ownership percentage. In October 2016, Dominion purchased an additional 3% membership interest in Atlantic Coast Pipeline from Duke for $14 million. The members, which are subsidiaries of the above-referenced parent companies, hold the following membership interests: Dominion, 48%; Duke, 47%; and Southern Company Gas (formerly known as AGL Resources Inc.), 5%. Atlantic Coast Pipeline is focused on constructing an approximately 600-mile natural gas pipeline running from West Virginia through Virginia to North Carolina, which has a total expected cost of $5.0 billion to $5.5 billion, excluding financing costs. In October 2014, Atlantic Coast Pipeline requested approval from FERC to utilize the pre-filing process under which environmental review for the natural gas pipeline project will commence. Atlantic Coast Pipeline filed its FERC application in September 2015 and expects to be in service in late 2019. The project is subject to FERC, state and other federal approvals. See Note 9 to the Consolidated Financial Statements for further information about Dominion's equity method investment in Atlantic Coast Pipeline.

In December 2012, Dominion formed Blue Racer with Caiman to provide midstream services to natural gas producers operating in the Utica Shale region in Ohio and portions of Pennsylvania. Blue Racer is an equal partnership between Dominion and Caiman, with Dominion contributing midstream assets and Caiman contributing private equity capital. Midstream services offered by Blue Racer include gathering, processing, fractionation, and natural gas liquids transportation and marketing. Blue Racer is expected to develop additional new capacity designed to meet producer needs as the development of the Utica Shale formation increases. See Note 9 to the Consolidated Financial Statements for further information about Dominion's equity method investment in Blue Racer.

Sources of Energy Supply

Dominion's and Dominion Gas' natural gas supply is obtained from various sources including purchases from major and independent producers in the Mid-Continent and Gulf Coast regions, local producers in the Appalachian area, gas marketers and, for Questar Gas specifically, from Wexpro and other producers in the Rocky Mountain region. Wexpro's gas development and production operations serve the majority of Questar Gas' gas supply requirements in accordance with the Wexpro Agreement and the Wexpro II Agreement, comprehensive agreements with the states of Utah and Wyoming. Dominion's and Dominion Gas' large underground natural gas storage network and the location of their pipeline systems are a significant link between the country's major interstate gas pipelines and large markets in the Northeast, mid-Atlantic and Rocky Mountain regions. Dominion's and Dominion Gas' pipelines are part of an interconnected gas transmission system, which provides access to supplies nationwide for local distribution companies, marketers, power generators and industrial and commercial customers.

Dominion's and Dominion Gas' underground storage facilities play an important part in balancing gas supply with consumer demand and are essential to serving the Northeast, mid-Atlantic, Midwest and Rocky Mountain regions. In addition, storage capacity is an important element in the effective management of both gas supply and pipeline transmission capacity.

The supply of gas to serve Dominion's retail energy marketing customers is procured through Dominion's energy marketing group and market wholesalers.

Seasonality

Dominion Energy's natural gas distribution business earnings vary seasonally, as a result of the impact of changes in temperature on demand by residential and commercial customers for gas to meet heating needs. Historically, the majority of these earnings have been generated during the heating season, which is generally from November to March; however, implementation of rate mechanisms in Ohio for East Ohio, and Utah, Wyoming and Idaho for Questar Gas, have reduced the earnings impact of weather-related fluctuations. Demand for services at Dominion's gas transmission and storage business can also be weather sensitive. Earnings are also impacted by changes in commodity prices driven by seasonal weather changes, the effects of unusual weather events on operations and the economy.

The earnings of Dominion's retail energy marketing operations also vary seasonally. Generally, the demand for gas peaks during the winter months to meet heating needs.

Corporate and Other

Corporate and Other Segment-Virginia Power and Dominion Gas

Virginia Power's and Dominion Gas' Corporate and Other segments primarily include certain specific items attributable to their operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Corporate and Other Segment-Dominion

Dominion's Corporate and Other segment includes its corporate, service company and other functions (including unallocated debt). In addition, Corporate and Other includes specific items attributable to Dominion's operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Regulation

The Companies are subject to regulation by various federal, state and local authorities, including the state commissions of Virginia, North Carolina, Ohio, West Virginia, Utah, Wyoming and Idaho, SEC, FERC, EPA, DOE, NRC, Army Corps of Engineers, and the Department of Transportation.

State Regulations

Electric

Virginia Power's electric utility retail service is subject to regulation by the Virginia Commission and the North Carolina Commission.

Virginia Power holds CPCNs which authorize it to maintain and operate its electric facilities now in operation and to sell electricity to customers. However, Virginia Power may not construct generating facilities or large capacity transmission lines without the prior approval of various state and federal government agencies. In addition, the Virginia Commission and the North Carolina Commission regulate Virginia Power's transactions with affiliates and transfers of certain facilities. The Virginia Commission also regulates the issuance of certain securities.

Electric Regulation in Virginia

The Regulation Act instituted a cost-of-service rate model, ending Virginia's planned transition to retail competition for electric supply service to most classes of customers.

The Regulation Act authorizes stand-alone rate adjustment clauses for recovery of costs for new generation projects, FERC-approved transmission costs, underground distribution lines, environmental compliance, conservation and energy efficiency programs and renewable energy programs, and also contains statutory provisions directing Virginia Power to file annual fuel cost recovery cases with the Virginia Commission. As amended, it provides for enhanced returns on capital expenditures on specific newly-proposed generation projects.

In February 2015, the Virginia Governor signed legislation into law which will keep Virginia Power's base rates unchanged until at least December 1, 2022. In addition, no biennial reviews will be conducted by the Virginia Commission for the five successive 12-month test periods beginning January 1, 2015, and ending December 31, 2019. The legislation states that Virginia Power's 2015 biennial review, filed in March 2015, would proceed for the sole purpose of reviewing and determining whether any refunds are due to customers based on earnings performance for generation and distribution services during the 2013 and 2014 test periods. In addition the legislation requires the Virginia Commission to conduct proceedings in 2017 and 2019 to determine the utility's ROE for use in connection with rate adjustment clauses and requires utilities to file integrated resource plans annually rather than biennially.

If the Virginia Commission's future rate decisions, including actions relating to Virginia Power's rate adjustment clause filings, differ materially from Virginia Power's expectations, it may adversely affect its results of operations, financial condition and cash flows.

See Note 13 to the Consolidated Financial Statements for additional information, which is incorporated herein by reference.

Electric Regulation in North Carolina

Virginia Power's retail electric base rates in North Carolina are regulated on a cost-of-service/rate-of-return basis subject to North Carolina statutes and the rules and procedures of the North Carolina Commission. North Carolina base rates are set by a process that allows Virginia Power to recover its operating costs and an ROIC. If retail electric earnings exceed the authorized ROE established by the North Carolina Commission, retail electric rates may be subject to review and possible reduction by the North Carolina Commission, which may decrease Virginia Power's future earnings. Additionally, if the North Carolina Commission does not allow recovery of costs incurred in providing service on a timely basis, Virginia Power's future earnings could be negatively impacted. Fuel rates are subject to revision under annual fuel cost adjustment proceedings.

Virginia Power's transmission service rates in North Carolina are regulated by the North Carolina Commission as part of Virginia Power's bundled retail service to North Carolina customers.

See Note 13 to the Consolidated Financial Statements for additional information, which is incorporated herein by reference.

Gas

Dominion Questar's natural gas development, production, transportation, and distribution services, including the rates it may charge its customers, are regulated by the state commissions of Utah, Wyoming and Idaho. East Ohio's natural gas distribution services, including the rates it may charge its customers, are regulated by the Ohio Commission. Hope's natural gas distribution services are regulated by the West Virginia Commission.

Gas Regulation in Utah, Wyoming and Idaho

Questar Gas is subject to regulation of rates and other aspects of its business by the Utah, Wyoming and Idaho Commissions. The Idaho Commission has contracted with the Utah Commission for rate oversight of Questar Gas' operations in a small area of southeastern Idaho. When necessary, Questar Gas seeks general base rate increases to recover increased operating costs and a fair return on rate base investments. Base rates are set based on the cost-of-service by rate class. Base rates for Questar Gas are designed primarily based on rate design methodology in which the majority of operating costs are recovered through volumetric charges.

In addition to general rate increases, Questar Gas makes routine separate filings with the Utah and Wyoming Commissions to reflect changes in the costs of purchased gas. The majority of these purchased gas costs are subject to rate recovery through the Wexpro Agreement and Wexpro II Agreement. Costs that are expected to be recovered in future rates are deferred as regulatory assets. The purchased gas recovery filings generally cover a prospective twelve-month period. Approved increases or decreases in gas cost recovery rates result in increases or decreases in revenues with corresponding increases or decreases in net purchased gas cost expenses.

Questar Gas withdrew its general rate case filed in July 2016 with the Utah Commission and agreed not to file a general rate case with the Utah Commission to adjust its base distribution non-gas rates prior to July 2019, unless otherwise ordered by the Utah Commission. In addition Questar Gas agreed not to file a general rate case with the Wyoming Commission with a requested rate effective date earlier than January 2020. This does not impact Questar Gas' ability to adjust rates through various riders. See Note 3 to the Consolidated Financial Statements for additional information.

Gas Regulation in Ohio

East Ohio is subject to regulation of rates and other aspects of its business by the Ohio Commission. When necessary, East Ohio seeks general base rate increases to recover increased operating costs and a fair return on rate base investments. Base rates are set based on the cost-of-service by rate class. A straight-fixed-variable rate design, in which the majority of operating costs are recovered through a monthly charge rather than a volumetric charge, is utilized to establish rates for a majority of East Ohio's customers pursuant to a 2008 rate case settlement.

In addition to general base rate increases, East Ohio makes routine filings with the Ohio Commission to reflect changes in the costs of gas purchased for operational balancing on its system. These purchased gas costs are subject to rate recovery through a mechanism that ensures dollar for dollar recovery of prudently incurred costs. Costs that are expected to be recovered in future rates are deferred as regulatory assets. The rider filings cover unrecovered gas costs plus prospective annual demand costs. Increases or decreases in gas cost rider rates result in increases or decreases in revenues with corresponding increases or decreases in net purchased gas cost expenses.

The Ohio Commission has also approved several stand-alone cost recovery mechanisms to recover specified costs and a return for infrastructure projects and certain other costs that vary widely over time; such costs are excluded from general base rates. See Note 13 to the Consolidated Financial Statements for additional information.

Gas Regulation in West Virginia

Hope is subject to regulation of rates and other aspects of its business by the West Virginia Commission. When necessary, Hope seeks general base rate increases to recover increased operating costs and a fair return on rate base investments. Base rates are set based on the cost-of-service by rate class. Base rates for Hope are designed primarily based on rate design methodology in which the majority of operating costs are recovered through volumetric charges.

In addition to general rate increases, Hope makes routine separate filings with the West Virginia Commission to reflect changes in the costs of purchased gas. The majority of these purchased gas costs are subject to rate recovery through a mechanism that ensures dollar for dollar recovery of prudently incurred costs. Costs that are expected to be recovered in future rates are deferred as regulatory assets. The purchased gas cost recovery filings generally cover a prospective twelve-month period. Approved increases or decreases in gas cost recovery rates result in increases or decreases in revenues with corresponding increases or decreases in net purchased gas cost expenses.

Legislation was passed in West Virginia authorizing a stand-alone cost recovery mechanism to recover specified costs and a return for infrastructure upgrades, replacements and expansions between general base rate cases.

Status of Competitive Retail Gas Services

The states of Ohio and West Virginia, in which Dominion and Dominion Gas have gas distribution operations, have considered legislation regarding a competitive deregulation of natural gas sales at the retail level.

Ohio—Since October 2000, East Ohio has offered the Energy Choice program, under which residential and commercial customers are encouraged to purchase gas directly from retail suppliers or through a community aggregation program. In October 2006, East Ohio restructured its commodity service by entering into gas purchase contracts with selected suppliers at a fixed price above the New York Mercantile Exchange month-end settlement and passing that gas cost to customers under the Standard Service Offer program. Starting in April 2009, East Ohio buys natural gas under the Standard Service Offer program only for customers not eligible to participate in the Energy Choice program and places Energy Choice-eligible customers in a direct retail relationship with selected suppliers, which is designated on the customers' bills.

In January 2013, the Ohio Commission granted East Ohio's motion to fully exit the merchant function for its nonresidential customers, beginning in April 2013, which requires those customers to choose a retail supplier or be assigned to one at a monthly variable rate set by the supplier. At December 31, 2016, approximately 1.0 million of Dominion Gas' 1.2 million Ohio customers were participating in the Energy Choice program. Subject to the Ohio Commission's approval, East Ohio may eventually exit the gas merchant function in Ohio entirely and have all customers select an alternate gas supplier. East Ohio continues to be the provider of last resort in the event of default by a supplier. Large industrial customers in Ohio also source their own natural gas supplies.

West Virginia—At this time, West Virginia has not enacted legislation allowing customers to choose providers in the retail natural gas markets served by Hope. However, the West Virginia Commission has issued regulations to govern pooling services, one of the tools that natural gas suppliers may utilize to provide retail customers a choice in the future and has issued rules requiring competitive gas service providers to be licensed in West Virginia.

Federal Regulations

Federal Energy Regulatory Commission

Electric

Under the Federal Power Act, FERC regulates wholesale sales and transmission of electricity in interstate commerce by public utilities. Virginia Power purchases and sells electricity in the PJM wholesale market and Dominion's merchant generators sell electricity in the PJM, MISO, CAISO and ISO-NE wholesale markets, and to wholesale purchasers in the states of Virginia, North Carolina, Indiana, Connecticut, Tennessee, Georgia, California and Utah, under Dominion's market-based sales tariffs authorized by FERC or pursuant to FERC authority to sell as a qualified facility. In addition, Virginia Power has FERC approval of a tariff to sell wholesale power at capped rates based on its embedded cost of generation. This cost-based sales tariff could be used to sell to loads within or outside Virginia Power's service territory. Any such sales would be voluntary.

Dominion and Virginia Power are subject to FERC's Standards of Conduct that govern conduct between transmission function employees of interstate gas and electricity transmission providers and the marketing function employees of their affiliates. The rule defines the scope of transmission and marketing-related functions that are covered by the standards and is designed to prevent transmission providers from giving their affiliates undue preferences.

Dominion and Virginia Power are also subject to FERC's affiliate restrictions that (1) prohibit power sales between Virginia Power and Dominion's merchant plants without first receiving FERC authorization, (2) require the merchant plants and Virginia Power to conduct their wholesale power sales operations separately, and (3) prohibit Virginia Power from sharing market information with merchant plant operating personnel. The rules are designed to prohibit Virginia Power from giving the merchant plants a competitive advantage.

EPACT included provisions to create an ERO. The ERO is required to promulgate mandatory reliability standards governing the operation of the bulk power system in the U.S. FERC has certified NERC as the ERO and also issued an initial order approving many reliability standards that went into effect in 2007. Entities that violate standards will be subject to fines of up to $1 million per day, per violation and can also be assessed non-monetary penalties, depending upon the nature and severity of the violation.

Dominion and Virginia Power plan and operate their facilities in compliance with approved NERC reliability requirements. Dominion and Virginia Power employees participate on various NERC committees, track the development and implementation of standards, and maintain proper compliance registration with NERC's regional organizations. Dominion and Virginia Power anticipate incurring additional compliance expenditures over the next several years as a result of the implementation of new cybersecurity programs. In addition, NERC has redefined critical assets which expanded the number of assets subject to NERC reliability standards, including cybersecurity assets. NERC continues to develop additional requirements specifically regarding supply chain standards and control centers that impact the bulk electric system. While Dominion and Virginia Power expect to incur additional compliance costs in connection with NERC requirements and initiatives, such expenses are not expected to significantly affect results of operations.

In April 2008, FERC granted an application for Virginia Power's electric transmission operations to establish a forward-looking formula rate mechanism that updates transmission rates on an annual basis and approved an ROE of 11.4%, effective as of January 1, 2008. The formula rate is designed to recover the expected revenue requirement for each calendar year and is updated based on actual costs. The FERC-approved formula method, which is based on projected costs, allows Virginia Power to earn a current return on its growing investment in electric transmission infrastructure.

Gas

FERC regulates the transportation and sale for resale of natural gas in interstate commerce under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, as amended. Under the Natural Gas Act, FERC has authority over rates, terms and conditions of services performed by Questar Pipeline, DTI, DCG, Iroquois and certain services performed by Cove Point. Pursuant to FERC's February 2014 approval of DTI's uncontested settlement offer, DTI's base rates for storage and transportation services are subject to a moratorium through the end of 2016. The design, construction and operation of Cove Point's LNG facility, including associated natural gas pipelines, the Liquefaction Project and the import and export of LNG are also regulated by FERC.

Dominion's and Dominion Gas' interstate gas transmission and storage activities are conducted on an open access basis, in accordance with certificates, tariffs and service agreements on file with FERC and FERC regulations.

Dominion and Dominion Gas operate in compliance with FERC standards of conduct, which prohibit the sharing of certain non-public transmission information or customer specific data by its interstate gas transmission and storage companies with non-transmission function employees. Pursuant to these standards of conduct, Dominion and Dominion Gas also make certain informational postings available on Dominion's website.

See Note 13 to the Consolidated Financial Statements for additional information.

Safety Regulations

Dominion and Dominion Gas are also subject to the Pipeline Safety Improvement Act of 2002 and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, which mandate inspections of interstate and intrastate natural gas transmission and storage pipelines, particularly those located in areas of high-density population. Dominion and Dominion Gas have evaluated their natural gas transmission and storage properties, as required by the Department of Transportation regulations under these Acts, and has implemented a program of identification, testing and potential remediation activities. These activities are ongoing.

The Companies are subject to a number of federal and state laws and regulations, including Occupational Safety and Health Administration, and comparable state statutes, whose purpose is to protect the health and safety of workers. The Companies have an internal safety, health and security program designed to monitor and enforce compliance with worker safety requirements, which is routinely reviewed and considered for improvement. The Companies believe that they are in material compliance with all applicable laws and regulations related to worker health and safety. Notwithstanding these preventive measures, incidents may occur that are outside of the Companies' control.

Environmental Regulations

Each of the Companies' operating segments faces substantial laws, regulations and compliance costs with respect to environmental matters. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the Companies. If compliance expenditures and associated operating costs are not recoverable from customers through regulated rates (in regulated businesses) or market prices (in unregulated businesses), those costs could adversely affect future results of operations and cash flows. The Companies have applied for or obtained the necessary environmental permits for the operation of their facilities. Many of these permits are subject to reissuance and continuing review. For a discussion of significant aspects of these matters, including current and planned capital expenditures relating to environmental compliance required to be discussed in this Item, see *Environmental Matters* in *Future Issues and Other Matters* in Item 7. MD&A, which information is incorporated herein by reference. Additional information can also be found in Item 3. Legal Proceedings and Note 22 to the Consolidated Financial Statements, which information is incorporated herein by reference.

Air

The CAA is a comprehensive program utilizing a broad range of regulatory tools to protect and preserve the nation's air quality. Regulated emissions include, but are not limited to, carbon, methane, VOC, other GHG, mercury, other toxic metals, hydrogen chloride, NOx, SO_2, and particulate matter. At a minimum, delegated states are required to establish regulatory programs to address all requirements of the CAA. However, states may choose to develop regulatory programs that are more restrictive. Many of the Companies' facilities are subject to the CAA's permitting and other requirements.

Global Climate Change

The national and international attention in recent years on GHG emissions and their relationship to climate change has resulted in federal, regional and state legislative and regulatory action in this area. See, for example, the discussion of the Clean Power Plan and the United Nation's Paris Agreement in *Environmental Matters* in *Future Issues and Other* Matters in Item 7. MD&A.

The Companies support national climate change legislation that would provide a consistent, economy-wide approach to addressing this issue and are currently taking action to protect the environment and address climate change while meeting the growing needs of their service territory. Dominion's CEO and operating segment CEOs are responsible for compliance with the laws and regulations governing environmental matters, including climate change, and Dominion's Board of Directors receives periodic updates on these matters. See *Environmental Strategy* below, *Environmental Matters* in *Future Issues and Other Matters* in Item 7. MD&A and Note 22 to the Consolidated Financial Statements for information on climate change legislation and regulation, which information is incorporated herein by reference.

Water

The CWA is a comprehensive program requiring a broad range of regulatory tools including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms. The CWA and analogous state laws impose restrictions and strict controls regarding the discharge of effluent into surface waters and require permits to be obtained from the EPA or the analogous state agency to discharge into state waters or waters of the U.S. Containment berms and similar structures may be required to help prevent accidental releases. Dominion must comply with applicable aspects of the CWA programs at its current and former operating facilities. From time to time, Dominion's projects and operations may impact tidal and non-tidal wetlands. In these instances, Dominion must obtain authorization from the appropriate federal, state and local agencies prior to impacting a subject wetland. The authorizing agency may impose significant direct or indirect mitigation costs to compensate for such impacts to wetlands.

Gas and Oil Wells

All wells drilled in tight-gas-sand and shale reservoirs require hydraulic-fracture stimulation to achieve economic production rates and recoverable reserves. The majority of Wexpro's current and future production and reserve potential is derived from reservoirs that require hydraulic-fracture stimulation to be commercially viable. Currently, all well construction activities, including hydraulic-fracture stimulation and management and disposal of hydraulic fracturing fluids, are regulated by federal and state agencies that review and approve all aspects of gas- and oil-well design and operation. New environmental initiatives, proposed federal and state legislation, and rule-making pertaining to hydraulic fracture stimulation could increase Wexpro's costs, restrict its access to natural gas reserves and impose additional permitting and reporting requirements. These potential restrictions on the use of hydraulic-fracture stimulation could materially affect Dominion's ability to develop gas and oil reserves.

Other Regulations

Other significant environmental regulations to which the Companies are subject include the CERCLA (providing for immediate response and removal actions, and contamination clean up, in the event of releases of hazardous substances into the environment), the Endangered Species Act (prohibiting activities that can result in harm to specific species of plants and animals), and federal and state laws protecting graves, sacred sites and cultural resources, including those of Native American populations. These regulations can result in compliance costs and potential adverse effects on project plans and schedules such that the Companies' businesses may be materially affected.

Nuclear Regulatory Commission

All aspects of the operation and maintenance of Dominion's and Virginia Power's nuclear power stations are regulated by the NRC. Operating licenses issued by the NRC are subject to revocation, suspension or modification, and the operation of a nuclear unit may be suspended if the NRC determines that the public interest, health or safety so requires.

From time to time, the NRC adopts new requirements for the operation and maintenance of nuclear facilities. In many cases, these new regulations require changes in the design, operation and maintenance of existing nuclear facilities. If the NRC adopts such requirements in the future, it could result in substantial increases in the cost of operating and maintaining Dominion's and Virginia Power's nuclear generating units. See Note 22 to the Consolidated Financial Statements for further information.

The NRC also requires Dominion and Virginia Power to decontaminate their nuclear facilities once operations cease. This process is referred to as decommissioning, and Dominion and Virginia Power are required by the NRC to be financially prepared. For information on decommissioning trusts, see *Dominion Generation-Nuclear Decommissioning* above and Note 9 to the Consolidated Financial Statements. See Note 22 to the Consolidated Financial Statements for information on spent nuclear fuel.

Environmental Strategy

Environmental stewardship is embedded in the Companies' culture and core values and is the responsibility of all employees. They are committed to working with their stakeholders and the communities in which the Companies operate to find sustainable solutions to the energy and environmental challenges that confront the Companies and the U.S. The Companies are committed to delivering reliable, clean and affordable energy while protecting the environment and strengthening the communities they serve. The Companies are dedicated to meeting their customers' growing energy needs with innovative, sustainable solutions. It is the Companies' belief that sustainable solutions must balance the interdependent goals of environmental stewardship and economic prosperity. Their integrated strategy to meet this objective consists of four major elements:

- Compliance with applicable environmental laws, regulations and rules;
- Conservation and load management;
- Renewable generation development; and
- Improvements in other energy infrastructure, including natural gas operations.

This strategy incorporates the Companies' efforts to voluntarily reduce GHG emissions, which are described below. See *Dominion Generation-Properties* and *Dominion Energy-Properties* for more information on certain of the projects described below.

Conservation and Load Management

Conservation and load management play a significant role in meeting the growing demand for electricity. The Regulation Act provides incentives for energy conservation through the implementation of conservation programs. Additional legislation in 2009 added definitions of peak-shaving and energy efficiency programs, and allowed for a margin on operating expenses and recovery of revenue reductions related to energy efficiency programs.

Virginia Power's DSM programs, implemented with Virginia Commission and North Carolina Commission approval, provide important incremental steps in assisting customers to reduce energy consumption through programs that include energy audits and incentives for customers to upgrade or install certain energy efficient measures and/or systems. The DSM programs began in Virginia in 2010 and in North Carolina in 2011. Currently, there are residential and non-residential DSM programs active in the two states. Virginia Power continues to evaluate opportunities to redesign current DSM programs and develop new DSM initiatives in Virginia and North Carolina.

In Ohio, East Ohio offers three DSM programs, approved by the Ohio Commission, designed to help customers reduce their energy consumption.

Questar Gas offers an energy-efficiency program, approved by the Utah and Wyoming Commissions, designed to help customers reduce their energy consumption.

Virginia Power continues to upgrade meters throughout Virginia to AMI, also referred to as smart meters. The AMI meter upgrades are part of an ongoing demonstration effort to help Virginia Power further evaluate the effectiveness of AMI meters in monitoring voltage stability, remotely turn off and on electric service, increase detection and reporting capabilities with respect to power outages and restorations, obtain remote daily meter readings and offer dynamic rates.

Renewable Generation

Renewable energy is also an important component of a diverse and reliable energy mix. Both Virginia and North Carolina have passed legislation setting targets for renewable power. Dominion is committed to meeting Virginia's goals of 12% of base year electric energy sales from renewable power sources by 2022, and 15% by 2025, and North Carolina's Renewable Portfolio Standard of 12.5% by 2021 and continues to add utility-scale solar capacity in Virginia.

See *Operating Segments* and Item 2. Properties for additional information, including Dominion's merchant solar properties.

Improvements in Other Energy Infrastructure

Dominion's existing five-year investment plan includes significant capital expenditures to upgrade or add new electric transmission and distribution lines, substations and other facilities to meet growing electricity demand within its service territory, maintain reliability and address environmental requirements. These enhancements are primarily aimed at meeting Dominion's continued goal of providing reliable service, and are intended to address both continued population growth and increases in electricity consumption by the typical consumer. An additional benefit will be added capacity to efficiently deliver electricity from the renewable projects now being developed or to be developed in the future. See *Properties* in Item 1. Business, *Operating Segments, DVP* for additional information.

Dominion and Dominion Gas, in connection with their existing five-year investment plans, are also pursuing the construction or upgrade of regulated infrastructure in their natural gas businesses. See *Properties and Investments* in Item 1. Business, *Operating Segments, Dominion Energy* for additional information, including natural gas infrastructure projects.

The Companies' GHG Management Strategy

The Companies have not established a standalone GHG emissions reduction target or timetable, but they are actively engaged in GHG emission reduction efforts. The Companies have an integrated strategy for reducing GHG emission intensity with diversification and lower carbon intensity as its cornerstone. The principal components of the strategy include initiatives that address electric energy management, electric energy production, electric energy delivery and natural gas storage, transmission and delivery, as follows:

- Enhance conservation and energy efficiency programs to help customers use energy wisely and reduce environmental impacts;
- Expand the Companies' renewable energy portfolio, principally solar, wind power, fuel cells and biomass, to help diversify the Companies' fleet, meet state renewable energy targets and lower the carbon footprint;
- Evaluate other new generating capacity, including low emissions natural-gas fired and emissions-free nuclear units to meet customers' future electricity needs;
- Construct new electric transmission infrastructure to modernize the grid, promote economic security and help deliver more green energy to population centers where it is needed most;
- Construct new natural gas infrastructure to expand availability of this cleaner fuel, to reduce emissions, and to promote energy and economic security both in the U.S. and abroad;
- Implement and enhance voluntary methane mitigation measures through the EPA's Natural Gas Star and Methane Challenge programs; and
- As part of their commitment to compliance with such environmental laws, Dominion and Virginia Power have sold or closed a number of coal-fired generation units over the past several years, and may close additional units in the future.

Since 2000, Dominion and Virginia Power have tracked the emissions of their electric generation fleet, which employs a mix of fuel and renewable energy sources. Comparing annual year 2015 to annual year 2000, the entire electric generating fleet (based on ownership percentage) reduced its average CO_2 emissions rate per MWh of energy produced from electric generation by approximately 43%. Comparing annual year 2015 to annual year 2000, the regulated electric generating fleet (based on ownership percentage) reduced its average CO_2 emissions rate per MWh of energy produced from electric generation by approximately 23%. Dominion and Virginia Power do not yet have final 2016 emissions data.

Dominion also develops a comprehensive GHG inventory annually. For Dominion Generation, Dominion's and Virginia Power's direct CO_2 equivalent emissions, based on ownership percentage, were 34.3 million metric tons and 30.9 million metric tons, respectively, in 2015, compared to 33.6 million metric tons and 30.1 million metric tons, respectively, in 2014. For the DVP operating segment's electric transmission and distribution operations, direct CO_2 equivalent emissions for 2015 were 53,819 metric tons, compared to 75,671 metric tons in 2014. For 2015, DTI's and Cove Point's direct CO_2 equivalent emissions together were 1.0 million metric tons, decreasing from 1.3 million metric tons in 2014, and Hope's and East Ohio's direct CO_2 equivalent emissions together remained unchanged since 2014 at 0.9 million metric tons. The Companies' GHG inventory follows all methodologies specified in the EPA Mandatory Greenhouse Gas Reporting Rule, 40 Code of Federal Regulations Part 98 for calculating emissions.

CYBERSECURITY

In an effort to reduce the likelihood and severity of cyber intrusions, the Companies have a comprehensive cybersecurity program designed to protect and preserve the confidentiality, integrity and availability of data and systems. In addition, the Companies are subject to mandatory cybersecurity regulatory requirements, interface regularly with a wide range of external organizations, and participate in classified briefings to maintain an awareness of current cybersecurity threats and vulnerabilities. The Companies' current security posture and regulatory compliance efforts are intended to address the evolving and changing cyber threats. See Item 1A. Risk Factors for additional information.

Item 1A. Risk Factors

The Companies' businesses are influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond their control. A number of these factors have been identified below. For other factors that may cause actual results to differ materially from those indicated in any forward-looking statement or projection contained in this report, see *Forward-Looking Statements* in Item 7. MD&A.

The Companies' results of operations can be affected by changes in the weather. Fluctuations in weather can affect demand for the Companies' services. For example, milder than normal weather can reduce demand for electricity and gas transmission and distribution services. In addition, severe weather, including hurricanes, winter storms, earthquakes, floods and other natural disasters can disrupt operation of the Companies' facilities and cause service outages, production delays and property damage that require incurring additional expenses. Changes in weather conditions can result in reduced water levels or changes in water temperatures that could adversely affect operations at some of the Companies' power stations. Furthermore, the Companies' operations could be adversely affected and their physical plant placed at greater risk of damage should changes in global climate produce, among other possible conditions, unusual variations in temperature and weather patterns, resulting in more intense, frequent and extreme weather events, abnormal levels of precipitation and, for operations located on or near coastlines, a change in sea level or sea temperatures.

The rates of Dominion's and Dominion Gas' gas transmission and distribution operations and Virginia Power's electric transmission, distribution and generation operations are subject to regulatory review. Revenue provided by Virginia Power's electric transmission, distribution and generation operations and Dominion's and Dominion Gas' gas transmission and distribution operations is based primarily on rates approved by state and federal regulatory agencies. The profitability of these businesses is dependent on their ability, through the rates that they are permitted to charge, to recover costs and earn a reasonable rate of return on their capital investment.

Virginia Power's wholesale rates for electric transmission service are updated on an annual basis through operation of a FERC-approved formula rate mechanism. Through this mechanism, Virginia Power's wholesale rates for electric transmission reflect the estimated cost-of-service for each calendar year. The difference in the estimated cost-of-service and actual cost-of-service for each calendar year is included as an adjustment to the wholesale rates for electric transmission service in a subsequent calendar year. These wholesale rates are subject to FERC review and prospective adjustment in the event that customers and/or interested state commissions file a complaint with FERC and are able to demonstrate that Virginia Power's wholesale revenue requirement is no longer just and reasonable. They are also subject to retroactive corrections to the extent that the formula rate was not properly populated with the actual costs.

Similarly, various rates and charges assessed by Dominion's and Dominion Gas' gas transmission businesses are subject to review by FERC. In addition, the rates of Dominion's and Dominion Gas' gas distribution businesses are subject to state regulatory review in the jurisdictions in which they operate. A failure by us to support these rates could result in rate decreases from current rate levels, which could adversely affect our results of operations, cash flows and financial condition.

Virginia Power's base rates, terms and conditions for generation and distribution services to customers in Virginia are reviewed by the Virginia Commission on a biennial basis in a proceeding that involves the determination of Virginia Power's actual earned ROE during a combined two-year historic test period, and the determination of Virginia Power's authorized ROE prospectively. Under certain circumstances described in the Regulation Act, Virginia Power may be required to share a portion of its earnings with customers through a refund process.

Legislation signed by the Virginia Governor in February 2015 suspends biennial reviews for the five successive 12-month test periods beginning January 1, 2015 and ending December 31, 2019, and no changes will be made to Virginia Power's existing base rates until at least December 1, 2022. During this period, Virginia Power bears the risk of any severe weather events and natural disasters, the risk of asset impairments related to the early retirement of any generation facilities due to the implementation of the Clean Power Plan regulations, as well as an increase in general operating and financing costs, and Virginia Power may not recover its associated costs through increases to base rates. If Virginia Power incurs any such significant additional expenses during this period, Virginia Power may not be able to recover its costs and/or earn a reasonable return on capital investment, which could negatively affect Virginia Power's future earnings.

Virginia Power's retail electric base rates for bundled generation, transmission, and distribution services to customers in North Carolina are regulated on a cost-of-service/rate-of-return basis subject to North Carolina statutes, and the rules and procedures of the North Carolina Commission. If retail electric earnings exceed the returns established by the North Carolina Commission, retail electric rates may be subject to review and possible reduction by the North Carolina Commission, which may decrease Virginia Power's future earnings. Additionally, if the North Carolina Commission does not allow recovery through base rates, on a timely basis, of costs incurred in providing service, Virginia Power's future earnings could be negatively impacted.

Governmental officials, stakeholders and advocacy groups may challenge these regulatory reviews. Such challenges may lengthen the time, complexity and costs associated with such regulatory reviews.

The Companies are subject to complex governmental regulation, including tax regulation, that could adversely affect their results of operations and subject the Companies to monetary penalties. The Companies' operations are subject to extensive federal, state and local regulation and require numerous permits, approvals and certificates from various governmental agencies. Such laws and regulations govern the terms and conditions of the services we offer, our relationships with affiliates, protection of our critical electric infrastructure assets and pipeline safety, among other matters. These operations are also subject to legislation governing taxation at the federal, state and local level. They must also comply with environmental legislation and associated regulations. Management believes that the necessary approvals have been obtained for existing operations and that the business is conducted in accordance with applicable laws. The Companies' businesses are subject to regulatory regimes which could result in substantial monetary penalties if any of the Companies is found not to be in compliance, including mandatory reliability standards and interaction in the wholesale markets. New laws or regulations, the revision or reinterpretation of existing laws or regulations, changes in enforcement practices of regulators, or penalties imposed for non-compliance with existing laws or regulations may result in substantial additional expense.

Dominion's and Virginia Power's generation business may be negatively affected by possible FERC actions that could change market design in the wholesale markets or affect pricing rules or revenue calculations in the RTO markets. Dominion's and Virginia Power's generation stations operating in RTO markets sell capacity, energy and ancillary services into wholesale electricity markets regulated by FERC. The wholesale markets allow these generation stations to take advantage of market price opportunities, but also expose them to market risk. Properly functioning competitive wholesale markets depend upon FERC's continuation of clearly identified market rules. From time to time FERC may investigate and authorize RTOs to make changes in market design. FERC also periodically reviews Dominion's authority to sell at market-based rates. Material changes by FERC to the design of the wholesale markets or its interpretation of market rules, Dominion's or Virginia Power's authority to sell power at market-based rates, or changes to pricing rules or rules involving revenue calculations, could adversely impact the future results of Dominion's or Virginia Power's generation business. For example, in July 2015, FERC approved changes to PJM's Reliability Pricing Model capacity market establishing a new Capacity Performance Resource product. This product offers the potential for higher capacity prices but can also impose significant economic penalties on generator owners such as Virginia Power for failure to perform during periods when electricity is in high demand. In addition, there have been changes to the interpretation and application of FERC's market manipulation rules. A failure to comply with these rules could lead to civil and criminal penalties.

The Companies' infrastructure build and expansion plans often require regulatory approval before construction can commence. The Companies may not complete facility construction, pipeline, conversion or other infrastructure projects that they commence, or they may complete projects on materially different terms or timing than initially anticipated, and they may not be able to achieve the intended benefits of any such project, if completed. Several facility construction, pipeline, electric transmission line, expansion, conversion and other infrastructure projects have been announced and additional projects may be considered in the future. The Companies compete for projects with companies of varying size and financial capabilities, including some that may have competitive advantages. Commencing construction on announced and future projects may require approvals from applicable state and federal agencies, and such approvals could include mitigation costs which may be material to the Companies. Projects may not be able to be completed on time as a result of weather conditions, delays in obtaining or failure to obtain regulatory approvals, delays in obtaining key materials, labor difficulties, difficulties with partners or potential partners, a decline in the credit strength of counterparties or vendors, or other factors beyond the Companies' control. Even if facility construction, pipeline, expansion, electric transmission line, conversion and other infrastructure projects are completed, the total costs of the projects may be higher than anticipated and the performance of the business of the Companies following completion of the projects may not meet expectations. Start-up and operational issues can arise in connection with the commencement of commercial operations at our facilities, including but not limited to commencement of commercial operations at our power generation facilities following expansions and fuel type conversions to natural gas and biomass. Such issues may include failure to meet specific operating parameters, which may require adjustments to meet or amend these operating parameters. Additionally, the Companies may not be able to timely and effectively integrate the projects into their operations and such integration may result in unforeseen operating difficulties or unanticipated costs. Further, regulators may disallow recovery of some of the costs of a project if they are deemed not to be prudently incurred. Any of these or other factors could adversely affect the Companies' ability to realize the anticipated benefits from the facility construction, pipeline, electric transmission line, expansion, conversion and other infrastructure projects.

The development and construction of several large-scale infrastructure projects simultaneously involves significant execution risk. The Companies are currently simultaneously developing or constructing several major projects, including the Liquefaction Project, the Atlantic Coast Pipeline Project, the Supply Header project, Greensville County and multiple DTI projects, which together help contribute to the over $24 billion in capital expenditures planned by the Companies through 2021. Several of the Companies' key projects are increasingly large-scale, complex and being constructed in constrained geographic areas (for example, the Liquefaction Project) or in difficult terrain (for example, the Atlantic Coast Pipeline Project). The advancement of the Companies' ventures is also affected by the interventions, litigation or other activities of stakeholder and advocacy groups, some of which oppose natural gas-related and energy infrastructure projects. For example, certain landowners and stakeholder groups oppose the Atlantic Coast Pipeline Project, which could impede the acquisition of rights-of-way and other land rights on a timely basis or on acceptable terms. Given that these projects provide the foundation for the Companies' strategic growth plan, if the Companies are unable to obtain or maintain the required approvals, develop the necessary technical expertise, allocate and coordinate sufficient resources, adhere to budgets and timelines, effectively handle public outreach efforts, or otherwise fail to successfully execute the projects, there could be an adverse impact to the Companies' financial position, results of operations and cash flows. For example, while Dominion has received the required approvals to commence construction of the Liquefaction Project from the DOE, all DOE export licenses are subject to review and possible withdrawal should the DOE conclude that such export authorization is no longer in the public interest. Failure to comply with regulatory approval conditions or an adverse ruling in any future litigation could adversely affect the Companies' ability to execute their business plan.

The Companies are dependent on their contractors for the successful and timely completion of large-scale infrastructure projects. The construction of such projects is expected to take several years, is typically confined within a limited geographic area or difficult terrain and could be subject to delays, cost overruns, labor disputes and other factors that could cause the total cost of the project to exceed the anticipated amount and adversely affect the Companies' financial performance and/or impair the Companies' ability to execute the business plan for the project as scheduled.

Further, an inability to obtain financing or otherwise provide liquidity for the projects on acceptable terms could negatively affect the Companies' financial condition, cash flows, the projects' anticipated financial results and/or impair the Companies' ability to execute the business plan for the projects as scheduled.

Any additional federal and/or state requirements imposed on energy companies mandating limitations on GHG emissions or requiring efficiency improvements may result in compliance costs that alone or in combination could make some of the Companies' electric generation units or natural gas facilities uneconomical to maintain or operate. The Clean Power Plan is targeted at reducing CO_2 emissions from existing fossil fuel-fired power generation facilities.

Compliance with the Clean Power Plan may require increasing the energy efficiency of equipment at facilities, committing significant capital toward carbon reduction programs, purchase of allowances and/or emission rate credits, fuel switching, and/or retirement of high-emitting generation facilities and potential replacement with lower emitting generation facilities. The Clean Power Plan uses a set of measures for reducing emissions from existing sources that includes efficiency improvements at coal plants, displacing coal-fired generation with increased utilization of natural gas combined cycle units, and expanding renewable resources. Compliance with the Clean Power Plan's anticipated implementing regulations may require Virginia Power to prematurely retire certain generating facilities, with the potential lack or delay of cost recovery and higher electric rates, which could affect consumer demand. The cost of compliance with the Clean Power Plan is subject to significant uncertainties due to the outcome of several interrelated assumptions and variables, including timing of the implementation of rules, required levels of reductions, allocation requirements of the new rules, the maturation and commercialization of carbon controls and/or reduction programs, and the selected compliance alternatives. Dominion and Virginia Power cannot estimate the aggregate effect of such requirements on their results of operations, financial condition or their customers. However, such expenditures, if material, could make Dominion's and Virginia Power's generation facilities uneconomical to operate, result in the impairment of assets, or otherwise adversely affect Dominion's or Virginia Power's results of operations, financial performance or liquidity.

There are also potential impacts on Dominion's and Dominion Gas' natural gas businesses as federal or state GHG regulations may require GHG emission reductions from the natural gas sector which, in addition to resulting in increased costs, could affect demand for natural gas. Additionally, GHG requirements could result in increased demand for energy conservation and renewable products, which could impact the natural gas businesses.

The Companies' operations are subject to a number of environmental laws and regulations which impose significant compliance costs to the Companies. The Companies' operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources, and health and safety. Compliance with these legal requirements requires the Companies to commit significant capital toward permitting, emission fees, environmental monitoring, installation and operation of environmental control equipment and purchase of allowances and/or offsets. Additionally, the Companies could be responsible for expenses relating to remediation and containment obligations, including at sites where they have been identified by a regulatory agency as a potentially responsible party. Expenditures relating to environmental compliance have been significant in the past, and the Companies expect that they will remain significant in the future. Certain facilities have become uneconomical to operate and have been shut down, converted to new fuel types or sold. These types of events could occur again in the future.

We expect that existing environmental laws and regulations may be revised and/or new laws may be adopted or become applicable, including regulation of GHG emissions which could have an impact on the Companies' business. Risks relating to expected regulation of GHG emissions from existing fossil fuel-fired electric generating units are discussed above. In addition, further regulation of air quality and GHG emissions under the CAA will be imposed on the natural gas sector, including rules to limit methane leakage. The Companies are also subject to recently finalized federal water and waste regulations, including regulations concerning cooling water intake structures, coal combustion by-product handling and disposal practices, wastewater discharges from steam electric generating stations, management and disposal of hydraulic fracturing fluids and the potential further regulation of polychlorinated biphenyls.

Compliance costs cannot be estimated with certainty due to the inability to predict the requirements and timing of implementation of any new environmental rules or regulations. Other factors which affect the ability to predict future environmental expenditures with certainty include the difficulty in estimating clean-up costs and quantifying liabilities under environmental laws that impose joint and several liability on all responsible parties. However, such expenditures, if material, could make the Companies' facilities uneconomical to operate, result in the impairment of assets, or otherwise adversely affect the Companies' results of operations, financial performance or liquidity.

Virginia Power is subject to risks associated with the disposal and storage of coal ash. Virginia Power historically produced and continues to produce coal ash, or CCRs, as a by-product of its coal-fired generation operations. The ash is stored and managed in impoundments (ash ponds) and landfills located at eight different facilities.

Virginia Power may face litigation regarding alleged CWA violations at Possum Point power station, and is facing litigation regarding alleged CWA violations at Chesapeake power station and could incur settlement expenses and other costs, depending on the outcome of any such litigation, including costs associated with closing, corrective action and ongoing monitoring of certain ash ponds. In addition, the EPA and Virginia recently issued regulations concerning the management and storage of CCRs and West Virginia may impose additional regulations that would apply to the facilities noted above. These regulations would require Virginia Power to make additional capital expenditures and increase its operating and maintenance expenses.

Further, while Virginia Power operates its ash ponds and landfills in compliance with applicable state safety regulations, a release of coal ash with a significant environmental impact, such as the Dan River ash basin release by a neighboring utility, could result in remediation costs, civil and/or criminal penalties, claims, litigation, increased regulation and compliance costs, and reputational damage, and could impact the financial condition of Virginia Power.

The Companies' operations are subject to operational hazards, equipment failures, supply chain disruptions and personnel issues which could negatively affect the Companies. Operation of the Companies' facilities involves risk, including the risk of potential breakdown or failure of equipment or processes due to aging infrastructure, fuel supply, pipeline integrity or transportation disruptions, accidents, labor disputes or work stoppages by employees, acts of terrorism or sabotage, construction delays or cost overruns, shortages of or delays in obtaining equipment, material and labor, operational restrictions resulting from environmental limitations and governmental interventions, and performance below expected levels. The Companies' businesses are dependent upon sophisticated information technology systems and network infrastructure, the failure of which could prevent them from accomplishing critical business functions. Because the Companies' transmission facilities, pipelines and other facilities are interconnected with those of third parties, the operation of their facilities and pipelines could be adversely affected by unexpected or uncontrollable events occurring on the systems of such third parties.

Operation of the Companies' facilities below expected capacity levels could result in lost revenues and increased expenses, including higher maintenance costs. Unplanned outages of the Companies' facilities and extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of the Companies' business. Unplanned outages typically increase the Companies' operation and maintenance expenses and may reduce their revenues as a result of selling less output or may require the Companies to incur significant costs as a result of operating higher cost units or obtaining replacement output from third parties in the open market to satisfy forward energy and capacity or other contractual obligations. Moreover, if the Companies are unable to perform their contractual obligations, penalties or liability for damages could result.

In addition, there are many risks associated with the Companies' operations and the transportation, storage and processing of natural gas and NGLs, including nuclear accidents, fires, explosions, uncontrolled release of natural gas and other environmental hazards, pole strikes, electric contact cases, the collision of third party equipment with pipelines and avian and other wildlife impacts. Such incidents could result in loss of human life or injuries among employees, customers or the public in general, environmental pollution, damage or destruction of facilities or business interruptions and associated public or employee safety impacts, loss of revenues, increased liabilities, heightened regulatory scrutiny and reputational risk. Further, the location of pipelines and storage facilities, or generation, transmission, substations and distribution facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks.

Dominion and Virginia Power have substantial ownership interests in and operate nuclear generating units; as a result, each may incur substantial costs and liabilities. Dominion's and Virginia Power's nuclear facilities are subject to operational, environmental, health and financial risks such as the on-site storage of spent nuclear fuel, the ability to dispose of such spent nuclear fuel, the ability to maintain adequate reserves for decommissioning, limitations on the amounts and types of insurance available, potential operational liabilities and extended outages, the costs of replacement power, the costs of maintenance and the costs of securing the facilities against possible terrorist attacks. Dominion and Virginia Power maintain decommissioning trusts and external insurance coverage to minimize the financial exposure to these risks; however, it is possible that future decommissioning costs could exceed amounts in the decommissioning trusts and/or damages could exceed the amount of insurance coverage. If Dominion's and Virginia Power's decommissioning trust funds are insufficient, and they are not allowed to recover the additional costs incurred through insurance, or in the case of Virginia Power through regulatory mechanisms, their results of operations could be negatively impacted.

Dominion's and Virginia Power's nuclear facilities are also subject to complex government regulation which could negatively impact their results of operations. The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generating facilities. In the event of noncompliance, the NRC has the authority to impose fines, set license conditions, shut down a nuclear unit, or take some combination of these actions, depending on its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could require Dominion and Virginia Power to make substantial expenditures at their nuclear plants. In addition, although the Companies have no reason to anticipate a serious nuclear incident at their plants, if an incident did occur, it could materially and adversely affect their results of operations and/or financial condition. A major incident at a nuclear facility anywhere in the world, such as the nuclear events in Japan in 2011, could cause the NRC to adopt increased safety regulations or otherwise limit or restrict the operation or licensing of domestic nuclear units.

Sustained declines in natural gas and NGL prices have resulted in, and could result in further, curtailments of third-party producers' drilling programs, delaying the production of volumes of natural gas and NGLs that Dominion and Dominion Gas gather, process, and transport and reducing the value of NGLs retained by Dominion Gas, which may adversely affect Dominion and Dominion Gas' revenues and earnings. Dominion and Dominion Gas obtain their supply of natural gas and NGLs from numerous third-party producers. Most producers are under no obligation to deliver a specific quantity of natural gas or NGLs to Dominion's and Dominion Gas' facilities. A number of other factors could reduce the volumes of natural gas and NGLs available to Dominion's and Dominion Gas' pipelines and other assets. Increased regulation of energy extraction activities could result in reductions in drilling for new natural gas wells, which could decrease the volumes of natural gas supplied to Dominion and Dominion Gas. Producers with direct commodity price exposure face liquidity constraints, which could present a credit risk to Dominion and Dominion Gas. Producers could shift their production activities to regions outside Dominion's and Dominion Gas' footprint. In addition, the extent of natural gas reserves and the rate of production from such reserves may be less than anticipated. If producers were to decrease the supply of natural gas or NGLs to Dominion's and Dominion Gas' systems and facilities for any reason, Dominion and Dominion Gas could experience lower revenues to the extent they are unable to replace the lost volumes on similar terms. In addition, Dominion Gas' revenue from processing and fractionation operations largely results from the sale of commodities at market prices. Dominion Gas receives the wet gas product from producers and may retain the extracted NGLs as compensation for its services. This exposes Dominion Gas to commodity price risk for the value of the spread between the NGL products and natural gas, and relative changes in these prices could adversely impact Dominion Gas' results.

Dominion's merchant power business operates in a challenging market, which could adversely affect its results of operations and future growth. The success of Dominion's merchant power business depends upon favorable market conditions including the ability to sell power at prices sufficient to cover its operating costs. Dominion operates in active wholesale markets that expose it to price volatility for electricity and fuel as well as the credit risk of counterparties. Dominion attempts to manage its price risk by entering into hedging transactions, including short-term and long-term fixed price sales and purchase contracts.

In these wholesale markets, the spot market price of electricity for each hour is generally determined by the cost of supplying the next unit of electricity to the market during that hour. In many cases, the next unit of electricity supplied would be provided by generating stations that consume fossil fuels, primarily natural gas. Consequently, the open market wholesale price for electricity generally reflects the cost of natural gas plus the cost to convert the fuel to electricity. Therefore, changes in the price of natural gas generally affect the open market wholesale price of electricity. To the extent Dominion does not enter into long-term power purchase agreements or otherwise effectively hedge its output, these changes in market prices could adversely affect its financial results.

Dominion purchases fuel under a variety of terms, including long-term and short-term contracts and spot market purchases. Dominion is exposed to fuel cost volatility for the portion of its fuel obtained through short-term contracts or on the spot market, including as a result of market supply shortages. Fuel prices can be volatile and the price that can be obtained for power produced from such fuel may not change at the same rate as fuel costs, thus adversely impacting Dominion's financial results.

In addition, in the event that any of the merchant generation facilities experience a forced outage, Dominion may not receive the level of revenue it anticipated.

The Companies' financial results can be adversely affected by various factors driving demand for electricity and gas and related services. Technological advances required by federal laws mandate new levels of energy efficiency in end-use devices, including lighting, furnaces and electric heat pumps and could lead to declines in per capita energy consumption. Additionally, certain regulatory and legislative bodies have introduced or are considering requirements and/or incentives to reduce energy consumption by a fixed date. Further, Virginia Power's business model is premised upon the cost efficiency of the production, transmission and distribution of large-scale centralized utility generation. However, advances in distributed generation technologies, such as solar cells, gas microturbines and fuel cells, may make these alternative generation methods competitive with large-scale utility generation, and change how customers acquire or use our services.

Reduced energy demand or significantly slowed growth in demand due to customer adoption of energy efficient technology, conservation, distributed generation, regional economic conditions, or the impact of additional compliance obligations, unless substantially offset through regulatory cost allocations, could adversely impact the value of the Companies' business activities.

Dominion Gas has experienced a decline in demand for certain of its processing services due to competing facilities operating in nearby areas.

Dominion and Dominion Gas may not be able to maintain, renew or replace their existing portfolio of customer contracts successfully, or on favorable terms. Upon contract expiration, customers may not elect to re-contract with Dominion and Dominion Gas as a result of a variety of factors, including the amount of competition in the industry, changes in the price of natural gas, their level of satisfaction with Dominion's and Dominion Gas' services, the extent to which Dominion and Dominion Gas are able to successfully execute their business plans and the effect of the regulatory framework on customer demand. The failure to replace any such customer contracts on similar terms could result in a loss of revenue for Dominion and Dominion Gas and related decreases in their earnings and cash flows.

Certain of Dominion and Dominion Gas' gas pipeline services are subject to long-term, fixed-price "negotiated rate" contracts that are not subject to adjustment, even if the cost to perform such services exceeds the revenues received from such contracts. Under FERC policy, a regulated service provider and a customer may mutually agree to sign a contract for service at a "negotiated rate" which may be above or below the FERC regulated, cost-based recourse rate for that service. These "negotiated rate" contracts are not generally subject to adjustment for increased costs which could be produced by inflation or other factors relating to the specific facilities being used to perform the services. Any shortfall of revenue as result of these "negotiated rate" contracts could decrease Dominion and Dominion Gas' earnings and cash flows.

Exposure to counterparty performance may adversely affect the Companies' financial results of operations. The Companies are exposed to credit risks of their counterparties and the risk that one or more counterparties may fail or delay the performance of their contractual obligations, including but not limited to payment for services. Some of Dominion's operations are conducted through less than wholly-owned subsidiaries. In such arrangements, Dominion is dependent on third parties to fund their required share of capital expenditures. Counterparties could fail or delay the performance of their contractual obligations for a number of reasons, including the effect of regulations on their operations. Defaults or failure to perform by customers, suppliers, joint venture partners, financial institutions or other third parties may adversely affect the Companies' financial results.

Dominion will also be exposed to counterparty credit risk relating to the terminal services agreements for the Liquefaction Project. While the counterparties' obligations are supported by parental guarantees and letters of credit, there is no assurance that such credit support would be sufficient to satisfy the obligations in the event of a counterparty default. In addition, if a controversy arises under either agreement resulting in a judgment in Dominion's favor, Dominion may need to seek to enforce a final U.S. court judgment in a foreign tribunal, which could involve a lengthy process.

Market performance and other changes may decrease the value of Dominion's decommissioning trust funds and Dominion's and Dominion Gas' benefit plan assets or increase Dominion's and Dominion Gas' liabilities, which could then require significant additional funding. The performance of the capital markets affects the value of the assets that are held in trusts to satisfy future obligations to decommission Dominion's nuclear plants and under Dominion's and Dominion Gas' pension and other postretirement benefit plans. Dominion and Dominion Gas have significant obligations in these areas and holds significant assets in these trusts. These assets are subject to market fluctuation and will yield uncertain returns, which may fall below expected return rates.

With respect to decommissioning trust funds, a decline in the market value of these assets may increase the funding requirements of the obligations to decommission Dominion's nuclear plants or require additional NRC-approved funding assurance.

A decline in the market value of the assets held in trusts to satisfy future obligations under Dominion's and Dominion Gas' pension and other postretirement benefit plans may increase the funding requirements under such plans. Additionally, changes in interest rates will affect the liabilities under Dominion's and Dominion Gas' pension and other postretirement benefit plans; as interest rates decrease, the liabilities increase, potentially requiring additional funding. Further, changes in demographics, including increased numbers of retirements or changes in mortality assumptions, may also increase the funding requirements of the obligations related to the pension and other postretirement benefit plans.

If the decommissioning trust funds and benefit plan assets are negatively impacted by market fluctuations or other factors, Dominion's and Dominion Gas' results of operations, financial condition and/or cash flows could be negatively affected.

The use of derivative instruments could result in financial losses and liquidity constraints. The Companies use derivative instruments, including futures, swaps, forwards, options and FTRs, to manage commodity, currency and financial market risks. In addition, Dominion and Dominion Gas purchase and sell commodity-based contracts for hedging purposes.

The Dodd-Frank Act was enacted into law in July 2010 in an effort to improve regulation of financial markets. The Dodd-Frank Act includes provisions that will require certain over-the-counter derivatives, or swaps, to be centrally cleared and executed through an exchange or other approved trading platform. Non-financial entities that use swaps to hedge or mitigate commercial risk, often referred to as end users, can choose to exempt their hedging transactions from these clearing and exchange trading requirements. Final rules for the over-the-counter derivative-related provisions of the Dodd-Frank Act will continue to be established through the ongoing rulemaking process of the applicable regulators, including rules regarding margin requirements for non-cleared swaps. If, as a result of the rulemaking process, the Companies' derivative activities are not exempted from the clearing, exchange trading or margin requirements, the Companies could be subject to higher costs, including from higher margin requirements, for their derivative activities. In addition, the implementation of, and compliance with, Title VII of the Dodd-Frank Act by the Companies' counterparties could result in increased costs related to the Companies' derivative activities.

Changing rating agency requirements could negatively affect the Companies' growth and business strategy. In order to maintain appropriate credit ratings to obtain needed credit at a reasonable cost in light of existing or future rating agency requirements, the Companies may find it necessary to take steps or change their business plans in ways that may adversely affect their growth and earnings. A reduction in the Companies' credit ratings could result in an increase in borrowing costs, loss of access to certain markets, or both, thus adversely affecting operating results and could require the Companies to post additional collateral in connection with some of its price risk management activities.

An inability to access financial markets could adversely affect the execution of the Companies' business plans. The Companies rely on access to short-term money markets and longer-term capital markets as significant sources of funding and liquidity for business plans with increasing capital expenditure needs, normal working capital and collateral requirements related to hedges of future sales and purchases of energy-related commodities. Deterioration in the Companies' creditworthiness, as evaluated by credit rating agencies or otherwise, or declines in market reputation either for the Companies or their industry in general, or general financial market disruptions outside of the Companies' control could increase their cost of borrowing or restrict their ability to access one or more financial markets. Further market disruptions could stem from delays in the current economic recovery, the bankruptcy of an unrelated company, general market disruption due to general credit market or political events, or the failure of financial institutions on which the Companies rely. Increased costs and restrictions on the Companies' ability to access financial markets may be severe enough to affect their ability to execute their business plans as scheduled.

Potential changes in accounting practices may adversely affect the Companies' financial results. The Companies cannot predict the impact that future changes in accounting standards or practices may have on public companies in general, the energy industry or their operations specifically. New accounting standards could be issued that could change the way they record revenues, expenses, assets and liabilities. These changes in accounting standards could adversely affect earnings or could increase liabilities.

War, acts and threats of terrorism, intentional acts and other significant events could adversely affect the Companies' operations. The Companies cannot predict the impact that any future terrorist attacks may have on the energy industry in general, or on the Companies' business in particular. Any retaliatory military strikes or sustained military campaign may affect the Companies' operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets. In addition, the Companies' infrastructure facilities, including projects under construction, could be direct targets of, or indirect casualties of, an act of terror. For example, a physical attack on a critical substation in California resulted in serious impacts to the power grid. Furthermore, the physical compromise of the Companies' facilities could adversely affect the Companies' ability to manage these facilities effectively. Instability in financial markets as a result of terrorism, war, intentional acts, pandemic, credit crises, recession or other factors could result in a significant decline in the U.S. economy and increase the cost of insurance coverage. This could negatively impact the Companies' results of operations and financial condition.

Hostile cyber intrusions could severely impair the Companies' operations, lead to the disclosure of confidential information, damage the reputation of the Companies and otherwise have an adverse effect on the Companies' business. The Companies own assets deemed as critical infrastructure, the operation of which is dependent on information technology systems. Further, the computer systems that run the Companies' facilities are not completely isolated from external networks. There appears to be an increasing level of activity, sophistication and maturity of threat actors, in particular nation state actors, that wish to disrupt the U.S. bulk power system and the U.S. gas transmission or distribution system. Such parties could view the Companies' computer systems, software or networks as attractive targets for cyber attack. For example, malware has been designed to target software that runs the nation's critical infrastructure such as power transmission grids and gas pipelines. In addition, the Companies' businesses require that they and their vendors collect and maintain sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss.

A successful cyber attack on the systems that control the Companies' electric generation, electric or gas transmission or distribution assets could severely disrupt business operations, preventing the Companies from serving customers or collecting revenues. The breach of certain business systems could affect the Companies' ability to correctly record, process and report financial information. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to the Companies' reputation. In addition, the misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant breach notification expenses and mitigation expenses such as credit monitoring. The Companies maintain property and casualty insurance that may cover certain damage caused by potential cyber incidents; however, other damage and claims arising from such incidents may not be covered or may exceed the amount of any insurance available. For these reasons, a significant cyber incident could materially and adversely affect the Companies' business, financial condition and results of operations.

Failure to attract and retain key executive officers and an appropriately qualified workforce could have an adverse effect on the Companies' operations. The Companies' business strategy is dependent on their ability to recruit, retain and motivate employees. The Companies' key executive officers are the CEO, CFO and presidents and those responsible for financial, operational, legal, regulatory and accounting functions. Competition for skilled management employees in these areas of the Companies' business operations is high. Certain events, such as an aging workforce, mismatch of skill set or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge base and the length of time required for skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees, or future availability and cost of contract labor may adversely affect the ability to manage and operate the Companies' business. In addition, certain specialized knowledge is required of the Companies' technical employees for transmission, generation and distribution operations. The Companies' inability to attract and retain these employees could adversely affect their business and future operating results.

The Questar Combination may not achieve its intended results. The Questar Combination is expected to result in various benefits, including, among other things, being accretive to earnings. Achieving the anticipated benefits of the transaction is subject to a number of uncertainties, including whether the business of Dominion Questar is integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could result in increased costs, decreases in the amount of expected revenues generated by the combined company and diversion of management's time and energy, all of which could have an adverse effect on the combined company's financial position, results of operations or cash flows.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

As of December 31, 2016, Dominion owned its principal executive office and three other corporate offices, all located in Richmond, Virginia. Dominion also leases corporate offices in other cities in which its subsidiaries operate. Virginia Power and Dominion Gas share Dominion's principal office in Richmond, Virginia, which is owned by Dominion. In addition, Virginia Power's DVP and Generation segments share certain leased buildings and equipment. See Item 1. Business for additional information about each segment's principal properties, which information is incorporated herein by reference.

Dominion's assets consist primarily of its investments in its subsidiaries, the principal properties of which are described here and in Item 1. Business.

Certain of Virginia Power's property is subject to the lien of the Indenture of Mortgage securing its First and Refunding Mortgage Bonds. There were no bonds outstanding as of December 31, 2016; however, by leaving the indenture open, Virginia Power expects to retain the flexibility to issue mortgage bonds in the future. Certain of Dominion's merchant generation facilities are also subject to liens.

Dominion Energy

Dominion and Dominion Gas

East Ohio's gas distribution network is located in Ohio. This network involves approximately 18,900 miles of pipe, exclusive of service lines. The right-of-way grants for many natural gas pipelines have been obtained from the actual owners of real estate, as underlying titles have been examined. Where rights-of-way have not been obtained, they could be acquired from private owners by condemnation, if necessary. Many natural gas pipelines are on publicly-owned property, where company rights and actions are determined on a case-by-case basis, with results that range from reimbursed relocation to revocation of permission to operate.

Dominion Gas has approximately 10,400 miles, excluding interests held by others, of gas transmission, gathering and storage pipelines located in the states of Maryland, New York, Ohio, Pennsylvania, Virginia and West Virginia. Dominion Gas also owns NGL processing plants capable of processing over 270,000 mcf per day of natural gas. Hastings is the largest plant and is capable of processing over 180,000 mcf per day of natural gas. Hastings can also fractionate over 580,000 Gals per day of NGLs into marketable products, including propane, isobutane, butane and natural gasoline. NGL operations have storage capacity of 1,226,500 Gals of propane, 109,000 Gals of isobutane, 442,000 Gals of butane, 2,000,000 Gals of natural gasoline and 1,012,500 Gals of mixed NGLs. Dominion Gas also operates 20 underground gas storage fields located in New York, Ohio, Pennsylvania and West Virginia, with approximately 2,000 storage wells and approximately 399,000 acres of operated leaseholds.

The total designed capacity of the underground storage fields operated by Dominion Gas is approximately 929 bcf. Certain storage fields are jointly-owned and operated by Dominion Gas. The capacity of those fields owned by Dominion Gas' partners totals approximately 220 bcf.

Dominion

Cove Point's LNG facility has an operational peak regasification daily send-out capacity of approximately 1.8 million Dths and an aggregate LNG storage capacity of approximately 14.6 bcfe. In addition, Cove Point has a liquefier that has the potential to create approximately 15,000 Dths/day.

The Cove Point pipeline is a 36-inch diameter underground, interstate natural gas pipeline that extends approximately 88 miles from Cove Point to interconnections with Transcontinental Gas Pipe Line Company, LLC in Fairfax County, Virginia, and with

Columbia Gas Transmission, LLC and DTI in Loudoun County, Virginia. In 2009, the original pipeline was expanded to include a 36-inch diameter expansion that extends approximately 48 miles, roughly 75% of which is parallel to the original pipeline.

Questar Gas distributes gas to customers in Utah, Wyoming and Idaho. Questar Gas owns and operates distribution systems and has a total of 29,200 miles of street mains, service lines and interconnecting pipelines. Questar Gas has a major operations center in Salt Lake City, and has operations centers, field offices and service-center facilities in other parts of its service area.

Questar Pipeline operates 2,200 miles of natural gas transportation pipelines that interconnect with other pipelines in Utah, Wyoming and western Colorado. Questar Pipeline's system ranges in diameter from lines that are less than four inches to 36-inches. Questar Pipeline owns the Clay Basin storage facility in northeastern Utah, which has a certificated capacity of 120 bcf, including 54 bcf of working gas.

DCG's interstate natural gas pipeline system in South Carolina and southeastern Georgia is comprised of nearly 1,500 miles of transmission pipeline.

In total, Dominion has 170 compressor stations with approximately 1,175,000 installed compressor horsepower.

DVP

See Item 1. Business, *General* for details regarding DVP's principal properties, which primarily include transmission and distribution lines.

Dominion Generation

Dominion and Virginia Power generate electricity for sale on a wholesale and a retail level. Dominion and Virginia Power supply electricity demand either from their generation facilities or through purchased power contracts. As of December 31, 2016, Dominion Generation's total utility and merchant generating capacity was approximately 26,400 MW.

The following tables list Dominion Generation's utility and merchant generating units and capability, as of December 31, 2016:

Virginia Power Utility Generation[1]

Plant	Location	Net Summer Capability (MW)	Percentage Net Summer Capability
Gas			
Brunswick County (CC)	Brunswick County, VA	1,376	
Warren County (CC)	Warren County, VA	1,342	
Ladysmith (CT)	Ladysmith, VA	783	
Remington (CT)	Remington, VA	608	
Bear Garden (CC)	Buckingham County, VA	590	
Possum Point (CC)	Dumfries, VA	573	
Chesterfield (CC)	Chester, VA	397	
Elizabeth River (CT)	Chesapeake, VA	348	
Possum Point	Dumfries, VA	316	
Bellemeade (CC)	Richmond, VA	267	
Bremo	Bremo Bluff, VA	227	
Gordonsville Energy (CC)	Gordonsville, VA	218	
Gravel Neck (CT)	Surry, VA	170	
Darbytown (CT)	Richmond, VA	168	
Rosemary (CC)	Roanoke Rapids, NC	165	
Total Gas		7,548	35%
Coal			
Mt. Storm	Mt. Storm, WV	1,629	
Chesterfield	Chester, VA	1,267	
Virginia City Hybrid Energy Center	Wise County, VA	610	
Clover	Clover, VA	439[2]	
Yorktown[3]	Yorktown, VA	323	
Mecklenburg	Clarksville, VA	138	
Total Coal		4,406	21
Nuclear			
Surry	Surry, VA	1,676	
North Anna	Mineral, VA	1,672[4]	
Total Nuclear		3,348	15
Oil			
Yorktown	Yorktown, VA	790	
Possum Point	Dumfries, VA	786	
Gravel Neck (CT)	Surry, VA	198	
Darbytown (CT)	Richmond, VA	168	
Possum Point (CT)	Dumfries, VA	72	
Chesapeake (CT)	Chesapeake, VA	51	
Low Moor (CT)	Covington, VA	48	
Northern Neck (CT)	Lively, VA	47	
Total Oil		2,160	10
Hydro			
Bath County	Warm Springs, VA	1,808[5]	
Gaston	Roanoke Rapids, NC	220	
Roanoke Rapids	Roanoke Rapids, NC	95	
Other	Various	3	
Total Hydro		2,126	10
Biomass			
Pittsylvania	Hurt, VA	83	
Altavista	Altavista, VA	51	
Polyester	Hopewell, VA	51	
Southampton	Southampton, VA	51	
Total Biomass		236	1
Solar			
Whitehouse Solar	Louisa County, VA	20	
Woodland Solar	Isle of Wight County, VA	19	
Scott Solar	Powhatan County, VA	17	
Total Solar		56	—
Various			
Mt. Storm (CT)	Mt. Storm, WV	11	—
		19,891	
Power Purchase Agreements		1,764	8
Total Utility Generation		21,655	100%

Note: (CT) denotes combustion turbine and (CC) denotes combined cycle.
(1) The table excludes Virginia Power's Morgans Corner solar facility located in Pasquotank County, NC which has a net summer capacity of 20 MW, as the facility is dedicated to serving a non-jurisdictional customer.
(2) Excludes 50% undivided interest owned by ODEC.
(3) Coal-fired units are expected to be retired at Yorktown power station as early as 2017 as a result of the issuance of MATS.
(4) Excludes 11.6% undivided interest owned by ODEC.
(5) Excludes 40% undivided interest owned by Allegheny Generating Company, a subsidiary of Allegheny Energy, Inc.

Dominion Merchant Generation

Plant	Location	Net Summer Capability (MW)	Percentage Net Summer Capability
Nuclear			
Millstone	Waterford, CT	2,001(1)	
Total Nuclear		2,001	43%
Gas			
Fairless (CC)	Fairless Hills, PA	1,240	
Manchester (CC)	Providence, RI	468	
Total Gas		1,708	36
Solar(2)			
Escalante I, II and III	Beaver County, UT	120(3)	
Amazon Solar Farm U.S. East	Oak Hall, VA	80	
Granite Mountain East and West	Iron County, UT	65(3)	
Summit Farms Solar	Moyock, NC	60	
Enterprise	Beaver County, UT	40(3)	
Iron Springs	Iron County, UT	40(3)	
Pavant Solar	Holden, UT	34(4)	
Camelot Solar	Mojave, CA	30(4)	
Indy I, II and III	Indianapolis, IN	20(4)	
Cottonwood Solar	Kings and Kern counties, CA	16(4)	
Alamo Solar	San Bernardino, CA	13(4)	
Maricopa West Solar	Kern County, CA	13(4)	
Imperial Valley 2 Solar	Imperial, CA	13(4)	
Richland Solar	Jeffersonville, GA	13(4)	
CID Solar	Corcoran, CA	13(4)	
Kansas Solar	Lenmore, CA	13(4)	
Kent South Solar	Lenmore, CA	13(4)	
Old River One Solar	Bakersfield, CA	13(4)	
West Antelope Solar	Lancaster, CA	13(4)	
Adams East Solar	Tranquility, CA	13(4)	
Catalina 2 Solar	Kern County, CA	12(4)	
Mulberry Solar	Selmer, TN	11(4)	
Selmer Solar	Selmer, TN	11(4)	
Columbia 2 Solar	Mojave, CA	10(4)	
Azalea Solar	Davisboro, GA	5(4)	
Somers Solar	Somers, CT	3(4)	
Total Solar		687	15
Wind			
Fowler Ridge(5)	Benton County, IN	150(6)	
NedPower(5)	Grant County, WV	132(7)	
Total Wind		282	6
Fuel Cell			
Bridgeport Fuel Cell	Bridgeport, CT	15	
Total Fuel Cell		15	—
Total Merchant Generation		4,693	100%

Note: (CC) denotes combined cycle.
(1) Excludes 6.53% undivided interest in Unit 3 owned by Massachusetts Municipal and Green Mountain.
(2) All solar facilities are alternating current.
(3) Excludes 50% noncontrolling interest owned by NRG.
(4) Excludes 33% noncontrolling interest owned by Terra Nova Renewable Partners. Dominion's interest is subject to a lien securing SBL Holdco's debt.
(5) Subject to a lien securing the facility's debt.
(6) Excludes 50% membership interest owned by BP.
(7) Excludes 50% membership interest owned by Shell.

Item 3. Legal Proceedings

From time to time, the Companies are alleged to be in violation or in default under orders, statutes, rules or regulations relating to the environment, compliance plans imposed upon or agreed to by the Companies, or permits issued by various local, state and/or federal agencies for the construction or operation of facilities. Administrative proceedings may also be pending on these matters. In addition, in the ordinary course of business, the Companies and their subsidiaries are involved in various legal proceedings.

In January 2016, Virginia Power self-reported a release of mineral oil from the Crystal City substation and began extensive cleanup. In February 2016, Virginia Power received a notice of violation from the VDEQ relating to this matter. Virginia Power has assumed the role of responsible party and is continuing to cooperate with ongoing requirements for investigative and corrective action. In September 2016, Virginia Power received a proposed consent order from the VDEQ related to this matter. The order was signed by Virginia Power in October 2016 and approved by the Virginia State Water Control Board in December 2016. The order included a penalty of $260,000, which is inclusive of both the Crystal City substation oil release and an oil release from another Virginia Power facility in 2016. The portion of the penalty attributable to the other facility represents less than $100,000 of the total proposed penalty.

In December 2016, Wexpro received a notice of violation from the Wyoming Division of Air Quality in connection with an alleged non-compliance with an air quality permit and certain air quality regulations relating to Wexpro's Church Buttes #63 well. The notice did not include a proposed penalty. Dominion is unable to evaluate the final outcome of this matter but it could result in a penalty in excess of $100,000.

See Notes 13 and 22 to the Consolidated Financial Statements and *Future Issues and Other Matters* in Item 7. MD&A, which information is incorporated herein by reference, for discussion of various environmental and other regulatory proceedings to which the Companies are a party.

Item 4. Mine Safety Disclosures

Not applicable.

Executive Officers of Dominion

Information concerning the executive officers of Dominion, each of whom is elected annually, is as follows:

Name and Age	Business Experience Past Five Years[1]
Thomas F. Farrell II (62)	Chairman of the Board of Directors, President and CEO of Dominion from April 2007 to date; Chairman and CEO of Dominion Midstream GP, LLC (the general partner of Dominion Midstream) from March 2014 to date and President from February 2015 to date; CEO of Dominion Gas from September 2013 to date and Chairman from March 2014 to date; Chairman and CEO of Virginia Power from February 2006 to date and Questar Gas from September 2016 to date.
Mark F. McGettrick (59)	Executive Vice President and CFO of Dominion from June 2009 to date, Dominion Midstream GP, LLC from March 2014 to date, Virginia Power from June 2009 to date, Dominion Gas from September 2013 to date, and Questar Gas from September 2016 to date.
Paul D. Koonce (57)	Executive Vice President and President & CEO—Dominion Generation Group of Dominion from January 2017 to date; Executive Vice President and CEO—Dominion Generation Group of Dominion from January 2016 to December 2016; Executive Vice President and CEO—Energy Infrastructure Group of Dominion from February 2013 to December 2015; Executive Vice President of Dominion from April 2006 to February 2013; Executive Vice President of Dominion Midstream GP, LLC from March 2014 to December 2015; President and COO of Virginia Power from June 2009 to date; President of Dominion Gas from September 2013 to December 2015.
Robert M. Blue (49)	Senior Vice President and President & CEO—Dominion Virginia Power of Dominion from January 2017 to date; President and COO of Virginia Power from January 2017 to date; Senior Vice President—Law, Regulation & Policy of Dominion, Dominion Gas and Dominion Midstream GP, LLC from February 2016 to December 2016 and Questar Gas from September 2016 to December 2016; President of Virginia Power from January 2016 to December 2016; Senior Vice President—Regulation, Law, Energy Solutions and Policy of Dominion and Dominion Gas from May 2015 to January 2016 and Dominion Midstream GP, LLC from July 2015 to January 2016; Senior Vice President—Regulation, Law, Energy Solutions and Policy of Virginia Power from May 2015 to December 2015; President of Virginia Power from January 2014 to May 2015; Senior Vice President-Law, Public Policy and Environment of Dominion from January 2011 to December 2013.
Diane Leopold (50)	Senior Vice President and President & CEO—Dominion Energy of Dominion and Dominion Midstream GP, LLC from January 2017 to date; President of Dominion Gas from January 2017 to date; President of DTI, East Ohio and Dominion Cove Point, Inc. from January 2014 to date; Senior Vice President of DTI from April 2012 to December 2013; Senior Vice President—Business Development & Generation Construction of Virginia Power from April 2009 to March 2012.
Mark O. Webb (52)	Senior Vice President—Corporate Affairs and Chief Legal Officer of Dominion, Virginia Power, Dominion Gas, Dominion Midstream GP, LLC, and Questar Gas from January 2017 to date; Senior Vice President, General Counsel and Chief Risk Officer of Dominion, Virginia Power and Dominion Gas from May 2016 to December 2016; Senior Vice President and General Counsel of Dominion Midstream GP, LLC from May 2016 to December 2016 and Questar Gas from September 2016 to December 2016; Vice President, General Counsel and Chief Risk Officer of Dominion, Virginia Power and Dominion Gas from January 2014 to May 2016; Vice President and General Counsel of Dominion Midstream GP, LLC from March 2014 to May 2016; Vice President and General Counsel of Dominion and Virginia Power from January 2013 to December 2013, and Dominion Gas from September 2013 to December 2013; Deputy General Counsel of DRS from July 2011 to December 2012.
Michele L. Cardiff (49)	Vice President, Controller and CAO of Dominion and Virginia Power from April 2014 to date, Dominion Gas and Dominion Midstream GP, LLC from March 2014 to date and Questar Gas from September 2016 to date; Vice President—Accounting of DRS from January 2014 to March 2014; Vice President and General Auditor of DRS from September 2012 to December 2013; Controller of Virginia Power from June 2009 to August 2012.
David A. Heacock (59)	President of Virginia Power from June 2009 to date and CNO from June 2009 to September 2016. Mr. Heacock will retire effective March 1, 2017.

(1) Any service listed for Virginia Power, Dominion Midstream GP, LLC, Dominion Gas, DTI, East Ohio, Dominion Cove Point, Inc., Questar Gas and DRS reflects service at a subsidiary of Dominion.

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Dominion

Dominion's common stock is listed on the NYSE. At January 31, 2017, there were approximately 126,500 record holders of Dominion's common stock. The number of record holders is comprised of individual shareholder accounts maintained on Dominion's transfer agent records and includes accounts with shares held in (1) certificate form, (2) book-entry in the Direct Registration System and (3) book-entry under Dominion Direct®. Discussions of expected dividend payments and restrictions on Dominion's payment of dividends required by this Item are contained in *Liquidity and Capital Resources* in Item 7. MD&A and Notes 17 and 20 to the Consolidated Financial Statements. Cash dividends were paid quarterly in 2016 and 2015. Quarterly information concerning stock prices and dividends is disclosed in Note 26 to the Consolidated Financial Statements, which information is incorporated herein by reference.

The following table presents certain information with respect to Dominion's common stock repurchases during the fourth quarter of 2016:

Dominion Purchases Of Equity Securities

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share(2)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased under the Plans or Programs(3)
10/1/2016-10/31/16	**233**	**$74.27**	**N/A**	**19,629,059 shares/$1.18 billion**
11/1/2016-11/30/16	**—**	**—**	**N/A**	**19,629,059 shares/$1.18 billion**
12/1/2016-12/31/16	**2,728**	**73.31**	**N/A**	**19,629,059 shares/$1.18 billion**
Total	**2,961**	**$73.38**	**N/A**	**19,629,059 shares/$1.18 billion**

(1) 233 and 2,728 shares were tendered by employees to satisfy tax withholding obligations on vested restricted stock in October and December 2016, respectively.
(2) Represents the weighted-average price paid per share.
(3) The remaining repurchase authorization is pursuant to repurchase authority granted by the Dominion Board of Directors in February 2005, as modified in June 2007. The aggregate authorization granted by the Dominion Board of Directors was 86 million shares (as adjusted to reflect a two-for-one stock split distributed in November 2007) not to exceed $4 billion.

Virginia Power

There is no established public trading market for Virginia Power's common stock, all of which is owned by Dominion. Potential restrictions on Virginia Power's payment of dividends are discussed in Note 20 to the Consolidated Financial Statements. In the first through fourth quarters of 2015, Virginia Power declared and paid quarterly cash dividends of $149 million, $121 million, $146 million and $75 million. In 2016, no dividends were declared or paid given the sufficiency of operating and other cash flows at Dominion. Virginia Power intends to pay quarterly cash dividends in 2017 but is neither required to nor restricted from making such payments.

Dominion Gas

All of Dominion Gas' membership interests are owned by Dominion. Potential restrictions on Dominion Gas' payment of distributions are discussed in Note 20 to the Consolidated Financial Statements. In the first through fourth quarters of 2015, Dominion Gas declared and paid quarterly cash distributions of $96 million, $68 million, $80 million and $448 million. Dominion Gas declared and paid cash distributions of $150 million in the second quarter of 2016.

Item 6. Selected Financial Data

The following table should be read in conjunction with the Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

Dominion

Year Ended December 31,	**2016[1]**	2015	2014[2]	2013[3]	2012[4]
(millions, except per share amounts)					
Operating revenue	**$11,737**	$11,683	$12,436	$13,120	$12,835
Income from continuing operations, net of tax[5]	**2,123**	1,899	1,310	1,789	1,427
Loss from discontinued operations, net of tax[5]	**—**	—	—	(92)	(1,125)
Net income attributable to Dominion	**2,123**	1,899	1,310	1,697	302
Income from continuing operations before loss from discontinued operations per common share-basic	**3.44**	3.21	2.25	3.09	2.49
Net income attributable to Dominion per common share-basic	**3.44**	3.21	2.25	2.93	0.53
Income from continuing operations before loss from discontinued operations per common share-diluted	**3.44**	3.20	2.24	3.09	2.49
Net income attributable to Dominion per common share-diluted	**3.44**	3.20	2.24	2.93	0.53
Dividends declared per common share	**2.80**	2.59	2.40	2.25	2.11
Total assets[6]	**71,610**	58,648	54,186	49,963	46,711
Long-term debt[6]	**30,231**	23,468	21,665	19,199	16,736

(1) Includes a $122 million after-tax charge related to future ash pond and landfill closure costs at certain utility generation facilities.

(2) Includes $248 million of after-tax charges associated with Virginia legislation enacted in April 2014 relating to the development of a third nuclear unit located at North Anna and offshore wind facilities, a $193 million after-tax charge related to Dominion's restructuring of its producer services business and a $174 million after-tax charge associated with the Liability Management Exercise.

(3) Includes a $109 million after-tax charge related to Dominion's restructuring of its producer services business ($76 million) and an impairment of certain natural gas infrastructure assets ($33 million). Also in 2013, Dominion recorded a $92 million after-tax net loss from the discontinued operations of Brayton Point and Kincaid.

(4) Includes a $1.1 billion after-tax loss from discontinued operations, including impairment charges, of Brayton Point and Kincaid and a $303 million after-tax charge primarily resulting from management's decision to cease operations and begin decommissioning Kewaunee in 2013.

(5) Amounts attributable to Dominion's common shareholders.

(6) As discussed in Note 2 to the Consolidated Financial Statements, prior period amounts have been reclassified to conform to the 2016 presentation.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

MD&A discusses Dominion's results of operations and general financial condition and Virginia Power's and Dominion Gas' results of operations. MD&A should be read in conjunction with Item 1. Business and the Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data. Virginia Power and Dominion Gas meet the conditions to file under the reduced disclosure format, and therefore have omitted certain sections of MD&A.

Contents of MD&A

MD&A consists of the following information:

Forward-looking Statements

This report contains statements concerning the Companies' expectations, plans, objectives, future financial performance and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. In most cases, the reader can identify these forward-looking statements by such words as "anticipate," "estimate," "forecast," "expect," "believe," "should," "could," "plan," "may," "continue," "target" or other similar words.

The Companies make forward-looking statements with full knowledge that risks and uncertainties exist that may cause actual results to differ materially from predicted results. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Additionally, other factors may cause actual results to differ materially from those indicated in any forward-looking statement. These factors include but are not limited to:

- Unusual weather conditions and their effect on energy sales to customers and energy commodity prices;
- Extreme weather events and other natural disasters, including hurricanes, high winds, severe storms, earthquakes, flooding and changes in water temperatures and availability that can cause outages and property damage to facilities;
- Federal, state and local legislative and regulatory developments, including changes in federal and state tax laws and regulations;
- Changes to federal, state and local environmental laws and regulations, including those related to climate change, the tightening of emission or discharge limits for GHGs and other emissions, more extensive permitting requirements and the regulation of additional substances;
- Cost of environmental compliance, including those costs related to climate change;
- Changes in implementation and enforcement practices of regulators relating to environmental standards and litigation exposure for remedial activities;
- Difficulty in anticipating mitigation requirements associated with environmental and other regulatory approvals;
- Risks associated with the operation of nuclear facilities, including costs associated with the disposal of spent nuclear fuel, decommissioning, plant maintenance and changes in existing regulations governing such facilities;
- Unplanned outages at facilities in which the Companies have an ownership interest;
- Fluctuations in energy-related commodity prices and the effect these could have on Dominion's and Dominion Gas' earnings and the Companies' liquidity position and the underlying value of their assets;
- Counterparty credit and performance risk;
- Global capital market conditions, including the availability of credit and the ability to obtain financing on reasonable terms;
- Risks associated with Virginia Power's membership and participation in PJM, including risks related to obligations created by the default of other participants;
- Fluctuations in the value of investments held in nuclear decommissioning trusts by Dominion and Virginia Power and in benefit plan trusts by Dominion and Dominion Gas;
- Fluctuations in interest rates or foreign currency exchange rates;
- Changes in rating agency requirements or credit ratings and their effect on availability and cost of capital;
- Changes in financial or regulatory accounting principles or policies imposed by governing bodies;
- Employee workforce factors including collective bargaining agreements and labor negotiations with union employees;
- Risks of operating businesses in regulated industries that are subject to changing regulatory structures;
- Impacts of acquisitions, including the recently completed Dominion Questar Combination, divestitures, transfers of assets to joint ventures or Dominion Midstream, including the recently completed contribution of Questar Pipeline to Dominion Midstream, and retirements of assets based on asset portfolio reviews;
- Receipt of approvals for, and timing of, closing dates for acquisitions and divestitures;
- The timing and execution of Dominion Midstream's growth strategy;
- Changes in rules for RTOs and ISOs in which Dominion and Virginia Power participate, including changes in rate designs, changes in FERC's interpretation of market rules and new and evolving capacity models;
- Political and economic conditions, including inflation and deflation;
- Domestic terrorism and other threats to the Companies' physical and intangible assets, as well as threats to cybersecurity;
- Changes in demand for the Companies' services, including industrial, commercial and residential growth or decline in the Companies' service areas, changes in supplies of natural gas delivered to Dominion and Dominion Gas' pipeline and processing systems, failure to maintain or replace customer

contracts on favorable terms, changes in customer growth or usage patterns, including as a result of energy conservation programs, the availability of energy efficient devices and the use of distributed generation methods;
- Additional competition in industries in which the Companies operate, including in electric markets in which Dominion's merchant generation facilities operate and potential competition from the development and deployment of alternative energy sources, such as self-generation and distributed generation technologies, and availability of market alternatives to large commercial and industrial customers;
- Competition in the development, construction and ownership of certain electric transmission facilities in Virginia Power's service territory in connection with FERC Order 1000;
- Changes in technology, particularly with respect to new, developing or alternative sources of generation and smart grid technologies;
- Changes to regulated electric rates collected by Virginia Power and regulated gas distribution, transportation and storage rates, including LNG storage, collected by Dominion and Dominion Gas;
- Changes in operating, maintenance and construction costs;
- Timing and receipt of regulatory approvals necessary for planned construction or expansion projects and compliance with conditions associated with such regulatory approvals;
- The inability to complete planned construction, conversion or expansion projects at all, or with the outcomes or within the terms and time frames initially anticipated;
- Adverse outcomes in litigation matters or regulatory proceedings; and
- The impact of operational hazards, including adverse developments with respect to pipeline and plant safety or integrity, equipment loss, malfunction or failure, operator error, and other catastrophic events.

Additionally, other risks that could cause actual results to differ from predicted results are set forth in Item 1A. Risk Factors.

The Companies' forward-looking statements are based on beliefs and assumptions using information available at the time the statements are made. The Companies caution the reader not to place undue reliance on their forward-looking statements because the assumptions, beliefs, expectations and projections about future events may, and often do, differ materially from actual results. The Companies undertake no obligation to update any forward-looking statement to reflect developments occurring after the statement is made.

Accounting Matters

Critical Accounting Policies and Estimates

Dominion has identified the following accounting policies, including certain inherent estimates, that as a result of the judgments, uncertainties, uniqueness and complexities of the underlying accounting standards and operations involved, could result in material changes to its financial condition or results of operations under different conditions or using different assumptions. Dominion has discussed the development, selection and disclosure of each of these policies with the Audit Committee of its Board of Directors.

Accounting for Regulated Operations

The accounting for Dominion's regulated electric and gas operations differs from the accounting for nonregulated operations in that Dominion is required to reflect the effect of rate regulation in its Consolidated Financial Statements. For regulated businesses subject to federal or state cost-of-service rate regulation, regulatory practices that assign costs to accounting periods may differ from accounting methods generally applied by nonregulated companies. When it is probable that regulators will permit the recovery of current costs through future rates charged to customers, these costs that otherwise would be expensed by nonregulated companies are deferred as regulatory assets. Likewise, regulatory liabilities are recognized when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for expenditures that have yet to be incurred. Generally, regulatory assets and liabilities are amortized into income over the period authorized by the regulator.

Dominion evaluates whether or not recovery of its regulatory assets through future rates is probable and makes various assumptions in its analysis. The expectations of future recovery are generally based on orders issued by regulatory commissions, legislation or historical experience, as well as discussions with applicable regulatory authorities and legal counsel. If recovery of a regulatory asset is determined to be less than probable, it will be written off in the period such assessment is made. See Notes 12 and 13 to the Consolidated Financial Statements for additional information.

Asset Retirement Obligations

Dominion recognizes liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists and the ARO can be reasonably estimated. These AROs are recognized at fair value as incurred and are capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, Dominion estimates the fair value of its AROs using present value techniques, in which it makes various assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. The impact on measurements of new AROs or remeasurements of existing AROs, using different cost escalation rates in the future, may be significant. When Dominion revises any assumptions used to calculate the fair value of existing AROs, it adjusts the carrying amount of both the ARO liability and the related long-lived asset for assets that are in service; for assets that have ceased operations, Dominion adjusts the carrying amount of the ARO liability with such changes recognized in income. Dominion accretes the ARO liability to reflect the passage of time. In 2016, Dominion recorded an increase in AROs of $449 million primarily related to future ash pond and landfill closure costs at certain utility generation facilities and the Dominion Questar Combination. See Note 22 to the Consolidated Financial Statements for additional information.

In 2016, 2015 and 2014, Dominion recognized $104 million, $93 million and $81 million, respectively, of accretion, and expects to recognize $117 million in 2017. Dominion records accretion and depreciation associated with utility nuclear decommissioning AROs and regulated pipeline replacement

AROs as an adjustment to the regulatory liabilities related to these items.

A significant portion of Dominion's AROs relates to the future decommissioning of its merchant and utility nuclear facilities. These nuclear decommissioning AROs are reported in the Dominion Generation segment. At December 31, 2016, Dominion's nuclear decommissioning AROs totaled $1.5 billion, representing approximately 60% of its total AROs. Based on their significance, the following discussion of critical assumptions inherent in determining the fair value of AROs relates to those associated with Dominion's nuclear decommissioning obligations.

Dominion obtains from third-party specialists periodic site-specific base year cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for its nuclear plants. These cost studies are based on relevant information available at the time they are performed; however, estimates of future cash flows for extended periods of time are by nature highly uncertain and may vary significantly from actual results. In addition, Dominion's cost estimates include cost escalation rates that are applied to the base year costs. Dominion determines cost escalation rates, which represent projected cost increases over time due to both general inflation and increases in the cost of specific decommissioning activities, for each nuclear facility. The selection of these cost escalation rates is dependent on subjective factors which are considered to be critical assumptions.

Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws involves uncertainty, since tax authorities may interpret the laws differently. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows, and adjustments to tax-related assets and liabilities could be material.

Given the uncertainty and judgment involved in the determination and filing of income taxes, there are standards for recognition and measurement in financial statements of positions taken or expected to be taken by an entity in its income tax returns. Positions taken by an entity in its income tax returns that are recognized in the financial statements must satisfy a more-likely-than-not recognition threshold, assuming that the position will be examined by tax authorities with full knowledge of all relevant information. At December 31, 2016, Dominion had $64 million of unrecognized tax benefits. Changes in these unrecognized tax benefits may result from remeasurement of amounts expected to be realized, settlements with tax authorities and expiration of statutes of limitations.

Deferred income tax assets and liabilities are recorded representing future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Dominion evaluates quarterly the probability of realizing deferred tax assets by considering current and historical financial results, expectations for future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. Failure to achieve forecasted taxable income or successfully implement tax planning strategies may affect the realization of deferred tax assets. Dominion establishes a valuation allowance when it is more-likely-than-not that all or a portion of a deferred tax asset will not be realized. At December 31, 2016, Dominion had established $135 million of valuation allowances.

Accounting for Derivative Contracts and Other Instruments At Fair Value

Dominion uses derivative contracts such as physical and financial forwards, futures, swaps, options and FTRs to manage commodity, interest rate and foreign currency exchange rate risks of its business operations. Derivative contracts, with certain exceptions, are reported in the Consolidated Balance Sheets at fair value. Accounting requirements for derivatives and related hedging activities are complex and may be subject to further clarification by standard-setting bodies. The majority of investments held in Dominion's nuclear decommissioning and rabbi trusts and pension and other postretirement funds are also subject to fair value accounting. See Notes 6 and 21 to the Consolidated Financial Statements for further information on these fair value measurements.

Fair value is based on actively-quoted market prices, if available. In the absence of actively-quoted market prices, management seeks indicative price information from external sources, including broker quotes and industry publications. When evaluating pricing information provided by brokers and other pricing services, Dominion considers whether the broker is willing and able to trade at the quoted price, if the broker quotes are based on an active market or an inactive market and the extent to which brokers are utilizing a particular model if pricing is not readily available. If pricing information from external sources is not available, or if Dominion believes that observable pricing information is not indicative of fair value, judgment is required to develop the estimates of fair value. In those cases, Dominion must estimate prices based on available historical and near-term future price information and use of statistical methods, including regression analysis, that reflect its market assumptions.

Dominion maximizes the use of observable inputs and minimizes the use of unobservable inputs when measuring fair value.

Use of Estimates in Goodwill Impairment Testing

As of December 31, 2016, Dominion reported $6.4 billion of goodwill in its Consolidated Balance Sheet. A significant portion resulted from the acquisition of the former CNG in 2000 and the Dominion Questar Combination in 2016.

In April of each year, Dominion tests its goodwill for potential impairment, and performs additional tests more frequently if an event occurs or circumstances change in the interim that would more-likely-than-not reduce the fair value of a reporting unit below its carrying amount. The 2016, 2015 and 2014 annual tests and any interim tests did not result in the recognition of any goodwill impairment.

In general, Dominion estimates the fair value of its reporting units by using a combination of discounted cash flows and other valuation techniques that use multiples of earnings for peer group companies and analyses of recent business combinations involving peer group companies. Fair value estimates are dependent on subjective factors such as Dominion's estimate of future cash flows, the selection of appropriate discount and growth rates, and the selection of peer group companies and recent transactions. These underlying assumptions and estimates are made as of a point in time; subsequent modifications, particularly changes in discount rates or growth rates inherent in Dominion's estimates of future cash flows, could result in a future impairment of goodwill. Although Dominion has consistently applied the same methods in developing the assumptions and estimates that underlie the fair value calculations, such as estimates of future cash flows, and based those estimates on relevant information available at the time, such cash flow estimates are highly uncertain by nature and may vary significantly from actual results. If the estimates of future cash flows used in the most recent tests had been 10% lower, the resulting fair values would have still been greater than the carrying values of each of those reporting units tested, indicating that no impairment was present.

See Note 11 to the Consolidated Financial Statements for additional information.

Use of Estimates in Long-lived Asset Impairment Testing

Impairment testing for an individual or group of long-lived assets or for intangible assets with definite lives is required when circumstances indicate those assets may be impaired. When an asset's carrying amount exceeds the undiscounted estimated future cash flows associated with the asset, the asset is considered impaired to the extent that the asset's fair value is less than its carrying amount. Performing an impairment test on long-lived assets involves judgment in areas such as identifying if circumstances indicate an impairment may exist, identifying and grouping affected assets, and developing the undiscounted and discounted estimated future cash flows (used to estimate fair value in the absence of market-based value) associated with the asset, including probability weighting such cash flows to reflect expectations about possible variations in their amounts or timing, expectations about operating the long-lived assets and the selection of an appropriate discount rate. When determining whether an asset or asset group has been impaired, management groups assets at the lowest level that has identifiable cash flows. Although cash flow estimates are based on relevant information available at the time the estimates are made, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. For example, estimates of future cash flows would contemplate factors which may change over time, such as the expected use of the asset, including future production and sales levels, expected fluctuations of prices of commodities sold and consumed and expected proceeds from dispositions. See Note 6 to the Consolidated Financial Statements for a discussion of impairments related to certain long-lived assets.

Employee Benefit Plans

Dominion sponsors noncontributory defined benefit pension plans and other postretirement benefit plans for eligible active employees, retirees and qualifying dependents. The projected costs of providing benefits under these plans are dependent, in part, on historical information such as employee demographics, the level of contributions made to the plans and earnings on plan assets. Assumptions about the future, including the expected long-term rate of return on plan assets, discount rates applied to benefit obligations, mortality rates and the anticipated rate of increase in healthcare costs and participant compensation, also have a significant impact on employee benefit costs. The impact of changes in these factors, as well as differences between Dominion's assumptions and actual experience, is generally recognized in the Consolidated Statements of Income over the remaining average service period of plan participants, rather than immediately.

The expected long-term rates of return on plan assets, discount rates, healthcare cost trend rates and mortality rates are critical assumptions. Dominion determines the expected long-term rates of return on plan assets for pension plans and other postretirement benefit plans by using a combination of:

- Expected inflation and risk-free interest rate assumptions;
- Historical return analysis to determine long term historic returns as well as historic risk premiums for various asset classes;
- Expected future risk premiums, asset volatilities and correlations;
- Forecasts of an independent investment advisor;
- Forward-looking return expectations derived from the yield on long-term bonds and the expected long-term returns of major stock market indices; and
- Investment allocation of plan assets. The strategic target asset allocation for Dominion's pension funds is 28% U.S. equity, 18% non-U.S. equity, 35% fixed income, 3% real estate and 16% other alternative investments, such as private equity investments.

Strategic investment policies are established for Dominion's prefunded benefit plans based upon periodic asset/liability studies. Factors considered in setting the investment policy include those mentioned above such as employee demographics, liability growth rates, future discount rates, the funded status of the plans and the expected long-term rate of return on plan assets. Deviations from the plans' strategic allocation are a function of Dominion's assessments regarding short-term risk and reward opportunities in the capital markets and/or short-term market movements which result in the plans' actual asset allocations varying from the strategic target asset allocations. Through periodic rebalancing, actual allocations are brought back in line with the target. Future asset/liability studies will focus on strategies to further reduce pension and other postretirement plan risk, while still achieving attractive levels of returns.

Dominion develops assumptions, which are then compared to the forecasts of an independent investment advisor to ensure reasonableness. An internal committee selects the final assumptions. Dominion calculated its pension cost using an expected long-term rate of return on plan assets assumption of 8.75% for 2016, 2015 and 2014. For 2017, the expected long-term rate of return for pension cost assumption is 8.75%. Dominion calculated its other postretirement benefit cost using an expected long-term rate of return on plan assets assumption of 8.50% for 2016, 2015 and 2014. For 2017, the expected long-term rate of return for other postretirement benefit cost assumption is 8.50%. The rate used in calculating other postretirement benefit cost is lower than the rate used in calculating pension cost because of differences in the relative amounts of various types of investments held as plan assets.

Dominion determines discount rates from analyses of AA/Aa rated bonds with cash flows matching the expected payments to be made under its plans. The discount rates used to calculate pension cost and other postretirement benefit cost ranged from 2.87% to 4.99% for pension plans and 3.56% to 4.94% for other postretirement benefit plans in 2016, were 4.40% in 2015, ranged from 5.20% to 5.30% for pension plans and 4.20% to 5.10% for other postretirement benefit plans in 2014. Dominion selected a discount rate ranging from 3.31% to 4.50% for pension plans and ranging from 3.92% to 4.47% for other postretirement benefit plans for determining its December 31, 2016 projected benefit obligations.

Dominion establishes the healthcare cost trend rate assumption based on analyses of various factors including the specific provisions of its medical plans, actual cost trends experienced and projected, and demographics of plan participants. Dominion's healthcare cost trend rate assumption as of December 31, 2016 was 7.00% and is expected to gradually decrease to 5.00% by 2021 and continue at that rate for years thereafter.

Mortality rates are developed from actual and projected plan experience for postretirement benefit plans. Dominion's actuary conducts an experience study periodically as part of the process to select its best estimate of mortality. Dominion considers both standard mortality tables and improvement factors as well as the plans' actual experience when selecting a best estimate. During 2016, Dominion conducted a new experience study as scheduled and, as a result, updated its mortality assumptions.

The following table illustrates the effect on cost of changing the critical actuarial assumptions previously discussed, while holding all other assumptions constant:

		Increase in Net Periodic Cost	
	Change in Actuarial Assumption	Pension Benefits	Other Postretirement Benefits
(millions, except percentages)			
Discount rate	**(0.25)%**	**$18**	**$ 2**
Long-term rate of return on plan assets	**(0.25)%**	**18**	**4**
Healthcare cost trend rate	**1 %**	**N/A**	**23**

In addition to the effects on cost, at December 31, 2016, a 0.25% decrease in the discount rate would increase Dominion's projected pension benefit obligation by $287 million and its accumulated postretirement benefit obligation by $43 million, while a 1.00% increase in the healthcare cost trend rate would increase its accumulated postretirement benefit obligation by $152 million.

See Note 21 to the Consolidated Financial Statements for additional information on Dominion's employee benefit plans.

New Accounting Standards

See Note 2 to the Consolidated Financial Statements for a discussion of new accounting standards.

Dominion

Results of Operations

Presented below is a summary of Dominion's consolidated results:

Year Ended December 31,	2016	$ Change	2015	$ Change	2014
(millions, except EPS)					
Net Income attributable to Dominion	**$2,123**	**$ 224**	$1,899	$ 589	$1,310
Diluted EPS	**3.44**	**0.24**	3.20	0.96	2.24

Overview

2016 vs. 2015

Net income attributable to Dominion increased 12%, primarily due to higher renewable energy investment tax credits and the new PJM capacity performance market effective June 2016. These increases were partially offset by a decrease in gains from agreements to convey shale development rights underneath several natural gas storage fields and charges related to future ash pond and landfill closure costs at certain utility generation facilities.

2015 vs. 2014

Net income attributable to Dominion increased 45%, primarily due to the absence of charges associated with Virginia legislation enacted in April 2014 relating to the development of a third nuclear unit located at North Anna and offshore wind facilities, the absence of losses related to the repositioning of Dominion's producer services business in the first quarter of 2014, and the absence of charges related to Dominion's Liability Management Exercise. See Note 13 to the Consolidated Financial Statements for more information on legislation related to North Anna and offshore wind facilities. See *Liquidity and Capital Resources* for more information on the Liability Management Exercise.

Analysis of Consolidated Operations

Presented below are selected amounts related to Dominion's results of operations:

Year Ended December 31,	2016	$ Change	2015	$ Change	2014
(millions)					
Operating Revenue	**$11,737**	**$ 54**	$11,683	$(753)	$12,436
Electric fuel and other energy-related purchases	**2,333**	**(392)**	2,725	(675)	3,400
Purchased electric capacity	**99**	**(231)**	330	(31)	361
Purchased gas	**459**	**(92)**	551	(804)	1,355
Net Revenue	**8,846**	**769**	8,077	757	7,320
Other operations and maintenance	**3,064**	**469**	2,595	(170)	2,765
Depreciation, depletion and amortization	**1,559**	**164**	1,395	103	1,292
Other taxes	**596**	**45**	551	9	542
Other income	**250**	**54**	196	(54)	250
Interest and related charges	**1,010**	**106**	904	(289)	1,193
Income tax expense	**655**	**(250)**	905	453	452

An analysis of Dominion's results of operations follows:

2016 vs. 2015

Net revenue increased 10%, primarily reflecting:

- A $544 million increase from electric utility operations, primarily reflecting:
  - A $225 million electric capacity benefit, primarily due to the new PJM capacity performance market effective June 2016 ($155 million) and the expiration of non-utility generator contracts in 2015 ($58 million);
  - An increase from rate adjustment clauses ($183 million); and
  - The absence of an $85 million write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015; and
- A $305 million increase due to the Dominion Questar Combination.

These increases were partially offset by:

- A $47 million decrease from merchant generation operations, primarily due to lower realized prices at certain merchant generation facilities ($64 million) and an increase in planned and unplanned outage days in 2016 ($26 million), partially offset by additional solar generating facilities placed into service ($37 million);
- A $19 million decrease from regulated natural gas transmission operations, primarily due to:
  - A $14 million decrease in gas transportation and storage activities, primarily due to decreased demand charges ($28 million), increased fuel costs ($13 million), contract rate changes ($11 million) and decreased revenue from gathering and extraction services ($8 million), partially offset by expansion projects placed in service ($18 million) and increased regulated gas sales ($20 million); and
  - A $17 million decrease in NGL activities, due to decreased prices ($15 million) and volumes ($2 million); partially offset by
  - A $12 million increase in other revenues, primarily due to an increase in services performed for Atlantic Coast Pipeline ($21 million), partially offset by decreased amortization of deferred revenue associated with conveyed shale development rights ($4 million); and
- A $12 million decrease from regulated natural gas distribution operations, primarily due to a decrease in rate adjustment clause revenue related to low income assistance programs ($26 million) and a decrease in sales to customers due to a reduction in heating degree days ($6 million), partially offset by an increase in AMR and PIR program revenues ($18 million).

Other operations and maintenance increased 18%, primarily reflecting:

- A $148 million increase due to the Dominion Questar Combination, including $58 million of transaction and transition costs;
- A $98 million increase in charges related to future ash pond and landfill closure costs at certain utility generation facilities;
- A $78 million decrease in gains from agreements to convey shale development rights underneath several natural gas storage fields;
- Organizational design initiative costs ($64 million);
- A $50 million increase in storm damage and service restoration costs, including $23 million for Hurricane Matthew;
- A $20 million increase in services performed for Atlantic Coast Pipeline. These expenses are billed to Atlantic Coast Pipeline and do not significantly impact net income; and
- A $16 million increase due to labor contract renegotiations as well as costs resulting from a union workforce temporary work stoppage; partially offset by
- A $26 million decrease in bad debt expense at regulated natural gas distribution operations primarily related to low income assistance programs. These bad debt expenses are recovered through rates and do not impact net income.

Depreciation, depletion and amortization increased 12%, primarily due to various expansion projects being placed into service.

Other income increased 28%, primarily due to an increase in earnings from equity method investments ($55 million) and an increase in AFUDC associated with rate-regulated projects ($12 million), partially offset by lower realized gains (net of investment income) on nuclear decommissioning trust funds ($19 million).

Interest and related charges increased 12%, primarily due to higher long-term debt interest expense resulting from debt issuances in 2016 ($134 million), partially offset by an increase in capitalized interest associated with the Cove Point Liquefaction Project ($45 million).

Income tax expense decreased 28%, primarily due to higher renewable energy investment tax credits ($189 million) and the impact of a state legislative change ($14 million), partially offset by higher pre-tax income ($15 million).

2015 vs. 2014

Net revenue increased 10%, primarily reflecting:

- The absence of losses related to the repositioning of Dominion's producer services business in the first quarter of 2014, reflecting the termination of natural gas trading and certain energy marketing activities ($313 million);
- A $159 million increase from electric utility operations, primarily reflecting:
  - An increase from rate adjustment clauses ($225 million);
  - An increase in sales to retail customers, primarily due to a net increase in cooling degree days ($38 million); and
  - A decrease in capacity related expenses ($33 million); partially offset by
  - An $85 million write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015;
  - A decrease in sales to customers due to the effect of changes in customer usage and other factors ($24 million); and
  - A decrease due to a charge based on the 2015 Biennial Review Order to refund revenues to customers ($20 million).
- The absence of losses related to the retail electric energy marketing business which was sold in the first quarter of 2014 ($129 million);
- A $77 million increase from merchant generation operations, primarily due to increased generation output reflecting the absence of planned outages at certain merchant generation facilities ($83 million) and additional solar generating facili-

ties placed into service ($53 million), partially offset by lower realized prices ($58 million);
- A $38 million increase from regulated natural gas distribution operations, primarily due to an increase in rate adjustment clause revenue related to low income assistance programs ($12 million), an increase in AMR and PIR program revenues ($24 million) and various expansion projects placed into service ($22 million); partially offset by a decrease in gathering revenues ($9 million); and
- A $30 million increase from regulated natural gas transmission operations, primarily reflecting:
  - A $61 million increase in gas transportation and storage activities, primarily due to the addition of DCG ($62 million), decreased fuel costs ($24 million) and various expansion projects placed into service ($24 million), partially offset by decreased regulated gas sales ($46 million); and
  - A $46 million net increase primarily due to services performed for Atlantic Coast Pipeline and Blue Racer; partially offset by
  - A $61 million decrease from NGL activities, primarily due to decreased prices.

Other operations and maintenance decreased 6%, primarily reflecting:
- The absence of charges associated with Virginia legislation enacted in April 2014 relating to the development of a third nuclear unit located at North Anna and offshore wind facilities ($370 million);
- An increase in gains from agreements to convey shale development rights underneath several natural gas storage fields ($63 million);
- A $97 million decrease in planned outage costs primarily due to a decrease in scheduled outage days at certain merchant generation facilities ($59 million) and non-nuclear utility generation facilities ($38 million); and
- A $22 million decrease in charges related to future ash pond and landfill closure costs at certain utility generation facilities.

These decreases were partially offset by:
- The absence of a gain on the sale of Dominion's electric retail energy marketing business in March 2014 ($100 million), net of a $31 million write-off of goodwill;
- An $80 million increase in certain electric transmission-related expenditures. These expenses are primarily recovered through state and FERC rates and do not impact net income;
- The absence of gains on the sale of assets to Blue Racer ($59 million);
- A $53 million increase in utility nuclear refueling outage costs primarily due to the amortization of outage costs that were previously deferred pursuant to Virginia legislation enacted in April 2014;
- A $46 million net increase due to services performed for Atlantic Coast Pipeline and Blue Racer. These expenses are billed to these entities and do not significantly impact net income; and
- A $22 million increase due to the acquisition of DCG.

Other income decreased 22%, primarily reflecting lower tax recoveries associated with contributions in aid of construction ($17 million), a decrease in interest income related to income taxes ($12 million), and lower net realized gains on nuclear decommissioning trust funds ($11 million).

Interest and related charges decreased 24%, primarily as a result of the absence of charges associated with Dominion's Liability Management Exercise in 2014.

Income tax expense increased 100%, primarily reflecting higher pre-tax income.

Outlook

Dominion's strategy is to continue focusing on its regulated businesses while maintaining upside potential in well-positioned nonregulated businesses. The goals of this strategy are to provide EPS growth, a growing dividend and to maintain a stable credit profile. Dominion expects 80% to 90% of earnings from its primary operating segments to come from regulated and long-term contracted businesses.

Dominion's 2017 net income is expected to remain substantially consistent on a per share basis as compared to 2016.

Dominion's 2017 results are expected to be positively impacted by the following:
- Decreased charges related to future ash pond and landfill closure costs at certain utility generation facilities;
- The inclusion of operations acquired from Dominion Questar for the entire year;
- Decreased transaction and transition costs associated with the Dominion Questar Combination;
- Growth in weather-normalized electric utility sales of approximately 1%;
- Construction and operation of growth projects in electric utility operations and associated rate adjustment clause revenue; and
- Construction and operation of growth projects in gas transmission and distribution.

Dominion's 2017 results are expected to be negatively impacted by the following:
- Lower power prices and an additional planned refueling outage at Millstone;
- Decreased Cove Point import contract revenues;
- An increase in depreciation, depletion, and amortization;
- A higher effective tax rate, driven primarily by a decrease in investment tax credits; and
- Share dilution.

Additionally, in 2017, Dominion expects to focus on meeting new and developing environmental requirements, including making investments in utility-scale solar generation, particularly in Virginia. In 2018, Dominion is expected to experience an increase in net income on a per share basis as compared to 2017 primarily due to the Liquefaction Project being in service for the full year.

Segment Results of Operations

Segment results include the impact of intersegment revenues and expenses, which may result in intersegment profit or loss. Presented below is a summary of contributions by Dominion's operating segments to net income attributable to Dominion:

Year Ended December 31,	2016		2015		2014	
	Net Income attributable to Dominion	**Diluted EPS**	Net Income attributable to Dominion	Diluted EPS	Net Income attributable to Dominion	Diluted EPS
(millions, except EPS)						
DVP	**$ 484**	**$ 0.78**	$ 490	$ 0.82	$ 502	$ 0.86
Dominion Generation	**1,397**	**2.26**	1,120	1.89	1,061	1.81
Dominion Energy	**726**	**1.18**	680	1.15	717	1.23
Primary operating segments	**2,607**	**4.22**	2,290	3.86	2,280	3.90
Corporate and Other	**(484)**	**(0.78)**	(391)	(0.66)	(970)	(1.66)
Consolidated	**$2,123**	**$ 3.44**	$1,899	$ 3.20	$1,310	$ 2.24

DVP

Presented below are operating statistics related to DVP's operations:

Year Ended December 31,	2016	% Change	2015	% Change	2014
Electricity delivered (million MWh)	**83.7**	**—%**	83.9	—%	83.5
Degree days:					
Cooling	**1,830**	**(1)**	1,849	13	1,638
Heating	**3,446**	**1**	3,416	(10)	3,793
Average electric distribution customer accounts (thousands)(1)	**2,549**	**1**	2,525	1	2,500

(1) Period average.

Presented below, on an after-tax basis, are the key factors impacting DVP's net income contribution:

2016 vs. 2015

	Increase (Decrease)	
	Amount	**EPS**
(millions, except EPS)		
Regulated electric sales:		
Weather	**$ (1)**	**$ —**
Other	**1**	**—**
FERC transmission equity return	**41**	**0.07**
Storm damage and service restoration	**(16)**	**(0.03)**
Depreciation and amortization	**(10)**	**(0.02)**
AFUDC return	**(8)**	**(0.01)**
Interest expense	**(5)**	**(0.01)**
Other	**(8)**	**(0.01)**
Share dilution	**—**	**(0.03)**
Change in net income contribution	**$ (6)**	**$(0.04)**

2015 vs. 2014

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Regulated electric sales:		
Weather	$ 5	$ 0.01
Other	(4)	—
FERC transmission equity return	36	0.06
Tax recoveries on contribution in aid of construction	(10)	(0.02)
Depreciation and amortization	(9)	(0.02)
Other operations and maintenance	(12)	(0.02)
AFUDC return	(6)	(0.01)
Interest expense	(5)	(0.01)
Other	(7)	(0.01)
Share dilution	—	(0.02)
Change in net income contribution	$(12)	$(0.04)

Dominion Generation

Presented below are operating statistics related to Dominion Generation's operations:

Year Ended December 31,	2016	% Change	2015	% Change	2014
Electricity supplied (million MWh):					
Utility	**87.9**	**3%**	85.2	2%	83.9
Merchant	**28.9**	**7**	26.9	8	25.0
Degree days (electric utility service area):					
Cooling	**1,830**	**(1)**	1,849	13	1,638
Heating	**3,446**	**1**	3,416	(10)	3,793

Presented below, on an after-tax basis, are the key factors impacting Dominion Generation's net income contribution:

2016 vs. 2015

	Increase (Decrease)	
	Amount	**EPS**
(millions, except EPS)		
Regulated electric sales:		
Weather	**$ 2**	**$ —**
Other	**13**	**0.02**
Renewable energy investment tax credits	**186**	**0.31**
Electric capacity	**137**	**0.23**
Merchant generation margin	**(34)**	**(0.06)**
Rate adjustment clause equity return	**24**	**0.04**
Noncontrolling interest(1)	**(28)**	**(0.05)**
Depreciation and amortization	**(25)**	**(0.04)**
Other	**2**	**0.01**
Share dilution	**—**	**(0.09)**
Change in net income contribution	**$277**	**$ 0.37**

(1) Represents noncontrolling interest related to merchant solar partnerships.

2015 vs. 2014

	Increase (Decrease)	
	Amount	EPS
(millions, except EPS)		
Merchant generation margin	$ 53	$ 0.09
Regulated electric sales:		
Weather	19	0.03
Other	(13)	(0.02)
Rate adjustment clause equity return	20	0.03
PJM ancillary services	(15)	(0.02)
Outage costs	26	0.05
Depreciation and amortization	(32)	(0.05)
Electric capacity	20	0.03
Other	(19)	(0.03)
Share dilution	—	(0.03)
Change in net income contribution	$ 59	$ 0.08

Dominion Energy

Presented below are selected operating statistics related to Dominion Energy's operations.

Year Ended December 31,	2016	% Change	2015	% Change	2014
Gas distribution throughput (bcf)(1):					
Sales	**61**	**126%**	27	(16)%	32
Transportation	**537**	**14**	470	33	353
Heating degree days (gas distribution service area):					
Eastern region	**5,235**	**(8)**	5,666	(10)	6,330
Western region(1)	**1,876**	**100**	—	—	—
Average gas distribution customer accounts (thousands)(1)(2):					
Sales	**1,234(3)**	**414**	240	(2)	244
Transportation	**1,071**	**1**	1,057	—	1,052
Average retail energy marketing customer accounts (thousands)(2)	**1,376**	**6**	1,296	1	1,283(4)

(1) Includes Dominion Questar effective September 2016.
(2) Period average.
(3) Includes Dominion Questar customer accounts for the entire year.
(4) Excludes 511 thousand average retail electric energy marketing customer accounts due to the sale of this business in March 2014.

Presented below, on an after-tax basis, are the key factors impacting Dominion Energy's net income contribution:

2016 VS. 2015

	Increase (Decrease) Amount	Increase (Decrease) EPS
(millions, except EPS)		
Gas distribution margin:		
Weather	**$ (4)**	**$(0.01)**
Rate adjustment clauses	**11**	**0.02**
Other	**6**	**0.01**
Assignment of shale development rights	**(48)**	**(0.08)**
Dominion Questar Combination	**78**	**0.13**
Other	**3**	**0.01**
Share dilution	**—**	**(0.05)**
Change in net income contribution	**$ 46**	**$ 0.03**

2015 VS. 2014

	Increase (Decrease) Amount	Increase (Decrease) EPS
(millions, except EPS)		
Gas distribution margin:		
Weather	$ (5)	$(0.01)
Rate adjustment clauses	16	0.03
Other	9	0.02
Assignment of shale development rights	33	0.06
Depreciation and amortization	(12)	(0.02)
Blue Racer	(39)(1)	(0.07)
Noncontrolling interest(2)	(13)	(0.02)
Retail energy marketing operations	(11)	(0.02)
Other	(15)	(0.04)
Share dilution	—	(0.01)
Change in net income contribution	$(37)	$(0.08)

(1) Primarily represents absence of a gain from the sale of the Northern System.
(2) Represents the portion of earnings attributable to Dominion Midstream's public unitholders.

Corporate and Other

Presented below are the Corporate and Other segment's after-tax results:

Year Ended December 31,	2016	2015	2014
(millions, except EPS amounts)			
Specific items attributable to operating segments	**$ (180)**	$ (136)	$ (544)
Specific items attributable to Corporate and Other segment	**(44)**	(5)	(149)
Total specific items	**(224)**	(141)	(693)
Other corporate operations	**(260)**	(250)	(277)
Total net expense	**$ (484)**	$ (391)	$ (970)
EPS impact	**$(0.78)**	$(0.66)	$(1.66)

TOTAL SPECIFIC ITEMS

Corporate and Other includes specific items attributable to Dominion's primary operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources. See Note 25 to the Consolidated Financial Statements for discussion of these items in more detail. Corporate and other also includes specific items attributable to the Corporate and Other segment. In 2016, this primarily included $53 million of after-tax transaction and transition costs associated with the Dominion Questar Combination. In 2014, this primarily included $174 million of after-tax charges associated with Dominion's Liability Management Exercise.

VIRGINIA POWER

RESULTS OF OPERATIONS

Presented below is a summary of Virginia Power's consolidated results:

Year Ended December 31,	2016	$ Change	2015	$ Change	2014
(millions)					
Net Income	**$1,218**	**$131**	$1,087	$229	$858

Overview

2016 VS. 2015

Net income increased 12%, primarily due to the new PJM capacity performance market effective June 2016, an increase in rate adjustment clause revenue and the absence of a write-off of deferred fuel costs associated with the Virginia legislation enacted in February 2015. These increases were partially offset by charges related to future ash pond and landfill closure costs at certain utility generation facilities.

2015 VS. 2014

Net income increased 27%, primarily due to the absence of charges associated with Virginia legislation enacted in April 2014 relating to the development of a third nuclear unit located at North Anna and offshore wind facilities.

Analysis of Consolidated Operations

Presented below are selected amounts related to Virginia Power's results of operations:

Year Ended December 31,	2016	$ Change	2015	$ Change	2014
(millions)					
Operating Revenue	**$7,588**	**$ (34)**	$7,622	$ 43	$7,579
Electric fuel and other energy-related purchases	**1,973**	**(347)**	2,320	(86)	2,406
Purchased electric capacity	**99**	**(231)**	330	(30)	360
Net Revenue	**5,516**	**544**	4,972	159	4,813
Other operations and maintenance	**1,857**	**223**	1,634	(282)	1,916
Depreciation and amortization	**1,025**	**72**	953	38	915
Other taxes	**284**	**20**	264	6	258
Other income	**56**	**(12)**	68	(25)	93
Interest and related charges	**461**	**18**	443	32	411
Income tax expense	**727**	**68**	659	111	548

An analysis of Virginia Power's results of operations follows:

2016 vs. 2015

Net revenue increased 11%, primarily reflecting:

- A $225 million electric capacity benefit, primarily due to the new PJM capacity performance market effective June 2016 ($155 million) and the expiration of non-utility generator contracts in 2015 ($58 million);
- An increase from rate adjustment clauses ($183 million); and
- The absence of an $85 million write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015.

Other operations and maintenance increased 14%, primarily reflecting:

- A $98 million increase in charges related to future ash pond and landfill closure costs at certain utility generation facilities;
- A $50 million increase in storm damage and service restoration costs, including $23 million for Hurricane Matthew;
- A $37 million increase in salaries, wages and benefits and general administrative expenses; and
- Organizational design initiative costs ($32 million).

Income tax expense increased 10%, primarily reflecting higher pre-tax income.

2015 vs. 2014

Net revenue increased 3%, primarily reflecting:

- An increase from rate adjustment clauses ($225 million);
- An increase in sales to retail customers, primarily due to a net increase in cooling degree days ($38 million); and
- A decrease in capacity related expenses ($33 million); partially offset by
- An $85 million write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015;
- A decrease in sales to customers due to the effect of changes in customer usage and other factors ($24 million); and
- A decrease due to a charge based on the 2015 Biennial Review Order to refund revenues to customers ($20 million).

Other operations and maintenance decreased 15%, primarily reflecting:

- The absence of $370 million in charges associated with Virginia legislation enacted in April 2014 relating to the development of a third nuclear unit located at North Anna and offshore wind facilities; and
- A $38 million decrease in planned outage costs primarily due to a decrease in scheduled outage days at certain non-nuclear utility generation facilities.

These decreases were partially offset by:

- An $80 million increase in certain electric transmission-related expenditures. These expenses are primarily recovered through state and FERC rates and do not impact net income; and
- A $53 million increase in utility nuclear refueling outage costs primarily due to the amortization of outage costs that were previously deferred pursuant to Virginia legislation enacted in April 2014.

Other income decreased 27%, primarily reflecting lower tax recoveries associated with contributions in aid of construction.

Income tax expense increased 20%, primarily reflecting higher pre-tax income.

DOMINION GAS

RESULTS OF OPERATIONS

Presented below is a summary of Dominion Gas' consolidated results:

Year Ended December 31,	2016	$ Change	2015	$ Change	2014
(millions)					
Net Income	**$392**	**$(65)**	$457	$(55)	$512

Overview

2016 vs. 2015

Net income decreased 14%, primarily due a decrease in gains from agreements to convey shale development rights underneath several natural gas storage fields.

2015 vs. 2014

Net income decreased 11%, primarily due to the absence of gains on the indirect sale of assets to Blue Racer, a decrease in income from NGL activities and higher interest expense, partially offset by increased gains from agreements to convey shale development rights underneath several natural gas storage fields.

Analysis of Consolidated Operations

Presented below are selected amounts related to Dominion Gas' results of operations:

Year Ended December 31,	2016	$ Change	2015	$ Change	2014
(millions)					
Operating Revenue	**$1,638**	**$(78)**	$1,716	$(182)	$1,898
Purchased gas	**109**	**(24)**	133	(182)	315
Other energy-related purchases	**12**	**(9)**	21	(19)	40
Net Revenue	**1,517**	**(45)**	1,562	19	1,543
Other operations and maintenance	**474**	**84**	390	52	338
Depreciation and amortization	**204**	**(13)**	217	20	197
Other taxes	**170**	**4**	166	9	157
Earnings from equity method investee	**21**	**(2)**	23	2	21
Other income	**11**	**10**	1	—	1
Interest and related charges	**94**	**21**	73	46	27
Income tax expense	**215**	**(68)**	283	(51)	334

An analysis of Dominion Gas' results of operations follows:

2016 vs. 2015

Net revenue decreased 3%, primarily reflecting:

- A $34 million decrease from regulated natural gas transmission operations, primarily reflecting:
  - A $36 million decrease in gas transportation and storage activities, primarily due to decreased demand charges ($28 million), increased fuel costs ($13 million), contract rate changes ($11 million) and decreased revenue from gathering and extraction services ($8 million), partially offset by increased regulated gas sales ($16 million) and expansion projects placed in service ($9 million); and
  - An $18 million decrease from NGL activities, due to decreased prices ($16 million) and volumes ($2 million); partially offset by
  - A $21 million increase in services performed for Atlantic Coast Pipeline; and
- A $12 million decrease from regulated natural gas distribution operations, primarily reflecting:
  - A decrease in rate adjustment clause revenue related to low income assistance programs ($26 million); and
  - A $9 million decrease in other revenue primarily due to a decrease in pooling and metering activities ($3 million), a decrease in Blue Racer management fees ($3 million) and a decrease in gathering activities ($2 million); partially offset by
  - An $18 million increase in AMR and PIR program revenues; and
  - An $8 million increase in off-system sales.

Other operations and maintenance increased 22%, primarily reflecting:

- A $78 million decrease in gains from agreements to convey shale development rights underneath several natural gas storage fields; and
- A $20 million increase in services performed for Atlantic Coast Pipeline. These expenses are billed to Atlantic Coast Pipeline and do not significantly impact net income; partially offset by
- A $26 million decrease in bad debt expense at regulated natural gas distribution operations primarily related to low income assistance programs. These bad debt expenses are recovered through rates and do not impact net income.

Other income increased $10 million, primarily due to a gain on the sale of 0.65% of the noncontrolling partnership interest in Iroquois ($5 million) and an increase in AFUDC associated with rate-regulated projects ($5 million).

Interest and related charges increased 29%, primarily due to higher interest expense resulting from the issuances of senior notes in November 2015 and the second quarter of 2016 ($28 million), partially offset by an increase in deferred rate adjustment clause interest expense ($7 million).

Income tax expense decreased 24% primarily reflecting lower pre-tax income.

2015 vs. 2014

Net revenue increased 1%, primarily reflecting:

- A $43 million increase from regulated natural gas distribution operations, primarily due to an increase in AMR and PIR program revenues ($24 million) and various expansion projects placed into service ($22 million); partially offset by
- A $27 million decrease from regulated natural gas transmission operations, primarily reflecting:
  - A $62 million decrease from NGL activities, primarily due to decreased prices; partially offset by
  - A $2 million increase in gas transportation and storage activities, primarily due to decreased fuel costs ($24 million) and various expansion projects placed into service ($24 million), partially offset by decreased regulated gas sales ($46 million); and
  - A $33 million net increase in other revenue primarily due to services performed for Atlantic Coast Pipeline and Blue Racer ($47 million), partially offset by a decrease in non-regulated gas sales ($8 million) and decreased farm-out revenues ($6 million).

Other operations and maintenance increased 15%, primarily reflecting:

- A $47 million net increase due to services performed for Atlantic Coast Pipeline and Blue Racer. These expenses are billed to these entities and do not significantly impact net income; and
- The absence of gains on the sale of assets to Blue Racer ($59 million); partially offset by
- An increase in gains from agreements to convey shale development rights underneath several natural gas storage fields ($63 million).

Depreciation and amortization increased 10% primarily due to various expansion projects placed into service.

Interest and related charges increased $46 million, primarily due to higher long-term debt interest expense resulting from debt issuances in December 2014.

Income tax expense decreased 15% primarily reflecting lower pre-tax income.

Liquidity and Capital Resources

Dominion depends on both internal and external sources of liquidity to provide working capital and as a bridge to long-term debt financings. Short-term cash requirements not met by cash provided by operations are generally satisfied with proceeds from short-term borrowings. Long-term cash needs are met through issuances of debt and/or equity securities.

At December 31, 2016, Dominion had $2.3 billion of unused capacity under its credit facilities. See additional discussion below under *Credit Facilities and Short-Term Debt.*

A summary of Dominion's cash flows is presented below:

Year Ended December 31,	2016	2015	2014
(millions)			
Cash and cash equivalents at beginning of year	**$ 607**	$ 318	$ 316
Cash flows provided by (used in):			
Operating activities	**4,127**	4,475	3,439
Investing activities	**(10,703)**	(6,503)	(5,181)
Financing activities	**6,230**	2,317	1,744
Net increase (decrease) in cash and cash equivalents	**(346)**	289	2
Cash and cash equivalents at end of year	**$ 261**	$ 607	$ 318

Operating Cash Flows

Net cash provided by Dominion's operating activities decreased $348 million, primarily due to higher operations and maintenance expenses, derivative activities, and increased payments for income taxes and interest. The decrease was partially offset with the benefit from the new PJM capacity performance market and higher deferred fuel cost recoveries and revenues from rate adjustment clauses in its Virginia jurisdiction.

Dominion believes that its operations provide a stable source of cash flow to contribute to planned levels of capital expenditures and maintain or grow the dividend on common shares. In December 2016, Dominion's Board of Directors established an annual dividend rate for 2017 of $3.02 per share of common stock, a 7.9% increase over the 2016 rate. Dividends are subject to declaration by the Board of Directors. In January 2017, Dominion's Board of Directors declared dividends payable in March 2017 of 75.5 cents per share of common stock.

Dominion's operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flows, and which are discussed in Item 1A. Risk Factors.

Credit Risk

Dominion's exposure to potential concentrations of credit risk results primarily from its energy marketing and price risk management activities. Presented below is a summary of Dominion's credit exposure as of December 31, 2016 for these activities. Gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights.

	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
(millions)			
Investment grade(1)	**$36**	**$—**	**$36**
Non-investment grade(2)	**9**	**—**	**9**
No external ratings:			
Internally rated-investment grade(3)	**16**	**—**	**16**
Internally rated-non-investment grade(4)	**37**	**—**	**37**
Total	**$98**	**$—**	**$98**

(1) Designations as investment grade are based upon minimum credit ratings assigned by Moody's and Standard & Poor's. The five largest counterparty exposures, combined, for this category represented approximately 27% of the total net credit exposure.
(2) The five largest counterparty exposures, combined, for this category represented approximately 10% of the total net credit exposure.
(3) The five largest counterparty exposures, combined, for this category represented approximately 15% of the total net credit exposure.
(4) The five largest counterparty exposures, combined, for this category represented approximately 16% of the total net credit exposure.

Investing Cash Flows

Net cash used in Dominion's investing activities increased $4.2 billion, primarily due to the Dominion Questar Combination and higher capital expenditures, partially offset by the absence of Dominion's acquisition of DCG in 2015 and the acquisition of fewer solar development projects in 2016.

Financing Cash Flows and Liquidity

Dominion relies on capital markets as significant sources of funding for capital requirements not satisfied by cash provided by its operations. As discussed in *Credit Ratings*, Dominion's ability to borrow funds or issue securities and the return demanded by investors are affected by credit ratings. In addition, the raising of external capital is subject to certain regulatory requirements, including registration with the SEC for certain issuances.

Dominion currently meets the definition of a well-known seasoned issuer under SEC rules governing the registration, communications and offering processes under the Securities Act of 1933. The rules provide for a streamlined shelf registration process to provide registrants with timely access to capital. This allows Dominion to use automatic shelf registration statements to register any offering of securities, other than those for exchange offers or business combination transactions.

Net cash provided by Dominion's financing activities increased $3.9 billion, primarily reflecting higher net debt issuances and higher issuances of common stock and Dominion Midstream common and convertible preferred units in connection with the Dominion Questar Combination.

Liability Management

During 2014, Dominion elected to redeem certain debt and preferred securities prior to their stated maturities. Proceeds from the issuance of lower-cost senior and enhanced junior subordinated notes were used to fund the redemption payments. See Note 17 to the Consolidated Financial Statements for descriptions of these redemptions.

From time to time, Dominion may reduce its outstanding debt and level of interest expense through redemption of debt securities prior to maturity and repurchases in the open market, in privately negotiated transactions, through tender offers or otherwise.

Credit Facilities and Short-term Debt

Dominion uses short-term debt to fund working capital requirements and as a bridge to long-term debt financings. The levels of borrowing may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In January 2016, Dominion expanded its short-term funding resources through a $1.0 billion increase to one of its joint revolving credit facility limits. In addition, Dominion utilizes cash and letters of credit to fund collateral requirements. Collateral requirements are impacted by commodity prices, hedging levels, Dominion's credit ratings and the credit quality of its counterparties.

In connection with commodity hedging activities, Dominion is required to provide collateral to counterparties under some circumstances. Under certain collateral arrangements, Dominion may satisfy these requirements by electing to either deposit cash, post letters of credit or, in some cases, utilize other forms of security. From time to time, Dominion may vary the form of collateral provided to counterparties after weighing the costs and benefits of various factors associated with the different forms of collateral. These factors include short-term borrowing and short-term investment rates, the spread over these short-term rates at which Dominion can issue commercial paper, balance sheet impacts, the costs and fees of alternative collateral postings with these and other counterparties and overall liquidity management objectives.

Dominion's commercial paper and letters of credit outstanding, as well as capacity available under credit facilities, were as follows:

December 31, 2016	Facility Limit	Outstanding Commercial Paper	Outstanding Letters of Credit	Facility Capacity Available
(millions)				
Joint revolving credit facility(1)(2)	**$5,000**	**$3,155**	**$—**	**$1,845**
Joint revolving credit facility(1)	**500**	**—**	**85**	**415**
Total	**$5,500**	**$3,155(3)**	**$85**	**$2,260**

(1) In May 2016, the maturity dates for these facilities were extended from April 2019 to April 2020. These credit facilities can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to a combined $2.0 billion of letters of credit.

(2) In January 2016, this facility limit was increased from $4.0 billion to $5.0 billion.

(3) The weighted-average interest rate of the outstanding commercial paper supported by Dominion's credit facilities was 1.05% at December 31, 2016.

Dominion Questar's revolving multi-year and 364-day credit facilities with limits of $500 million and $250 million, respectively, were terminated in October 2016.

Short-term Notes

In November 2015, Dominion issued $400 million of private placement short-term notes that matured in May 2016 and bore interest at a variable rate. In December 2015, Dominion issued an additional $200 million of the variable rate short-term notes that matured in May 2016. The proceeds were used for general corporate purposes.

In February 2016, Dominion purchased and cancelled $100 million of the variable rate short-term notes that would have otherwise matured in May 2016 using the proceeds from the February 2016 issuance of senior notes that mature in 2018.

In September 2016, Dominion borrowed $1.2 billion under a term loan agreement that bore interest at a variable rate. The net proceeds were used to finance the Dominion Questar Combination. In December 2016, the loan was repaid with cash received from Dominion Midstream in connection with the contribution of Questar Pipeline. The loan would have otherwise matured in September 2017. See Note 3 to the Consolidated Financial Statements for more information.

Long-term Debt

During 2016, Dominion issued the following long-term public debt:

Type	Principal	Rate	Maturity
	(millions)		
Senior notes	**$ 500**	**1.60%**	**2019**
Senior notes	**400**	**2.00%**	**2021**
Remarketable subordinated notes	**700**	**2.00%**	**2021**
Remarketable subordinated notes	**700**	**2.00%**	**2024**
Senior notes	**400**	**2.85%**	**2026**
Senior notes	**400**	**2.95%**	**2026**
Senior notes	**750**	**3.15%**	**2026**
Senior notes	**500**	**4.00%**	**2046**
Enhanced junior subordinated notes	**800**	**5.25%**	**2076**
Total notes issued	**$5,150**		

During 2016, Dominion also issued the following long-term private debt:

- In February 2016, Dominion issued $500 million of 2.125% senior notes in a private placement. The notes mature in 2018. The proceeds were used to repay or repurchase short-term debt, including commercial paper and short-term notes, and for general corporate purposes.
- In May 2016, Dominion Gas issued $150 million of private placement 3.8% senior notes that mature in 2031. The proceeds were used for general corporate purposes. In June 2016, Dominion Gas issued $250 million of private placement 2.875% senior notes that mature in 2023. The proceeds were used for general corporate purposes and to repay short-term debt, including commercial paper. Also in June 2016, Dominion Gas issued € 250 million of private placement 1.45% senior notes that mature in 2026. The notes were recorded at $280 million at issuance and included in long-term debt in the Consolidated Balance Sheets at $263 million at December 31,

2016. The proceeds were used for general corporate purposes and to repay short-term debt, including commercial paper.

- In September 2016, Dominion issued $300 million of private placement 1.50% senior notes that mature in 2018. The proceeds were used for general corporate purposes and to repay short-term debt, including commercial paper.
- In December 2016, Questar Gas issued $50 million of 3.62% private placement senior notes, and $50 million of 3.67% private placement senior notes, that mature in 2046 and 2051, respectively. The proceeds were used for general corporate purposes.
- In December 2016, Dominion issued $250 million of private placement 1.875% senior notes that mature in 2018. The proceeds were used for general corporate purposes and to repay short-term debt, including commercial paper.

During 2016, Dominion also remarketed the following long-term debt:

- In March 2016 and May 2016, Dominion successfully remarketed the $550 million 2013 Series A 1.07% RSNs due 2021 and the $550 million 2013 Series B 1.18% RSNs due 2019, respectively, pursuant to the terms of the related 2013 Equity Units. In connection with the remarketings, the interest rates on the Series A and Series B junior subordinated notes were reset to 4.104% and 2.962%, respectively. Dominion did not receive any proceeds from the remarketings. See Note 17 to the Consolidated Financial Statements for more information.
- In December 2016, Virginia Power remarketed the $37 million Industrial Development Authority of the Town of Louisa, Virginia Pollution Control Refunding Revenue Bonds, Series 2008 C, which mature in 2035 and bear interest at a coupon rate of 1.85% until May 2019 after which they will bear interest at a market rate to be determined at that time. Previously, the bonds bore interest at a coupon rate of .70%. This remarketing was accounted for as a debt extinguishment with the previous investors.

During 2016, Dominion also borrowed the following under term loan agreements:

- In December 2016, Dominion Midstream borrowed $300 million under a term loan agreement that matures in December 2019 and bears interest at a variable rate. The net proceeds were used to finance a portion of the acquisition of Questar Pipeline from Dominion. See Note 3 to the Consolidated Financial Statements for more information.
- In December 2016, SBL Holdco borrowed $405 million under a term loan agreement that bears interest at a variable rate. The term loan amortizes over an 18-year period and matures in December 2023. The debt is nonrecourse to Dominion and is secured by SBL Holdco's interest in certain merchant solar facilities. See Note 15 to the Consolidated Financial Statements for more information. The proceeds were used for general corporate purposes.

During 2016, Dominion repaid $1.8 billion of short-term notes and repaid and repurchased $1.6 billion of long-term debt.

In January 2017, Dominion issued $400 million of 1.875% senior notes and $400 million of 2.75% senior notes that mature in 2019 and 2022, respectively.

Issuance of Common Stock and Other Equity Securities

Dominion maintains Dominion Direct® and a number of employee savings plans through which contributions may be invested in Dominion's common stock. These shares may either be newly issued or purchased on the open market with proceeds contributed to these plans. In January 2014, Dominion began purchasing its common stock on the open market for these plans. In April 2014, Dominion began issuing new common shares for these direct stock purchase plans.

During 2016, Dominion issued 4.2 million shares of common stock totaling $314 million through employee savings plans, direct stock purchase and dividend reinvestment plans and other employee and director benefit plans. Dominion received cash proceeds of $295 million from the issuance of 4.0 million of such shares through Dominion Direct® and employee savings plans.

In both April 2016 and July 2016, Dominion issued 8.5 million shares under the related stock purchase contract entered into as part of Dominion's 2013 Equity Units and received $1.1 billion of total proceeds. Additionally, Dominion completed a market issuance of equity in April 2016 of 10.2 million shares and received proceeds of $756 million through a registered underwritten public offering. A portion of the net proceeds was used to finance the Dominion Questar Combination. See Note 3 to the Consolidated Financial Statements for more information.

During 2017, Dominion plans to issue shares for employee savings plans, direct stock purchase and dividend reinvestment plans and stock purchase contracts. See Note 17 to the Consolidated Financial Statements for a description of common stock to be issued by Dominion for stock purchase contracts.

During the fourth quarter of 2016, Dominion Midstream received $482 million of proceeds from the issuance of common units and $490 million of proceeds from the issuance of convertible preferred units. The net proceeds were primarily used to finance a portion of the acquisition of Questar Pipeline from Dominion. See Note 3 to the Consolidated Financial Statements for more information.

Repurchase of Common Stock

Dominion did not repurchase any shares in 2016 and does not plan to repurchase shares during 2017, except for shares tendered by employees to satisfy tax withholding obligations on vested restricted stock, which does not count against its stock repurchase authorization.

Purchase of Dominion Midstream Units

In September 2015, Dominion initiated a program to purchase from the market up to $50 million of common units representing limited partner interests in Dominion Midstream, which expired in September 2016. Dominion purchased approximately 658,000 common units for $17 million and 887,000 common units for $25 million for the years ended December 31, 2016 and 2015, respectively.

Acquisition of Dominion Questar

In accordance with the terms of the Dominion Questar Combination, at closing, each share of issued and outstanding Dominion Questar common stock was converted into the right to receive $25.00 per share in cash. The total consideration was $4.4 billion based on 175.5 million shares of Dominion Questar outstanding at closing. Dominion also acquired Dominion Questar's outstanding debt of approximately $1.5 billion. Dominion financed the Dominion Questar Combination through the: (1) August 2016 issuance of $1.4 billion of 2016 Equity Units, (2) August

2016 issuance of $1.3 billion of senior notes, (3) September 2016 borrowing of $1.2 billion under a term loan agreement, which was repaid with cash received from Dominion Midstream in connection with the contribution of Questar Pipeline and (4) $500 million of the proceeds from the April 2016 issuance of common stock.

Credit Ratings

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and are not a recommendation to buy, sell or hold securities. Dominion believes that its current credit ratings provide sufficient access to the capital markets. However, disruptions in the banking and capital markets not specifically related to Dominion may affect its ability to access these funding sources or cause an increase in the return required by investors. Dominion's credit ratings affect its liquidity, cost of borrowing under credit facilities and collateral posting requirements under commodity contracts, as well as the rates at which it is able to offer its debt securities.

Both quantitative (financial strength) and qualitative (business or operating characteristics) factors are considered by the credit rating agencies in establishing an individual company's credit rating. Credit ratings should be evaluated independently and are subject to revision or withdrawal at any time by the assigning rating organization. The credit ratings for Dominion are affected by its financial profile, mix of regulated and nonregulated businesses and respective cash flows, changes in methodologies used by the rating agencies and event risk, if applicable, such as major acquisitions or dispositions.

In February 2016, Standard & Poor's lowered the following ratings for Dominion: issuer to BBB+ from A-, senior unsecured debt securities to BBB from BBB+ and junior/remarketable subordinated debt securities to BBB- from BBB. In addition, Standard & Poor's affirmed Dominion's commercial paper rating of A-2 and revised its outlook to stable from negative.

In March 2016, Fitch and Standard & Poor's changed the rating for Dominion's junior subordinated debt securities to account for its inability to defer interest payments on the remarketed 2013 Series A RSNs. Subsequently, junior subordinated debt securities without an interest deferral feature are rated one notch higher by Fitch and Standard & Poor's (BBB) than junior subordinated debt securities with an interest deferral feature (BBB-). See Note 17 to the Consolidated Financial Statements for a description of the remarketed notes.

Credit ratings as of February 23, 2017 follow:

	Fitch	Moody's	Standard & Poor's
Dominion			
Issuer	**BBB+**	**Baa2**	**BBB+**
Senior unsecured debt securities	**BBB+**	**Baa2**	**BBB**
Junior subordinated notes(1)	**BBB**	**Baa3**	**BBB**
Enhanced junior subordinated notes(2)	**BBB-**	**Baa3**	**BBB-**
Junior/ remarketable subordinated notes(2)	**BBB-**	**Baa3**	**BBB-**
Commercial paper	**F2**	**P-2**	**A-2**

(1) Securities do not have an interest deferral feature.
(2) Securities have an interest deferral feature.

As of February 23, 2017, Fitch, Moody's, and Standard & Poor's maintained a stable outlook for their respective ratings of Dominion.

A downgrade in an individual company's credit rating does not necessarily restrict its ability to raise short-term and long-term financing as long as its credit rating remains investment grade, but it could result in an increase in the cost of borrowing. Dominion works closely with Fitch, Moody's and Standard & Poor's with the objective of achieving its targeted credit ratings. Dominion may find it necessary to modify its business plan to maintain or achieve appropriate credit ratings and such changes may adversely affect growth and EPS.

Debt Covenants

As part of borrowing funds and issuing debt (both short-term and long-term) or preferred securities, Dominion must enter into enabling agreements. These agreements contain covenants that, in the event of default, could result in the acceleration of principal and interest payments; restrictions on distributions related to capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments; and in some cases, the termination of credit commitments unless a waiver of such requirements is agreed to by the lenders/security holders. These provisions are customary, with each agreement specifying which covenants apply. These provisions are not necessarily unique to Dominion.

Some of the typical covenants include:

- The timely payment of principal and interest;
- Information requirements, including submitting financial reports filed with the SEC and information about changes in Dominion's credit ratings to lenders;
- Performance obligations, audits/inspections, continuation of the basic nature of business, restrictions on certain matters related to merger or consolidation and restrictions on disposition of all or substantially all assets;
- Compliance with collateral minimums or requirements related to mortgage bonds; and
- Limitations on liens.

Dominion is required to pay annual commitment fees to maintain its credit facilities. In addition, Dominion's credit agreements contain various terms and conditions that could affect its ability to borrow under these facilities. They include maximum debt to total capital ratios and cross-default provisions.

As of December 31, 2016, the calculated total debt to total capital ratio, pursuant to the terms of the agreements, was as follows:

Company	Maximum Allowed Ratio(1)	Actual Ratio(2)
Dominion	**70%**	**61%**

(1) Pursuant to a waiver received in April 2016 and in connection with the closing of the Dominion Questar Combination, the 65% maximum debt to total capital ratio in Dominion's credit agreements has, with respect to Dominion only, been temporarily increased to 70% until the end of the fiscal quarter ending June 30, 2017.
(2) Indebtedness as defined by the bank agreements excludes certain junior subordinated and remarketable subordinated notes reflected as long-term debt as well as AOCI reflected as equity in the Consolidated Balance Sheets.

If Dominion or any of its material subsidiaries fails to make payment on various debt obligations in excess of $100 million, the lenders could require the defaulting company, if it is a borrower under Dominion's credit facilities, to accelerate its repayment of any outstanding borrowings and the lenders could terminate their commitments, if any, to lend funds to that company under the credit facilities. In addition, if the defaulting company is Virginia Power, Dominion's obligations to repay any outstanding borrowing under the credit facilities could also be accelerated and the lenders' commitments to Dominion could terminate.

Dominion executed RCCs in connection with its issuance of the following hybrid securities:

- June 2006 hybrids;
- September 2006 hybrids; and
- June 2009 hybrids.

In October 2014, Dominion redeemed all of the June 2009 hybrids. The redemption was conducted in compliance with the RCC. See Note 17 to the Consolidated Financial Statements for additional information, including terms of the RCCs.

At December 31, 2016, the termination dates and covered debt under the RCCs associated with Dominion's hybrids were as follows:

Hybrid	RCC Termination Date	Designated Covered Debt Under RCC
June 2006 hybrids	**6/30/2036**	**September 2006 hybrids**
September 2006 hybrids	**9/30/2036**	**June 2006 hybrids**

Dominion monitors these debt covenants on a regular basis in order to ensure that events of default will not occur. As of December 31, 2016, there have been no events of default under Dominion's debt covenants.

Dividend Restrictions

Certain agreements associated with Dominion's credit facilities contain restrictions on the ratio of debt to total capitalization. These limitations did not restrict Dominion's ability to pay dividends or receive dividends from its subsidiaries at December 31, 2016.

See Note 17 to the Consolidated Financial Statements for a description of potential restrictions on dividend payments by Dominion in connection with the deferral of interest payments and contract adjustment payments on certain junior subordinated notes and equity units, initially in the form of corporate units, which information is incorporated herein by reference.

Future Cash Payments for Contractual Obligations and Planned Capital Expenditures

Contractual Obligations

Dominion is party to numerous contracts and arrangements obligating it to make cash payments in future years. These contracts include financing arrangements such as debt agreements and leases, as well as contracts for the purchase of goods and services and financial derivatives. Presented below is a table summarizing cash payments that may result from contracts to which Dominion is a party as of December 31, 2016. For purchase obligations and other liabilities, amounts are based upon contract terms, including fixed and minimum quantities to be purchased at fixed or market-based prices. Actual cash payments will be based upon actual quantities purchased and prices paid and will likely differ from amounts presented below. The table excludes all amounts classified as current liabilities in the Consolidated Balance Sheets, other than current maturities of long-term debt, interest payable and certain derivative instruments. The majority of Dominion's current liabilities will be paid in cash in 2017.

	2017	2018-2019	2020-2021	2022 and thereafter	Total
(millions)					
Long-term debt(1)	**$1,711**	**$ 6,666**	**$3,888**	**$19,927**	**$32,192**
Interest payments(2)	**1,339**	**2,349**	**1,902**	**14,596**	**20,186**
Leases(3)	**72**	**127**	**71**	**238**	**508**
Purchase obligations(4):					
Purchased electric capacity for utility operations	**149**	**153**	**98**	**—**	**400**
Fuel commitments for utility operations	**1,300**	**1,163**	**386**	**1,487**	**4,336**
Fuel commitments for nonregulated operations	**122**	**114**	**124**	**131**	**491**
Pipeline transportation and storage	**305**	**495**	**380**	**1,253**	**2,433**
Other(5)	**648**	**179**	**43**	**14**	**884**
Other long-term liabilities(6):					
Other contractual obligations(7)	**77**	**188**	**28**	**24**	**317**
Total cash payments	**$5,723**	**$11,434**	**$6,920**	**$37,670**	**$61,747**

(1) Based on stated maturity dates rather than the earlier redemption dates that could be elected by instrument holders.
(2) Includes interest payments over the terms of the debt and payments on related stock purchase contracts. Interest is calculated using the applicable interest rate or forward interest rate curve at December 31, 2016 and outstanding principal for each instrument with the terms ending at each instrument's stated maturity. See Note 17 to the Consolidated Financial Statements. Does not reflect Dominion's ability to defer interest and stock purchase contract payments on certain junior subordinated notes or RSNs and equity units, initially in the form of Corporate Units.
(3) Primarily consists of operating leases.
(4) Amounts exclude open purchase orders for services that are provided on demand, the timing of which cannot be determined.
(5) Includes capital, operations, and maintenance commitments.
(6) Excludes regulatory liabilities, AROs and employee benefit plan obligations, which are not contractually fixed as to timing and amount. See Notes 12, 14 and 21 to the Consolidated Financial Statements. Due to uncertainty about the timing and amounts that will ultimately be paid, $48 million of income taxes payable associated with unrecognized tax benefits are excluded. Deferred income taxes are also excluded since cash payments are based primarily on taxable income for each discrete fiscal year. See Note 5 to the Consolidated Financial Statements.
(7) Includes interest rate and foreign currency swap agreements.

Planned Capital Expenditures

Dominion's planned capital expenditures are expected to total approximately $5.8 billion, $5.0 billion and $5.2 billion in 2017, 2018 and 2019, respectively. Dominion's planned expenditures are expected to include construction and expansion of electric generation and natural gas transmission and storage facilities, construction improvements and expansion of electric transmission and distribution assets, purchases of nuclear fuel, maintenance and the construction of the Liquefaction Project and Dominion's portion of the Atlantic Coast Pipeline.

Dominion expects to fund its capital expenditures with cash from operations and a combination of securities issuances and short-term borrowings. Planned capital expenditures include capital projects that are subject to approval by regulators and the Board of Directors.

See *DVP, Dominion Generation* and *Dominion Energy-Properties* in Item 1. Business for a discussion of Dominion's expansion plans.

These estimates are based on a capital expenditures plan reviewed and endorsed by Dominion's Board of Directors in late 2016 and are subject to continuing review and adjustment and actual capital expenditures may vary from these estimates. Dominion may also choose to postpone or cancel certain planned capital expenditures in order to mitigate the need for future debt financings and equity issuances.

Use of Off-Balance Sheet Arrangements

Leasing Arrangement

In July 2016, Dominion signed an agreement with a lessor to construct and lease a new corporate office property in Richmond, Virginia. The lessor is providing equity and has obtained financing commitments from debt investors, totaling $365 million, to fund the estimated project costs. The project is expected to be completed by mid-2019. Dominion has been appointed to act as the construction agent for the lessor, during which time Dominion will request cash draws from the lessor and debt investors to fund all project costs, which totaled $46 million as of December 31, 2016. If the project is terminated under certain events of default, Dominion could be required to pay up to 89.9% of the then funded amount. For specific full recourse events, Dominion could be required to pay up to 100% of the then funded amount.

The five-year lease term will commence once construction is substantially complete and the facility is able to be occupied. At the end of the initial lease term, Dominion can (i) extend the term of the lease for an additional five years, subject to the approval of the participants, at current market terms, (ii) purchase the property for an amount equal to the project costs or, (iii) subject to certain terms and conditions, sell the property to a third party using commercially reasonable efforts to obtain the highest cash purchase price for the property. If the project is sold and the proceeds from the sale are insufficient to repay the investors for the project costs, Dominion may be required to make a payment to the lessor, up to 87% of project costs, for the difference between the project costs and sale proceeds.

The respective transactions have been structured so that Dominion is not considered the owner during construction for financial accounting purposes and, therefore, will not reflect the construction activity in its consolidated financial statements. The financial accounting treatment of the lease agreement will be impacted by the new accounting standard issued in February 2016. See Note 2 to the Consolidated Financial Statements for additional information. Dominion will be considered the owner of the leased property for tax purposes, and as a result, will be entitled to tax deductions for depreciation and interest expense.

Guarantees

Dominion primarily enters into guarantee arrangements on behalf of its consolidated subsidiaries. These arrangements are not subject to the provisions of FASB guidance that dictate a guarantor's accounting and disclosure requirements for guarantees, including indirect guarantees of indebtedness of others. See Note 22 to the Consolidated Financial Statements for additional information, which information is incorporated herein by reference.

Future Issues and Other Matters

See Item 1. Business and Notes 13 and 22 to the Consolidated Financial Statements for additional information on various environmental, regulatory, legal and other matters that may impact future results of operations, financial condition and/or cash flows.

Environmental Matters

Dominion is subject to costs resulting from a number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations.

Environmental Protection and Monitoring Expenditures

Dominion incurred $394 million, $298 million and $313 million of expenses (including accretion and depreciation) during 2016, 2015, and 2014 respectively, in connection with environmental protection and monitoring activities, including charges related to future ash pond and landfill closure costs, and expects these expenses to be approximately $190 million and $185 million in 2017 and 2018, respectively. In addition, capital expenditures related to environmental controls were $191 million, $94 million, and $101 million for 2016, 2015 and 2014, respectively. These expenditures are expected to be approximately $185 million and $115 million for 2017 and 2018, respectively.

Future Environmental Regulations

Air

The CAA is a comprehensive program utilizing a broad range of regulatory tools to protect and preserve the nation's air quality. At a minimum, delegated states are required to establish regulatory programs to address all requirements of the CAA. However, states may choose to develop regulatory programs that are more restrictive. Many of the Companies' facilities are subject to the CAA's permitting and other requirements.

In August 2015, the EPA issued final carbon standards for existing fossil fuel power plants. Known as the Clean Power Plan, the rule uses a set of measures for reducing emissions from existing sources that includes efficiency improvements at coal plants, displacing coal-fired generation with increased utilization of natural gas combined cycle units and expanding renewable resources. The new rule requires states to impose standards of performance limits for existing fossil fuel-fired electric generating units or equivalent statewide intensity-based or mass-based CO_2 binding goals or limits. States are required to submit final plans identifying how they will comply with the rule by September 2018. The EPA also issued a proposed federal plan and model trading rule that states can adopt or that would be put in place if, in response to the final guidelines, a state either does not submit a state plan or its plan is not approved by the EPA. Virginia Power's most recent integrated resources plan filed in April 2016 includes four alternative plans that represent plausible compliance strategies with the rule as proposed, and which include additional coal unit retirements and additional low or zero-carbon resources. The final rule has been challenged in the U.S. Court of Appeals for the D.C. Circuit. In February 2016, the U.S. Supreme Court issued a stay of the Clean Power Plan until the disposition of the petitions challenging the rule now before the Court of Appeals, and, if such petitions are filed in the future, before the U.S. Supreme Court. Dominion does not know whether these legal challenges will impact the submittal deadlines for the state implementation plans. In June 2016, the Governor of Virginia signed an executive order directing the Virginia Natural Resources Secretary to convene a workgroup charged with recommending concrete steps to reduce carbon pollution which include the Clean Power Plan as an option. Unless the rule survives the court challenges and until the state plans are developed and the EPA approves the plans, Dominion cannot predict the potential financial statement impacts but believes the potential expenditures to comply could be material.

In December 2012, the EPA issued a final rule that set a more stringent annual air quality standard for fine particulate matter. The EPA issued final attainment/nonattainment designations in January 2015. Until states develop their implementation plans, Dominion cannot determine whether or how facilities located in areas designated nonattainment for the standard will be impacted, but does not expect such impacts to be material.

The EPA has finalized rules establishing a new 1-hour NAAQS for NO_2 and a new 1-hour NAAQS for SO_2, which could require additional NO_X and SO_2 controls in certain areas where Dominion operates. Until the states have developed implementation plans for these standards, the impact on Dominion's facilities that emit NO_X and SO_2 is uncertain. Additionally, the impact of permit limits for implementing NAAQS on Dominion's facilities is uncertain at this time.

Climate Change

In December 2015, the Paris Agreement was formally adopted under the United Nations Framework Convention on Climate Change. The accord establishes a universal framework for addressing GHG emissions involving actions by all nations through the concept of nationally determined contributions in which each nation defines the GHG commitment it can make and sets in place a process for increasing those commitments every five years. It also contains a global goal of holding the increase in the global average temperature to well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 degrees Celsius above pre-industrial levels and to aim to reach global peaking of GHG emissions as soon as possible.

A key element of the initial U.S. nationally determined contributions of achieving a 26% to 28% reduction below 2005 levels by 2025 is the implementation of the Clean Power Plan, which establishes interim emission reduction targets for fossil fuel-fired electric generating units over the period 2022 through 2029 with final targets to be achieved by 2030. The EPA estimates that the Clean Power Plan will result in a nationwide reduction in CO_2 emissions from fossil fuel-fired electric generating units of 32% from 2005 levels by 2030.

In March 2016, as part of its Climate Action Plan, the EPA began development of regulations for reducing methane emissions from existing sources in the oil and natural gas sectors. In November 2016, the EPA issued an Information Collection Request to collect information on existing sources upstream of local distribution companies in this sector. Depending on the results of this Information Collection Request, the EPA may propose new regulations on existing sources. Dominion cannot currently estimate the potential impacts on results of operations, financial condition and/or cash flows related to this matter.

PHMSA Regulation

The most recent reauthorization of PHMSA included new provisions on historical records research, maximum-allowed operating pressure validation, use of automated or remote-controlled valves on new or replaced lines, increased civil penalties and evaluation of expanding integrity management beyond high-consequence areas. PHMSA has not yet issued new rulemaking on most of these items.

Legal Matters

Collective Bargaining Agreement

In April 2016, the labor contract between Dominion and Local 69 expired. In August 2016, the parties reached a tentative agreement for a new labor contract, however, the agreement was not submitted to members of Local 69 for approval. In September 2016, following a temporary lock out of union members, Local 69 agreed to not strike at DTI and Hope at least through April 1, 2017. In exchange, DTI and Hope agreed to recall the union members to work and not lock them out during that period. Contract negotiations resumed in October 2016 and are continuing. Local 69 represents approximately 760 DTI employees in West Virginia, New York, Pennsylvania, Ohio and Virginia and approximately 150 Hope employees in West Virginia.

Dodd-Frank Act

The Dodd-Frank Act was enacted into law in July 2010 in an effort to improve regulation of financial markets. The CEA, as amended by Title VII of the Dodd-Frank Act, requires certain over-the counter derivatives, or swaps, to be cleared through a derivatives clearing organization and, if the swap is subject to a clearing requirement, to be executed on a designated contract market or swap execution facility. Non-financial entities that use swaps to hedge or mitigate commercial risk, often referred to as end users, may elect the end-user exception to the CEA's clearing requirements. Dominion has elected to exempt its swaps from the CEA's clearing requirements. The CFTC may continue to adopt final rules and implement provisions of the Dodd-Frank Act through its ongoing rulemaking process, including rules regarding margin requirements for non-cleared swaps. If, as a result of the rulemaking process, Dominion's derivative activities are not exempted from clearing, exchange trading or margin requirements, it could be subject to higher costs due to decreased market liquidity or increased margin payments. In addition, Dominion's swap dealer counterparties may attempt to pass-through additional trading costs in connection with the implementation of, and compliance with, Title VII of the Dodd-Frank Act. Due to the evolving rulemaking process, Dominion is currently unable to assess the potential impact of the Dodd-Frank Act's derivative-related provisions on its financial condition, results of operations or cash flows.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The matters discussed in this Item may contain "forward-looking statements" as described in the introductory paragraphs of Item 7. MD&A. The reader's attention is directed to those paragraphs and Item 1A. Risk Factors for discussion of various risks and uncertainties that may impact the Companies.

Market Risk Sensitive Instruments and Risk Management

The Companies' financial instruments, commodity contracts and related financial derivative instruments are exposed to potential losses due to adverse changes in commodity prices, interest rates and equity security prices as described below. Commodity price risk is present in Dominion's and Virginia Power's electric operations and Dominion's and Dominion Gas' natural gas procurement and marketing operations due to the exposure to market shifts in prices received and paid for electricity, natural gas and other commodities. The Companies use commodity derivative contracts to manage price risk exposures for these operations. Interest rate risk is generally related to their outstanding debt and future issuances of debt. In addition, the Companies are exposed to investment price risk through various portfolios of equity and debt securities.

The following sensitivity analysis estimates the potential loss of future earnings or fair value from market risk sensitive instruments over a selected time period due to a 10% change in commodity prices or interest rates.

Commodity Price Risk

To manage price risk, Dominion and Virginia Power hold commodity-based derivative instruments held for non-trading purposes associated with purchases and sales of electricity, natural gas and other energy-related products and Dominion Gas primarily holds commodity-based financial derivative instruments held for non-trading purposes associated with purchases and sales of natural gas and other energy-related products.

The derivatives used to manage commodity price risk are executed within established policies and procedures and may include instruments such as futures, forwards, swaps, options and FTRs that are sensitive to changes in the related commodity prices. For sensitivity analysis purposes, the hypothetical change in market prices of commodity-based financial derivative instruments is determined based on models that consider the market prices of commodities in future periods, the volatility of the market prices in each period, as well as the time value factors of the derivative instruments. Prices and volatility are principally determined based on observable market prices.

A hypothetical 10% decrease in commodity prices would have resulted in a decrease in fair value of $27 million and $24 million of Dominion's commodity-based derivative instruments as of December 31, 2016 and December 31, 2015, respectively.

A hypothetical 10% decrease in commodity prices would have resulted in a decrease in the fair value of $62 million and $42 million of Virginia Power's commodity-based derivative instruments as of December 31, 2016 and December 31, 2015, respectively. The increase in sensitivity is largely due to an increase in commodity derivative activity and higher commodity prices.

A hypothetical 10% increase in commodity prices of Dominion Gas' commodity-based financial derivative instruments would have resulted in a decrease in fair value of $4 million and $5 million as of December 31, 2016 and 2015, respectively.

The impact of a change in energy commodity prices on the Companies' commodity-based financial derivative instruments at a point in time is not necessarily representative of the results that will be realized when the contracts are ultimately settled. Net losses from commodity derivative instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction, such as revenue from physical sales of the commodity.

Interest Rate Risk

The Companies manage their interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. They also enter into interest rate sensitive derivatives, including interest rate swaps and interest rate lock agreements. For variable rate debt and interest rate swaps designated under fair value hedging and outstanding for the Companies, a hypothetical 10% increase in market interest rates would not have resulted in a material change in annual earnings at December 31, 2016 or 2015.

The Companies may also use forward-starting interest rate swaps and interest rate lock agreements as anticipatory hedges. As of December 31, 2016, Dominion and Virginia Power had $2.9 billion and $1.7 billion, respectively, in aggregate notional amounts of these interest rate derivatives outstanding. A hypothetical 10% decrease in market interest rates would have resulted in a decrease of $58 million and $45 million, respectively, in the fair value of Dominion's and Virginia Power's interest rate derivatives at December 31, 2016. As of December 31, 2015, Dominion, Virginia Power and Dominion Gas had $4.6 billion, $2.0 billion and $250 million, respectively, in aggregate notional amounts of these interest rate derivatives outstanding. A hypothetical 10% decrease in market interest rates would have resulted in a decrease of $71 million, $52 million and $2 million, respectively, in the fair value of Dominion's, Virginia Power's and Dominion Gas' interest rate derivatives at December 31, 2015.

In June 2016, Dominion Gas entered into foreign currency swaps with the purpose of hedging the foreign currency exchange risk associated with Euro denominated debt. As of December 31, 2016, Dominion and Dominion Gas had $280 million (€ 250 million) in aggregate notional amounts of these foreign currency swaps outstanding. A hypothetical 10% increase in market interest rates would have resulted in a $5 million decrease in the fair value of Dominion's and Dominion Gas' foreign currency swaps at December 31, 2016.

The impact of a change in interest rates on the Companies' interest rate-based financial derivative instruments at a point in time is not necessarily representative of the results that will be realized when the contracts are ultimately settled. Net gains and/or losses from interest rate derivative instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction.

Investment Price Risk

Dominion and Virginia Power are subject to investment price risk due to securities held as investments in nuclear decommissioning and rabbi trust funds that are managed by third-party investment managers. These trust funds primarily hold marketable securities that are reported in the Consolidated Balance Sheets at fair value.

Dominion recognized net realized gains (including investment income) on nuclear decommissioning and rabbi trust investments of $144 million and $184 million in 2016 and 2015, respectively. Net realized gains and losses include gains and losses from the sale of investments as well as any other-than-temporary declines in fair value. Dominion recorded, in AOCI and regulatory liabilities, a net increase in unrealized gains of $183 million in 2016, and a net decrease in unrealized gains of $157 million in 2015.

Virginia Power recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $67 million and $88 million in 2016 and 2015, respectively. Net realized gains and losses include gains and losses from the sale of investments as well as any other-than-temporary declines in fair value. Virginia Power recorded, in AOCI and regulatory liabilities, a net increase in unrealized gains of $93 million in 2016, and a net decrease in unrealized gains of $76 million in 2015.

Dominion sponsors pension and other postretirement employee benefit plans that hold investments in trusts to fund employee benefit payments. Virginia Power and Dominion Gas employees participate in these plans. Dominion's pension and other postretirement plan assets experienced aggregate actual returns of $534 million in 2016 and aggregate actual losses of $72 million in 2015, versus expected returns of $691 million and $648 million, respectively. Dominion Gas' pension and other postretirement plan assets for employees represented by collective bargaining units experienced aggregate actual returns of $130 million in 2016 and aggregate actual losses of $13 million in 2015, versus expected returns of $157 million and $150 million, respectively. Differences between actual and expected returns on plan assets are accumulated and amortized during future periods. As such, any investment-related declines in these trusts will result in future increases in the net periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash to be contributed to the employee benefit plans. A hypothetical 0.25% decrease in the assumed long-term rates of return on Dominion's plan assets would result in an increase in net periodic cost of $18 million and $16 million as of December 31, 2016 and 2015, respectively, for pension benefits and $4 million and $3 million as of December 31, 2016 and 2015, respectively, for other postretirement benefits. A hypothetical 0.25% decrease in the assumed long-term rates of return on Dominion Gas' plan assets, for employees represented by collective bargaining units, would result in an increase in net periodic cost of $4 million as of both December 31, 2016 and 2015, for pension benefits and $1 million as of both December 31, 2016 and 2015, for other postretirement benefits.

Risk Management Policies

The Companies have established operating procedures with corporate management to ensure that proper internal controls are maintained. In addition, Dominion has established an independent function at the corporate level to monitor compliance with the credit and commodity risk management policies of all subsidiaries, including Virginia Power and Dominion Gas. Dominion maintains credit policies that include the evaluation of a prospective counterparty's financial condition, collateral requirements where deemed necessary and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. In addition, Dominion also monitors the financial condition of existing counterparties on an ongoing basis. Based on these credit policies and the Companies' December 31, 2016 provision for credit losses, management believes that it is unlikely that a material adverse effect on the Companies' financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
Dominion Resources, Inc.
Richmond, Virginia

We have audited the accompanying consolidated balance sheets of Dominion Resources, Inc. and subsidiaries ("Dominion") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of Dominion's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Dominion Resources, Inc. and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Dominion's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2017 expressed an unqualified opinion on Dominion's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 28, 2017

Dominion Resources, Inc.
Consolidated Statements of Income

Year Ended December 31,	**2016**	2015	2014
(millions, except per share amounts)			
Operating Revenue	**$11,737**	$11,683	$12,436
Operating Expenses			
Electric fuel and other energy-related purchases	**2,333**	2,725	3,400
Purchased electric capacity	**99**	330	361
Purchased gas	**459**	551	1,355
Other operations and maintenance	**3,064**	2,595	2,765
Depreciation, depletion and amortization	**1,559**	1,395	1,292
Other taxes	**596**	551	542
Total operating expenses	**8,110**	8,147	9,715
Income from operations	**3,627**	3,536	2,721
Other income	**250**	196	250
Interest and related charges	**1,010**	904	1,193
Income from operations including noncontrolling interests before income taxes	**2,867**	2,828	1,778
Income tax expense	**655**	905	452
Net income including noncontrolling interests	**2,212**	1,923	1,326
Noncontrolling interests	**89**	24	16
Net income attributable to Dominion	**2,123**	1,899	1,310
Earnings Per Common Share			
Net income attributable to Dominion—Basic	**$ 3.44**	$ 3.21	$ 2.25
Net income attributable to Dominion—Diluted	**$ 3.44**	$ 3.20	$ 2.24
Dividends declared per common share	**$ 2.80**	$ 2.59	$ 2.40

The accompanying notes are an integral part of Dominion's Consolidated Financial Statements.

Dominion Resources, Inc.
Consolidated Statements of Comprehensive Income

Year Ended December 31,	**2016**	2015	2014
(millions)			
Net income including noncontrolling interests	**$2,212**	$1,923	$1,326
Other comprehensive income (loss), net of taxes:			
Net deferred gains on derivatives-hedging activities, net of $(37), $(74) and $(20) tax	**55**	110	17
Changes in unrealized net gains on investment securities, net of $(53), $23 and $(59) tax	**93**	6	128
Changes in net unrecognized pension and other postretirement benefit costs, net of $189, $29 and $189 tax	**(319)**	(66)	(305)
Amounts reclassified to net income:			
Net derivative (gains) losses-hedging activities, net of $100, $68 and $(59) tax	**(159)**	(108)	93
Net realized gains on investment securities, net of $15, $29 and $33 tax	**(28)**	(50)	(54)
Net pension and other postretirement benefit costs, net of $(22), $(35) and $(24) tax	**34**	51	33
Changes in other comprehensive loss from equity method investees, net of $—, $1 and $3 tax	**(1)**	(1)	(4)
Total other comprehensive loss	**(325)**	(58)	(92)
Comprehensive income including noncontrolling interests	**1,887**	1,865	1,234
Comprehensive income attributable to noncontrolling interests	**89**	24	16
Comprehensive income attributable to Dominion	**$1,798**	$1,841	$1,218

The accompanying notes are an integral part of Dominion's Consolidated Financial Statements.

Dominion Resources, Inc.
Consolidated Balance Sheets

At December 31,	2016	2015
(millions)		
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 261**	$ 607
Customer receivables (less allowance for doubtful accounts of $18 and $32)	**1,523**	1,200
Other receivables (less allowance for doubtful accounts of $2 at both dates)	**183**	169
Inventories:		
Materials and supplies	**1,087**	902
Fossil fuel	**341**	381
Gas stored	**96**	65
Derivative assets	**140**	255
Prepayments	**194**	198
Regulatory assets	**244**	351
Other	**179**	61
Total current assets	**4,248**	4,189
Investments		
Nuclear decommissioning trust funds	**4,484**	4,183
Investment in equity method affiliates	**1,561**	1,320
Other	**298**	271
Total investments	**6,343**	5,774
Property, Plant and Equipment		
Property, plant and equipment	**69,556**	57,776
Accumulated depreciation, depletion and amortization	**(19,592)**	(16,222)
Total property, plant and equipment, net	**49,964**	41,554
Deferred Charges and Other Assets		
Goodwill	**6,399**	3,294
Pension and other postretirement benefit assets	**1,078**	943
Intangible assets, net	**618**	570
Regulatory assets	**2,473**	1,865
Other	**487**	459
Total deferred charges and other assets	**11,055**	7,131
Total assets	**$ 71,610**	$ 58,648

At December 31,	2016	2015
(millions)		
Liabilities and Equity		
Current Liabilities		
Securities due within one year	**$ 1,709**	$ 1,825
Short-term debt	**3,155**	3,509
Accounts payable	**1,000**	726
Accrued interest, payroll and taxes	**798**	515
Regulatory liabilities	**163**	100
Other(1)	**1,290**	1,444
Total current liabilities	**8,115**	8,119
Long-Term Debt		
Long-term debt	**24,878**	20,048
Junior subordinated notes	**2,980**	1,340
Remarketable subordinated notes	**2,373**	2,080
Total long-term debt	**30,231**	23,468
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**8,602**	7,414
Asset retirement obligations	**2,236**	1,887
Pension and other postretirement benefit liabilities	**2,112**	1,199
Regulatory liabilities	**2,622**	2,285
Other	**852**	674
Total deferred credits and other liabilities	**16,424**	13,459
Total liabilities	**54,770**	45,046
Commitments and Contingencies (see Note 22)		
Equity		
Common stock-no par(2)	**8,550**	6,680
Retained earnings	**6,854**	6,458
Accumulated other comprehensive loss	**(799)**	(474)
Total common shareholders' equity	**14,605**	12,664
Noncontrolling interests	**2,235**	938
Total equity	**16,840**	13,602
Total liabilities and equity	**$71,610**	$58,648

(1) See Note 3 for amounts attributable to related parties.
(2) 1 billion shares authorized; 628 million shares and 596 million shares outstanding at December 31, 2016 and 2015, respectively.

The accompanying notes are an integral part of Dominion's Consolidated Financial Statements.

Dominion Resources, Inc.
Consolidated Statements of Equity

	Common Stock		Dominion Shareholders				
(millions)	Shares	Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholders' Equity	Noncontrolling Interests	Total Equity
December 31, 2013	581	$5,783	$ 6,183	$(324)	$11,642	$ —	$11,642
Net income including noncontrolling interests			1,323		1,323	3	1,326
Issuance of Dominion Midstream common units, net of offering costs					—	392	392
Issuance of stock-employee and direct stock purchase plans	3	205			205		205
Stock awards (net of change in unearned compensation)		14			14		14
Other stock issuances(1)	1	14			14		14
Present value of stock purchase contract payments related to RSNs(2)		(143)			(143)		(143)
Dividends			(1,411)(3)		(1,411)		(1,411)
Other comprehensive loss, net of tax				(92)	(92)		(92)
Other		3			3	7	10
December 31, 2014	585	5,876	6,095	(416)	11,555	402	11,957
Net income including noncontrolling interests			1,899		1,899	24	1,923
Dominion Midstream's acquisition of interest in Iroquois					—	216	216
Acquisition of Four Brothers and Three Cedars					—	47	47
Contributions from SunEdison to Four Brothers and Three Cedars					—	103	103
Sale of interest in merchant solar projects		26			26	179	205
Purchase of Dominion Midstream common units		(6)			(6)	(19)	(25)
Issuance of common stock	11	786			786		786
Stock awards (net of change in unearned compensation)		13			13		13
Dividends			(1,536)		(1,536)		(1,536)
Dominion Midstream distributions					—	(16)	(16)
Other comprehensive loss, net of tax				(58)	(58)		(58)
Other		(15)			(15)	2	(13)
December 31, 2015	596	6,680	6,458	(474)	12,664	938	13,602
Net income including noncontrolling interests			**2,123**		**2,123**	**89**	**2,212**
Contributions from SunEdison to Four Brothers and Three Cedars					**—**	**189**	**189**
Sale of interest in merchant solar projects		**22**			**22**	**117**	**139**
Sale of Dominion Midstream common units—net of offering costs					**—**	**482**	**482**
Sale of Dominion Midstream convertible preferred units—net of offering costs					**—**	**490**	**490**
Purchase of Dominion Midstream common units		**(3)**			**(3)**	**(14)**	**(17)**
Issuance of common stock	**32**	**2,152**			**2,152**		**2,152**
Stock awards (net of change in unearned compensation)		**14**			**14**		**14**
Present value of stock purchase contract payments related to RSNs(2)		**(191)**			**(191)**		**(191)**
Tax effect of Questar Pipeline contribution to Dominion Midstream		**(116)**			**(116)**		**(116)**
Dividends and distributions			**(1,727)**		**(1,727)**	**(62)**	**(1,789)**
Other comprehensive loss, net of tax				**(325)**	**(325)**		**(325)**
Other		**(8)**			**(8)**	**6**	**(2)**
December 31, 2016	**628**	**$8,550**	**$ 6,854**	**$(799)**	**$14,605**	**$2,235**	**$16,840**

(1) Contains shares issued in excess of principal amounts related to converted securities. See Note 17 for further information on convertible securities.
(2) See Note 17 for further information.
(3) Includes subsidiary preferred dividends related to noncontrolling interests of $13 million.

The accompanying notes are an integral part of Dominion's Consolidated Financial Statements

Dominion Resources, Inc.
Consolidated Statements of Cash Flows

Year Ended December 31,	2016	2015	2014
(millions)			
Operating Activities			
Net income including noncontrolling interests	**$ 2,212**	$ 1,923	$ 1,326
Adjustments to reconcile net income including noncontrolling interests to net cash provided by operating activities:			
Depreciation, depletion and amortization (including nuclear fuel)	**1,849**	1,669	1,560
Deferred income taxes and investment tax credits	**725**	854	449
Current income tax for Questar Pipeline contribution to Dominion Midstream	**(212)**	—	—
Gains on the sale of assets and businesses and equity method investment in Iroquois	**(50)**	(123)	(220)
Charges associated with North Anna and offshore wind legislation	**—**	—	374
Charges associated with Liability Management Exercise	**—**	—	284
Charges associated with future ash pond and landfill closure costs	**197**	99	121
Other adjustments	**(108)**	(42)	(113)
Changes in:			
Accounts receivable	**(286)**	294	131
Inventories	**1**	(26)	(43)
Deferred fuel and purchased gas costs, net	**54**	94	(180)
Prepayments	**21**	(25)	24
Accounts payable	**97**	(199)	(202)
Accrued interest, payroll and taxes	**203**	(52)	(41)
Margin deposit assets and liabilities	**(66)**	237	361
Net realized and unrealized changes related to derivative activities	**(335)**	(176)	(38)
Other operating assets and liabilities	**(175)**	(52)	(354)
Net cash provided by operating activities	**4,127**	4,475	3,439
Investing Activities			
Plant construction and other property additions (including nuclear fuel)	**(6,085)**	(5,575)	(5,345)
Acquisition of Dominion Questar, net of cash acquired	**(4,381)**	—	—
Acquisition of solar development projects	**(40)**	(418)	(206)
Acquisition of DCG	**—**	(497)	—
Proceeds from sales of securities	**1,422**	1,340	1,235
Purchases of securities	**(1,504)**	(1,326)	(1,241)
Proceeds from the sale of electric retail energy marketing business	**—**	—	187
Proceeds from Blue Racer	**—**	—	85
Proceeds from assignments of shale development rights	**10**	79	60
Other	**(125)**	(106)	44
Net cash used in investing activities	**(10,703)**	(6,503)	(5,181)
Financing Activities			
Issuance (repayment) of short-term debt, net	**(654)**	734	848
Issuance of short-term notes	**1,200**	600	400
Repayment and repurchase of short-term notes	**(1,800)**	(400)	(400)
Issuance and remarketing of long-term debt	**7,722**	2,962	6,085
Repayment and repurchase of long-term debt, including redemption premiums	**(1,610)**	(892)	(3,993)
Net proceeds from issuance of Dominion Midstream common units	**482**	—	392
Net proceeds from issuance of Dominion Midstream convertible preferred units	**490**	—	—
Proceeds from sale of interest in merchant solar projects	**117**	184	—
Contributions from SunEdison to Four Brothers and Three Cedars	**189**	103	—
Subsidiary preferred stock redemption	**—**	—	(259)
Issuance of common stock	**2,152**	786	205
Common dividend payments	**(1,727)**	(1,536)	(1,398)
Subsidiary preferred dividend payments	**—**	—	(11)
Other	**(331)**	(224)	(125)
Net cash provided by financing activities	**6,230**	2,317	1,744
Increase (decrease) in cash and cash equivalents	**(346)**	289	2
Cash and cash equivalents at beginning of year	**607**	318	316
Cash and cash equivalents at end of year	**$ 261**	$ 607	$ 318
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 905**	$ 843	$ 889
Income taxes	**145**	75	72
Significant noncash investing and financing activities:(1)(2)			
Accrued capital expenditures	**427**	478	315
Dominion Midstream's acquisition of a noncontrolling partnership interest in Iroquois in exchange for issuance of Dominion Midstream common units	**—**	216	—

(1) See Note 3 for noncash activities related to the acquisition of Four Brothers and Three Cedars.
(2) See Note 17 for noncash activities related to the remarketing of RSNs in 2016.

The accompanying notes are an integral part of Dominion's Consolidated Financial Statements.

[THIS PAGE INTENTIONALLY LEFT BLANK]

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of
Virginia Electric and Power Company
Richmond, Virginia

We have audited the accompanying consolidated balance sheets of Virginia Electric and Power Company (a wholly-owned subsidiary of Dominion Resources, Inc.) and subsidiaries ("Virginia Power") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of Virginia Power's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. Virginia Power is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of Virginia Power's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Virginia Electric and Power Company and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 28, 2017

Virginia Electric and Power Company
Consolidated Statements of Income

Year Ended December 31,	**2016**	2015	2014
(millions)			
Operating Revenue[1]	**$7,588**	$7,622	$7,579
Operating Expenses			
Electric fuel and other energy-related purchases[1]	**1,973**	2,320	2,406
Purchased electric capacity	**99**	330	360
Other operations and maintenance:			
Affiliated suppliers	**310**	279	286
Other	**1,547**	1,355	1,630
Depreciation and amortization	**1,025**	953	915
Other taxes	**284**	264	258
Total operating expenses	**5,238**	5,501	5,855
Income from operations	**2,350**	2,121	1,724
Other income	**56**	68	93
Interest and related charges	**461**	443	411
Income from operations before income tax expense	**1,945**	1,746	1,406
Income tax expense	**727**	659	548
Net Income	**1,218**	1,087	858
Preferred dividends[2]	**—**	—	13
Balance available for common stock	**$1,218**	$1,087	$ 845

(1) See Note 24 for amounts attributable to affiliates.
(2) Includes $2 million associated with the write-off of issuance expenses related to the redemption of Virginia Power's preferred stock in 2014. See Note 18 for additional information.

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

Virginia Electric and Power Company
Consolidated Statements of Comprehensive Income

Year Ended December 31,	**2016**	2015	2014
(millions)			
Net income	**$1,218**	$1,087	$858
Other comprehensive income (loss), net of taxes:			
Net deferred losses on derivatives-hedging activities, net of $1, $2 and $2 tax	**(2)**	(1)	(4)
Changes in unrealized net gains (losses) on nuclear decommissioning trust funds, net of $(7), $1 and $(9) tax	**11**	(4)	15
Amounts reclassified to net income:			
Net derivative (gains) losses-hedging activities, net of $—, $— and $2 tax	**1**	1	(3)
Net realized gains on nuclear decommissioning trust funds, net of $2, $4 and $4 tax	**(4)**	(6)	(6)
Other comprehensive income (loss)	**6**	(10)	2
Comprehensive income	**$1,224**	$1,077	$860

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

Virginia Electric and Power Company
Consolidated Balance Sheets

At December 31,	2016	2015
(millions)		
ASSETS		
Current Assets		
Cash and cash equivalents	$ 11	$ 18
Customer receivables (less allowance for doubtful accounts of $10 and $27)	892	822
Other receivables (less allowance for doubtful accounts of $1 at both dates)	99	109
Affiliated receivables	112	296
Inventories (average cost method):		
Materials and supplies	525	502
Fossil fuel	328	371
Prepayments(1)	30	38
Regulatory assets	179	326
Other(1)	72	22
Total current assets	2,248	2,504
Investments		
Nuclear decommissioning trust funds	2,106	1,945
Other	3	3
Total investments	2,109	1,948
Property, Plant and Equipment		
Property, plant and equipment	40,030	37,639
Accumulated depreciation and amortization	(12,436)	(11,708)
Total property, plant and equipment, net	27,594	25,931
Deferred Charges and Other Assets		
Pension and other postretirement benefit assets(1)	130	77
Intangible assets, net	225	213
Regulatory assets	770	667
Derivative assets(1)	128	109
Other	104	116
Total deferred charges and other assets	1,357	1,182
Total assets	$ 33,308	$ 31,565

(1) See Note 24 for amounts attributable to affiliates.

At December 31,	2016	2015
(millions)		
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities		
Securities due within one year	**$ 678**	$ 476
Short-term debt	**65**	1,656
Accounts payable	**444**	366
Payables to affiliates	**109**	73
Affiliated current borrowings	**262**	376
Accrued interest, payroll and taxes(1)	**239**	190
Asset retirement obligations	**181**	143
Regulatory liabilities	**115**	35
Other(1)	**429**	415
Total current liabilities	**2,522**	3,730
Long-Term Debt	**9,852**	8,892
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**5,103**	4,654
Asset retirement obligations	**1,262**	1,104
Regulatory liabilities	**1,962**	1,929
Pension and other postretirement benefit liabilities(1)	**396**	316
Other	**346**	299
Total deferred credits and other liabilities	**9,069**	8,302
Total liabilities	**21,443**	20,924
Commitments and Contingencies (see Note 22)		
Common Shareholder's Equity		
Common stock-no par(2)	**5,738**	5,738
Other paid-in capital	**1,113**	1,113
Retained earnings	**4,968**	3,750
Accumulated other comprehensive income	**46**	40
Total common shareholder's equity	**11,865**	10,641
Total liabilities and shareholder's equity	**$33,308**	$31,565

(1) See Note 24 for amounts attributable to affiliates.
(2) 500,000 shares authorized; 274,723 shares outstanding at December 31, 2016 and 2015.

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

Virginia Electric and Power Company
Consolidated Statements of Common Shareholder's Equity

	Common Stock		Other Paid-In	Retained	Accumulated Other Comprehensive	
	Shares	Amount	Capital	Earnings	Income (Loss)	Total
(millions, except for shares)	(thousands)					
Balance at December 31, 2013	275	$5,738	$1,113	$2,899	$ 48	$ 9,798
Net income				858		858
Dividends				(603)		(603)
Other comprehensive income, net of tax					2	2
Balance at December 31, 2014	275	5,738	1,113	3,154	50	10,055
Net income				1,087		1,087
Dividends				(491)		(491)
Other comprehensive loss, net of tax					(10)	(10)
Balance at December 31, 2015	275	5,738	1,113	3,750	40	10,641
Net income				**1,218**		**1,218**
Other comprehensive income, net of tax					**6**	**6**
Balance at December 31, 2016	**275**	**$5,738**	**$1,113**	**$4,968**	**$ 46**	**$11,865**

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

Virginia Electric and Power Company
Consolidated Statements of Cash Flows

Year Ended December 31,	**2016**	2015	2014
(millions)			
Operating Activities			
Net income	**$ 1,218**	$ 1,087	$ 858
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (including nuclear fuel)	**1,210**	1,121	1,090
Deferred income taxes and investment tax credits	**469**	251	396
Charges associated with North Anna and offshore wind legislation	**—**	—	374
Charges associated with future ash pond and landfill closure costs	**197**	99	121
Other adjustments	**(16)**	(27)	(35)
Changes in:			
Accounts receivable	**(65)**	128	(27)
Affiliated accounts receivable and payable	**220**	(314)	23
Inventories	**20**	(20)	(45)
Prepayments	**8**	214	(220)
Deferred fuel expenses, net	**69**	64	(191)
Accounts payable	**25**	(75)	5
Accrued interest, payroll and taxes	**49**	(9)	(19)
Net realized and unrealized changes related to derivative activities	**(153)**	(67)	(37)
Other operating assets and liabilities	**18**	103	(45)
Net cash provided by operating activities	**3,269**	2,555	2,248
Investing Activities			
Plant construction and other property additions	**(2,489)**	(2,474)	(2,911)
Purchases of nuclear fuel	**(153)**	(172)	(196)
Acquisition of solar development projects	**(7)**	(43)	—
Purchases of securities	**(775)**	(651)	(574)
Proceeds from sales of securities	**733**	639	549
Other	**(33)**	(87)	(2)
Net cash used in investing activities	**(2,724)**	(2,788)	(3,134)
Financing Activities			
Issuance (repayment) of short-term debt, net	**(1,591)**	295	519
Issuance (repayment) of affiliated current borrowings, net	**(114)**	(51)	330
Issuance and remarketing of long-term debt	**1,688**	1,112	950
Repayment and repurchase of long-term debt	**(517)**	(625)	(61)
Preferred stock redemption	**—**	—	(259)
Common dividend payments to parent	**—**	(491)	(590)
Preferred dividend payments	**—**	—	(11)
Other	**(18)**	(4)	7
Net cash provided by (used in) financing activities	**(552)**	236	885
Increase (decrease) in cash and cash equivalents	**(7)**	3	(1)
Cash and cash equivalents at beginning of year	**18**	15	16
Cash and cash equivalents at end of year	**$ 11**	$ 18	$ 15
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 435**	$ 422	$ 383
Income taxes	**79**	517	386
Significant noncash investing activities:			
Accrued capital expenditures	**256**	169	181

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

[THIS PAGE INTENTIONALLY LEFT BLANK]

Report of Independent Registered Public Accounting Firm

To the Board of Directors of
Dominion Gas Holdings, LLC
Richmond, Virginia

We have audited the accompanying consolidated balance sheets of Dominion Gas Holdings, LLC (a wholly-owned subsidiary of Dominion Resources, Inc.) and subsidiaries ("Dominion Gas") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of Dominion Gas' management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. Dominion Gas is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of Dominion Gas' internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Dominion Gas Holdings, LLC and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Richmond, Virginia
February 28, 2017

Dominion Gas Holdings, LLC
Consolidated Statements of Income

Year Ended December 31,	2016	2015	2014
(millions)			
Operating Revenue[(1)]	**$1,638**	$1,716	$1,898
Operating Expenses			
Purchased gas[(1)]	**109**	133	315
Other energy-related purchases[(1)]	**12**	21	40
Other operations and maintenance:			
Affiliated suppliers	**81**	64	64
Other[(1)(2)]	**393**	326	274
Depreciation and amortization	**204**	217	197
Other taxes	**170**	166	157
Total operating expenses	**969**	927	1,047
Income from operations	**669**	789	851
Earnings from equity method investee	**21**	23	21
Other income	**11**	1	1
Interest and related charges[(1)]	**94**	73	27
Income from operations before income tax expense	**607**	740	846
Income tax expense	**215**	283	334
Net Income	**$ 392**	$ 457	$ 512

(1) See Note 24 for amounts attributable to related parties.
(2) Includes a gain on the sale of assets to a related party of $59 million in 2014. See Note 9 for more information.

The accompanying notes are an integral part of Dominion Gas' Consolidated Financial Statements.

Dominion Gas Holdings, LLC
Consolidated Statements of Comprehensive Income

Year Ended December 31,	**2016**	2015	2014
(millions)			
Net income	**$392**	$457	$512
Other comprehensive income (loss), net of taxes:			
Net deferred gains (losses) on derivatives-hedging activities, net of $10, $(4) and $19 tax	**(16)**	6	(31)
Changes in unrecognized pension costs, net of $14, $13 and $6 tax	**(20)**	(20)	(10)
Amounts reclassified to net income:			
Net derivative (gains) losses-hedging activities, net of $(6), $3 and $(5) tax	**9**	(3)	8
Net pension and other postretirement benefit costs, net of $(2), $(3) and $(3) tax	**3**	4	5
Other comprehensive loss	**(24)**	(13)	(28)
Comprehensive income	**$368**	$444	$484

The accompanying notes are an integral part of Dominion Gas' Consolidated Financial Statements.

Dominion Gas Holdings, LLC
Consolidated Balance Sheets

At December 31,	2016	2015
(millions)		
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 23**	$ 13
Customer receivables (less allowance for doubtful accounts of $1 at both dates)(1)	**281**	219
Other receivables (less allowance for doubtful accounts of $1 and $2)(1)	**13**	7
Affiliated receivables	**17**	98
Inventories:		
Materials and supplies	**57**	54
Gas stored	**13**	24
Prepayments(1)	**94**	88
Regulatory assets	**26**	23
Gas imbalances(1)	**37**	17
Other	**21**	23
Total current assets	**582**	566
Investments	**99**	104
Property, Plant and Equipment		
Property, plant and equipment	**10,475**	9,693
Accumulated depreciation and amortization	**(2,851)**	(2,690)
Total property, plant and equipment, net	**7,624**	7,003
Deferred Charges and Other Assets		
Goodwill	**542**	542
Intangible assets, net	**98**	83
Regulatory assets	**577**	449
Pension and other postretirement benefit assets(1)	**1,557**	1,510
Other(1)	**63**	51
Total deferred charges and other assets	**2,837**	2,635
Total assets	**$11,142**	$10,308

(1) See Note 24 for amounts attributable to related parties.

At December 31,	**2016**	2015
(millions)		

Liabilities and Equity

Current Liabilities		
Securities due within one year	**$ —**	$ 400
Short-term debt	**460**	391
Accounts payable	**221**	201
Payables to affiliates	**29**	22
Affiliated current borrowings	**118**	95
Accrued interest, payroll and taxes(1)	**225**	183
Regulatory liabilities	**35**	55
Other(1)	**127**	128
Total current liabilities	**1,215**	1,475
Long-Term Debt	**3,528**	2,869
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**2,438**	2,214
Regulatory liabilities	**219**	201
Other(1)	**206**	231
Total deferred credits and other liabilities	**2,863**	2,646
Total liabilities	**7,606**	6,990
Commitments and Contingencies (see Note 22)		
Equity		
Membership interests	**3,659**	3,417
Accumulated other comprehensive loss	**(123)**	(99)
Total equity	**3,536**	3,318
Total liabilities and equity	**$11,142**	$10,308

(1) See Note 24 for amounts attributable to related parties.

The accompanying notes are an integral part of Dominion Gas' Consolidated Financial Statements.

Dominion Gas Holdings, LLC
Consolidated Statements of Equity

(millions)	Membership Interests	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2013	$3,485	$ (58)	$3,427
Net income	512		512
Equity contribution from parent	1		1
Distributions	(346)		(346)
Other comprehensive loss, net of tax		(28)	(28)
Balance at December 31, 2014	3,652	(86)	3,566
Net income	457		457
Distributions	(692)		(692)
Other comprehensive loss, net of tax		(13)	(13)
Balance at December 31, 2015	3,417	(99)	3,318
Net income	**392**		**392**
Distributions	**(150)**		**(150)**
Other comprehensive loss, net of tax		**(24)**	**(24)**
Balance at December 31, 2016	**$3,659**	**$(123)**	**$3,536**

The accompanying notes are an integral part of Dominion Gas' Consolidated Financial Statements.

Dominion Gas Holdings, LLC
Consolidated Statements of Cash Flows

Year Ended December 31,	2016	2015	2014
(millions)			
Operating Activities			
Net income	**$ 392**	$ 457	$ 512
Adjustments to reconcile net income to net cash provided by operating activities:			
Gains on sales of assets	**(50)**	(123)	(124)
Depreciation and amortization	**204**	217	197
Deferred income taxes and investment tax credits	**238**	163	216
Other adjustments	**(6)**	16	2
Changes in:			
Accounts receivable	**(68)**	115	(42)
Affiliated receivables and payables	**88**	(105)	(5)
Inventories	**8**	(13)	(2)
Prepayments	**(6)**	99	(99)
Accounts payable	**15**	(51)	(35)
Accrued interest, payroll and taxes	**42**	(11)	(15)
Pension and other postretirement benefits	**(141)**	(119)	(112)
Other operating assets and liabilities	**(68)**	(17)	(22)
Net cash provided by operating activities	**648**	628	471
Investing Activities			
Plant construction and other property additions	**(854)**	(795)	(719)
Proceeds from sale of equity method investment in Iroquois	**7**	—	—
Proceeds from sale of assets to affiliate	**—**	—	47
Proceeds from assignments of shale development rights	**10**	79	60
Other	**(18)**	(11)	(4)
Net cash used in investing activities	**(855)**	(727)	(616)
Financing Activities			
Issuance of short-term debt, net	**69**	391	—
Issuance (repayment) of affiliated current borrowings, net	**23**	(289)	(892)
Repayment of long-term debt	**(400)**	—	—
Issuance of long-term debt	**680**	700	1,400
Distribution payments to parent	**(150)**	(692)	(346)
Other	**(5)**	(7)	(16)
Net cash provided by financing activities	**217**	103	146
Increase in cash and cash equivalents	**10**	4	1
Cash and cash equivalents at beginning of year	**13**	9	8
Cash and cash equivalents at end of year	**$ 23**	$ 13	$ 9
Supplemental Cash Flow Information			
Cash paid (received) during the year for:			
Interest and related charges, excluding capitalized amounts	**$ 81**	$ 70	$ 23
Income taxes	**(92)**	98	266
Significant noncash investing and financing activities:			
Accrued capital expenditures	**59**	57	35
Extinguishment of affiliated long-term debt in exchange for assets sold to affiliate	**—**	—	67

The accompanying notes are an integral part of Dominion Gas' Consolidated Financial Statements.

[THIS PAGE INTENTIONALLY LEFT BLANK]

Note 1. Nature of Operations

Dominion, headquartered in Richmond, Virginia, is one of the nation's largest producers and transporters of energy. Dominion's operations are conducted through various subsidiaries, including Virginia Power and Dominion Gas. Virginia Power is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. Virginia Power is a member of PJM, an RTO, and its electric transmission facilities are integrated into the PJM wholesale electricity markets. All of Virginia Power's stock is owned by Dominion. Dominion Gas is a holding company that conducts business activities through a regulated interstate natural gas transmission pipeline and underground storage system in the Northeast, mid-Atlantic and Midwest states, regulated gas transportation and distribution operations in Ohio, and gas gathering and processing activities primarily in West Virginia, Ohio and Pennsylvania. All of Dominion Gas' membership interests are held by Dominion. The Dominion Questar Combination was completed in September 2016. See Note 3 for a description of operations acquired in the Dominion Questar Combination.

Dominion's operations also include the Cove Point LNG import, transport and storage facility in Maryland, an equity investment in Atlantic Coast Pipeline and regulated gas transportation and distribution operations in West Virginia. Dominion's nonregulated operations include merchant generation, energy marketing and price risk management activities, retail energy marketing operations and an equity investment in Blue Racer.

In October 2014, Dominion Midstream launched its initial public offering of 20,125,000 common units representing limited partner interests at a price of $21 per unit. Dominion received $392 million in net proceeds from the sale of the units, after deducting underwriting discounts, structuring fees and estimated offering expenses. At December 31, 2016, Dominion owns the general partner, 50.9% of the common and subordinated units and 37.5% of the convertible preferred interests in Dominion Midstream, which owns a preferred equity interest and the general partner interest in Cove Point, DCG, Questar Pipeline and a 25.93% noncontrolling partnership interest in Iroquois. The public's ownership interest in Dominion Midstream is reflected as noncontrolling interest in Dominion's Consolidated Financial Statements.

Dominion manages its daily operations through three primary operating segments: DVP, Dominion Generation and Dominion Energy. Dominion also reports a Corporate and Other segment, which includes its corporate, service company and other functions (including unallocated debt). In addition, Corporate and Other includes specific items attributable to Dominion's operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Virginia Power manages its daily operations through two primary operating segments: DVP and Dominion Generation. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

Dominion Gas manages its daily operations through one primary operating segment: Dominion Energy. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segment that are not included in profit measures evaluated by executive management in assessing the segment's performance or in allocating resources and the effect of certain items recorded at Dominion Gas as a result of Dominion's basis in the net assets contributed.

See Note 25 for further discussion of the Companies' operating segments.

Note 2. Significant Accounting Policies

General

The Companies make certain estimates and assumptions in preparing their Consolidated Financial Statements in accordance with GAAP. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses and cash flows for the periods presented. Actual results may differ from those estimates.

The Companies' Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of their respective majority-owned subsidiaries and non-wholly-owned entities in which they have a controlling financial interest. For certain partnership structures, income is allocated based on the liquidation value of the underlying contractual arrangements. NRG's ownership interest in Four Brothers and Three Cedars, as well as Terra Nova Renewable Partners' 33% interest in certain of Dominion's merchant solar projects, is reflected as noncontrolling interest in Dominion's Consolidated Financial Statements. See Note 3 for further information on these transactions.

The Companies report certain contracts, instruments and investments at fair value. See Note 6 for further information on fair value measurements.

Dominion maintains pension and other postretirement benefit plans. Virginia Power and Dominion Gas participate in certain of these plans. See Note 21 for further information on these plans.

Certain amounts in the 2015 and 2014 Consolidated Financial Statements and footnotes have been reclassified to conform to the 2016 presentation for comparative purposes. The reclassifications did not affect the Companies' net income, total assets, liabilities, equity or cash flows, except for the reclassification of debt issuance costs.

Amounts disclosed for Dominion are inclusive of Virginia Power and/or Dominion Gas, where applicable.

Operating Revenue

Operating revenue is recorded on the basis of services rendered, commodities delivered or contracts settled and includes amounts yet to be billed to customers. Dominion and Virginia Power collect sales, consumption and consumer utility taxes and Dominion Gas collects sales taxes; however, these amounts are excluded from revenue. Dominion's customer receivables at December 31, 2016 and 2015 included $631 million and $462 million, respectively, of accrued unbilled revenue based on estimated amounts of electricity and natural gas delivered but not yet billed to its utility customers. Virginia Power's customer receivables at December 31, 2016 and 2015 included $349 million and $333 million, respectively, of accrued unbilled revenue based on estimated amounts of electricity delivered but not yet billed to its customers. Dominion Gas' customer receivables at December 31, 2016 and 2015 included $134 million and $98 million, respectively, of accrued unbilled revenue based on estimated amounts of natural gas delivered but not yet billed to its customers.

The primary types of sales and service activities reported as operating revenue for Dominion are as follows:

- **Regulated electric sales** consist primarily of state-regulated retail electric sales, and federally-regulated wholesale electric sales and electric transmission services;
- **Nonregulated electric sales** consist primarily of sales of electricity at market-based rates and contracted fixed rates, and associated derivative activity;
- **Regulated gas sales** consist primarily of state- and FERC-regulated natural gas sales and related distribution services and associated derivative activity;
- **Nonregulated gas sales** consist primarily of sales of natural gas production at market-based rates and contracted fixed prices, sales of gas purchased from third parties, gas trading and marketing revenue and associated derivative activity;
- **Gas transportation and storage** consists primarily of FERC-regulated sales of transmission and storage services. Also included are state-regulated gas distribution charges to retail distribution service customers opting for alternate suppliers and sales of gathering services; and
- **Other revenue** consists primarily of sales of NGL production and condensate, extracted products and associated derivative activity. Other revenue also includes miscellaneous service revenue from electric and gas distribution operations, sales of energy-related products and services from Dominion's retail energy marketing operations and gas processing and handling revenue.

The primary types of sales and service activities reported as operating revenue for Virginia Power are as follows:

- **Regulated electric sales** consist primarily of state-regulated retail electric sales and federally-regulated wholesale electric sales and electric transmission services; and
- **Other revenue** consists primarily of miscellaneous service revenue from electric distribution operations and miscellaneous revenue from generation operations, including sales of capacity and other commodities.

The primary types of sales and service activities reported as operating revenue for Dominion Gas are as follows:

- **Regulated gas sales** consist primarily of state- and FERC-regulated natural gas sales and related distribution services;
- **Nonregulated gas sales** consist primarily of sales of natural gas production at market-based rates and contracted fixed prices and sales of gas purchased from third parties. Revenue from sales of gas production is recognized based on actual volumes of gas sold to purchasers and is reported net of royalties;
- **Gas transportation and storage** consists primarily of FERC-regulated sales of transmission and storage services. Also included are state-regulated gas distribution charges to retail distribution service customers opting for alternate suppliers and sales of gathering services;
- **NGL revenue** consists primarily of sales of NGL production and condensate, extracted products and associated derivative activity; and
- **Other revenue** consists primarily of miscellaneous service revenue, gas processing and handling revenue.

Electric Fuel, Purchased Energy and Purchased Gas-Deferred Costs

Where permitted by regulatory authorities, the differences between Dominion's and Virginia Power's actual electric fuel and purchased energy expenses and Dominion's and Dominion Gas' purchased gas expenses and the related levels of recovery for these expenses in current rates are deferred and matched against recoveries in future periods. The deferral of costs in excess of current period fuel rate recovery is recognized as a regulatory asset, while rate recovery in excess of current period fuel expenses is recognized as a regulatory liability.

Of the cost of fuel used in electric generation and energy purchases to serve utility customers, approximately 84% is currently subject to deferred fuel accounting, while substantially all of the remaining amount is subject to recovery through similar mechanisms.

Virtually all of Dominion Gas', Cove Point's, Questar Gas' and Hope's natural gas purchases are either subject to deferral accounting or are recovered from the customer in the same accounting period as the sale.

Income Taxes

A consolidated federal income tax return is filed for Dominion and its subsidiaries, including Virginia Power and Dominion Gas' subsidiaries. In addition, where applicable, combined income tax returns for Dominion and its subsidiaries are filed in various states; otherwise, separate state income tax returns are filed.

Although Dominion Gas is disregarded for income tax purposes, a provision for income taxes is recognized to reflect the inclusion of its business activities in the tax returns of its parent, Dominion. Virginia Power and Dominion Gas participate in intercompany tax sharing agreements with Dominion and its subsidiaries. Current income taxes are based on taxable income or loss and credits determined on a separate company basis.

Under the agreements, if a subsidiary incurs a tax loss or earns a credit, recognition of current income tax benefits is limited to refunds of prior year taxes obtained by the carryback of the net operating loss or credit or to the extent the tax loss or credit is absorbed by the taxable income of other Dominion consolidated group members. Otherwise, the net operating loss or credit is carried forward and is recognized as a deferred tax asset until realized.

Effective January 2016, deferred tax liabilities and assets are classified as noncurrent in the Consolidated Balance Sheets. For prior years, the Companies presented deferred taxes in either the current or noncurrent sections of the Consolidated Balance Sheets based on the classification of the related financial accounting assets or liabilities, or, for items such as operating loss carryforwards, the period in which the deferred taxes were expected to reverse.

Accounting for income taxes involves an asset and liability approach. Deferred income tax assets and liabilities are provided, representing future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Accordingly, deferred taxes are recognized for the future consequences of different treatments used for the reporting of transactions in financial accounting and income tax returns. The Companies establish a valuation allowance when it is more-likely-than-not that all, or a portion, of a deferred tax asset will not be realized. Where the treatment of temporary differences is different for rate-regulated operations, a regulatory asset is recognized if it is probable that future revenues will be provided for the payment of deferred tax liabilities.

The Companies recognize positions taken, or expected to be taken, in income tax returns that are more-likely-than-not to be realized, assuming that the position will be examined by tax authorities with full knowledge of all relevant information.

If it is not more-likely-than-not that a tax position, or some portion thereof, will be sustained, the related tax benefits are not recognized in the financial statements. Unrecognized tax benefits may result in an increase in income taxes payable, a reduction of income tax refunds receivable or changes in deferred taxes. Also, when uncertainty about the deductibility of an amount is limited to the timing of such deductibility, the increase in income taxes payable (or reduction in tax refunds receivable) is accompanied by a decrease in deferred tax liabilities. Except when such amounts are presented net with amounts receivable from or amounts prepaid to tax authorities, noncurrent income taxes payable related to unrecognized tax benefits are classified in other deferred credits and other liabilities on the Consolidated Balance Sheets and current payables are included in accrued interest, payroll and taxes on the Consolidated Balance Sheets.

The Companies recognize interest on underpayments and overpayments of income taxes in interest expense and other income, respectively. Penalties are also recognized in other income.

Dominion's, Virginia Power's and Dominion Gas' interest and penalties were immaterial in 2016, 2015 and 2014.

At December 31, 2016, Virginia Power had an income tax-related affiliated receivable of $112 million, comprised of $122 million of federal income taxes due from Dominion net of $10 million for state income taxes due to Dominion. Dominion Gas also had an affiliated receivable of $11 million due from Dominion, representing $10 million of federal income taxes and $1 million of state income taxes. The net affiliated receivables are expected to be refunded by Dominion.

In addition, Virginia Power's Consolidated Balance Sheet at December 31, 2016 included $2 million of noncurrent federal income taxes payable, $6 million of state income taxes receivable and $13 million of noncurrent state income taxes receivable. Dominion Gas' Consolidated Balance Sheet at December 31, 2016 included $1 million of noncurrent federal income taxes payable, $1 million of state income taxes receivable and $7 million of noncurrent state income taxes payable.

At December 31, 2015, Virginia Power's Consolidated Balance Sheet included a $296 million affiliated receivable, representing excess federal income tax payments expected to be refunded, $9 million of federal income taxes payable for prior years, less than $1 million of state income taxes payable, $10 million of state income taxes receivable, $14 million of noncurrent state income taxes receivable and $2 million of noncurrent state income taxes payable. In March 2016, Virginia Power received a $300 million refund of its 2015 income tax payments.

At December 31, 2015, Dominion Gas' Consolidated Balance Sheet included $91 million of affiliated receivables, representing excess federal income tax payments expected to be refunded and the benefit of utilizing a subsidiary's tax loss to offset taxable income in Dominion's consolidated tax return, less than $1 million of state income taxes payable, $4 million of state income taxes receivable and $22 million of noncurrent state income taxes payable. In March 2016, Dominion Gas received a $92 million refund for its 2015 income tax payments and benefit of a subsidiary's tax loss.

Investment tax credits are recognized by nonregulated operations in the year qualifying property is placed in service. For regulated operations, investment tax credits are deferred and amortized over the service lives of the properties giving rise to the credits. Production tax credits are recognized as energy is generated and sold.

Cash and Cash Equivalents

Current banking arrangements generally do not require checks to be funded until they are presented for payment. The following table illustrates the checks outstanding but not yet presented for payment and recorded in accounts payable for the Companies:

Year Ended December 31,	**2016**	2015
(millions)		
Dominion	**$24**	$27
Virginia Power	**11**	11
Dominion Gas	**9**	7

For purposes of the Consolidated Statements of Cash Flows, cash and cash equivalents include cash on hand, cash in banks and temporary investments purchased with an original maturity of three months or less.

Derivative Instruments

Dominion uses derivative instruments such as physical and financial forwards, futures, swaps, options and FTRs to manage the commodity, interest rate and foreign currency exchange rate risks of its business operations. Virginia Power uses derivative instruments such as physical and financial forwards, futures, swaps, options and FTRs to manage commodity and interest rate risks. Dominion Gas uses derivative instruments such as physical and financial forwards, futures and swaps to manage commodity, interest rate and foreign currency exchange rate risks.

All derivatives, except those for which an exception applies, are required to be reported in the Consolidated Balance Sheets at fair value. Derivative contracts representing unrealized gain positions and purchased options are reported as derivative assets. Derivative contracts representing unrealized losses and options sold are reported as derivative liabilities. One of the exceptions to fair value accounting, normal purchases and normal sales, may be elected when the contract satisfies certain criteria, including a requirement that physical delivery of the underlying commodity is probable. Expenses and revenues resulting from deliveries under normal purchase contracts and normal sales contracts, respectively, are included in earnings at the time of contract performance.

The Companies do not offset amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. Dominion had margin assets of $82 million and $16 million associated with cash collateral at December 31, 2016 and 2015, respectively. Dominion's margin liabilities associated with cash collateral at December 31, 2016 or 2015 were immaterial. Virginia Power's and Dominion Gas' margin assets and liabilities associated with cash collateral were immaterial at December 31, 2016 and 2015. See Note 7 for further information about derivatives.

To manage price risk, the Companies hold certain derivative instruments that are not designated as hedges for accounting purposes. However, to the extent the Companies do not hold offsetting positions for such derivatives, they believe these instruments represent economic hedges that mitigate their exposure to fluctuations in commodity prices. As part of Dominion's strategy to market energy and manage related risks, it formerly managed a portfolio of commodity-based financial derivative instruments held for trading purposes. Dominion used established policies and procedures to manage the risks associated with price fluctuations in these energy commodities and used various derivative instruments to reduce risk by creating offsetting market positions. In the second quarter of 2013, Dominion commenced a repositioning of its producer services business. The repositioning was completed in the first quarter of 2014 and resulted in the termination of natural gas trading and certain energy marketing activities.

Statement of Income Presentation:

- **Derivatives Held for Trading Purposes:** All income statement activity, including amounts realized upon settlement, is presented in operating revenue on a net basis.
- **Derivatives Not Held for Trading Purposes:** All income statement activity, including amounts realized upon settlement, is presented in operating revenue, operating expenses, interest and related charges or other income based on the nature of the underlying risk.

Changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities for jurisdictions subject to cost-based rate regulation. Realized gains or losses on the derivative instruments are generally recognized when the related transactions impact earnings.

Derivative Instruments Designated as Hedging Instruments

The Companies designate a portion of their derivative instruments as either cash flow or fair value hedges for accounting purposes. For all derivatives designated as hedges, the Companies formally document the relationship between the hedging instrument and the hedged item, as well as the risk management objective and the strategy for using the hedging instrument. The Companies assess whether the hedging relationship between the derivative and the hedged item is highly effective at offsetting changes in cash flows or fair values both at the inception of the hedging relationship and on an ongoing basis. Any change in the fair value of the derivative that is not effective at offsetting changes in the cash flows or fair values of the hedged item is recognized currently in earnings. Also, the Companies may elect to exclude certain gains or losses on hedging instruments from the assessment of hedge effectiveness, such as gains or losses attributable to changes in the time value of options or changes in the difference between spot prices and forward prices, thus requiring that such changes be recorded currently in earnings. Hedge accounting is discontinued prospectively for derivatives that cease to be highly effective hedges. For derivative instruments that are accounted for as fair value hedges or cash flow hedges, the cash flows from the derivatives and from the related hedged items are classified in operating cash flows.

Cash Flow Hedges-A majority of the Companies' hedge strategies represents cash flow hedges of the variable price risk associated with the purchase and sale of electricity, natural gas, NGLs and other energy-related products. The Companies also use interest rate swaps to hedge their exposure to variable interest rates on long-term debt as well as foreign currency swaps to hedge their exposure to interest payments denominated in Euros. For transactions in which the Companies are hedging the variability of cash flows, changes in the fair value of the derivatives are reported in AOCI, to the extent they are effective at offsetting changes in the hedged item. Any derivative gains or losses reported in AOCI are reclassified to earnings when the forecasted item is included in earnings, or earlier, if it becomes probable that the forecasted transaction will not occur. For cash flow hedge transactions, hedge accounting is discontinued if the occurrence of the forecasted transaction is no longer probable.

Dominion entered into interest rate derivative instruments to hedge its forecasted interest payments related to planned debt issuances in 2014. These interest rate derivatives were designated by Dominion as cash flow hedges prior to the formation of Dominion Gas. For the purposes of the Dominion Gas financial statements, the derivative balances, AOCI balance, and any income statement impact related to these interest rate derivative instruments entered into by Dominion have been, and will continue to be, included in the Dominion Gas' Consolidated Financial Statements as the forecasted interest payments related to the debt issuances now occur at Dominion Gas.

Fair Value Hedges-Dominion also uses fair value hedges to mitigate the fixed price exposure inherent in certain firm commodity commitments and commodity inventory. In addition, Dominion has designated interest rate swaps as fair value hedges on certain fixed rate long-term debt to manage interest rate exposure. For fair value hedge transactions, changes in the fair value of the derivative are generally offset currently in earnings by the recognition of changes in the hedged item's fair value. Hedge accounting is discontinued if the hedged item no longer qualifies for hedge accounting. See Note 6 for further information about fair value measurements and associated valuation methods for derivatives. See Note 7 for further information on derivatives.

Property, Plant and Equipment

Property, plant and equipment is recorded at lower of original cost or fair value, if impaired. Capitalized costs include labor, materials and other direct and indirect costs such as asset retirement costs, capitalized interest and, for certain operations subject to cost-of-service rate regulation, AFUDC and overhead costs. The cost of repairs and maintenance, including minor additions and replacements, is generally charged to expense as it is incurred.

In 2016, 2015 and 2014, Dominion capitalized interest costs and AFUDC to property, plant and equipment of $159 million, $100 million and $80 million, respectively. In 2016, 2015 and

2014, Virginia Power capitalized AFUDC to property, plant and equipment of $21 million, $30 million and $39 million, respectively. In 2016, 2015 and 2014, Dominion Gas capitalized AFUDC to property, plant and equipment of $8 million, $1 million and $1 million, respectively.

Under Virginia law, certain Virginia jurisdictional projects qualify for current recovery of AFUDC through rate adjustment clauses. AFUDC on these projects is calculated and recorded as a regulatory asset and is not capitalized to property, plant and equipment. In 2016, 2015 and 2014, Virginia Power recorded $31 million, $19 million and $8 million of AFUDC related to these projects, respectively.

For property subject to cost-of-service rate regulation, including Virginia Power electric distribution, electric transmission, and generation property, Dominion Gas natural gas distribution and transmission property, and for certain Dominion natural gas property, the undepreciated cost of such property, less salvage value, is generally charged to accumulated depreciation at retirement. Cost of removal collections from utility customers not representing AROs are recorded as regulatory liabilities. For property subject to cost-of-service rate regulation that will be abandoned significantly before the end of its useful life, the net carrying value is reclassified from plant-in-service when it becomes probable it will be abandoned.

For property that is not subject to cost-of-service rate regulation, including nonutility property, cost of removal not associated with AROs is charged to expense as incurred. The Companies also record gains and losses upon retirement based upon the difference between the proceeds received, if any, and the property's net book value at the retirement date.

Depreciation of property, plant and equipment is computed on the straight-line method based on projected service lives. The Companies' average composite depreciation rates on utility property, plant and equipment are as follows:

Year Ended December 31,	2016	2015	2014
(percent)			
Dominion			
Generation	**2.83**	2.78	2.66
Transmission	**2.47**	2.42	2.38
Distribution	**3.02**	3.11	3.12
Storage	**2.29**	2.42	2.39
Gas gathering and processing	**2.66**	3.19	2.81
General and other	**4.12**	3.67	3.62
Virginia Power			
Generation	**2.83**	2.78	2.66
Transmission	**2.36**	2.33	2.34
Distribution	**3.32**	3.33	3.34
General and other	**3.49**	3.40	3.29
Dominion Gas			
Transmission	**2.43**	2.46	2.40
Distribution	**2.55**	2.45	2.47
Storage	**2.19**	2.44	2.40
Gas gathering and processing	**2.58**	3.20	2.82
General and other	**4.54**	4.72	5.77

In 2014, Virginia Power made a one-time adjustment to depreciation expense as ordered by the Virginia Commission. This adjustment resulted in an increase of $38 million ($23 million after-tax) in depreciation and amortization expense in Virginia Power's Consolidated Statements of Income.

Capitalized costs of development wells and leaseholds are amortized on a field-by-field basis using the unit-of-production method and the estimated proved developed or total proved gas and oil reserves, at a rate of $2.08 per mcfe in 2016.

Dominion's nonutility property, plant and equipment is depreciated using the straight-line method over the following estimated useful lives:

Asset	Estimated Useful Lives
Merchant generation-nuclear	**44 years**
Merchant generation-other	**15-36 years**
Nonutility gas gathering and processing	**3-50 years**
General and other	**5-59 years**

Depreciation and amortization related to Virginia Power's and Dominion Gas' nonutility property, plant and equipment and exploration and production properties was immaterial for the years ended December 31, 2016, 2015 and 2014, except for Dominion Gas' nonutility gas gathering and processing properties which are depreciated using the straight-line method over estimated useful lives between 10 and 50 years.

Nuclear fuel used in electric generation is amortized over its estimated service life on a units-of-production basis. Dominion and Virginia Power report the amortization of nuclear fuel in electric fuel and other energy-related purchases expense in their Consolidated Statements of Income and in depreciation and amortization in their Consolidated Statements of Cash Flows.

Long-Lived and Intangible Assets

The Companies perform an evaluation for impairment whenever events or changes in circumstances indicate that the carrying amount of long-lived assets or intangible assets with finite lives may not be recoverable. A long-lived or intangible asset is written down to fair value if the sum of its expected future undiscounted cash flows is less than its carrying amount. Intangible assets with finite lives are amortized over their estimated useful lives. See Note 6 for a discussion of impairments related to certain long-lived assets.

Regulatory Assets and Liabilities

The accounting for Dominion's and Dominion Gas' regulated gas and Virginia Power's regulated electric operations differs from the accounting for nonregulated operations in that they are required to reflect the effect of rate regulation in their Consolidated Financial Statements. For regulated businesses subject to federal or state cost-of-service rate regulation, regulatory practices that assign costs to accounting periods may differ from accounting methods generally applied by nonregulated companies. When it is probable that regulators will permit the recovery of current costs through future rates charged to customers, these costs that otherwise would be expensed by nonregulated companies are deferred as regulatory assets. Likewise, regulatory liabilities are recognized when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for expenditures that have yet to be incurred. Generally, regulatory assets and liabilities are amortized into income over the period authorized by the regulator.

The Companies evaluate whether or not recovery of their regulatory assets through future rates is probable and make various assumptions in their analyses. The expectations of future recovery are generally based on orders issued by regulatory commissions, legislation or historical experience, as well as discussions with applicable regulatory authorities and legal counsel. If recovery of a regulatory asset is determined to be less than probable, it will be written off in the period such assessment is made.

Asset Retirement Obligations

The Companies recognize AROs at fair value as incurred or when sufficient information becomes available to determine a reasonable estimate of the fair value of future retirement activities to be performed, for which a legal obligation exists. These amounts are generally capitalized as costs of the related tangible long-lived assets. Since relevant market information is not available, fair value is estimated using discounted cash flow analyses. Periodically, the Companies evaluate the key assumptions underlying their AROs including estimates of the amounts and timing of future cash flows associated with retirement activities. AROs are adjusted when significant changes in these assumptions are identified. Dominion and Dominion Gas report accretion of AROs and depreciation on asset retirement costs associated with their natural gas pipeline and storage well assets as an adjustment to the related regulatory liabilities when revenue is recoverable from customers for AROs. Virginia Power reports accretion of AROs and depreciation on asset retirement costs associated with decommissioning its nuclear power stations as an adjustment to the regulatory liability for certain jurisdictions. Additionally, Virginia Power reports accretion of AROs and depreciation on asset retirement costs associated with certain prospective rider projects as an adjustment to the regulatory asset for certain jurisdictions. Accretion of all other AROs and depreciation of all other asset retirement costs are reported in other operations and maintenance expense and depreciation expense, respectively, in the Consolidated Statements of Income.

Debt Issuance Costs

The Companies defer and amortize debt issuance costs and debt premiums or discounts over the expected lives of the respective debt issues, considering maturity dates and, if applicable, redemption rights held by others. Effective January 2016, deferred debt issuance costs were recorded as a reduction in long-term debt in the Consolidated Balance Sheets. Such costs had previously been recorded as an asset in other current assets and other deferred charges and other assets in the Consolidated Balance Sheets. Amortization of the issuance costs is reported as interest expense. Unamortized costs associated with redemptions of debt securities prior to stated maturity dates are generally recognized and recorded in interest expense immediately. As permitted by regulatory authorities, gains or losses resulting from the refinancing of debt allocable to utility operations subject to cost-based rate regulation are deferred and amortized over the lives of the new issuances.

Investments

Marketable Equity and Debt Securities

Dominion accounts for and classifies investments in marketable equity and debt securities as trading or available-for-sale securities. Virginia Power classifies investments in marketable equity and debt securities as available-for-sale securities.

- *Trading securities* include marketable equity and debt securities held by Dominion in rabbi trusts associated with certain deferred compensation plans. These securities are reported in other investments in the Consolidated Balance Sheets at fair value with net realized and unrealized gains and losses included in other income in the Consolidated Statements of Income.
- *Available-for-sale securities* include all other marketable equity and debt securities, primarily comprised of securities held in the nuclear decommissioning trusts. These investments are reported at fair value in nuclear decommissioning trust funds in the Consolidated Balance Sheets. Net realized and unrealized gains and losses (including any other-than-temporary impairments) on investments held in Virginia Power's nuclear decommissioning trusts are recorded to a regulatory liability for certain jurisdictions subject to cost-based regulation. For all other available-for-sale securities, including those held in Dominion's merchant generation nuclear decommissioning trusts, net realized gains and losses (including any other-than-temporary impairments) are included in other income and unrealized gains and losses are reported as a component of AOCI, after-tax.

In determining realized gains and losses for marketable equity and debt securities, the cost basis of the security is based on the specific identification method.

Non-marketable Investments

The Companies account for illiquid and privately held securities for which market prices or quotations are not readily available under either the equity or cost method. Non-marketable investments include:

- *Equity method investments* when the Companies have the ability to exercise significant influence, but not control, over the investee. Dominion's investments are included in investments in equity method affiliates and Virginia Power's investments are included in other investments in their Consolidated Balance Sheets. The Companies record equity method adjustments in other income in the Consolidated Statements of Income including: their proportionate share of investee income or loss, gains or losses resulting from investee capital transactions, amortization of certain differences between the carrying value and the equity in the net assets of the investee at the date of investment and other adjustments required by the equity method.
- *Cost method investments* when Dominion and Virginia Power do not have the ability to exercise significant influence over the investee. Dominion's and Virginia Power's investments are included in other investments and nuclear decommissioning trust funds.

Other-than-temporary Impairment

Dominion and Virginia Power periodically review their investments to determine whether a decline in fair value should be considered other-than-temporary. If a decline in fair value of any security is determined to be other-than-temporary, the security is written down to its fair value at the end of the reporting period.

Decommissioning Trust Investments—Special Considerations

- The recognition provisions of the FASB's other-than-temporary impairment guidance apply only to debt securities classified as available-for-sale or held-to-maturity, while the presentation and disclosure requirements apply to both debt and equity securities.

- *Debt Securities*—Using information obtained from their nuclear decommissioning trust fixed-income investment managers, Dominion and Virginia Power record in earnings any unrealized loss for a debt security when the manager intends to sell the debt security or it is more-likely-than-not that the manager will have to sell the debt security before recovery of its fair value up to its cost basis. If that is not the case, but the debt security is deemed to have experienced a credit loss, Dominion and Virginia Power record the credit loss in earnings and any remaining portion of the unrealized loss in AOCI. Credit losses are evaluated primarily by considering the credit ratings of the issuer, prior instances of non-performance by the issuer and other factors.
- *Equity securities and other investments*—Dominion's and Virginia Power's method of assessing other-than-temporary declines requires demonstrating the ability to hold individual securities for a period of time sufficient to allow for the anticipated recovery in their market value prior to the consideration of the other criteria mentioned above. Since Dominion and Virginia Power have limited ability to oversee the day-to-day management of nuclear decommissioning trust fund investments, they do not have the ability to ensure investments are held through an anticipated recovery period. Accordingly, they consider all equity and other securities as well as non-marketable investments held in nuclear decommissioning trusts with market values below their cost bases to be other-than-temporarily impaired.

Inventories

Materials and supplies and fossil fuel inventories are valued primarily using the weighted-average cost method. Stored gas inventory is valued using the weighted-average cost method, except for East Ohio gas distribution operations, which are valued using the LIFO method. Under the LIFO method, current stored gas inventory was valued at $13 million and $24 million at December 31, 2016 and December 31, 2015, respectively. Based on the average price of gas purchased during 2016 and 2015, the cost of replacing the current portion of stored gas inventory exceeded the amount stated on a LIFO basis by $55 million and $109 million, respectively.

Gas Imbalances

Natural gas imbalances occur when the physical amount of natural gas delivered from, or received by, a pipeline system or storage facility differs from the contractual amount of natural gas delivered or received. Dominion and Dominion Gas value these imbalances due to, or from, shippers and operators at an appropriate index price at period end, subject to the terms of its tariff for regulated entities. Imbalances are primarily settled in-kind. Imbalances due to Dominion from other parties are reported in other current assets and imbalances that Dominion and Dominion Gas owe to other parties are reported in other current liabilities in the Consolidated Balance Sheets.

Goodwill

Dominion and Dominion Gas evaluate goodwill for impairment annually as of April 1 and whenever an event occurs or circumstances change in the interim that would more-likely-than-not reduce the fair value of a reporting unit below its carrying amount.

New Accounting Standards

Revenue Recognition

In May 2014, the FASB issued revised accounting guidance for revenue recognition from contracts with customers. The core principle of this revised accounting guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments in this update also require disclosure of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. For the Companies, the revised accounting guidance is effective for interim and annual periods beginning January 1, 2018. The Companies have completed their preliminary evaluations of the impact of this guidance and, pending evaluation of the items discussed below, expect no significant impact on their results of operations. Now that their preliminary evaluations are complete, the Companies will expand the scope of their assessment to include all contracts with customers. In addition, the Companies are considering certain issues that could potentially change the accounting for certain transactions. Among the issues being considered are accounting for contributions in aid of construction, recognition of revenue when collectability is in question, recognition of revenue in contracts with variable consideration, accounting for alternative revenue programs, and the capitalization of costs to acquire new contracts. The Companies plan on applying the standard using the modified retrospective method as opposed to the full retrospective method.

Financial Instruments

In January 2016, the FASB issued revised accounting guidance for the recognition, measurement, presentation and disclosure of financial instruments. Most notably the update revises the accounting for equity securities, except for those accounted for under the equity method of accounting or resulting in consolidation, by requiring equity securities to be measured at fair value with the changes in fair value recognized in net income. However, an entity may measure equity investments that do not have a readily determinable fair value at cost minus impairment, if any, plus changes from observable price changes in orderly transactions for the identical or a similar investment of the same issuer. The guidance also simplifies the impairment assessment of equity investments without readily determinable fair values, revises the presentation of financial assets and liabilities and amends certain disclosure requirements associated with the fair value of financial instruments. The guidance is effective for the Companies' interim and annual reporting periods beginning January 1, 2018, with a cumulative-effect adjustment to the balance sheet. Amendments related to equity securities without readily determinable fair values are to be applied prospectively to such investments that exist as of the date of adoption.

Net realized and unrealized gains and losses (including any other-than-temporary impairments) on equity securities subject to cost-based regulation will not be impacted by the adoption of this standard. For all other available for sale equity securities, unrealized gains and losses currently recorded through other comprehensive income will be recognized in net income upon the adoption of this standard.

Leases

In February 2016, the FASB issued revised accounting guidance for the recognition, measurement, presentation and disclosure of leasing arrangements. The update requires that a liability and corresponding right-of-use asset are recorded on the balance sheet for all leases, including those leases currently classified as operating leases, while also refining the definition of a lease. In addition lessees will be required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. Lessor accounting remains largely unchanged.

The guidance is effective for the Companies' interim and annual reporting periods beginning January 1, 2019, although it can be early adopted, with a modified retrospective approach, which requires lessees and lessors to recognize and measure leases at the beginning of the earliest period presented for leases that commenced prior to the date of adoption. The Companies are currently in the preliminary stages of evaluating the impact of this guidance on their financial position and plan to complete their initial assessment in 2017. The Companies expect to elect the practical expedients, which would require no reassessment of whether existing contracts are or contain leases as well as no reassessment of lease classification for existing leases. While the Companies cannot quantify the impact until their assessment is complete, the Companies believe the adoption could have a material impact to the Companies' financial position.

Derecognition and Partial Sales of Nonfinancial Assets

In February 2017, the FASB issued revised accounting guidance clarifying the scope of asset derecognition guidance and accounting for partial sales of nonfinancial assets. The guidance is effective for Dominion's interim and annual reporting periods beginning January 1, 2018, and Dominion may elect to apply the update under the full retrospective method or the modified retrospective method. Dominion is currently evaluating the impacts of the revised accounting guidance on its consolidated financial statements and disclosures.

Note 3. Acquisitions and Dispositions

Dominion

Acquisition of Dominion Questar

In September 2016, Dominion completed the Dominion Questar Combination and Dominion Questar became a wholly-owned subsidiary of Dominion. Dominion Questar, a Rockies-based integrated natural gas company, included Questar Gas, Wexpro and Questar Pipeline at closing. Questar Gas has regulated gas distribution operations in Utah, southwestern Wyoming and southeastern Idaho. Wexpro develops and produces natural gas from reserves supplied to Questar Gas under a cost-of-service framework. Questar Pipeline provides FERC-regulated interstate natural gas transportation and storage services in Utah, Wyoming and western Colorado. The Dominion Questar Combination provides Dominion with pipeline infrastructure that provides a principal source of gas supply to Western states. Dominion Questar's regulated businesses also provide further balance between Dominion's electric and gas operations.

In accordance with the terms of the Dominion Questar Combination, at closing, each share of issued and outstanding Dominion Questar common stock was converted into the right to receive $25.00 per share in cash. The total consideration was $4.4 billion based on 175.5 million shares of Dominion Questar outstanding at closing.

Dominion financed the Dominion Questar Combination through the: (1) August 2016 issuance of $1.4 billion of 2016 Equity Units, (2) August 2016 issuance of $1.3 billion of senior notes, (3) September 2016 borrowing of $1.2 billion under a term loan agreement and (4) $500 million of the proceeds from the April 2016 issuance of common stock. See Notes 17 and 19 for more information.

Purchase Price Allocation

Dominion Questar's assets acquired and liabilities assumed were measured at estimated fair value at the closing date and are included in the Dominion Energy operating segment. The majority of operations acquired are subject to the rate-setting authority of FERC, as well as the Utah Commission and/or the Wyoming Commission and therefore are accounted for pursuant to ASC 980, *Regulated Operations*. The fair values of Dominion Questar's assets and liabilities subject to rate-setting and cost recovery provisions provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. As such, the fair values of these assets and liabilities equal their carrying values. Accordingly, neither the assets and liabilities acquired, nor the pro forma financial information, reflect any adjustments related to these amounts.

The fair value of Dominion Questar's assets acquired and liabilities assumed that are not subject to the rate-setting provisions discussed above was determined using the income approach. In addition, the fair value of Dominion Questar's 50% interest in White River Hub, accounted for under the equity method, was determined using the market approach and income approach. The valuations are considered Level 3 fair value measurements due to the use of significant judgmental and unobservable inputs, including projected timing and amount of future cash flows and discount rates reflecting risk inherent in the future cash flows and future market prices.

The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill at the closing date. The goodwill reflects the value associated with enhancing Dominion's regulated portfolio of businesses, including the expected increase in demand for low-carbon, natural gas-fired generation in the Western states and the expected continued growth of rate-regulated businesses located in a defined service area with a stable regulatory environment. The goodwill recognized is not deductible for income tax purposes, and as such, no deferred taxes have been recorded related to goodwill.

The table below shows the preliminary allocation of the purchase price to the assets acquired and liabilities assumed at closing. The allocation is subject to change during the remainder of the measurement period, which ends one year from the closing date, as additional information is obtained about the facts and circumstances that existed at the closing date. Any material adjustments to provisional amounts identified during the measurement period will be recognized and disclosed in the reporting period in which the adjustment amounts are determined. During the fourth quarter, certain modifications were made to preliminary valuation amounts for acquired property, plant and equipment, current liabilities, and deferred income taxes, resulting in a $6 million net decrease to goodwill, which relate primarily to the sale of Questar Fueling Company in December 2016 as further described in the *Sale of Questar Fueling Company.*

	Amount
(millions)	
Total current assets	$ 224
Investments[(1)]	58
Property, plant and equipment[(2)]	4,131
Goodwill	3,105
Total deferred charges and other assets, excluding goodwill	75
Total Assets	7,593
Total current liabilities[(3)]	793
Long-term debt[(4)]	963
Deferred income taxes	801
Regulatory liabilities	259
Asset retirement obligations	160
Other deferred credits and other liabilities	220
Total Liabilities	3,196
Total estimated purchase price	$4,397

(1) Includes $40 million for an equity method investment in White River Hub. The fair value adjustment on the equity method investment in White River Hub is considered to be equity method goodwill and is not amortized.
(2) Nonregulated property, plant and equipment, excluding land, will be depreciated over remaining useful lives primarily ranging from 9 to 18 years.
(3) Includes $301 million of short-term debt, of which no amounts remain outstanding at December 31, 2016, as well as a $250 million term loan which matures in August 2017 and bears interest at a variable rate.
(4) Unsecured senior and medium-term notes have maturities which range from 2017 to 2048 and bear interest at rates from 2.98% to 7.20%.

Regulatory Matters
The transaction required approval of Dominion Questar's shareholders, clearance from the Federal Trade Commission under the Hart-Scott-Rodino Act and approval from both the Utah Commission and the Wyoming Commission. In February 2016, the Federal Trade Commission granted antitrust approval of the Dominion Questar Combination under the Hart-Scott-Rodino Act. In May 2016, Dominion Questar's shareholders voted to approve the Dominion Questar Combination. In August 2016 and September 2016, approvals were granted by the Utah Commission and the Wyoming Commission, respectively.
Information regarding the transaction was also provided to the Idaho Public Utilities Commission, who acknowledged the Dominion Questar Combination in October 2016, and directed Dominion Questar to notify the Idaho Public Utilities Commission when it makes filings with the Utah Commission.

With the approval of the Dominion Questar Combination in Utah and Wyoming, Dominion agreed to the following:
- Contribution of $75 million to Dominion Questar's qualified and non-qualified defined-benefit pension plans and its other post-employment benefit plans within six months of the closing date. This contribution was made in January 2017.
- Increasing Dominion Questar's historical level of corporate contributions to charities by $1 million per year for at least five years.
- Withdrawal of Questar Gas' general rate case filed in July 2016 with the Utah Commission and agreement to not file a general rate case with the Utah Commission to adjust its base distribution non-gas rates prior to July 2019, unless otherwise ordered by the Utah Commission. In addition, Questar Gas agreed not to file a general rate case with the Wyoming Commission with a requested rate effective date earlier than January 2020. Questar Gas' ability to adjust rates through various riders is not affected.

Results of Operations and Pro Forma Information
The impact of the Dominion Questar Combination on Dominion's operating revenue and net income attributable to Dominion in the Consolidated Statements of Income for the twelve months ended December 31, 2016 was an increase of $379 million and $73 million, respectively.

Dominion incurred transaction and transition costs, of which $58 million was recorded in other operations and maintenance expense for the twelve months ended December 31, 2016, and $16 million was recorded in interest and related charges for the twelve months ended December 31, 2016, in Dominion's Consolidated Statements of Income. These costs consist of the amortization of financing costs, the charitable contribution commitment described above, employee-related expenses, professional fees, and other miscellaneous costs.

The following unaudited pro forma financial information reflects the consolidated results of operations of Dominion assuming the Dominion Questar Combination had taken place on January 1, 2015. The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or the future consolidated results of operations of the combined company.

	Twelve Months Ended December 31,	
	2016[(1)]	2015
(millions, except EPS)		
Operating Revenue	$12,497	$12,818
Net Income	2,300	2,108
Earnings Per Common Share – Basic	$ 3.73	$ 3.56
Earnings Per Common Share – Diluted	$ 3.73	$ 3.55

(1) Amounts include adjustments for non-recurring costs directly related to the Dominion Questar Combination.

Contribution of Questar Pipeline to Dominion Midstream
In October 2016, Dominion entered into the Contribution Agreement under which Dominion contributed Questar Pipeline to Dominion Midstream. Upon closing of the agreement on December 1, 2016, Dominion Midstream became the owner of

all of the issued and outstanding membership interests of Questar Pipeline in exchange for consideration consisting of Dominion Midstream common and convertible preferred units with a combined value of $467 million and cash payment of $823 million, $300 million of which is considered a debt-financed distribution, for a total of $1.3 billion. In addition, under the terms of the Contribution Agreement, Dominion Midstream repurchased 6,656,839 common units from Dominion, and repaid its $301 million promissory note to Dominion in December 2016. The cash proceeds from these transactions were utilized in December 2016 to repay the $1.2 billion term loan agreement borrowed in September 2016. Since Dominion consolidates Dominion Midstream for financial reporting purposes, the transactions associated with the Contribution Agreement were eliminated upon consolidation. See Note 5 for the tax impacts of the transactions.

Sale of Questar Fueling Company
In December 2016, Dominion completed the sale of Questar Fueling Company. The proceeds from the sale were $28 million, net of transaction costs. No gain or loss was recorded in Dominion's Consolidated Statements of Income, as the sale resulted in measurement period adjustments to the net assets acquired of Dominion Questar. See the *Purchase Price Allocation* section above for additional details on the measurement period adjustments recorded.

Wholly-Owned Merchant Solar Projects

Acquisitions
The following table presents significant completed acquisitions of wholly-owned merchant solar projects by Dominion. Long-term power purchase, interconnection and operation and maintenance agreements have been executed for all of the projects. Dominion has claimed federal investment tax credits on the projects. These projects are included in the Dominion Generation operating segment.

Completed Acquisition Date	Seller	Number of Projects	Project Location	Project Name(s)	Initial Acquisition Cost (millions)(1)	Project Cost (millions)(2)	Date of Commercial Operations	MW Capacity
March 2014	Recurrent Energy Development Holdings, LLC	6	California	Camelot, Kansas, Kent South, Old River One, Adams East, Columbia 2	$ 50	$428	Fourth quarter 2014	139
November 2014	CSI Project Holdco, LLC	1	California	West Antelope	79	79	November 2014	20
December 2014	EDF Renewable Development, Inc.	1	California	CID	71	71	January 2015	20
April 2015	EC&R NA Solar PV, LLC	1	California	Alamo	66	66	May 2015	20
April 2015	EDF Renewable Development, Inc.	3	California	Cottonwood(3)	106	106	May 2015	24
June 2015	EDF Renewable Development, Inc.	1	California	Catalina 2	68	68	July 2015	18
July 2015	SunPeak Solar, LLC	1	California	Imperial Valley 2	42	71	August 2015	20
November 2015	EC&R NA Solar PV, LLC	1	California	Maricopa West	65	65	December 2015	20
November 2015	Community Energy, Inc.	1	Virginia	Amazon Solar Farm U.S. East	34	212	October 2016	80

(1) The purchase price was primarily allocated to Property, Plant and Equipment.
(2) Includes acquisition cost.
(3) One of the projects, Marin Carport, began commercial operations in 2016.

In addition during 2016, Dominion acquired 100% of the equity interests of seven solar projects in Virginia, North Carolina and South Carolina for an aggregate purchase price of $32 million, all of which was allocated to property, plant and equipment. The projects are expected to cost approximately $425 million in total once constructed, including initial acquisition costs, and to generate approximately 221 MW combined. One of the projects commenced commercial operations in 2016 and the remaining projects are expected to begin commercial operations in 2017.

In August 2016, Dominion entered into an agreement to acquire 100% of the equity interests of two solar projects in California from Solar Frontier Americas Holding LLC for approximately $128 million in cash. The acquisition is expected to close prior to both projects commencing operations, which is expected by the end of 2017. The projects are expected to cost approximately $130 million once constructed, including the initial acquisition cost, and to generate approximately 50 MW combined.

In September 2016, Dominion entered into an agreement to acquire 100% of the equity interests of a solar project in Virginia from Community Energy Solar, LLC. The acquisition is expected to close during the first quarter of 2017, prior to the project commencing operations by the end of 2017, for an amount to be determined based on the costs incurred through closing. The project is expected to cost approximately $210 million once constructed, including the initial acquisition cost, and to generate approximately 100 MW.

In January 2017, Dominion entered into an agreement to acquire 100% of the equity interests of a solar project in North Carolina from Cypress Creek Renewables, LLC for $154 million in cash. The acquisition is expected to close during the second quarter of 2017, prior to the project commencing commercial operations, which is expected by the end of the third quarter of 2017. The project is expected to cost $160 million once constructed, including the initial acquisition cost, and to generate approximately 79 MW.

Sale of Interest in Merchant Solar Projects
In September 2015, Dominion signed an agreement to sell a noncontrolling interest (consisting of 33% of the equity interests) in all of its then currently wholly-owned merchant solar projects, 24 solar projects totaling 425 MW, to SunEdison, including projects discussed in the table above. In December 2015, the sale of interest in 15 of the solar projects closed for $184 million with the sale of interest in the remaining projects completed in January 2016 for $117 million. Upon closing, SunEdison sold its interest in these projects to Terra Nova Renewable Partners. Terra Nova Renewable Partners has a future option to buy all or a portion of Dominion's remaining 67% ownership in the projects upon the occurrence of certain events, none of which are expected to occur in 2017.

Non-Wholly-Owned Merchant Solar Projects

Acquisitions of Four Brothers and Three Cedars
In June 2015, Dominion acquired 50% of the units in Four Brothers from SunEdison for $64 million of consideration, consisting of $2 million in cash and a $62 million payable. Dominion has no remaining obligation related to this payable as of December 31, 2016. Four Brothers operates four solar projects located in Utah, which produce and sell electricity and renewable energy credits. The facilities began commercial operations during the third quarter of 2016, generating 320 MW, at a cost of approximately $670 million.

In September 2015, Dominion acquired 50% of the units in Three Cedars from SunEdison for $43 million of consideration, consisting of $6 million in cash and a $37 million payable. As of

December 31, 2016, a $2 million payable is included in other current liabilities in Dominion's Consolidated Balance Sheets. Three Cedars operates three solar projects located in Utah, which produce and sell electricity and renewable energy credits. The facilities began commercial operations during the third quarter of 2016, generating 210 MW, at a cost of approximately $450 million.

The Four Brothers and Three Cedars facilities operate under long-term power purchase, interconnection and operation and maintenance agreements. Dominion will claim 99% of the federal investment tax credits on the projects.

Dominion owns 50% of the voting interests in Four Brothers and Three Cedars and has a controlling financial interest over the entities through its rights to control operations. The allocation of the $64 million purchase price for Four Brothers resulted in $89 million of property, plant and equipment and $25 million of noncontrolling interest. The allocation of the $43 million purchase price for Three Cedars resulted in $65 million of property, plant and equipment and $22 million of noncontrolling interest. The noncontrolling interest for each entity was measured at fair value using the discounted cash flow method, with the primary components of the valuation being future cash flows (both incoming and outgoing) and the discount rate. Dominion determined its discount rate based on the cost of capital a utility-scale investor would expect, as well as the cost of capital an individual project developer could achieve via a combination of nonrecourse project financing and outside equity partners. The acquired assets of Four Brothers and Three Cedars are included in the Dominion Generation operating segment.

Dominion has assumed the majority of the agreements to provide administrative and support services in connection with operations and maintenance of the facilities and technical management services of the solar facilities. Costs related to services to be provided under these agreements were immaterial for the years ended December 31, 2016 and 2015. Subsequent to Dominion's acquisition of Four Brothers and Three Cedars, SunEdison made contributions to Four Brothers and Three Cedars of $292 million in aggregate through December 31, 2016, which are reflected as noncontrolling interests in the Consolidated Balance Sheets.

In November 2016, NRG acquired the 50% of units in Four Brothers and Three Cedars previously held by SunEdison.

Dominion Midstream Acquisition of Interest in Iroquois

In September 2015, Dominion Midstream acquired from NG and NJNR a 25.93% noncontrolling partnership interest in Iroquois, which owns and operates a 416-mile, FERC-regulated natural gas transmission pipeline in New York and Connecticut. In exchange for this partnership interest, Dominion Midstream issued 8.6 million common units representing limited partnership interests in Dominion Midstream (6.8 million common units to NG for its 20.4% interest and 1.8 million common units to NJNR for its 5.53% interest). The investment was recorded at $216 million based on the value of Dominion Midstream's common units at closing. These common units are reflected as noncontrolling interest in Dominion's Consolidated Financial Statements. Dominion Midstream's noncontrolling partnership interest is reflected in the Dominion Energy operating segment. In addition to this acquisition, Dominion Gas currently holds a 24.07% noncontrolling partnership interest in Iroquois. Dominion Midstream and Dominion Gas each account for their interest in Iroquois as an equity method investment. See Notes 9 and 15 for more information regarding Iroquois.

Acquisition of DCG

In January 2015, Dominion completed the acquisition of 100% of the equity interests of DCG from SCANA Corporation for $497 million in cash, as adjusted for working capital. DCG owns and operates nearly 1,500 miles of FERC-regulated interstate natural gas pipeline in South Carolina and southeastern Georgia. This acquisition supports Dominion's natural gas expansion into the southeastern U.S. The allocation of the purchase price resulted in $277 million of net property, plant and equipment, $250 million of goodwill, of which approximately $225 million is expected to be deductible for income tax purposes, and $38 million of regulatory liabilities. The goodwill reflects the value associated with enhancing Dominion's regulated gas position, economic value attributable to future expansion projects as well as increased opportunities for synergies. The acquired assets of DCG are included in the Dominion Energy operating segment.

On March 24, 2015, DCG converted to a limited liability company under the laws of South Carolina and changed its name from Carolina Gas Transmission Corporation to DCG. On April 1, 2015, Dominion contributed 100% of the issued and outstanding membership interests of DCG to Dominion Midstream in exchange for total consideration of $501 million, as adjusted for working capital. Total consideration to Dominion consisted of the issuance of a two-year, $301 million senior unsecured promissory note payable by Dominion Midstream at an annual interest rate of 0.6%, and 5,112,139 common units, valued at $200 million, representing limited partner interests in Dominion Midstream. The number of units was based on the volume weighted average trading price of Dominion Midstream's common units for the ten trading days prior to April 1, 2015, or $39.12 per unit. Since Dominion consolidates Dominion Midstream for financial reporting purposes, this transaction was eliminated upon consolidation and did not impact Dominion's financial position or cash flows.

Sale of Electric Retail Energy Marketing Business

In March 2014, Dominion completed the sale of its electric retail energy marketing business. The proceeds were $187 million, net of transaction costs. The sale resulted in a gain, subject to post-closing adjustments, of $100 million ($57 million after-tax) net of a $31 million write-off of goodwill, and is included in other operations and maintenance expense in Dominion's Consolidated Statements of Income. The sale of the electric retail energy marketing business did not qualify for discontinued operations classification.

Virginia Power

Acquisition of Solar Project

In December 2015, Virginia Power completed the acquisition of 100% of a solar development project in North Carolina from Morgans Corner for $47 million, all of which was allocated to property, plant and equipment. The project was placed into service in December 2015 with a total cost of $49 million, including the initial acquisition cost. The project generates 20 MW. The output generated by the project is used to meet a ten year non-jurisdictional supply agreement with the U.S. Navy, which has the unilateral option to extend for an additional ten years. In October 2015, the North Carolina Commission granted the transfer of the existing CPCN from Morgans Corner to Virginia Power. The acquired asset is included in the Virginia Power Generation operating segment.

Dominion and Dominion Gas

Blue Racer

See Note 9 for a discussion of transactions related to Blue Racer.

Assignments of Shale Development Rights

See Note 10 for a discussion of assignments of shale development rights.

Note 4. Operating Revenue

The Companies' operating revenue consists of the following:

Year Ended December 31,	**2016**	2015	2014
(millions)			
Dominion			
Electric sales:			
Regulated	**$ 7,348**	$ 7,482	$ 7,460
Nonregulated	**1,519**	1,488	1,839
Gas sales:			
Regulated	**500**	218	334
Nonregulated	**354**	471	751
Gas transportation and storage	**1,636**	1,616	1,543
Other	**380**	408	509
Total operating revenue	**$11,737**	$11,683	$12,436
Virginia Power			
Regulated electric sales	**$ 7,348**	$ 7,482	$ 7,460
Other	**240**	140	119
Total operating revenue	**$ 7,588**	$ 7,622	$ 7,579
Dominion Gas			
Gas sales:			
Regulated	**$ 119**	$ 122	$ 209
Nonregulated	**13**	10	26
Gas transportation and storage	**1,307**	1,366	1,353
NGL revenue	**62**	93	212
Other	**137**	125	98
Total operating revenue	**$ 1,638**	$ 1,716	$ 1,898

Note 5. Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws involves uncertainty, since tax authorities may interpret the laws differently. The Companies are routinely audited by federal and state tax authorities. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows, and adjustments to tax-related assets and liabilities could be material.

In December 2015, U.S. federal legislation was enacted, providing an extension of the 50% bonus depreciation allowance for qualifying expenditures incurred in 2015, 2016 and 2017, and a phasing down of the allowance to 40% in 2018 and 30% in 2019 and expiration thereafter. In addition, the legislation extends the 30% investment tax credit for qualifying expenditures incurred through 2019 and provides a phase down of the credit to 26% in 2020, 22% in 2021 and 10% in 2022 and thereafter.

Continuing Operations

Details of income tax expense for continuing operations including noncontrolling interests were as follows:

	Dominion			Virginia Power			Dominion Gas		
Year Ended December 31,	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
(millions)									
Current:									
Federal	**$ (155)**	$ (24)	$ (11)	**$168**	$316	$ 85	**$ (27)**	$ 90	$ 86
State	**85**	75	14	**90**	92	67	**4**	30	32
Total current expense (benefit)	**(70)**	51	3	**258**	408	152	**(23)**	120	118
Deferred:									
Federal									
Taxes before operating loss carryforwards and investment tax credits	**1,050**	384	956	**435**	154	381	**239**	156	192
Tax utilization (benefit) of operating loss carryforwards	**(161)**	539	(352)	**(2)**	96	—	**(2)**	6	—
Investment tax credits	**(248)**	(134)	(152)	**(25)**	(11)	—	**—**	—	—
State	**50**	66	(2)	**27**	13	16	**1**	1	24
Total deferred expense	**691**	855	450	**435**	252	397	**238**	163	216
Investment tax credit—gross deferral	**35**	—	—	**35**	—	—	**—**	—	—
Investment tax credit—amortization	**(1)**	(1)	(1)	**(1)**	(1)	(1)	**—**	—	—
Total income tax expense	**$ 655**	$ 905	$ 452	**$727**	$659	$548	**$215**	$283	$334

In 2016, Dominion realized a taxable gain resulting from the contribution of Questar Pipeline to Dominion Midstream. The contribution and related transactions resulted in increases in the tax basis of Questar Pipeline's assets and the number of Dominion Midstream's common and convertible preferred units held by noncontrolling interests. The direct tax effects of the transactions included a provision for current income taxes ($212 million) and an offsetting benefit for deferred income taxes ($96 million) and were charged to common shareholders' equity. The federal tax liability was reduced by $129 million of tax credits generated in 2016 that otherwise would have resulted in additional credit carryforwards and a $17 million benefit provided by the domestic production activities deduction. These benefits, as indirect effects of the contribution transaction, are reflected in Dominion's current federal income tax expense.

In 2015, Dominion's current federal income tax benefit includes the recognition of a $20 million benefit related to a carryback to be filed for nuclear decommissioning expenditures included in its 2014 net operating loss.

For continuing operations including noncontrolling interests, the statutory U.S. federal income tax rate reconciles to the Companies' effective income tax rate as follows:

	Dominion			Virginia Power			Dominion Gas		
Year Ended December 31,	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
U.S. statutory rate	**35.0%**	35.0%	35.0%	**35.0%**	35.0%	35.0%	**35.0%**	35.0%	35.0%
Increases (reductions) resulting from:									
State taxes, net of federal benefit	**2.4**	3.7	—	**3.8**	3.9	3.8	**0.5**	2.7	4.4
Investment tax credits	**(11.7)**	(4.7)	(8.6)	**—**	(0.6)	—	**—**	—	—
Production tax credits	**(0.8)**	(0.8)	(1.2)	**(0.5)**	(0.6)	(0.6)	**—**	—	—
Valuation allowances	**1.2**	(0.3)	0.7	**0.1**	—	—	**—**	—	—
AFUDC—equity	**(0.6)**	(0.3)	—	**(0.6)**	(0.6)	—	**(0.2)**	0.2	—
Legislative change	**(0.6)**	(0.1)	—	**—**	—	—	**—**	—	—
Employee stock ownership plan deduction	**(0.6)**	(0.6)	(0.9)	**—**	—	—	**—**	—	—
Other, net	**(1.4)**	0.1	0.4	**(0.4)**	0.6	0.8	**0.1**	0.3	0.1
Effective tax rate	**22.9%**	32.0%	25.4%	**37.4%**	37.7%	39.0%	**35.4%**	38.2%	39.5%

In 2016, Dominion's effective tax rate reflects a valuation allowance on a state credit not expected to be utilized by a Dominion subsidiary which files a separate state return.

The Companies' deferred income taxes consist of the following:

	Dominion		Virginia Power		Dominion Gas	
At December 31,	**2016**	2015	**2016**	2015	**2016**	2015
(millions)						
Deferred income taxes:						
Total deferred income tax assets	**$ 1,827**	$ 1,152	**$ 268**	$ 164	**$ 126**	$ 129
Total deferred income tax liabilities	**10,381**	8,552	**5,323**	4,805	**2,564**	2,343
Total net deferred income tax liabilities	**$ 8,554**	$ 7,400	**$5,055**	$4,641	**$2,438**	$2,214
Total deferred income taxes:						
Plant and equipment, primarily depreciation method and basis differences	**$ 7,782**	$ 6,299	**$4,604**	$4,133	**$1,726**	$1,541
Nuclear decommissioning	**1,240**	1,158	**406**	378	**—**	—
Deferred state income taxes	**747**	646	**321**	302	**204**	205
Federal benefit of deferred state income taxes	**(261)**	(226)	**(112)**	(106)	**(71)**	(72)
Deferred fuel, purchased energy and gas costs	**(25)**	(1)	**(29)**	(3)	**4**	1
Pension benefits	**155**	291	**(138)**	(99)	**646**	613
Other postretirement benefits	**(68)**	(15)	**49**	30	**(6)**	(7)
Loss and credit carryforwards	**(1,547)**	(1,004)	**(88)**	(53)	**(5)**	(4)
Valuation allowances	**135**	73	**3**	—	**—**	—
Partnership basis differences	**688**	367	**—**	—	**43**	41
Other	**(292)**	(188)	**39**	59	**(103)**	(104)
Total net deferred income tax liabilities	**$ 8,554**	$ 7,400	**$5,055**	$4,641	**$2,438**	$2,214
Deferred Investment Tax Credits – Regulated Operations	**48**	14	**48**	13	**—**	—
Total Deferred Taxes and Deferred Investment Tax Credits	**$ 8,602**	$ 7,414	**$5,103**	$4,654	**$2,438**	$2,214

At December 31, 2016, Dominion had the following deductible loss and credit carryforwards:

	Deductible Amount	Deferred Tax Asset	Valuation Allowance	Expiration Period
(millions)				
Federal losses	**$1,060**	**$ 358**	**$ —**	**2031-2036**
Federal investment credits	**—**	**708**	**—**	**2033-2036**
Federal production credits	**—**	**102**	**—**	**2031-2036**
Other federal credits	**—**	**48**	**—**	**2031-2036**
State losses	**1,383**	**102**	**(59)**	**2018-2034**
State minimum tax credits	**—**	**135**	**—**	**No expiration**
State investment and other credits	**—**	**94**	**(76)**	**2017-2027**
Total		**$1,547**	**$(135)**	

At December 31, 2016, Virginia Power had the following deductible loss and credit carryforwards:

	Deductible Amount	Deferred Tax Asset	Valuation Allowance	Expiration Period
(millions)				
Federal losses	**$12**	**$ 3**	**$—**	**2031-2034**
Federal investment credits	**—**	**40**	**—**	**2034-2036**
Federal production and other credits	**—**	**35**	**—**	**2031-2036**
State investment credits	**—**	**10**	**(3)**	**2018-2024**
Total		**$88**	**$(3)**	

At December 31, 2016, Dominion Gas had the following deductible loss and credit carryforwards:

	Deductible Amount	Deferred Tax Asset	Valuation Allowance	Expiration Period
(millions)				
Federal losses	**$14**	**$4**	**$—**	**2031-2036**
Other federal credits	**—**	**1**	**—**	**2032-2035**
Total		**$5**	**$—**	

A reconciliation of changes in the Companies' unrecognized tax benefits follows:

	Dominion			Virginia Power			Dominion Gas		
	2016	2015	2014	**2016**	2015	2014	**2016**	2015	2014
(millions)									
Balance at January 1	**$103**	$145	$222	**$12**	$ 36	$ 39	**$ 29**	$29	$29
Increases-prior period positions	**9**	2	24	**4**	—	2	**1**	—	—
Decreases-prior period positions	**(44)**	(40)	(26)	**(3)**	(25)	(16)	**(19)**	—	—
Increases-current period positions	**6**	8	16	**—**	1	11	**—**	—	—
Settlements with tax authorities	**(8)**	(5)	—	**—**	—	—	**(4)**	—	—
Expiration of statutes of limitations	**(2)**	(7)	(91)	**—**	—	—	**—**	—	—
Balance at December 31	**$ 64**	$103	$145	**$13**	$ 12	$ 36	**$ 7**	$29	$29

Certain unrecognized tax benefits, or portions thereof, if recognized, would affect the effective tax rate. Changes in these unrecognized tax benefits may result from remeasurement of amounts expected to be realized, settlements with tax authorities and expiration of statutes of limitations. For Dominion and its subsidiaries, these unrecognized tax benefits were $45 million, $69 million and $77 million at December 31, 2016, 2015 and 2014, respectively. For Dominion, the change in these unrecognized tax benefits decreased income tax expense by $18 million, $6 million and $47 million in 2016, 2015 and 2014, respectively. For Virginia Power, these unrecognized tax benefits were $9 million at December 31, 2016 and $8 million at December 31, 2015 and 2014. For Virginia Power, the change in these unrecognized tax benefits increased income tax expense by $1 million in 2016 and affected income tax expense by less than $1 million in 2015 and 2014. For Dominion Gas, these unrecognized tax benefits were $5 million at December 31, 2016 and $19 million at December 31, 2015 and 2014. For Dominion Gas, the change in these unrecognized tax benefits decreased income tax expense by $11 million in 2016 and affected income tax expense by less than $1 million in 2015 and 2014.

Effective for its 2014 tax year, Dominion was accepted into the CAP. Through the CAP, Dominion has the opportunity to resolve complex tax matters with the IRS before filing its federal income tax returns, thus achieving certainty for such tax return filing positions agreed to by the IRS. The IRS has completed its audit of tax years 2013, 2014 and 2015, for which the statute of limitations has not yet expired. Although Dominion has not received a final letter indicating no changes to its taxable income for tax year 2015, no adjustments are expected. The IRS examination of tax year 2016 is ongoing.

It is reasonably possible that settlement negotiations and expiration of statutes of limitations could result in a decrease in unrecognized tax benefits in 2017 by up to $25 million for Dominion, $3 million for Virginia Power and $7 million for Dominion Gas. If such changes were to occur, other than revisions of the accrual for interest on tax underpayments and overpayments, earnings could increase by up to $20 million for Dominion, $3 million for Virginia Power and $5 million for Dominion Gas.

Otherwise, with regard to 2016 and prior years, Dominion, Virginia Power and Dominion Gas cannot estimate the range of reasonably possible changes to unrecognized tax benefits that may occur in 2017.

For each of the major states in which Dominion operates, the earliest tax year remaining open for examination is as follows:

State	Earliest Open Tax Year
Pennsylvania(1)	**2012**
Connecticut	**2013**
Virginia(2)	**2013**
West Virginia(1)	**2013**
New York(1)	**2007**

(1) Considered a major state for Dominion Gas' operations.
(2) Considered a major state for Virginia Power's operations.

The Companies are also obligated to report adjustments resulting from IRS settlements to state tax authorities. In addition, if Dominion utilizes operating losses or tax credits generated in years for which the statute of limitations has expired, such amounts are generally subject to examination.

NOTE 6. FAIR VALUE MEASUREMENTS

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. However, the use of a mid-market pricing convention (the mid-point between bid and ask prices) is permitted. Fair values are based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. This includes not only the credit standing of counterparties involved and the impact of credit enhancements but also the impact of the Companies' own nonperformance risk on their liabilities. Fair value measurements assume that the transaction occurs in the principal market for the asset or liability (the market with the most volume and activity for the asset or liability from the perspective of the reporting entity), or in the absence of a principal market, the most advantageous market for the asset or liability (the market in which the reporting entity would be able to maximize the amount received or minimize the amount paid). Dominion applies fair value measurements to certain assets and liabilities including commodity, interest rate, and foreign currency derivative instruments, and other investments including those held in nuclear decommissioning, Dominion's rabbi, pension and other postretirement benefit plan trusts, in accordance with the requirements discussed above. Virginia Power applies fair value measurements to certain assets and liabilities including commodity and interest rate derivative instruments and other investments including those held in the nuclear decommissioning trust, in accordance with the requirements discussed above. Dominion Gas applies fair value measurements to certain assets and liabilities including commodity, interest rate, and foreign currency derivative instruments and investments held in pension and other postretirement benefit plan trusts, in accordance with the requirements described above. The Companies apply credit adjustments to their derivative fair values in accordance with the requirements described above.

Inputs and Assumptions

The Companies maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. Fair value is based on actively-quoted market prices, if available. In the absence of actively-quoted market prices, price information is sought from external sources, including broker quotes and industry publications. When evaluating pricing information provided by brokers and other pricing services, the Companies consider whether the broker is willing and able to trade at the quoted price, if the broker quotes are based on an active market or an inactive market and the extent to which brokers are utilizing a particular model if pricing is not readily available. If pricing information from external sources is not available, or if the Companies believe that observable pricing is not indicative of fair value, judgment is required to develop the estimates of fair value. In those cases the Companies must estimate prices based on available historical and near-term future price information and certain statistical methods, including regression analysis, that reflect their market assumptions.

The Companies' commodity derivative valuations are prepared by Dominion's ERM department. The ERM department creates daily mark-to-market valuations for the Companies' derivative transactions using computer-based statistical models. The inputs that go into the market valuations are transactional information stored in the systems of record and market pricing information that resides in data warehouse databases. The majority of forward prices are automatically uploaded into the data warehouse databases from various third-party sources. Inputs obtained from third-party sources are evaluated for reliability considering the reputation, independence, market presence, and methodology used by the third-party. If forward prices are not available from third-party sources, then the ERM department models the forward prices based on other available market data. A team consisting of risk management and risk quantitative analysts meets each business day to assess the validity of market prices and mark-to-market valuations. During this meeting, the changes in mark-to-market valuations from period to period are examined and qualified against historical expectations. If any discrepancies are identified during this process, the mark-to-market valuations or the market pricing information is evaluated further and adjusted, if necessary.

For options and contracts with option-like characteristics where observable pricing information is not available from external sources, Dominion and Virginia Power generally use a modified Black-Scholes Model that considers time value, the volatility of the underlying commodities and other relevant assumptions when estimating fair value. Dominion and Virginia Power use other option models under special circumstances, including a Spread Approximation Model when contracts include different commodities or commodity locations and a Swing Option Model when contracts allow either the buyer or seller the ability to exercise within a range of quantities. For contracts with unique characteristics, the Companies may estimate fair value using a discounted cash flow approach deemed appropriate in the circumstances and applied consistently from period to period. For individual contracts, the use of different valuation models or assumptions could have a significant effect on the contract's estimated fair value.

The inputs and assumptions used in measuring fair value include the following:

For commodity derivative contracts:

- Forward commodity prices
- Transaction prices
- Price volatility
- Price correlation
- Volumes
- Commodity location
- Interest rates
- Credit quality of counterparties and the Companies
- Credit enhancements
- Time value

For interest rate derivative contracts:

- Interest rate curves
- Credit quality of counterparties and the Companies
- Notional value
- Credit enhancements
- Time value

For foreign currency derivative contracts:

- Foreign currency forward exchange rates
- Interest rates
- Credit quality of counterparties and the Companies
- Notional value
- Credit enhancements
- Time value

For investments:

- Quoted securities prices and indices
- Securities trading information including volume and restrictions
- Maturity
- Interest rates
- Credit quality

The Companies regularly evaluate and validate the inputs used to estimate fair value by a number of methods, including review and verification of models, as well as various market price verification procedures such as the use of pricing services and multiple broker quotes to support the market price of the various commodities and investments in which the Companies transact.

Levels

The Companies also utilize the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad levels:

- Level 1—Quoted prices (unadjusted) in active markets for identical assets and liabilities that they have the ability to access at the measurement date. Instruments categorized in Level 1 primarily consist of financial instruments such as certain exchange-traded derivatives, and exchange-listed equities, U.S. and international equity securities, mutual funds and certain Treasury securities held in nuclear decommissioning trust funds for Dominion and Virginia Power, benefit plan trust funds for Dominion and Dominion Gas, and rabbi trust funds for Dominion.
- Level 2—Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 primarily include commodity forwards and swaps, interest rate swaps, foreign currency swaps and cash and cash equivalents, corporate debt instruments, government securities and other fixed income investments held in nuclear decommissioning trust funds for Dominion and Virginia Power, benefit plan trust funds for Dominion and Dominion Gas and rabbi trust funds for Dominion.
- Level 3—Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 for the Companies consist of long-dated commodity derivatives, FTRs, certain natural gas and power options and other modeled commodity derivatives.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. In these cases, the lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability. Alternative investments, consisting of investments in partnerships, joint ventures and other alternative investments held in nuclear decommissioning and benefit plan trust funds, are generally valued using NAV based on the proportionate share of the fair value as determined by reference to the most recent audited fair value financial statements or fair value statements provided by the investment manager adjusted for any significant events occurring between the investment manager's and the Companies' measurement date. Alternative investments recorded at NAV are not classified in the fair value hierarchy.

For derivative contracts, the Companies recognize transfers among Level 1, Level 2 and Level 3 based on fair values as of the first day of the month in which the transfer occurs. Transfers out of Level 3 represent assets and liabilities that were previously classified as Level 3 for which the inputs became observable for classification in either Level 1 or Level 2. Because the activity and liquidity of commodity markets vary substantially between regions and time periods, the availability of observable inputs for substantially the full term and value of the Companies' over-the-counter derivative contracts is subject to change.

Level 3 Valuations

Fair value measurements are categorized as Level 3 when price or other inputs that are considered to be unobservable are significant to their valuations. Long-dated commodity derivatives are generally based on unobservable inputs due to the length of time to settlement and the absence of market activity and are therefore categorized as Level 3. FTRs are categorized as Level 3 fair value measurements because the only relevant pricing available comes from ISO auctions, which are generally not considered to be liquid markets. Other modeled commodity derivatives have unobservable inputs in their valuation, mostly due to non-transparent and illiquid markets.

The Companies enter into certain physical and financial forwards, futures, options and swaps, which are considered Level 3 as they have one or more inputs that are not observable and are significant to the valuation. The discounted cash flow method is used to value Level 3 physical and financial forwards and futures contracts. An option model is used to value Level 3 physical and financial options. The discounted cash flow model for forwards and futures calculates mark-to-market valuations based on forward market prices, original transaction prices, volumes, risk-free rate of return, and credit spreads. The option model calculates mark-to-market valuations using variations of the Black-Scholes option model. The inputs into the models are the forward market prices, implied price volatilities, risk-free rate of return, the option expiration dates, the option strike prices, the original sales prices, and volumes. For Level 3 fair value measurements, forward market prices, credit spreads and implied price volatilities are considered unobservable. The unobservable inputs are developed and substantiated using historical information, available market data, third-party data, and statistical analysis. Periodically, inputs to valuation models are reviewed and revised as needed, based on historical information, updated market data, market liquidity and relationships, and changes in third-party pricing sources.

The following table presents Dominion's quantitative information about Level 3 fair value measurements at December 31, 2016. The range and weighted average are presented in dollars for market price inputs and percentages for price volatility and credit spreads.

	Fair Value (millions)	Valuation Techniques	Unobservable Input	Range	Weighted Average[1]
Assets:					
Physical and Financial Forwards and Futures:					
Natural Gas[2]	**$ 70**	Discounted Cash Flow	Market Price (per Dth)[4]	(2) - 12	—
			Credit Spreads[5]	1% - 4%	2%
FTRs	**7**	Discounted Cash Flow	Market Price (per MWh)[4]	(9) - 7	1
Physical and Financial Options:					
Natural Gas	**3**	Option Model	Market Price (per Dth)[4]	2 - 7	3
			Price Volatility[6]	18% - 50%	24%
Electricity	**67**	Option Model	Market Price (per MWh)[4]	21 - 55	34
			Price Volatility[6]	14% - 104%	31%
Total assets	**$147**				
Liabilities:					
Physical and Financial Forwards and Futures:					
Natural Gas[2]	**$ 2**	Discounted Cash Flow	Market Price (per Dth)[4]	(2) - 4	4
Liquids[3]	**3**	Discounted Cash Flow	Market Price (per Gal)[4]	0 - 2	1
FTRs	**3**	Discounted Cash Flow	Market Price (per MWh)[4]	(9) - 3	—
Total liabilities	**$ 8**				

(1) Averages weighted by volume.
(2) Includes basis.
(3) Includes NGLs and oil.
(4) Represents market prices beyond defined terms for Levels 1 and 2.
(5) Represents credit spreads unrepresented in published markets.
(6) Represents volatilities unrepresented in published markets.

Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Inputs	Position	Change to Input	Impact on Fair Value Measurement
Market Price	Buy	Increase (decrease)	Gain (loss)
Market Price	Sell	Increase (decrease)	Loss (gain)
Price Volatility	Buy	Increase (decrease)	Gain (loss)
Price Volatility	Sell	Increase (decrease)	Loss (gain)
Credit Spread	Asset	Increase (decrease)	Loss (gain)

Nonrecurring Fair Value Measurements

DOMINION GAS

Natural Gas Assets

In the fourth quarter of 2014, Dominion Gas recorded an impairment charge of $9 million ($6 million after-tax) in other operations and maintenance expense in its Consolidated Statements of Income, to write off previously capitalized costs following the cancellation of a development project.

Recurring Fair Value Measurements

Fair value measurements are separately disclosed by level within the fair value hierarchy with a separate reconciliation of fair value measurements categorized as Level 3. Fair value disclosures for assets held in Dominion's and Dominion Gas' pension and other postretirement benefit plans are presented in Note 21.

Dominion

The following table presents Dominion's assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

(millions)	Level 1	Level 2	Level 3	Total
At December 31, 2016				
Assets:				
Derivatives:				
Commodity	**$ —**	**$ 115**	**$147**	**$ 262**
Interest rate	**—**	**17**	**—**	**17**
Investments[1]:				
Equity securities:				
U.S.	**2,913**	**—**	**—**	**2,913**
Fixed Income:				
Corporate debt instruments	**—**	**487**	**—**	**487**
Government securities	**424**	**614**	**—**	**1,038**
Cash equivalents and other	**5**	**—**	**—**	**5**
Total assets	**$3,342**	**$1,233**	**$147**	**$4,722**
Liabilities:				
Derivatives:				
Commodity	**$ —**	**$ 88**	**$ 8**	**$ 96**
Interest rate	**—**	**53**	**—**	**53**
Foreign currency	**—**	**6**	**—**	**6**
Total liabilities	**$ —**	**$ 147**	**$ 8**	**$ 155**
At December 31, 2015				
Assets:				
Derivatives:				
Commodity	$ 1	$ 249	$114	$ 364
Interest rate	—	24	—	24
Investments[1]:				
Equity securities:				
U.S.	2,625	—	—	2,625
Fixed Income:				
Corporate debt instruments	—	439	—	439
Government securities	458	574	—	1,032
Cash equivalents and other	2	2	—	4
Total assets	$3,086	$1,288	$114	$4,488
Liabilities:				
Derivatives:				
Commodity	$ —	$ 141	$ 19	$ 160
Interest rate	—	183	—	183
Total liabilities	$ —	$ 324	$ 19	$ 343

(1) Includes investments held in the nuclear decommissioning and rabbi trusts. Excludes $89 million and $101 million of assets at December 31, 2016 and 2015, respectively, measured at fair value using NAV (or its equivalent) as a practical expedient which are not required to be categorized in the fair value hierarchy.

The following table presents the net change in Dominion's assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

(millions)	**2016**	2015	2014
Balance at January 1,	**$ 95**	$107	$ (16)
Total realized and unrealized gains (losses):			
Included in earnings	**(35)**	(5)	97
Included in other comprehensive income (loss)	**—**	(9)	7
Included in regulatory assets/liabilities	**(39)**	(4)	109
Settlements	**38**	9	(88)
Purchases	**87**	—	—
Transfers out of Level 3	**(7)**	(3)	(2)
Balance at December 31,	**$139**	$ 95	$107
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets still held at the reporting date	**$ (1)**	$ 2	$ 6

The following table presents Dominion's gains and losses included in earnings in the Level 3 fair value category:

(millions)	Operating Revenue	Electric Fuel and Other Energy-Related Purchases	Purchased Gas	Total
Year Ended December 31, 2016				
Total gains (losses) included in earnings	**$—**	**$(35)**	**$—**	**$(35)**
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets/liabilities still held at the reporting date	**—**	**(1)**	**—**	**(1)**
Year Ended December 31, 2015				
Total gains (losses) included in earnings	$ 6	$(11)	$—	$ (5)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets/liabilities still held at the reporting date	1	1	—	2
Year Ended December 31, 2014				
Total gains (losses) included in earnings	$ 4	$ 97	$(4)	$ 97
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets/liabilities still held at the reporting date	4	1	1	6

Virginia Power

The following table presents Virginia Power's quantitative information about Level 3 fair value measurements at December 31, 2016. The range and weighted average are presented in dollars for market price inputs and percentages for price volatility and credit spreads.

	Fair Value (millions)	Valuation Techniques	Unobservable Input	Range	Weighted Average[1]
Assets:					
Physical and Financial Forwards and Futures:					
Natural gas[2]	**$ 68**	Discounted Cash Flow	Market Price (per Dth)[3]	(2) - 7	—
			Credit Spreads[4]	1% - 4%	2%
FTRs	**7**	Discounted Cash Flow	Market Price (per MWh)[3]	(9) - 7	1
Physical and Financial Options:					
Natural Gas	**3**	Option Model	Market Price (per Dth)[3]	2 - 7	3
			Price Volatility[5]	18% - 34%	24%
Electricity	**67**	Option Model	Market Price (per MWh)[3]	21 - 55	34
			Price Volatility[5]	14% - 104%	31%
Total assets	**$145**				
Liabilities:					
Physical and Financial Forwards and Futures:					
FTRs	**$ 2**	Discounted Cash Flow	Market Price (per MWh)[3]	(9) - 3	—
Total liabilities	**$ 2**				

(1) Averages weighted by volume.
(2) Includes basis.
(3) Represents market prices beyond defined terms for Levels 1 and 2.
(4) Represents credit spreads unrepresented in published markets.
(5) Represents volatilities unrepresented in published markets.

Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Inputs	Position	Change to Input	Impact on Fair Value Measurement
Market Price	Buy	Increase (decrease)	Gain (loss)
Market Price	Sell	Increase (decrease)	Loss (gain)
Price Volatility	Buy	Increase (decrease)	Gain (loss)
Price Volatility	Sell	Increase (decrease)	Loss (gain)
Credit Spread	Asset	Increase (decrease)	Loss (gain)

The following table presents Virginia Power's assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

	Level 1	Level 2	Level 3	Total
(millions)				
At December 31, 2016				
Assets:				
Derivatives:				
Commodity	**$ —**	**$ 43**	**$145**	**$ 188**
Interest rate	**—**	**6**	**—**	**6**
Investments(1):				
Equity securities:				
U.S.	**1,302**	**—**	**—**	**1,302**
Fixed Income:				
Corporate debt instruments	**—**	**277**	**—**	**277**
Government Securities	**136**	**291**	**—**	**427**
Total assets	**$1,438**	**$617**	**$145**	**$2,200**
Liabilities:				
Derivatives:				
Commodity	**$ —**	**$ 8**	**$ 2**	**$ 10**
Interest rate	**—**	**21**	**—**	**21**
Total liabilities	**$ —**	**$ 29**	**$ 2**	**$ 31**
At December 31, 2015				
Assets:				
Derivatives:				
Commodity	$ —	$ 13	$101	$ 114
Interest rate	—	13	—	13
Investments(1):				
Equity securities:				
U.S.	1,163	—	—	1,163
Fixed Income:				
Corporate debt instruments	—	238	—	238
Government Securities	180	254	—	434
Total assets	$1,343	$518	$101	$1,962
Liabilities:				
Derivatives:				
Commodity	$ —	$ 19	$ 8	$ 27
Interest rate	—	59	—	59
Total liabilities	$ —	$ 78	$ 8	$ 86

(1) Includes investments held in the nuclear decommissioning trust. Excludes $26 million and $34 million of assets at December 31, 2016 and 2015, respectively, measured at fair value using NAV (or its equivalent) as a practical expedient which are not required to be categorized in the fair value hierarchy.

The following table presents the net change in Virginia Power's assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

	2016	2015	2014
(millions)			
Balance at January 1,	**$ 93**	$102	$ (7)
Total realized and unrealized gains (losses):			
Included in earnings	**(35)**	(13)	96
Included in regulatory assets/liabilities	**(37)**	(5)	109
Settlements	**35**	13	(96)
Purchases	**87**	—	—
Transfers out of Level 3	**—**	(4)	—
Balance at December 31,	**$143**	$ 93	$102

The gains and losses included in earnings in the Level 3 fair value category were classified in electric fuel and other energy-related purchases expense in Virginia Power's Consolidated Statements of Income for the years ended December 31, 2016, 2015 and 2014. There were no unrealized gains and losses included in earnings in the Level 3 fair value category relating to assets/liabilities still held at the reporting date for the years ended December 31, 2016, 2015 and 2014.

Dominion Gas

The following table presents Dominion Gas' quantitative information about Level 3 fair value measurements at December 31, 2016. The range and weighted average are presented in dollars for market price inputs.

	Fair Value (millions)	Valuation Techniques	Unobservable Input	Range	Weighted Average(1)
Liabilities:					
Physical and Financial Forwards and Futures:					
NGLs	**$2**	Discounted Cash Flow	Market Price (per Gal)(2)	0 - 2	1
Total liabilities	**$2**				

(1) Averages weighted by volume.
(2) Represents market prices beyond defined terms for Levels 1 and 2.

Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Inputs	Position	Change to Input	Impact on Fair Value Measurement
Market Price	Buy	Increase (decrease)	Gain (loss)
Market Price	Sell	Increase (decrease)	Loss (gain)

The following table presents Dominion Gas' assets and liabilities for commodity, interest rate, and foreign currency derivatives that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

	Level 1	Level 2	Level 3	Total
(millions)				
At December 31, 2016				
Liabilities:				
Commodity	**$—**	**$ 3**	**$ 2**	**5**
Foreign currency	**—**	**6**	**—**	**6**
Total liabilities	**$—**	**$ 9**	**$ 2**	**$11**
At December 31, 2015				
Assets:				
Commodity	$—	$ 5	$ 6	$11
Total assets	$—	$ 5	$ 6	$11
Liabilities:				
Interest rate	$—	$14	$—	14
Total liabilities	$—	$14	$—	$14

The following table presents the net change in Dominion Gas' derivative assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

	2016	2015	2014
(millions)			
Balance at January 1,	**$ 6**	$ 2	$ (6)
Total realized and unrealized gains (losses):			
Included in earnings	**—**	1	2
Included in other comprehensive income (loss)	**—**	(5)	10
Settlements	**—**	(1)	(4)
Transfers out of Level 3	**(8)**	9	—
Balance at December 31,	**$(2)**	$ 6	$ 2

The gains and losses included in earnings in the Level 3 fair value category were classified in operating revenue in Dominion Gas' Consolidated Statements of Income for the years ended December 31, 2016, 2015 and 2014. There were no unrealized gains and losses included in earnings in the Level 3 fair value category relating to assets/liabilities still held at the reporting date for the years ended December 31, 2016, 2015 and 2014.

Fair Value of Financial Instruments

Substantially all of the Companies' financial instruments are recorded at fair value, with the exception of the instruments described below, which are reported at historical cost. Estimated fair values have been determined using available market information and valuation methodologies considered appropriate by management. The carrying amount of cash and cash equivalents, restricted cash (which is recorded in other current assets), customer and other receivables, affiliated receivables, short-term debt, affiliated current borrowings, payables to affiliates and accounts payable are representative of fair value because of the short-term nature of these instruments. For the Companies' financial instruments that are not recorded at fair value, the carrying amounts and estimated fair values are as follows:

At December 31,	2016		2015	
	Carrying Amount	**Estimated Fair Value(1)**	Carrying Amount	Estimated Fair Value(1)
(millions)				
Dominion				
Long-term debt, including securities due within one year(2)	**$26,587**	**$28,273**	$21,873	$23,210
Junior subordinated notes(3)	**2,980**	**2,893**	1,340	1,192
Remarketable subordinated notes(3)	**2,373**	**2,418**	2,080	2,129
Virginia Power				
Long-term debt, including securities due within one year(3)	**$10,530**	**$11,584**	$ 9,368	$10,400
Dominion Gas				
Long-term debt, including securities due within one year(4)	**$ 3,528**	**$ 3,603**	$ 3,269	$ 3,299

(1) Fair value is estimated using market prices, where available, and interest rates currently available for issuance of debt with similar terms and remaining maturities. All fair value measurements are classified as Level 2. The carrying amount of debt issues with short-term maturities and variable rates refinanced at current market rates is a reasonable estimate of their fair value.

(2) Carrying amount includes amounts which represent the unamortized debt issuance costs, discount or premium, and foreign currency remeasurement adjustments. At December 31, 2016, and 2015, includes the valuation of certain fair value hedges associated with Dominion's fixed rate debt of $(1) million and $7 million, respectively.

(3) Carrying amount includes amounts which represent the unamortized debt issuance costs, discount or premium.

(4) Carrying amount includes amounts which represent the unamortized debt issuance costs, discount or premium, and foreign currency remeasurement adjustments.

Note 7. Derivatives And Hedge Accounting Activities

The Companies are exposed to the impact of market fluctuations in the price of electricity, natural gas and other energy-related products they market and purchase, as well as interest rate and foreign currency exchange rate risks of their business operations. The Companies use derivative instruments to manage exposure to these risks, and designate certain derivative instruments as fair value or cash flow hedges for accounting purposes. As discussed in Note 2, for jurisdictions subject to cost-based rate regulation, changes in the fair value of derivatives are deferred as regulatory assets or regulatory liabilities until the related transactions impact earnings. See Note 6 for further information about fair value measurements and associated valuation methods for derivatives.

Derivative assets and liabilities are presented gross on the Companies' Consolidated Balance Sheets. Dominion's derivative contracts include both over-the-counter transactions and those that are executed on an exchange or other trading platform (exchange contracts) and centrally cleared. Virginia Power's and Dominion Gas' derivative contracts include over-the-counter transactions. Over-the-counter contracts are bilateral contracts that are transacted directly with a third party. Exchange contracts utilize a financial intermediary, exchange, or clearinghouse to enter, execute, or clear the transactions. Certain over-the-counter and exchange contracts contain contractual rights of setoff through master netting arrangements, derivative clearing agreements, and contract default provisions. In addition, the contracts are subject to conditional rights of setoff through counterparty nonperformance, insolvency, or other conditions.

In general, most over-the-counter transactions and all exchange contracts are subject to collateral requirements. Types of collateral for over-the-counter and exchange contracts include cash, letters of credit, and, in some cases, other forms of security, none of which are subject to restrictions. Cash collateral is used in the table below to offset derivative assets and liabilities. Certain accounts receivable and accounts payable recognized on the Companies' Consolidated Balance Sheets, as well as letters of credit and other forms of security, all of which are not included in the tables below, are subject to offset under master netting or similar arrangements and would reduce the net exposure.

DOMINION

Balance Sheet Presentation

The tables below present Dominion's derivative asset and liability balances by type of financial instrument, before and after the effects of offsetting:

	December 31, 2016			December 31, 2015		
	Gross Amounts of Recognized Assets	**Gross Amounts Offset in the Consolidated Balance Sheet**	**Net Amounts of Assets Presented in the Consolidated Balance Sheet**	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
(millions)						
Commodity contracts:						
Over-the-counter	**$211**	**$—**	**$211**	$217	$—	$217
Exchange	**44**	**—**	**44**	138	—	138
Interest rate contracts:						
Over-the-counter	**17**	**—**	**17**	24	—	24
Total derivatives, subject to a master netting or similar arrangement	**272**	**—**	**272**	379	—	379
Total derivatives, not subject to a master netting or similar arrangement	**7**	**—**	**7**	9	—	9
Total	**$279**	**$—**	**$279**	$388	$—	$388

	December 31, 2016				December 31, 2015			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
	Net Amounts of Assets Presented in the Consolidated Balance Sheet	**Financial Instruments**	**Cash Collateral Received**	**Net Amounts**	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts
(millions)								
Commodity contracts:								
Over-the-counter	**$211**	**$14**	**$—**	**$197**	$217	$ 37	$—	$180
Exchange	**44**	**44**	**—**	**—**	138	82	—	56
Interest rate contracts:								
Over-the-counter	**17**	**9**	**—**	**8**	24	22	—	2
Total	**$272**	**$67**	**$—**	**$205**	$379	$141	$—	$238

	December 31, 2016			December 31, 2015		
	Gross Amounts of Recognized Liabilities	**Gross Amounts Offset in the Consolidated Balance Sheet**	**Net Amounts of Liabilities Presented in the Consolidated Balance Sheet**	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
(millions)						
Commodity contracts:						
Over-the-counter	**$ 23**	**$—**	**$ 23**	$ 70	$—	$ 70
Exchange	**71**	**—**	**71**	82	—	82
Interest rate contracts:						
Over-the-counter	**53**	**—**	**53**	183	—	183
Foreign currency contracts:						
Over-the-counter	**6**	**—**	**6**	—	—	—
Total derivatives, subject to a master netting or similar arrangement	**153**	**—**	**153**	335	—	335
Total derivatives, not subject to a master netting or similar arrangement	**2**	**—**	**2**	8	—	8
Total	**$155**	**$—**	**$155**	$343	$—	$343

	December 31, 2016				December 31, 2015			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts
(millions)								
Commodity contracts:								
Over-the-counter	$ 23	$14	$—	$ 9	$ 70	$ 37	$—	$ 33
Exchange	71	44	27	—	82	82	—	—
Interest rate contracts:								
Over-the-counter	53	9	—	44	183	22	—	161
Foreign currency contracts:								
Over-the-counter	6	—	—	6	—	—	—	—
Total	$153	$67	$27	$59	$335	$141	$—	$194

Volumes

The following table presents the volume of Dominion's derivative activity as of December 31, 2016. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions, except in the case of offsetting transactions, for which they represent the absolute value of the net volume of their long and short positions.

	Current	Noncurrent
Natural Gas (bcf):		
Fixed price(1)	91	18
Basis	223	593
Electricity (MWh):		
Fixed price(1)	11,880,630	1,963,426
FTRs	46,269,912	—
Liquids (Gal)(2)	46,311,225	12,741,120
Interest rate(3)	$1,800,000,000	$2,903,640,679
Foreign currency(3)(4)	$ —	$ 280,000,000

(1) Includes options.
(2) Includes NGLs and oil.
(3) Maturity is determined based on final settlement period.
(4) Euro equivalent volumes are € 250,000,000.

Ineffectiveness and AOCI

For the years ended December 31, 2016, 2015 and 2014, gains or losses on hedging instruments determined to be ineffective and amounts excluded from the assessment of effectiveness were not material. Amounts excluded from the assessment of effectiveness include gains or losses attributable to changes in the time value of options and changes in the differences between spot prices and forward prices.

The following table presents selected information related to gains (losses) on cash flow hedges included in AOCI in Dominion's Consolidated Balance Sheet at December 31, 2016:

	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
(millions)			
Commodities:			
Gas	$ 10	$ 10	36 months
Electricity	(20)	(20)	12 months
Other	(3)	(3)	15 months
Interest rate	(274)	(5)	375 months
Foreign currency	7	(1)	114 months
Total	$(280)	$(19)	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., anticipated sales) in earnings, thereby achieving the realization of prices contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in market prices, interest rates and foreign currency exchange rates.

Fair Value and Gains and Losses on Derivative Instruments

The following tables present the fair values of Dominion's derivatives and where they are presented in its Consolidated Balance Sheets:

	Fair Value - Derivatives under Hedge Accounting	Fair Value - Derivatives not under Hedge Accounting	Total Fair Value
(millions)			
At December 31, 2016			
ASSETS			
Current Assets			
Commodity	**$ 29**	**$101**	**$130**
Interest rate	**10**	**—**	**10**
Total current derivative assets	**39**	**101**	**140**
Noncurrent Assets			
Commodity	**—**	**132**	**132**
Interest rate	**7**	**—**	**7**
Total noncurrent derivative assets(1)	**7**	**132**	**139**
Total derivative assets	**$ 46**	**$233**	**$279**
LIABILITIES			
Current Liabilities			
Commodity	**$ 51**	**$ 41**	**$ 92**
Interest rate	**33**	**—**	**33**
Foreign currency	**3**	**—**	**3**
Total current derivative liabilities(2)	**87**	**41**	**128**
Noncurrent Liabilities			
Commodity	**1**	**3**	**4**
Interest rate	**20**	**—**	**20**
Foreign currency	**3**	**—**	**3**
Total noncurrent derivative liabilities(3)	**24**	**3**	**27**
Total derivative liabilities	**$111**	**$ 44**	**$155**
At December 31, 2015			
ASSETS			
Current Assets			
Commodity	$101	$151	$252
Interest rate	3	—	3
Total current derivative assets	104	151	255
Noncurrent Assets			
Commodity	3	109	112
Interest rate	21	—	21
Total noncurrent derivative assets(1)	24	109	133
Total derivative assets	$128	$260	$388
LIABILITIES			
Current Liabilities			
Commodity	$ 32	$116	$148
Interest rate	164	—	164
Total current derivative liabilities(2)	196	116	312
Noncurrent Liabilities			
Commodity	—	12	12
Interest rate	19	—	19
Total noncurrent derivative liabilities(3)	19	12	31
Total derivative liabilities	$215	$128	$343

(1) Noncurrent derivative assets are presented in other deferred charges and other assets in Dominion's Consolidated Balance Sheets.
(2) Current derivative liabilities are presented in other current liabilities in Dominion's Consolidated Balance Sheets.
(3) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Dominion's Consolidated Balance Sheets.

The following tables present the gains and losses on Dominion's derivatives, as well as where the associated activity is presented in its Consolidated Balance Sheets and Statements of Income:

Derivatives in cash flow hedging relationships	Amount of Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)(1)	Amount of Gain (Loss) Reclassified from AOCI to Income	Increase (Decrease) in Derivatives Subject to Regulatory Treatment(2)
(millions)			
Year Ended December 31, 2016			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Operating revenue		**$ 330**	
Purchased gas		**(13)**	
Electric fuel and other energy-related purchases		**(10)**	
Total commodity	**$ 164**	**$ 307**	**$ —**
Interest rate(3)	**(66)**	**(31)**	**(26)**
Foreign currency(4)	**(6)**	**(17)**	**—**
Total	**$ 92**	**$ 259**	**$(26)**
Year Ended December 31, 2015			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Operating revenue		$ 203	
Purchased gas		(15)	
Electric fuel and other energy-related purchases		(1)	
Total commodity	$ 230	$ 187	$ 4
Interest rate(3)	(46)	(11)	(13)
Total	$ 184	$ 176	$ (9)
Year Ended December 31, 2014			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Operating revenue		$(130)	
Purchased gas		(13)	
Electric fuel and other energy-related purchases		7	
Total commodity	$ 245	$(136)	$ (4)
Interest rate(3)	(208)	(16)	(81)
Total	$ 37	$(152)	$(85)

(1) Amounts deferred into AOCI have no associated effect in Dominion's Consolidated Statements of Income.
(2) Represents net derivative activity deferred into and amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Dominion's Consolidated Statements of Income.
(3) Amounts recorded in Dominion's Consolidated Statements of Income are classified in interest and related charges.
(4) Amounts recorded in Dominion's Consolidated Statements of Income are classified in other income.

Derivatives not designated as hedging instruments	Amount of Gain (Loss) Recognized in Income on Derivatives[(1)]		
Year Ended December 31,	**2016**	2015	2014
(millions)			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Operating revenue	**$ 2**	$ 24	$(310)
Purchased gas	**4**	(14)	(51)
Electric fuel and other energy-related purchases	**(70)**	(14)	113
Other operations & maintenance	**1**	—	—
Interest rate[(2)]	**—**	(1)	—
Total	**$(63)**	$ (5)	$(248)

(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Dominion's Consolidated Statements of Income.
(2) Amounts recorded in Dominion's Consolidated Statements of Income are classified in interest and related charges.

Virginia Power

Balance Sheet Presentation

The tables below present Virginia Power's derivative asset and liability balances by type of financial instrument, before and after the effects of offsetting:

	December 31, 2016			December 31, 2015		
	Gross Amounts of Recognized Assets	**Gross Amounts Offset in the Consolidated Balance Sheet**	**Net Amounts of Assets Presented in the Consolidated Balance Sheet**	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
(millions)						
Commodity contracts:						
Over-the-counter	**$147**	**$—**	**$147**	$101	$—	$101
Interest rate contracts:						
Over-the-counter	**6**	**—**	**6**	13	—	13
Total derivatives, subject to a master netting or similar arrangement	**153**	**—**	**153**	114	—	114
Total derivatives, not subject to a master netting or similar arrangement	**41**	**—**	**41**	13	—	13
Total	**$194**	**$—**	**$194**	$127	$—	$127

	December 31, 2016				December 31, 2015			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
	Net Amounts of Assets Presented in the Consolidated Balance Sheet	**Financial Instruments**	**Cash Collateral Received**	**Net Amounts**	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts
(millions)								
Commodity contracts:								
Over-the-counter	**$147**	**$ 2**	**$—**	**$145**	$101	$ 3	$—	$ 98
Interest rate contracts:								
Over-the-counter	**6**	**—**	**—**	**6**	13	10	—	3
Total	**$153**	**$ 2**	**$—**	**$151**	$114	$13	$—	$101

	December 31, 2016			December 31, 2015		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
(millions)						
Commodity contracts:						
Over-the-counter	**$ 2**	**$—**	**$ 2**	$ 5	$—	$ 5
Interest rate contracts:						
Over-the-counter	**21**	**—**	**21**	59	—	59
Total derivatives, subject to a master netting or similar arrangement	**23**	**—**	**23**	64	—	64
Total derivatives, not subject to a master netting or similar arrangement	**8**	**—**	**8**	22	—	22
Total	**$31**	**$—**	**$31**	$86	$—	$86

	December 31, 2016				December 31, 2015			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts
(millions)								
Commodity contracts:								
Over-the-counter	**$ 2**	**$ 2**	**$—**	**$—**	$ 5	$ 3	$—	$ 2
Interest rate contracts:								
Over-the-counter	**21**	**—**	**—**	**21**	59	10	—	49
Total	**$23**	**$ 2**	**$—**	**$21**	$64	$13	$—	$51

Volumes

The following table presents the volume of Virginia Power's derivative activity at December 31, 2016. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions, except in the case of offsetting transactions, for which they represent the absolute value of the net volume of their long and short positions.

	Current	Noncurrent
Natural Gas (bcf):		
Fixed price(1)	**27**	**14**
Basis	**101**	**539**
Electricity (MWh):		
Fixed price(1)	**1,343,310**	**1,963,426**
FTRs	**43,853,950**	**—**
Interest rate	**$800,000,000**	**$850,000,000**

(1) Includes options.

Ineffectiveness and AOCI

For the years ended December 31, 2016, 2015 and 2014, gains or losses on hedging instruments determined to be ineffective were not material.

The following table presents selected information related to gains (losses) on cash flow hedges included in AOCI in Virginia Power's Consolidated Balance Sheet at December 31, 2016:

	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
(millions)			
Interest rate	**$(8)**	**$(1)**	**375 months**
Total	**$(8)**	**$(1)**	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., interest payments) in earnings, thereby achieving the realization of interest rates contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in interest rates.

Fair Value and Gains and Losses on Derivative Instruments

The following tables present the fair values of Virginia Power's derivatives and where they are presented in its Consolidated Balance Sheets:

	Fair Value - Derivatives under Hedge Accounting	Fair Value - Derivatives not under Hedge Accounting	Total Fair Value
(millions)			
At December 31, 2016			
ASSETS			
Current Assets			
Commodity	**$—**	**$ 60**	**$ 60**
Interest rate	**6**	**—**	**6**
Total current derivative assets(1)	**6**	**60**	**66**
Noncurrent Assets			
Commodity	**—**	**128**	**128**
Total noncurrent derivative assets	**—**	**128**	**128**
Total derivative assets	**$ 6**	**$188**	**$194**
LIABILITIES			
Current Liabilities			
Commodity	**$—**	**$ 10**	**$ 10**
Interest rate	**8**	**—**	**8**
Total current derivative liabilities(2)	**8**	**10**	**18**
Noncurrent Liabilities			
Interest rate	**13**	**—**	**13**
Total noncurrent derivative liabilities(3)	**13**	**—**	**13**
Total derivative liabilities	**$21**	**$ 10**	**$ 31**
At December 31, 2015			
ASSETS			
Current Assets			
Commodity	$—	$ 18	$ 18
Total current derivative assets(1)	—	18	18
Noncurrent Assets			
Commodity	—	96	96
Interest rate	13	—	13
Total noncurrent derivative assets	13	96	109
Total derivative assets	$13	$114	$127
LIABILITIES			
Current Liabilities			
Commodity	$—	$ 23	$ 23
Interest rate	57	—	57
Total current derivative liabilities(2)	57	23	80
Noncurrent Liabilities			
Commodity	—	4	4
Interest rate	2	—	2
Total noncurrent derivative liabilities(3)	2	4	6
Total derivative liabilities	$59	$ 27	$ 86

(1) Current derivative assets are presented in other current assets in Virginia Power's Consolidated Balance Sheets.
(2) Current derivative liabilities are presented in other current liabilities in Virginia Power's Consolidated Balance Sheets.
(3) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Virginia Power's Consolidated Balance Sheets.

The following tables present the gains and losses on Virginia Power's derivatives, as well as where the associated activity is presented in its Consolidated Balance Sheets and Statements of Income:

Derivatives in cash flow hedging relationships	Amount of Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)(1)	Amount of Gain (Loss) Reclassified from AOCI to Income	Increase (Decrease) in Derivatives Subject to Regulatory Treatment(2)
(millions)			
Year Ended December 31, 2016			
Derivative Type and Location of Gains (Losses)			
Interest rate(3)	**$ (3)**	**$(1)**	**$(26)**
Total	**$ (3)**	**$(1)**	**$(26)**
Year Ended December 31, 2015			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Electric fuel and other energy-related purchases		$(1)	
Total commodity	$ —	$(1)	$ 4
Interest rate(3)	(3)	—	(13)
Total	$ (3)	$(1)	$ (9)
Year Ended December 31, 2014			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Electric fuel and other energy-related purchases		$ 5	
Total commodity	$ 4	$ 5	$ (4)
Interest rate(3)	(10)	—	(81)
Total	$ (6)	$ 5	$(85)

(1) Amounts deferred into AOCI have no associated effect in Virginia Power's Consolidated Statements of Income.
(2) Represents net derivative activity deferred into and amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Virginia Power's Consolidated Statements of Income.
(3) Amounts recorded in Virginia Power's Consolidated Statements of Income are classified in interest and related charges.

Derivatives not designated as hedging instruments	Amount of Gain (Loss) Recognized in Income on Derivatives(1)		
Year Ended December 31,	**2016**	2015	2014
(millions)			
Derivative Type and Location of Gains (Losses)			
Commodity(2)	**$(70)**	$(13)	$105
Total	**$(70)**	$(13)	$105

(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Virginia Power's Consolidated Statements of Income.
(2) Amounts recorded in Virginia Power's Consolidated Statements of Income are classified in electric fuel and other energy-related purchases.

Dominion Gas

Balance Sheet Presentation

The tables below present Dominion Gas' derivative asset and liability balances by type of financial instrument, before and after the effects of offsetting:

	December 31, 2016			December 31, 2015		
(millions)	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
Commodity contracts:						
Over-the-counter	$—	$—	$—	$11	$—	$11
Total derivatives, subject to a master netting or similar arrangement	$—	$—	$—	$11	$—	$11

	December 31, 2016				December 31, 2015			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts	Net Amounts of Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts
Commodity contracts:								
Over-the-counter	$—	$—	$—	$—	$11	$—	$—	$11
Total	$—	$—	$—	$—	$11	$—	$—	$11

	December 31, 2016			December 31, 2015		
(millions)	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
Commodity contracts:						
Over-the-counter	$ 5	$—	$ 5	$—	$—	$—
Interest rate contracts:						
Over-the-counter	—	—	—	14	—	14
Foreign currency contracts:						
Over-the-counter	6	—	6	—	—	—
Total derivatives, subject to a master netting or similar arrangement	$11	$—	$11	$14	$—	$14

	December 31, 2016				December 31, 2015			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts
Commodity contracts:								
Over-the-counter	$ 5	$—	$—	$ 5	$—	$—	$—	$—
Interest rate contracts:								
Over-the-counter	—	—	—	—	14	—	—	14
Foreign currency contracts:								
Over-the-counter	6	—	—	6	—	—	—	—
Total	$11	$—	$—	$11	$14	$—	$—	$14

Volumes

The following table presents the volume of Dominion Gas' derivative activity at December 31, 2016. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions, except in the case of offsetting transactions, for which they represent the absolute value of the net volume of their long and short positions.

	Current	Noncurrent
NGLs (Gal)	**39,549,225**	**7,953,120**
Foreign currency[1]	**$ —**	**$280,000,000**

(1) Maturity is determined based on final settlement period. Euro equivalent volumes are €250,000,000.

Ineffectiveness and AOCI

For the years ended December 31, 2016, 2015 and 2014, gains or losses on hedging instruments determined to be ineffective were not material.

The following table presents selected information related to gains (losses) on cash flow hedges included in AOCI in Dominion Gas' Consolidated Balance Sheet at December 31, 2016:

	AOCI After-Tax	Amounts Expected to be Reclassified to Earnings during the next 12 Months After-Tax	Maximum Term
(millions)			
Commodities:			
NGLs	**$ (3)**	**$(3)**	**15 months**
Interest rate	**(28)**	**(3)**	**336 months**
Foreign currency	**7**	**(1)**	**114 months**
Total	**$(24)**	**$(7)**	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., anticipated sales) in earnings, thereby achieving the realization of prices contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in market prices, interest rates, and foreign currency exchange rates.

Fair Value and Gains and Losses on Derivative Instruments

The following tables present the fair values of Dominion Gas' derivatives and where they are presented in its Consolidated Balance Sheets:

	Fair Value - Derivatives under Hedge Accounting	Fair Value - Derivatives not under Hedge Accounting	Total Fair Value
(millions)			
At December 31, 2016			
LIABILITIES			
Current Liabilities			
Commodity	**$ 4**	**—**	**$ 4**
Foreign currency	**3**	**—**	**3**
Total current derivative liabilities[3]	**7**	**—**	**7**
Noncurrent Liabilities			
Commodity	**1**	**—**	**1**
Foreign currency	**3**	**—**	**3**
Total noncurrent derivative liabilities[4]	**4**	**—**	**4**
Total derivative liabilities	**$11**	**$—**	**$11**
At December 31, 2015			
ASSETS			
Current Assets			
Commodity	$10	$—	$10
Total current derivative assets[1]	10	—	10
Noncurrent Assets			
Commodity	1	—	1
Total noncurrent derivative assets[2]	1	—	1
Total derivative assets	$11	$—	$11
LIABILITIES			
Current Liabilities			
Interest rate	$14	$—	$14
Total current derivative liabilities[3]	14	—	14
Total derivative liabilities	$14	$—	$14

(1) Current derivative assets are presented in other current assets in Dominion Gas' Consolidated Balance Sheets.
(2) Noncurrent derivative assets are presented in other deferred charges and other assets in Dominion Gas' Consolidated Balance Sheets.
(3) Current derivative liabilities are presented in other current liabilities in Dominion Gas' Consolidated Balance Sheets.
(4) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Dominion Gas' Consolidated Balance Sheets.

The following tables present the gains and losses on Dominion Gas' derivatives, as well as where the associated activity is presented in its Consolidated Balance Sheets and Statements of Income:

Derivatives in cash flow hedging relationships	Amount of Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)[(1)]	Amount of Gain (Loss) Reclassified from AOCI to Income
(millions)		
Year Ended December 31, 2016		
Derivative Type and Location of Gains (Losses)		
Commodity:		
Operating revenue		**$ 4**
Total commodity	**$(12)**	**$ 4**
Interest rate[(2)]	**(8)**	**(2)**
Foreign currency[(3)]	**(6)**	**(17)**
Total	**$(26)**	**$(15)**
Year Ended December 31, 2015		
Derivative Type and Location of Gains (Losses)		
Commodity:		
Operating revenue		$ 6
Total commodity	$ 16	$ 6
Interest rate[(2)]	(6)	—
Total	$ 10	$ 6
Year Ended December 31, 2014		
Derivative Type and Location of Gains (Losses)		
Commodity:		
Operating revenue		$ 2
Purchased gas		(14)
Total commodity	$ 12	$(12)
Interest rate[(2)]	(62)	(1)
Total	$(50)	$(13)

(1) Amounts deferred into AOCI have no associated effect in Dominion Gas' Consolidated Statements of Income.
(2) Amounts recorded in Dominion Gas' Consolidated Statements of Income are classified in interest and related charges.
(3) Amounts recorded in Dominion Gas' Consolidated Statements of Income are classified in other income.

Derivatives not designated as hedging instruments	Amount of Gain (Loss) Recognized in Income on Derivatives		
Year Ended December 31,	**2016**	2015	2014
(millions)			
Derivative Type and Location of Gains (Losses)			
Commodity			
Operating revenue	**$1**	$6	$—
Total	**$1**	$6	$—

Note 8. Earnings Per Share

The following table presents the calculation of Dominion's basic and diluted EPS:

	2016	2015	2014
(millions, except EPS)			
Net income attributable to Dominion	**$2,123**	$1,899	$1,310
Average shares of common stock outstanding-Basic	**616.4**	592.4	582.7
Net effect of dilutive securities[(1)]	**0.7**	1.3	1.8
Average shares of common stock outstanding-Diluted	**617.1**	593.7	584.5
Earnings Per Common Share-Basic	**$ 3.44**	$ 3.21	$ 2.25
Earnings Per Common Share-Diluted	**$ 3.44**	$ 3.20	$ 2.24

(1) Dilutive securities consist primarily of the 2013 Equity Units for 2016 and 2015 and the 2013 Equity Units and contingently convertible senior notes for 2014. Dominion redeemed all of its contingently convertible senior notes in 2014. See Note 17 for more information.

The 2014 Equity Units were excluded from the calculation of diluted EPS for the years ended December 31, 2016, 2015 and 2014, as the dilutive stock price threshold was not met. The 2016 Equity Units were excluded from the calculation of diluted EPS for the year ended December 31, 2016, as the dilutive stock price threshold was not met. See Note 17 for more information. The Dominion Midstream convertible preferred units are potentially dilutive securities but had no effect on the calculation of diluted EPS for the year ended December 31, 2016. See Note 19 for more information.

NOTE 9. INVESTMENTS

DOMINION

Equity and Debt Securities

RABBI TRUST SECURITIES

Marketable equity and debt securities and cash equivalents held in Dominion's rabbi trusts and classified as trading totaled $104 million and $100 million at December 31, 2016 and 2015, respectively.

DECOMMISSIONING TRUST SECURITIES

Dominion holds marketable equity and debt securities (classified as available-for-sale), cash equivalents and cost method investments in nuclear decommissioning trust funds to fund future decommissioning costs for its nuclear plants. Dominion's decommissioning trust funds are summarized below:

	Amortized Cost	Total Unrealized Gains(1)	Total Unrealized Losses(1)	Fair Value
(millions)				
At December 31, 2016				
Marketable equity securities:				
U.S.	**$1,449**	**$1,408**	**$ —**	**$2,857**
Fixed income:				
Corporate debt instruments	**478**	**13**	**(4)**	**487**
Government securities	**978**	**22**	**(8)**	**992**
Common/collective trust funds	**67**	**—**	**—**	**67**
Cost method investments	**69**	**—**	**—**	**69**
Cash equivalents and other(2)	**12**	**—**	**—**	**12**
Total	**$3,053**	**$1,443**	**$(12)(3)**	**$4,484**
At December 31, 2015				
Marketable equity securities:				
U.S.	$1,354	$1,217	$ —	$2,571
Fixed income:				
Corporate debt instruments	436	11	(7)	440
Government securities	962	30	(4)	988
Common/collective trust funds	100	—	—	100
Cost method investments	70	—	—	70
Cash equivalents and other(2)	14	—	—	14
Total	$2,936	$1,258	$(11)(3)	$4,183

(1) Included in AOCI and the nuclear decommissioning trust regulatory liability as discussed in Note 2.
(2) Includes pending sales of securities of $9 million and $12 million at December 31, 2016 and 2015, respectively.
(3) The fair value of securities in an unrealized loss position was $576 million and $592 million at December 31, 2016 and 2015, respectively.

The fair value of Dominion's marketable debt securities held in nuclear decommissioning trust funds at December 31, 2016 by contractual maturity is as follows:

	Amount
(millions)	
Due in one year or less	**$ 192**
Due after one year through five years	**418**
Due after five years through ten years	**368**
Due after ten years	**568**
Total	**$1,546**

Presented below is selected information regarding Dominion's marketable equity and debt securities held in nuclear decommissioning trust funds:

Year Ended December 31,	**2016**	2015	2014
(millions)			
Proceeds from sales	**$1,422**	$1,340	$1,235
Realized gains(1)	**128**	219	171
Realized losses(1)	**55**	84	30

(1) Includes realized gains and losses recorded to the nuclear decommissioning trust regulatory liability as discussed in Note 2.

Dominion recorded other-than-temporary impairment losses on investments held in nuclear decommissioning trust funds as follows:

Year Ended December 31,	2016	2015	2014
(millions)			
Total other-than-temporary impairment losses(1)	**$ 51**	$ 66	$21
Losses recorded to nuclear decommissioning trust regulatory liability	**(16)**	(26)	(5)
Losses recognized in other comprehensive income (before taxes)	**(12)**	(9)	(3)
Net impairment losses recognized in earnings	**$ 23**	$ 31	$13

(1) Amounts include other-than-temporary impairment losses for debt securities of $13 million, $9 million and $3 million at December 31, 2016, 2015 and 2014, respectively.

VIRGINIA POWER

Virginia Power holds marketable equity and debt securities (classified as available-for-sale), cash equivalents and cost method investments in nuclear decommissioning trust funds to fund future decommissioning costs for its nuclear plants. Virginia Power's decommissioning trust funds are summarized below:

	Amortized Cost	Total Unrealized Gains(1)	Total Unrealized Losses(1)	Fair Value
(millions)				
At December 31, 2016				
Marketable equity securities:				
U.S.	**$ 677**	**$624**	**$—**	**$1,301**
Fixed income:				
Corporate debt instruments	**274**	**6**	**(4)**	**276**
Government securities	**420**	**9**	**(2)**	**427**
Common/collective trust funds	**26**	**—**	**—**	**26**
Cost method investments	**69**	**—**	**—**	**69**
Cash equivalents and other(2)	**7**	**—**	**—**	**7**
Total	**$1,473**	**$639**	**$(6)(3)**	**$2,106**
At December 31, 2015				
Marketable equity securities:				
U.S.	$ 633	$528	$—	$1,161
Fixed income:				
Corporate debt instruments	238	5	(5)	238
Government securities	421	15	(2)	434
Common/collective trust funds	34	—	—	34
Cost method investments	70	—	—	70
Cash equivalents and other(2)	8	—	—	8
Total	$1,404	$548	$(7)(3)	$1,945

(1) Included in AOCI and the nuclear decommissioning trust regulatory liability as discussed in Note 2.
(2) Includes pending sales of securities of $7 million and $8 million at December 31, 2016 and 2015, respectively.
(3) The fair value of securities in an unrealized loss position was $287 million and $281 million at December 31, 2016 and 2015, respectively.

The fair value of Virginia Power's marketable debt securities at December 31, 2016, by contractual maturity is as follows:

	Amount
(millions)	
Due in one year or less	**$ 55**
Due after one year through five years	**181**
Due after five years through ten years	**208**
Due after ten years	**285**
Total	**$729**

Presented below is selected information regarding Virginia Power's marketable equity and debt securities held in nuclear decommissioning trust funds.

Year Ended December 31,	2016	2015	2014
(millions)			
Proceeds from sales	**$733**	$639	$549
Realized gains(1)	**63**	110	73
Realized losses(1)	**27**	43	12

(1) Includes realized gains and losses recorded to the nuclear decommissioning trust regulatory liability as discussed in Note 2.

Virginia Power recorded other-than-temporary impairment losses on investments held in nuclear decommissioning trust funds as follows:

Year Ended December 31,	2016	2015	2014
(millions)			
Total other-than-temporary impairment losses(1)	**$ 26**	$ 36	$ 8
Losses recorded to nuclear decommissioning trust regulatory liability	**(16)**	(26)	(4)
Losses recorded in other comprehensive income (before taxes)	**(7)**	(6)	(2)
Net impairment losses recognized in earnings	**$ 3**	$ 4	$ 2

(1) Amounts include other-than-temporary impairment losses for debt securities of $8 million, $6 million and $2 million at December 31, 2016, 2015 and 2014, respectively.

EQUITY METHOD INVESTMENTS

Dominion and Dominion Gas

Investments that Dominion and Dominion Gas account for under the equity method of accounting are as follows:

Company	Ownership%	Investment Balance 2016	Investment Balance 2015	Description
As of December 31,		2016	2015	
(millions)				
Dominion				
Blue Racer	50%	**$ 677**	$ 661	Midstream gas and related services
Iroquois	50%(1)	**316**	324	Gas transmission system
Atlantic Coast Pipeline	48%	**256**	59	Gas transmission system
Fowler Ridge	50%	**116**	125	Wind-powered merchant generation facility
NedPower	50%	**112**	119	Wind-powered merchant generation facility
Other	various	**84**	32	
Total		**$1,561**	$1,320	
Dominion Gas				
Iroquois	24.07%	**$ 98**	$ 102	Gas transmission system
Total		**$ 98**	$ 102	

(1) Comprised of Dominion Midstream's interest of 25.93% and Dominion Gas' interest of 24.07%. See Note 15 for more information.

Dominion's equity earnings on its investments totaled $111 million, $56 million and $46 million in 2016, 2015 and 2014, respectively. Dominion received distributions from these investments of $104 million, $83 million and $60 million in 2016, 2015, and 2014, respectively. As of December 31, 2016 and 2015, the carrying amount of Dominion's investments exceeded its share of underlying equity in net assets by $260 million and $234 million, respectively. These differences are comprised at December 31, 2016 and 2015, of $84 million and $72 million, respectively, related to basis differences from Dominion's investments in Blue Racer and wind projects, which are being amortized over the useful lives of the underlying assets, and $176 million and $162 million, respectively, reflecting equity method goodwill that is not being amortized.

Dominion Gas' equity earnings on its investment totaled $21 million, $23 million and $21 million in 2016, 2015 and 2014, respectively. Dominion Gas received distributions from its investment of $22 million, $28 million and $20 million in 2016, 2015, and 2014, respectively. As of December 31, 2016 and 2015, the carrying amount of Dominion Gas' investment exceeded its share of underlying equity in net assets by $8 million. The difference reflects equity method goodwill and is not being amortized. In May 2016, Dominion Gas sold 0.65% of the non-controlling partnership interest in Iroquois to TransCanada for approximately $7 million, which resulted in a $5 million ($3 million after-tax) gain, included in other income in Dominion Gas' Consolidated Statements of Income.

Equity earnings are recorded in other income in Dominion's and Dominion Gas' Consolidated Statements of Income.

Blue Racer

In December 2012, Dominion formed a joint venture with Caiman to provide midstream services to natural gas producers operating in the Utica Shale region in Ohio and portions of Pennsylvania. Blue Racer is an equal partnership between Dominion and Caiman, with Dominion contributing midstream assets and Caiman contributing private equity capital.

In March 2014, Dominion Gas sold the Northern System to an affiliate, that subsequently sold the Northern System to Blue Racer for consideration of $84 million. Dominion Gas' consideration consisted of $17 million in cash proceeds and the extinguishment of affiliated current borrowings of $67 million and Dominion's consideration consisted of cash proceeds of $84 million. The sale resulted in a gain of $59 million ($35 million after-tax for Dominion Gas and $34 million after-tax for Dominion) net of a $3 million write-off of goodwill, and is included in other operations and maintenance expense in both Dominion Gas' and Dominion's Consolidated Statements of Income.

In December 2016, Dominion Gas repurchased a portion of the Western System from Blue Racer for $10 million, which is included in property, plant and equipment in Dominion Gas' Consolidated Balance Sheets.

Dominion

Atlantic Coast Pipeline

In September 2014, Dominion, along with Duke and Southern Company Gas (formerly known as AGL Resources Inc.), announced the formation of Atlantic Coast Pipeline. The Atlantic Coast Pipeline partnership agreement includes provisions to allow Dominion an option to purchase additional ownership interest in Atlantic Coast Pipeline to maintain a leading ownership percentage. In October 2016, Dominion purchased an additional 3% membership interest in Atlantic Coast Pipeline from Duke for $14 million. The members, which are subsidiaries of the above-referenced parent companies, hold the following membership interests: Dominion, 48%; Duke, 47%; and Southern Company Gas (formerly known as AGL Resources Inc.), 5%.

Atlantic Coast Pipeline is focused on constructing an approximately 600-mile natural gas pipeline running from West Virginia through Virginia to North Carolina. Subsidiaries and affiliates of all three members plan to be customers of the pipeline under 20-year contracts. Public Service Company of North Carolina, Inc. also plans to be a customer of the pipeline under a 20-year contract. Atlantic Coast Pipeline is considered an equity method investment as Dominion has the ability to exercise significant influence, but not control, over the investee. See Note 15 for more information.

Note 10. Property, Plant and Equipment

Major classes of property, plant and equipment and their respective balances for the Companies are as follows:

At December 31,	2016	2015
(millions)		
Dominion		
Utility:		
Generation	**$17,147**	$15,656
Transmission	**14,315**	11,461
Distribution	**16,381**	13,128
Storage	**2,814**	2,460
Nuclear fuel	**1,537**	1,464
Gas gathering and processing	**216**	799
Oil and gas	**1,652**	—
General and other	**1,450**	927
Plant under construction	**6,254**	5,550
Total utility	**61,766**	51,445
Nonutility:		
Merchant generation-nuclear	**1,419**	1,339
Merchant generation-other	**4,149**	2,683
Nuclear fuel	**897**	938
Gas gathering and processing	**619**	—
Other-including plant under construction	**706**	1,371
Total nonutility	**7,790**	6,331
Total property, plant and equipment	**$69,556**	$57,776
Virginia Power		
Utility:		
Generation	**$17,147**	$15,656
Transmission	**7,871**	6,963
Distribution	**10,573**	10,048
Nuclear fuel	**1,537**	1,464
General and other	**745**	709
Plant under construction	**2,146**	2,793
Total utility	**40,019**	37,633
Nonutility-other	**11**	6
Total property, plant and equipment	**$40,030**	$37,639
Dominion Gas		
Utility:		
Transmission	**$ 4,231**	$ 3,804
Distribution	**3,019**	2,765
Storage	**1,627**	1,583
Gas gathering and processing	**198**	797
General and other	**184**	165
Plant under construction	**448**	443
Total utility	**9,707**	9,557
Nonutility:		
Gas gathering and processing	**$ 619**	$ —
Other-including plant under construction	**149**	136
Total nonutility	**768**	136
Total property, plant and equipment	**$10,475**	$ 9,693

Jointly-Owned Power Stations

Dominion's and Virginia Power's proportionate share of jointly-owned power stations at December 31, 2016 is as follows:

	Bath County Pumped Storage Station(1)	North Anna Units 1 and 2(1)	Clover Power Station(1)	Millstone Unit 3(2)
(millions, except percentages)				
Ownership interest	**60%**	**88.4%**	**50%**	**93.5%**
Plant in service	**$1,052**	**$ 2,520**	**$ 586**	**$1,190**
Accumulated depreciation	**(585)**	**(1,210)**	**(219)**	**(349)**
Nuclear fuel	**—**	**718**	**—**	**469**
Accumulated amortization of nuclear fuel	**—**	**(549)**	**—**	**(366)**
Plant under construction	**8**	**69**	**4**	**51**

(1) Units jointly owned by Virginia Power.
(2) Unit jointly owned by Dominion.

The co-owners are obligated to pay their share of all future construction expenditures and operating costs of the jointly-owned facilities in the same proportion as their respective ownership interest. Dominion and Virginia Power report their share of operating costs in the appropriate operating expense (electric fuel and other energy-related purchases, other operations and maintenance, depreciation, depletion and amortization and other taxes, etc.) in the Consolidated Statements of Income.

Assignments of Shale Development Rights

In December 2013, Dominion Gas closed on agreements with two natural gas producers to convey over time approximately 100,000 acres of Marcellus Shale development rights underneath several of its natural gas storage fields. The agreements provide for payments to Dominion Gas, subject to customary adjustments, of approximately $200 million over a period of nine years, and an overriding royalty interest in gas produced from the acreage. In 2013, Dominion Gas received approximately $100 million in cash proceeds, resulting in a $20 million ($12 million after-tax) gain, recorded to operations and maintenance expense in Dominion Gas' Consolidated Statements of Income. In 2014, Dominion Gas received $16 million in additional cash proceeds resulting from post-closing adjustments. In March 2015, Dominion Gas and one of the natural gas producers closed on an amendment to the agreement, which included the immediate conveyance of approximately 9,000 acres of Marcellus Shale development rights and a two-year extension of the term of the original agreement. The conveyance of development rights resulted in the recognition of $43 million ($27 million after-tax) of previously deferred revenue to operations and maintenance expense in Dominion Gas' Consolidated Statements of Income. In April 2016, Dominion Gas and the natural gas producer closed on an amendment to the agreement, which included the immediate conveyance of a 32% partial interest in the remaining approximately 70,000 acres. This conveyance resulted in the recognition of the remaining $35 million ($21 million after-tax) of previously deferred revenue to operations and maintenance expense in Dominion Gas' Consolidated Statements of Income.

In November 2014, Dominion Gas closed an agreement with a natural gas producer to convey over time approximately 24,000 acres of Marcellus Shale development rights underneath one of its natural gas storage fields. The agreement provides for payments to

Dominion Gas, subject to customary adjustments, of approximately $120 million over a period of four years, and an overriding royalty interest in gas produced from the acreage. In November 2014, Dominion Gas closed on the agreement and received proceeds of $60 million associated with an initial conveyance of approximately 12,000 acres, resulting in a $60 million ($36 million after-tax) gain, recorded to operations and maintenance expense in Dominion Gas' Consolidated Statements of Income. In connection with that agreement, in 2016, Dominion Gas conveyed approximately 4,000 acres of Marcellus Shale development rights and received proceeds of $10 million and an overriding royalty interest in gas produced from the acreage. These transactions resulted in a $10 million ($6 million after-tax) gain. The gains are included in other operations and maintenance expense in Dominion Gas' Consolidated Statements of Income.

In March 2015, Dominion Gas conveyed to a natural gas producer approximately 11,000 acres of Marcellus Shale development rights underneath one of its natural gas storage fields and received proceeds of $27 million and an overriding royalty interest in gas produced from the acreage. This transaction resulted in a $27 million ($16 million after-tax) gain, included in other operations and maintenance expense in Dominion Gas' Consolidated Statements of Income.

In September 2015, Dominion Gas closed on an agreement with a natural gas producer to convey approximately 16,000 acres of Utica and Point Pleasant Shale development rights underneath one of its natural gas storage fields. The agreement provided for a payment to Dominion Gas, subject to customary adjustments, of $52 million and an overriding royalty interest in gas produced from the acreage. In September 2015, Dominion Gas received proceeds of $52 million associated with the conveyance of the acreage, resulting in a $52 million ($29 million after-tax) gain, included in other operations and maintenance expense in Dominion Gas' Consolidated Statements of Income.

Note 11. Goodwill and Intangible Assets

Goodwill

The changes in Dominion's and Dominion Gas' carrying amount and segment allocation of goodwill are presented below:

	Dominion Generation	Dominion Energy	DVP	Corporate and Other(1)	Total
(millions)					
Dominion					
Balance at December 31, 2014(2)	$1,422(3)	$ 696(3)	$926	$—	$3,044
DCG acquisition	—	250(4)	—	—	250
Balance at December 31, 2015(2)	$1,422	$ 946	$926	$—	$3,294
Dominion Questar Combination	**—**	**3,105(4)**	**—**	**—**	**3,105**
Balance at December 31, 2016(2)	**$1,422**	**$4,051**	**$926**	**$—**	**$6,399**
Dominion Gas					
Balance at December 31, 2014(2)	$ —	$ 542	$ —	$—	$ 542
No events affecting goodwill	—	—	—	—	—
Balance at December 31, 2015(2)	**$ —**	**$ 542**	**$ —**	**$—**	**$ 542**
No events affecting goodwill	**—**	**—**	**—**	**—**	**—**
Balance at December 31, 2016(2)	**$ —**	**$ 542**	**$ —**	**$—**	**$ 542**

(1) Goodwill recorded at the Corporate and Other segment is allocated to the primary operating segments for goodwill impairment testing purposes.
(2) Goodwill amounts do not contain any accumulated impairment losses.
(3) Recast to reflect nonregulated retail energy marketing operations in the Dominion Energy segment.
(4) See Note 3 for discussion of Dominion's acquisitions.

Other Intangible Assets

The Companies' other intangible assets are subject to amortization over their estimated useful lives. Dominion's amortization expense for intangible assets was $73 million, $78 million and $71 million for 2016, 2015 and 2014, respectively. In 2016, Dominion acquired $124 million of intangible assets, primarily representing software, with an estimated weighted-average amortization period of approximately 15 years. Amortization expense for Virginia Power's intangible assets was $29 million, $25 million and $24 million for 2016, 2015 and 2014, respectively. In 2016, Virginia Power acquired $40 million of intangible assets, primarily representing software, with an estimated weighted-average amortization period of 12 years. Dominion Gas' amortization expense for intangible assets was $6 million, $18 million and $17 million for 2016, 2015 and 2014, respectively. In 2016, Dominion Gas acquired $20 million of intangible assets, primarily representing software, with an estimated weighted-average amortization period of approximately 12 years. The components of intangible assets are as follows:

At December 31,	2016		2015	
	Gross Carrying Amount	**Accumulated Amortization**	Gross Carrying Amount	Accumulated Amortization
(millions)				
Dominion				
Software, licenses and other	**$955**	**$337**	$942	$372
Total	**$955**	**$337**	$942	$372
Virginia Power				
Software, licenses and other	**$326**	**$101**	$301	$ 88
Total	**$326**	**$101**	$301	$ 88
Dominion Gas				
Software, licenses and other	**$147**	**$ 49**	$211	$128
Total	**$147**	**$ 49**	$211	$128

Annual amortization expense for these intangible assets is estimated to be as follows:

	2017	2018	2019	2020	2021
(millions)					
Dominion	**$78**	**$67**	**$57**	**$45**	**$32**
Virginia Power	**$29**	**$25**	**$22**	**$16**	**$ 9**
Dominion Gas	**$13**	**$11**	**$10**	**$10**	**$ 9**

Note 12. Regulatory Assets and Liabilities

Regulatory assets and liabilities include the following:

At December 31,	2016	2015
(millions)		
Dominion		
Regulatory assets:		
Deferred nuclear refueling outage costs(1)	**$ 71**	$ 75
Deferred rate adjustment clause costs(2)	**63**	90
Unrecovered gas costs(3)	**19**	12
Deferred cost of fuel used in electric generation(4)	**—**	111
Other	**91**	63
Regulatory assets-current	**244**	351
Unrecognized pension and other postretirement benefit costs(5)	**1,401**	1,015
Deferred rate adjustment clause costs(2)	**329**	295
PJM transmission rates(6)	**192**	192
Derivatives(7)	**174**	110
Income taxes recoverable through future rates(8)	**123**	126
Utility reform legislation(9)	**99**	65
Other	**155**	62
Regulatory assets-non-current	**2,473**	1,865
Total regulatory assets	**$2,717**	$2,216
Regulatory liabilities:		
Deferred cost of fuel used in electric generation(4)	**$ 61**	$ —
PIPP(10)	**28**	46
Other	**74**	54
Regulatory liabilities-current	**163**	100
Provision for future cost of removal and AROs(11)	**1,427**	1,120
Nuclear decommissioning trust(12)	**902**	804
Derivatives(7)	**69**	79
Deferred cost of fuel used in electric generation(4)	**14**	97
Other	**210**	185
Regulatory liabilities-non-current	**2,622**	2,285
Total regulatory liabilities	**$2,785**	$2,385
Virginia Power		
Regulatory assets:		
Deferred nuclear refueling outage costs(1)	**$ 71**	$ 75
Deferred rate adjustment clause costs(2)	**51**	80
Deferred cost of fuel used in electric generation(4)	**—**	111
Other	**57**	60
Regulatory assets-current	**179**	326
Deferred rate adjustment clause costs(2)	**246**	213
PJM transmission rates(6)	**192**	192
Derivatives(7)	**133**	110
Income taxes recoverable through future rates(8)	**76**	97
Other	**123**	55
Regulatory assets-non-current	**770**	667
Total regulatory assets	**$ 949**	$ 993
Regulatory liabilities:		
Deferred cost of fuel used in electric generation(4)	**$ 61**	$ —
Other	**54**	35
Regulatory liabilities-current	**115**	35
Provision for future cost of removal(11)	**946**	890
Nuclear decommissioning trust(12)	**902**	804
Derivatives(7)	**69**	79
Deferred cost of fuel used in electric generation(4)	**14**	97
Other	**31**	59
Regulatory liabilities-non-current	**1,962**	1,929
Total regulatory liabilities	**$2,077**	$1,964

At December 31,	2016	2015
(millions)		
Dominion Gas		
Regulatory assets:		
Unrecovered gas costs(3)	**$ 12**	$ 11
Deferred rate adjustment clause costs(2)	**12**	10
Other	**2**	2
Regulatory assets-current	**26**	23
Unrecognized pension and other postretirement benefit costs(5)	**358**	282
Utility reform legislation(9)	**99**	65
Deferred rate adjustment clause costs(2)	**79**	82
Income taxes recoverable through future rates(8)	**23**	20
Other	**18**	—
Regulatory assets-non-current	**577**	449
Total regulatory assets	**$603**	$472
Regulatory liabilities:		
PIPP(10)	**$ 28**	$ 46
Other	**7**	9
Regulatory liabilities-current	**35**	55
Provision for future cost of removal and AROs(11)	**174**	170
Other	**45**	31
Regulatory liabilities-non-current	**219**	201
Total regulatory liabilities	**$254**	$256

(1) Legislation enacted in Virginia in April 2014 requires Virginia Power to defer operation and maintenance costs incurred in connection with the refueling of any nuclear-powered generating plant. These deferred costs will be amortized over the refueling cycle, not to exceed 18 months.

(2) Primarily reflects deferrals under the electric transmission FERC formula rate and the deferral of costs associated with certain current and prospective rider projects for Virginia Power and deferrals of costs associated with certain current and prospective rider projects for Dominion Gas. See Note 13 for more information.

(3) Reflects unrecovered gas costs at regulated gas operations, which are recovered through filings with the applicable regulatory authority.

(4) Reflects deferred fuel expenses for the Virginia and North Carolina jurisdictions of Dominion's and Virginia Power's generation operations. See Note 13 for more information.

(5) Represents unrecognized pension and other postretirement employee benefit costs expected to be recovered through future rates generally over the expected remaining service period of plan participants by certain of Dominion's and Dominion Gas' rate-regulated subsidiaries.

(6) Reflects amount related to the PJM transmission cost allocation matter. See Note 13 for more information.

(7) As discussed under Derivative Instruments in Note 2, for jurisdictions subject to cost-based rate regulation, changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities as they are expected to be recovered from or refunded to customers.

(8) Amounts to be recovered through future rates to pay income taxes that become payable when rate revenue is provided to recover AFUDC-equity and depreciation of property, plant and equipment for which deferred income taxes were not recognized for ratemaking purposes, including amounts attributable to tax rate changes.

(9) Ohio legislation under House Bill 95, which became effective in September 2011. This law updates natural gas legislation by enabling gas companies to include more up-to-date cost levels when filing rate cases. It also allows gas companies to seek approval of capital expenditure plans under which gas companies can recognize carrying costs on associated capital investments placed in service and can defer the carrying costs plus depreciation and property tax expenses for recovery from ratepayers in the future.

(10) Under PIPP, eligible customers can make reduced payments based on their ability to pay. The difference between the customer's total bill and the PIPP plan amount is deferred and collected or returned annually under the PIPP rate adjustment clause according to East Ohio tariff provisions. See Note 13 for more information.

(11) Rates charged to customers by the Companies' regulated businesses include a provision for the cost of future activities to remove assets that are expected to be incurred at the time of retirement.

(12) Primarily reflects a regulatory liability representing amounts collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of Virginia Power's utility nuclear generation stations, in excess of the related AROs.

At December 31, 2016, $303 million of Dominion's, $230 million of Virginia Power's and $31 million of Dominion Gas' regulatory assets represented past expenditures on which they do not currently earn a return. With the exception of the $192 million PJM transmission cost allocation matter, the majority of these expenditures are expected to be recovered within the next two years.

Note 13. Regulatory Matters

Regulatory Matters Involving Potential Loss Contingencies

As a result of issues generated in the ordinary course of business, the Companies are involved in various regulatory matters. Certain regulatory matters may ultimately result in a loss; however, as such matters are in an initial procedural phase, involve uncertainty as to the outcome of pending reviews or orders, and/or involve significant factual issues that need to be resolved, it is not possible for the Companies to estimate a range of possible loss. For matters for which the Companies cannot estimate a range of possible loss, a statement to this effect is made in the description of the matter. Other matters may have progressed sufficiently through the regulatory process such that the Companies are able to estimate a range of possible loss. For regulatory matters for which the Companies are able to reasonably estimate a range of possible losses, an estimated range of possible loss is provided, in excess of the accrued liability (if any) for such matters. Any estimated range is based on currently available information, involves elements of judgment and significant uncertainties and may not represent the Companies' maximum possible loss exposure. The circumstances of such regulatory matters will change from time to time and actual results may vary significantly from the current estimate. For current matters not specifically reported below, management does not anticipate that the outcome from such matters would have a material effect on the Companies' financial position, liquidity or results of operations.

FERC—Electric

Under the Federal Power Act, FERC regulates wholesale sales and transmission of electricity in interstate commerce by public utilities. Dominion's merchant generators sell electricity in the PJM, MISO, CAISO and ISO-NE wholesale markets, and to wholesale purchasers in the states of Virginia, North Carolina, Indiana, Connecticut, Tennessee, Georgia, California and Utah, under Dominion's market-based sales tariffs authorized by FERC or pursuant to FERC authority to sell as a qualified facility. Virginia Power purchases and, under its FERC market-based rate authority, sells electricity in the wholesale market. In addition, Virginia Power has FERC approval of a tariff to sell wholesale power at capped rates based on its embedded cost of generation. This cost-based sales tariff could be used to sell to loads within or outside Virginia Power's service territory. Any such sales would be voluntary.

Rates

In April 2008, FERC granted an application for Virginia Power's electric transmission operations to establish a forward-looking formula rate mechanism that updates transmission rates on an annual basis and approved an ROE of 11.4%, effective as of January 1, 2008. The formula rate is designed to recover the expected revenue requirement for each calendar year and is updated based on actual costs. The FERC-approved formula method, which is based on projected costs, allows Virginia Power to earn a current return on its growing investment in electric transmission infrastructure.

In March 2010, ODEC and North Carolina Electric Membership Corporation filed a complaint with FERC against Virginia Power claiming that $223 million in transmission costs related to specific projects were unjust, unreasonable and unduly discriminatory or preferential and should be excluded from Virginia Power's transmission formula rate. In October 2010, FERC issued an order dismissing the complaint in part and established hearings and settlement procedures on the remaining part of the complaint. In February 2012, Virginia Power submitted to FERC a settlement agreement to resolve all issues set for hearing. The settlement was accepted by FERC in May 2012 and provides for payment by Virginia Power to the transmission customer parties collectively of $250,000 per year for ten years and resolves all matters other than allocation of the incremental cost of certain underground transmission facilities.

In March 2014, FERC issued an order excluding from Virginia Power's transmission rates for wholesale transmission customers located outside Virginia the incremental costs of undergrounding certain transmission line projects. FERC found it is not just and reasonable for non-Virginia wholesale transmission customers to be allocated the incremental costs of undergrounding the facilities because the projects are a direct result of Virginia legislation and Virginia Commission pilot programs intended to benefit the citizens of Virginia. The order is retroactively effective as of March 2010 and will cause the reallocation of the costs charged to wholesale transmission customers with loads outside Virginia to wholesale transmission customers with loads in Virginia. FERC determined that there was not sufficient evidence on the record to determine the magnitude of the underground increment and held a hearing to determine the appropriate amount of undergrounding cost to be allocated to each wholesale transmission customer in Virginia. While Virginia Power cannot predict the outcome of the hearing, it is not expected to have a material effect on results of operations.

PJM Transmission Rates

In April 2007, FERC issued an order regarding its transmission rate design for the allocation of costs among PJM transmission customers, including Virginia Power, for transmission service provided by PJM. For new PJM-planned transmission facilities that operate at or above 500 kV, FERC established a PJM regional rate design where customers pay according to each customer's share of the region's load. For recovery of costs of existing facilities, FERC approved the existing methodology whereby a customer pays the cost of facilities located in the same zone as the customer. A number of parties appealed the order to the U.S. Court of Appeals for the Seventh Circuit.

In August 2009, the court issued its decision affirming the FERC 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 for further consideration by FERC. On remand, FERC reaffirmed its earlier decision to allocate the costs of new facilities 500 kV and above according to the customer's share of the region's load. A number of parties filed appeals of the order to the U.S. Court of Appeals for the Seventh Circuit. In June 2014, the court again remanded the cost allocation issue to FERC. In December 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the cost allocation issue. The hearing only concerns the costs of new facilities approved by PJM prior to February 1, 2013. Transmission facilities approved after February 1, 2013 are allocated on a hybrid cost allocation method approved by FERC and not subject to any court review.

In June 2016, PJM, the PJM transmission owners and state commissions representing substantially all of the load in the PJM market submitted a settlement to FERC to resolve the outstanding issues regarding this matter. Under the terms of the settlement, Virginia Power would be required to pay approximately $200 million to PJM over the next 10 years. Although the settlement agreement has not been accepted by FERC, and the settlement is opposed by a small group of parties to the proceeding, Virginia Power believes it is probable it will be required to make payment as an outcome of the settlement. Accordingly, as of December 31, 2016, Virginia Power has a contingent liability of $200 million in other deferred credits and other liabilities, which is offset by a $192 million regulatory asset for the amount that will be recovered through retail rates in Virginia. The remaining $8 million was recorded in other operations and maintenance expense, during 2015, in the Consolidated Statements of Income.

Other Regulatory Matters

Electric Regulation in Virginia

The Regulation Act enacted in 2007 instituted a cost-of-service rate model, ending Virginia's planned transition to retail competition for electric supply service to most classes of customers.

The Regulation Act authorizes stand-alone rate adjustment clauses for recovery of costs for new generation projects, FERC-approved transmission costs, underground distribution lines, environmental compliance, conservation and energy efficiency programs and renewable energy programs, and also contains statutory provisions directing Virginia Power to file annual fuel cost recovery cases with the Virginia Commission. As amended, it provides for enhanced returns on capital expenditures on specific newly-proposed generation projects.

If the Virginia Commission's future rate decisions, including actions relating to Virginia Power's rate adjustment clause filings, differ materially from Virginia Power's expectations, it may adversely affect its results of operations, financial condition and cash flows.

Regulation Act Legislation

In February 2015, the Virginia Governor signed legislation into law which will keep Virginia Power's base rates unchanged until at least December 1, 2022. In addition, no biennial reviews will be conducted by the Virginia Commission for the five successive

12-month test periods beginning January 1, 2015, and ending December 31, 2019. The legislation states that Virginia Power's 2015 biennial review, filed in March 2015, would proceed for the sole purpose of reviewing and determining whether any refunds are due to customers based on earnings performance for generation and distribution services during the 2013 and 2014 test periods. In addition the legislation requires the Virginia Commission to conduct proceedings in 2017 and 2019 to determine the utility's ROE for use in connection with rate adjustment clauses and requires utilities to file integrated resource plans annually rather than biennially. In November 2015, the Virginia Commission ordered testimony, briefs and a separate bifurcated hearing in Virginia Power's then-pending Rider B, R, S, and W cases on whether the Virginia Commission can adjust the ROE applicable to these rate adjustment clauses prior to 2017. In February 2016, the Virginia Commission issued final orders in these cases, stating that it could adjust the ROE and setting a base ROE of 9.6% for the projects. After separate, additional bifurcated hearings, the Virginia Commission issued final orders setting base ROEs of 9.6% in March 2016 for Rider GV, in April 2016 for Riders C1A and C2A, in June 2016 for Riders BW and US-2, and in August 2016 for Rider U. In February 2017, the Virginia Commission issued final orders setting base ROEs of 9.4% for Riders B, R, S, W, and GV effective April 1, 2017.

In February 2016, certain industrial customers of APCo petitioned the Virginia Commission to issue a declaratory judgment that Virginia legislation enacted in 2015 keeping APCo's base rates unchanged until at least 2020 (and Virginia Power's base rates unchanged until at least 2022) is unconstitutional, and to require APCo to make biennial review filings in 2016 and 2018. Virginia Power intervened to support the constitutionality of this legislation. In July 2016, the Virginia Commission held in a divided opinion that this legislation is constitutional, and the industrial customers appealed this order to the Supreme Court of Virginia. In November 2016, the Supreme Court of Virginia granted the appeal as a matter of right and consolidated it for oral argument with other similar appeals from the Virginia Commission's order. These appeals are pending.

2015 Biennial Review

Pursuant to the Regulation Act, in March 2015, Virginia Power filed its base rate case and schedules for the Virginia Commission's 2015 biennial review of Virginia Power's rates, terms and conditions. Per legislation enacted in February 2015, this biennial review was limited to reviewing Virginia Power's earnings on rates for generation and distribution services for the combined 2013 and 2014 test period, and determining whether credits are due to customers in the event Virginia Power's earnings exceeded the earnings band determined in the 2013 Biennial Review Order. In November 2015, the Virginia Commission issued the 2015 Biennial Review Order.

After deciding several contested regulatory earnings adjustments, the Virginia Commission ruled that Virginia Power earned on average an ROE of approximately 10.89% on its generation and distribution services for the combined 2013 and 2014 test periods. Because this ROE was more than 70 basis points above Virginia Power's authorized ROE of 10.0%, the Virginia Commission ordered that approximately $20 million in excess earnings be credited to customer bills based on usage in 2013 and 2014 over a six-month period beginning within 60 days of the 2015 Biennial Review Order. Based upon 2015 legislation keeping Virginia Power's base rates unchanged until at least December 1, 2022, the Virginia Commission did not order certain existing rate adjustment clauses to be combined with Virginia Power's base rates. The Virginia Commission did not determine whether Virginia Power had a revenue deficiency or sufficiency when projecting the annual revenues generated by base rates to the revenues required to recover costs of service and earn a fair return. In December 2015, a group of large industrial customers filed notices of appeal with the Supreme Court of Virginia from both the 2015 Biennial Review Order and the Virginia Commission's order denying their petition for rehearing or reconsideration. In April 2016, the Supreme Court of Virginia granted these appeals as a matter of right. Also in April 2016, the Attorney General filed an unopposed motion to suspend appellate briefing pending the outcome of a separate case at the Virginia Commission raising the same issues. In May 2016, the Supreme Court of Virginia denied the Attorney General's unopposed motion to suspend briefing in the previously granted appeals from the Virginia Commission's orders. The Supreme Court of Virginia later granted leave for the industrial customer appellants to withdraw their appeals, thus concluding this matter.

Virginia Fuel Expenses

In May 2016, Virginia Power submitted its annual fuel factor to the Virginia Commission to recover an estimated $1.4 billion in Virginia jurisdictional projected fuel expenses for the rate year beginning July 1, 2016. Virginia Power's proposed fuel rate represented a fuel revenue decrease of $286 million when applied to projected kilowatt-hour sales for the period July 1, 2016 to June 30, 2017. In October 2016, the Virginia Commission approved Virginia Power's proposed fuel rate.

Solar Facility Projects

In February 2017, Virginia Power received approval from the Virginia Commission for a CPCN to construct and operate the Remington solar facility and related distribution interconnection facilities. The total estimated cost of the Remington solar facility is approximately $47 million, excluding financing costs. The facility is now the subject of a public-private partnership whereby the Commonwealth of Virginia, a non-jurisdictional customer, will compensate Virginia Power for the facility's net electrical energy output, and Microsoft Corporation will purchase all environmental attributes (including renewable energy certificates) generated by the facility. There is no rate adjustment clause associated with this CPCN, nor will any costs of the project be recovered from jurisdictional customers.

In October 2015, Virginia Power filed an application with the Virginia Commission for CPCNs to construct and operate the Scott Solar, Whitehouse, and Woodland solar facilities and related distribution-level interconnection facilities. Virginia Power also applied for approval of Rider US-2 to recover the costs of these projects. In June 2016, the Virginia Commission granted the requested CPCNs and approved a $4 million revenue requirement, subject to true-up on a cost-of-service basis using a 9.6% ROE for Rider US-2 for the rate year beginning September 1, 2016. These projects were placed into service in

December 2016, and increased Dominion's renewable generation by a combined 56 MW at a total cost of approximately $130 million, excluding financing costs. See below for further information on Rider US-2.

In August 2016, Virginia Power filed an application with the Virginia Commission for a CPCN to construct and operate the Oceana solar facility and related distribution interconnection facilities on land owned by the U.S. Navy. The facility would begin commercial operations in late 2017 and increase Dominion's renewable generation by approximately 18 MW at an estimated cost of approximately $40 million, excluding financing costs. The facility is the subject of a public-private partnership whereby the Commonwealth of Virginia, a non-jurisdictional customer, will compensate Virginia Power for the facility's net electrical energy output. Virginia Power will retire renewable energy certificates on the Commonwealth's behalf in an amount equal to those generated by the facility. There is no rate adjustment clause associated with this CPCN filing, nor will any costs of the project be recovered from jurisdictional customers. This case is pending.

Rate Adjustment Clauses

Below is a discussion of significant riders associated with various Virginia Power projects:

- The Virginia Commission previously approved Rider T1 concerning transmission rates. In May 2016, Virginia Power proposed a $639 million total revenue requirement for the rate year beginning September 1, 2016, which represents a $1 million increase over the revenues projected to be produced during the rate year under current rates. In July 2016, the Virginia Commission approved Virginia Power's proposed total revenue requirement.
- The Virginia Commission previously approved Rider S in conjunction with the Virginia City Hybrid Energy Center. In February 2016, the Virginia Commission approved a $251 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2016. It also established a 10.6% ROE for Rider S effective April 1, 2016. In June 2016, Virginia Power proposed a $254 million revenue requirement for the rate year beginning April 1, 2017, which represents a $3 million increase over the previous year. In February 2017, the Virginia Commission established a 10.4% ROE for Rider S effective April 1, 2017. This case is pending.
- The Virginia Commission previously approved Rider W in conjunction with Warren County. In February 2016, the Virginia Commission approved a $118 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2016. It also established a 10.6% ROE for Rider W effective April 1, 2016. In June 2016, Virginia Power proposed a $126 million revenue requirement for the rate year beginning April 1, 2017, which represents an $8 million increase over the previous year. In February 2017, the Virginia Commission established a 10.4% ROE for Rider W effective April 1, 2017. This case is pending.
- The Virginia Commission previously approved Rider R in conjunction with Bear Garden. In February 2016, the Virginia Commission approved a $74 million revenue requirement, subject to true-up, for the rate year beginning April 1, 2016. It also established a 10.6% ROE for Rider R effective April 1, 2016. In June 2016, Virginia Power proposed a $75 million revenue requirement for the rate year beginning April 1, 2017, which represents a $1 million increase over the previous year. In February 2017, the Virginia Commission established a 10.4% ROE for Rider R effective April 1, 2017. This case is pending.
- The Virginia Commission previously approved Rider B in conjunction with the conversion of three power stations to biomass. In February 2016, the Virginia Commission approved a $30 million revenue requirement for the rate year beginning April 1, 2016. It also established an 11.6% ROE for Rider B effective April 1, 2016. In June 2016, Virginia Power proposed a $28 million revenue requirement for the rate year beginning April 1, 2017, which represents a $2 million decrease versus the previous year. In February 2017, the Virginia Commission established an 11.4% ROE for Rider B effective April 1, 2017. This case is pending.
- The Virginia Commission previously approved Rider U in conjunction with cost recovery to move certain electric distribution facilities underground as authorized by prior Virginia legislation. In August 2016, the Virginia Commission approved a net $20 million revenue requirement and a 9.6% ROE for the rate year beginning September 1, 2016, and an additional $2 million in credits to offset approved revenue requirements for Phase One for each of the 2017-2018 and 2018-2019 rate years. The order limited the total investment in Phase One of Virginia Power's proposed program to $140 million, with $123 million recoverable through Rider U. In December 2016, Virginia Power proposed a total $31 million revenue requirement for Phase One and Phase Two costs for the rate year beginning September 1, 2017. Virginia Power's estimated total investment in Phase Two is $110 million. This case is pending.
- The Virginia Commission previously approved Riders C1A and C2A in connection with cost recovery for DSM programs. In April 2016, the Virginia Commission approved a $46 million revenue requirement, subject to true-up, for the rate year beginning May 1, 2016. It also established a 9.6% ROE for Riders C1A and C2A effective May 1, 2016. The Virginia Commission approved one new energy efficiency program at a reduced cost cap, denied a second energy efficiency program, and approved the extension of an existing peak shaving program recovered in base rates at no additional incremental cost. In October 2016, Virginia Power proposed a total revenue requirement of $45 million for the rate year beginning July 1, 2017. Virginia Power also proposed two new energy efficiency programs for Virginia Commission approval with a requested five-year cost cap of $178 million. Virginia Power further proposed to extend an existing energy efficiency program for an additional two years under current funding, and an existing peak shaving program for an additional five years with an additional $5 million cost cap. This case is pending.
- The Virginia Commission previously approved Rider BW in conjunction with Brunswick County. In June 2016, the Virginia Commission approved a $119 million revenue requirement for the rate year beginning September 1, 2016. It also established a 10.6% ROE for Rider BW effective September 1, 2016. In October 2016, Virginia Power proposed a

$134 million revenue requirement for the rate year beginning September 1, 2017, which represents a $15 million increase over the previous year. This case is pending.

- The Virginia Commission previously approved Rider US-2 in conjunction with the Scott Solar, Whitehouse, and Woodland solar facilities. In June 2016, the Virginia Commission approved a $4 million revenue requirement for the rate year beginning September 1, 2016. It also established a 9.6% ROE for Rider US-2 effective September 1, 2016. In October 2016, Virginia Power proposed a $10 million revenue requirement for the rate year beginning September 1, 2017, which represents a $6 million increase over the previous year. This case is pending.
- In July 2015, Virginia Power filed an application with the Virginia Commission for a CPCN to construct and operate Greensville County and related transmission interconnection facilities. Virginia Power also applied for approval of Rider GV to recover the costs of Greensville County. In March 2016, the Virginia Commission granted the requested CPCN and approved a $40 million revenue requirement for the rate year beginning April 1, 2016. It also established a 9.6% ROE for Rider GV effective April 1, 2016. In June 2016, Virginia Power proposed an $89 million revenue requirement for the rate year beginning April 1, 2017, which represents a $49 million increase over the previous year. In February 2017, the Virginia Commission established a 9.4% ROE for Rider GV effective April 1, 2017. This matter is pending.

Electric Transmission Projects

In November 2013, the Virginia Commission issued an order granting Virginia Power a CPCN to construct approximately 7 miles of new overhead 500 kV transmission line from the existing Surry switching station in Surry County to a new Skiffes Creek switching station in James City County, and approximately 20 miles of new 230 kV transmission line in James City County, York County, and the City of Newport News from the proposed new Skiffes Creek switching station to Virginia Power's existing Whealton substation in the City of Hampton. In February 2014, the Virginia Commission granted reconsideration requested by Virginia Power and issued an Order Amending Certificate. Several appeals were filed with the Supreme Court of Virginia. In April 2015, the Supreme Court of Virginia issued its opinion in the consolidated appeals of the Virginia Commission's order granting a CPCN for the Skiffes Creek transmission line and related facilities. The Supreme Court of Virginia unanimously affirmed all but one of the alleged grounds for appeal. The court approved the proposed project including the proposed route for a 500 kV overhead transmission line from Surry to the Skiffes Creek switching station site. The court reversed and remanded the Virginia Commission's determination in one set of appeals that the Skiffes Creek switching station was a transmission line for purposes of statutory exemption from local zoning ordinances. In May 2015, the Supreme Court of Virginia denied separate petitions filed by Virginia Power and the Virginia Commission to rehear its ruling regarding the Skiffes Creek switching station. Pending receipt of remaining required permits and approvals, Virginia Power expects to construct the project.

Virginia Power previously filed an application with the Virginia Commission for a CPCN to construct and operate in Loudoun County, Virginia, a new approximately 230 kV Poland Road substation, and a new approximately four mile overhead 230 kV double circuit transmission line between the existing 230 kV Loudoun-Brambleton line and the Poland Road substation. In August 2016, the Virginia Commission granted a CPCN to construct and operate the project along a revised route. The total estimated cost of the project is approximately $55 million.

In November 2015, Virginia Power filed an application with the Virginia Commission for a CPCN to convert an existing transmission line to 230 kV in Prince William County, Virginia, and Loudoun County, Virginia, and to construct and operate a new approximately five mile overhead 230 kV double circuit transmission line between a tap point near the Gainesville substation and a new to-be-constructed Haymarket substation. The total estimated cost of the project is approximately $55 million. This case is pending.

In November 2015, Virginia Power filed an application with the Virginia Commission for a CPCN to construct and operate in multiple Virginia counties an approximately 38 mile overhead 230 kV transmission line between the Remington and Gordonsville substations, along with associated facilities. The total estimated cost of the project is approximately $105 million. This case is pending.

In February 2016, the Virginia Commission issued an order granting Virginia Power a CPCN to construct and operate the Remington CT-Warrenton 230 kV double circuit transmission line, the Vint Hill-Wheeler and Wheeler-Gainesville 230 kV lines and the 230 kV Vint Hill and Wheeler switching stations along Virginia Power's proposed route. The total estimated cost of the project is approximately $110 million.

In March 2016, Virginia Power filed an application with the Virginia Commission for a CPCN to rebuild and operate in multiple Virginia counties approximately 33 miles of the existing 500 kV transmission line between the Cunningham switching station and the Dooms substation, along with associated station work. The total estimated cost of the project is approximately $60 million. This case is pending.

In August 2016, Virginia Power filed an application with the Virginia Commission for a CPCN to rebuild and operate in multiple Virginia counties approximately 28 miles of the existing 500 kV transmission line between the Carson switching station and a terminus located near the Rogers Road switching station under construction in Greensville County, Virginia, along with associated work at the Carson switching station. The total estimated cost of the project is approximately $55 million. This case is pending.

In January 2017, Virginia Power filed an application with the Virginia Commission for a CPCN to rebuild and rearrange its Idylwood substation in Fairfax County, Virginia. The total estimated cost of the project is approximately $110 million. This case is pending.

North Anna

Virginia Power is considering the construction of a third nuclear unit at a site located at North Anna nuclear power station. If Virginia Power decides to build a new unit, it must first receive a COL from the NRC, approval of the Virginia Commission and certain environmental permits and other approvals. The COL is expected in 2017. Virginia Power has not yet committed to building a new nuclear unit at North Anna nuclear power station.

Requests by BREDL for a contested NRC hearing on Virginia Power's COL application have been dismissed, and in September 2016, the U.S. Court of Appeals for the D.C. Circuit dismissed with prejudice petitions for judicial review that BREDL and other organizations had filed challenging the NRC's reliance on a rule generically assessing the environmental impacts of continued onsite storage of spent nuclear fuel in various licensing proceedings, including Virginia Power's COL proceeding. This dismissal followed the Court's June 2016 decision in New York v. NRC, upholding the NRC's continued storage rule and August 2016 denial of requests for rehearing en banc. Therefore, the contested portion of the COL proceeding is closed. The NRC is required to conduct a hearing in all COL proceedings. This mandatory NRC hearing is anticipated to occur in the first half of 2017 and will be uncontested.

In August 2016, Virginia Power received a 60-day notice of intent to sue from the Sierra Club alleging Endangered Species Act violations. The notice alleges that the U.S. Army Corps of Engineers failed to conduct adequate environmental and consultation reviews, related to a potential third nuclear unit located at North Anna, prior to issuing a CWA section 404 permit to Virginia Power in September 2011. No lawsuit has been filed and in November 2016, the Army Corps of Engineers suspended the section 404 permit while it gathers additional information. This permitting issue is not expected to affect the NRC's issuance of the COL. Virginia Power is currently unable to make an estimate of the potential impacts to its consolidated financial statements related to this matter.

North Carolina Regulation

In March 2016, Virginia Power filed its base rate case and schedules with the North Carolina Commission. Virginia Power proposed a non-fuel, base rate increase of $51 million effective November 1, 2016 with an ROE of 10.5%. In October 2016, Virginia Power entered into a stipulation and settlement agreement for a non-fuel, base rate increase of $35 million with an ROE of 9.9% effective November 1, 2016, on a temporary basis subject to refund, with any permanent rates ordered by the North Carolina Commission effective January 1, 2017. In December 2016, the North Carolina Commission approved the stipulation and settlement agreement.

In August 2016, Virginia Power submitted its annual filing to the North Carolina Commission to adjust the fuel component of its electric rates. Virginia Power proposed a total $36 million decrease to the fuel component of its electric rates for the rate year beginning January 1, 2017. In December 2016, the North Carolina Commission approved the requested decrease and an additional $1 million reduction to Virginia Power's fuel rates.

Ohio Regulation

PIR Program

In 2008, East Ohio began PIR, aimed at replacing approximately 25% of its pipeline system. In March 2015, East Ohio filed an application with the Ohio Commission requesting approval to extend the PIR program for an additional five years and to increase the annual capital investment, with corresponding increases in the annual rate-increase caps. In September 2016, the Ohio Commission approved a stipulation filed jointly by East Ohio and the Staff of the Ohio Commission to settle East Ohio's pending application. As requested, the PIR Program and associated cost recovery will continue for another five-year term, calendar years 2017 through 2021, and East Ohio will be permitted to increase its annual capital expenditures to $200 million by 2018 and 3% per year thereafter subject to the cost recovery rate increase caps proposed by East Ohio. Costs associated with calendar year 2016 investment will be recovered under the existing terms.

In February 2016, East Ohio filed an application to adjust the PIR cost recovery for 2015 costs. The filing reflects gross plant investment for 2015 of $171 million, cumulative gross plant investment of $1 billion and a revenue requirement of $131 million. This application was approved by the Ohio Commission in April 2016.

AMR Program

In 2007, East Ohio began installing automated meter reading technology for its 1.2 million customers in Ohio. The AMR program approved by the Ohio Commission was completed in 2012. Although no further capital investment will be added, East Ohio is approved to recover depreciation, property taxes, carrying charges and a return until East Ohio has another rate case.

In February 2016, East Ohio filed an application to adjust the AMR cost recovery for costs incurred during the calendar year 2015. The filing reflects a revenue requirement of approximately $7 million. This application was approved by the Ohio Commission in April 2016.

PIPP Plus Program

Under the Ohio PIPP Plus Program, eligible customers can make reduced payments based on their ability to pay their bill. The difference between the customer's total bill and the PIPP amount is deferred and collected under the PIPP Rider in accordance with the rules of the Ohio Commission. In July 2016, East Ohio's annual update of the PIPP Rider was automatically approved by the Ohio Commission after a 45-day waiting period from the date of the filing. The revised rider rate reflects the recovery over the twelve-month period from July 2016 through June 2017 of projected deferred program costs of approximately $32 million from April 2016 through June 2017, net of a refund for over-recovery of accumulated arrearages of approximately $28 million as of March 31, 2016.

UEX Rider

East Ohio has approval for a UEX Rider through which it recovers the bad debt expense of most customers not participating in the PIPP Plus Program. The UEX Rider is adjusted annually to achieve dollar for dollar recovery of East Ohio's actual write-offs of uncollectible amounts. In August 2016, the Ohio Commission approved an increase to East Ohio's UEX Rider, which reflects a refund of over-recovered accumulated bad debt expense of approximately $8 million as of March 31, 2016, and recovery of prospective net bad debt expense projected to total approximately $19 million for the twelve-month period from April 2016 to March 2017.

PSMP

In November 2016, the Ohio Commission approved East Ohio's request to defer the operation and maintenance costs associated with implementing PSMP of up to $15 million per year.

West Virginia Regulation

In May 2016, Hope filed a PREP application with the West Virginia Commission requesting approval of a projected capital investment for 2017 of $27 million as part of a total five-year projected capital investment of $152 million. In September 2016, Hope reached a settlement with all parties to the case agreeing to new PREP customer rates, for the year beginning November 1, 2016, that provide for annual projected revenue of $2 million related to capital investments of $20 million and $27 million for 2016 and 2017, respectively. In October 2016, the West Virginia Commission approved the settlement.

FERC—Gas

Cove Point

In November 2016, pursuant to the terms of a previous settlement, Cove Point filed a general rate case for its FERC-jurisdictional services, with 23 proposed rates to be effective January 1, 2017. Cove Point proposed an annual cost-of-service of approximately $140 million. In December 2016, FERC accepted a January 1, 2017 effective date for all proposed rates but five which were suspended to be effective June 1, 2017.

Note 14. Asset Retirement Obligations

AROs represent obligations that result from laws, statutes, contracts and regulations related to the eventual retirement of certain of the Companies' long-lived assets. Dominion's and Virginia Power's AROs are primarily associated with the decommissioning of their nuclear generation facilities and ash pond and landfill closures. Dominion Gas' AROs primarily include plugging and abandonment of gas and oil wells and the interim retirement of natural gas gathering, transmission, distribution and storage pipeline components.

The Companies have also identified, but not recognized, AROs related to the retirement of Dominion's LNG facility, Dominion's and Dominion Gas' storage wells in their underground natural gas storage network, certain Virginia Power electric transmission and distribution assets located on property with easements, rights of way, franchises and lease agreements, Virginia Power's hydroelectric generation facilities and the abatement of certain asbestos not expected to be disturbed in Dominion's and Virginia Power's generation facilities. The Companies currently do not have sufficient information to estimate a reasonable range of expected retirement dates for any of these assets since the economic lives of these assets can be extended indefinitely through regular repair and maintenance and they currently have no plans to retire or dispose of any of these assets. As a result, a settlement date is not determinable for these assets and AROs for these assets will not be reflected in the Consolidated Financial Statements until sufficient information becomes available to determine a reasonable estimate of the fair value of the activities to be performed. The Companies continue to monitor operational and strategic developments to identify if sufficient information exists to reasonably estimate a retirement date for these assets. The changes to AROs during 2015 and 2016 were as follows:

	Amount
(millions)	
Dominion	
AROs at December 31, 2014	$ 1,714
Obligations incurred during the period(1)	315
Obligations settled during the period	(106)
Revisions in estimated cash flows(1)	88
Accretion	93
Other	(1)
AROs at December 31, 2015(2)	$ 2,103
Obligations incurred during the period(3)	**204**
Obligations settled during the period	**(171)**
Revisions in estimated cash flows(1)	**245**
Accretion	**104**
AROs at December 31, 2016(2)	**$ 2,485**
Virginia Power	
AROs at December 31, 2014	$ 855
Obligations incurred during the period(1)	289
Obligations settled during the period	(39)
Revisions in estimated cash flows(1)	92
Accretion	50
AROs at December 31, 2015	$ 1,247
Obligations incurred during the period	**9**
Obligations settled during the period	**(115)**
Revisions in estimated cash flows(1)	**245**
Accretion	**57**
AROs at December 31, 2016	**$ 1,443**

(millions)	Amount
Dominion Gas	
AROs at December 31, 2014	$ 147
Obligations incurred during the period	5
Obligations settled during the period	(6)
Revisions in estimated cash flows	(5)
Accretion	9
Other	(1)
AROs at December 31, 2015(4)	$ 149
Obligations incurred during the period	**6**
Obligations settled during the period	**(8)**
Revisions in estimated cash flows	**—**
Accretion	**9**
AROs at December 31, 2016(4)	**$ 156**

(1) Primarily reflects future ash pond and landfill closure costs at certain utility generation facilities. See Note 22 for further information.
(2) Includes $216 million and $249 million reported in other current liabilities at December 31, 2015, and 2016, respectively.
(3) Primarily reflects AROs assumed in the Dominion Questar Combination. See Note 3 for further information.
(4) Includes $137 million and $147 million reported in other deferred credits and other liabilities, with the remainder recorded in other current liabilities, at December 31, 2015 and 2016, respectively.

Dominion and Virginia Power have established trusts dedicated to funding the future decommissioning of their nuclear plants. At December 31, 2016 and 2015, the aggregate fair value of Dominion's trusts, consisting primarily of equity and debt securities, totaled $4.5 billion and $4.2 billion, respectively. At December 31, 2016 and 2015, the aggregate fair value of Virginia Power's trusts, consisting primarily of debt and equity securities, totaled $2.1 billion and 1.9 billion, respectively.

NOTE 15. VARIABLE INTEREST ENTITIES

The primary beneficiary of a VIE is required to consolidate the VIE and to disclose certain information about its significant variable interests in the VIE. The primary beneficiary of a VIE is the entity that has both 1) the power to direct the activities that most significantly impact the entity's economic performance and 2) the obligation to absorb losses or receive benefits from the entity that could potentially be significant to the VIE.

Dominion

At December 31, 2016, Dominion owns the general partner, 50.9% of the common and subordinated units and 37.5% of the convertible preferred interests in Dominion Midstream, which owns a preferred equity interest and the general partner interest in Cove Point. Additionally, Dominion owns the manager and 67% of the membership interest in certain merchant solar facilities, as discussed in Note 2. Dominion has concluded that these entities are VIEs due to the limited partners or members lacking the characteristics of a controlling financial interest. In addition, in 2016 Dominion created a wholly owned subsidiary, SBL Holdco, as a holding company of its interest in the VIE merchant solar facilities and accordingly SBL Holdco is a VIE. Dominion is the primary beneficiary of Dominion Midstream, SBL Holdco and the merchant solar facilities, and Dominion Midstream is the primary beneficiary of Cove Point, as they have the power to direct the activities that most significantly impact their economic performance as well as the obligation to absorb losses and benefits which could be significant to them. Dominion's securities due within one year and long-term debt include $17 million and $377 million, respectively, of debt issued in 2016 by SBL Holdco net of issuance costs that is nonrecourse to Dominion and is secured by SBL Holdco's interest in the merchant solar facilities.

Dominion owns a 48% membership interest in Atlantic Coast Pipeline. See Note 9 for more details regarding the nature of this entity. Dominion concluded that Atlantic Coast Pipeline is a VIE because it has insufficient equity to finance its activities without additional subordinated financial support. Dominion has concluded that it is not the primary beneficiary of Atlantic Coast Pipeline as it does not have the power to direct the activities of Atlantic Coast Pipeline that most significantly impact its economic performance, as the power to direct is shared among multiple unrelated parties. Dominion is obligated to provide capital contributions based on its ownership percentage. Dominion's maximum exposure to loss is limited to its current and future investment.

Dominion and Virginia Power

Dominion's and Virginia Power's nuclear decommissioning trust funds and Dominion's rabbi trusts hold investments in limited partnerships or similar type entities (see Note 9 for further details). Dominion and Virginia Power concluded that these partnership investments are VIEs due to the limited partners lacking the characteristics of a controlling financial interest. Dominion and Virginia Power have concluded neither is the primary beneficiary as they do not have the power to direct the activities that most significantly impact these VIEs' economic performance. Dominion and Virginia Power are obligated to provide capital contributions to the partnerships as required by each partnership agreement based on their ownership percentages. Dominion and Virginia Power's maximum exposure to loss is limited to their current and future investments.

Dominion and Dominion Gas

Dominion previously concluded that Iroquois was a VIE because a non-affiliated Iroquois equity holder had the ability during a limited period of time to transfer its ownership interests to another Iroquois equity holder or its affiliate. At the end of the first quarter of 2016, such right no longer existed and, as a result, Dominion concluded that Iroquois is no longer a VIE.

Virginia Power

Virginia Power had long-term power and capacity contracts with five non-utility generators, which contain certain variable pricing mechanisms in the form of partial fuel reimbursement that Virginia Power considers to be variable interests. Contracts with two of these non-utility generators expired during 2015 leaving a remaining aggregate summer generation capacity of approximately 418 MW. After an evaluation of the information provided by these entities, Virginia Power was unable to determine whether they were VIEs. However, the information they provided, as well as Virginia Power's knowledge of generation facilities in Virginia, enabled Virginia Power to conclude that, if they were VIEs, it would not be the primary beneficiary. This conclusion reflects Virginia Power's determination that its variable interests do not convey the power to direct the most significant activities that impact the economic performance of the entities during the remaining terms of Virginia Power's contracts and for the years the entities are expected to operate after its contractual relationships expire. The remaining contracts expire at various dates ranging from 2017 to 2021. Virginia Power is not subject to any risk of loss from these potential VIEs other than its remaining purchase commitments which totaled $287 million as of December 31, 2016. Virginia Power paid $144 million, $200 million, and $223 million for electric capacity and $31 million, $83 million, and $138 million for electric energy to these entities for the years ended December 31, 2016, 2015 and 2014, respectively.

Dominion Gas

DTI has been engaged to oversee the construction of, and to subsequently operate and maintain, the projects undertaken by Atlantic Coast Pipeline based on the overall direction and oversight of Atlantic Coast Pipeline's members. An affiliate of DTI holds a membership interest in Atlantic Coast Pipeline, therefore DTI is considered to have a variable interest in Atlantic Coast Pipeline. The members of Atlantic Coast Pipeline hold the power to direct the construction, operations and maintenance activities of the entity. DTI has concluded it is not the primary beneficiary of Atlantic Coast Pipeline as it does not have the power to direct the activities of Atlantic Coast Pipeline that most significantly impact its economic performance. DTI has no obligation to absorb any losses of the VIE. See Note 24 for information about associated related party receivable balances.

Virginia Power and Dominion Gas

Virginia Power and Dominion Gas purchased shared services from DRS, an affiliated VIE, of $346 million and $123 million, $318 million and $115 million, and $335 million and $106 million for the years ended December 31, 2016, 2015 and 2014, respectively. Virginia Power and Dominion Gas determined that neither is the primary beneficiary of DRS as neither has both the power to direct the activities that most significantly impact its economic performance as well as the obligation to absorb losses and benefits which could be significant to it. DRS provides accounting, legal, finance and certain administrative and technical services to all Dominion subsidiaries, including Virginia Power and Dominion Gas. Virginia Power and Dominion Gas have no obligation to absorb more than their allocated shares of DRS costs.

NOTE 16. SHORT-TERM DEBT AND CREDIT AGREEMENTS

The Companies use short-term debt to fund working capital requirements and as a bridge to long-term debt financings. The levels of borrowing may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In January 2016, Dominion expanded its short-term funding resources through a $1.0 billion increase to one of its joint revolving credit facility limits. In addition, Dominion utilizes cash and letters of credit to fund collateral requirements. Collateral requirements are impacted by commodity prices, hedging levels, Dominion's credit ratings and the credit quality of its counterparties.

Dominion

Commercial paper and letters of credit outstanding, as well as capacity available under credit facilities, were as follows:

	Facility Limit	Outstanding Commercial Paper	Outstanding Letters of Credit	Facility Capacity Available
(millions)				
At December 31, 2016				
Joint revolving credit facility(1)(2)	**$5,000**	**$3,155**	**$—**	**$1,845**
Joint revolving credit facility(1)	**500**	**—**	**85**	**415**
Total	**$5,500**	**$3,155(3)**	**$85**	**$2,260**
At December 31, 2015				
Joint revolving credit facility(1)	$4,000	$3,353	$—	$ 647
Joint revolving credit facility(1)	500	156	59	285
Total	$4,500	$3,509(3)	$59	$ 932

(1) In May 2016, the maturity dates for these facilities were extended from April 2019 to April 2020. These credit facilities can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to a combined $2.0 billion of letters of credit.
(2) In January 2016, this facility limit was increased from $4.0 billion to $5.0 billion.
(3) The weighted-average interest rates of the outstanding commercial paper supported by Dominion's credit facilities were 1.05% and 0.62% at December 31, 2016 and 2015, respectively.

Dominion Questar's revolving multi-year and 364-day credit facilities with limits of $500 million and $250 million, respectively, were terminated in October 2016. Questar Gas' short-term financing is supported by the two joint revolving credit facilities discussed above with Dominion, Virginia Power and Dominion Gas, to which Questar Gas was added as a borrower in November 2016, with an initial aggregate sub-limit of $250 million. In December 2016, Questar Gas entered into a commercial paper program pursuant to which it began accessing the commercial paper markets.

In addition to the credit facilities mentioned above, SBL Holdco has $30 million of credit facilities which have a stated maturity date of December 2017 with automatic one-year renewals through the maturity of the SBL Holdco term loan agreement in 2023. As of December 31, 2016, no amounts were outstanding under these facilities.

Virginia Power

Virginia Power's short-term financing is supported through its access as co-borrower to the two joint revolving credit facilities. These credit facilities can be used for working capital, as support for the combined commercial paper programs of the Companies and for other general corporate purposes.

Virginia Power's share of commercial paper and letters of credit outstanding under its joint credit facilities with Dominion, Dominion Gas and Questar Gas were as follows:

	Facility Limit(1)	Outstanding Commercial Paper	Outstanding Letters of Credit
(millions)			
At December 31, 2016			
Joint revolving credit facility(1)(2)	**$5,000**	**$ 65**	**$—**
Joint revolving credit facility(1)	**500**	**—**	**1**
Total	**$5,500**	**$ 65(3)**	**$ 1**
At December 31, 2015			
Joint revolving credit facility(1)	$4,000	$1,500	$—
Joint revolving credit facility(1)	500	156	—
Total	$4,500	$1,656(3)	$—

(1) The full amount of the facilities is available to Virginia Power, less any amounts outstanding to co-borrowers Dominion, Dominion Gas and Questar Gas. Sub-limits for Virginia Power are set within the facility limit but can be changed at the option of Dominion, Dominion Gas and Questar Gas multiple times per year. At December 31, 2016, the sub-limit for Virginia Power was an aggregate $2.0 billion. If Virginia Power has liquidity needs in excess of its sub-limit, the sub-limit may be changed or such needs may be satisfied through short-term intercompany borrowings from Dominion. In May 2016, the maturity dates for these facilities were extended from April 2019 to April 2020. These credit facilities can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $2.0 billion (or the sub-limit, whichever is less) of letters of credit.

(2) In January 2016, this facility limit was increased from $4.0 billion to $5.0 billion.

(3) The weighted-average interest rates of the outstanding commercial paper supported by these credit facilities were 0.97% and 0.60% at December 31, 2016 and 2015, respectively.

In addition to the credit facility commitments mentioned above, Virginia Power also has a $100 million credit facility. In May 2016, the maturity date for this credit facility was extended from April 2019 to April 2020. In October 2016, this facility was reduced from $120 million to $100 million. As of December 31, 2016, this facility supports $100 million of certain variable rate tax-exempt financings of Virginia Power.

Dominion Gas

Dominion Gas' short-term financing is supported by its access as co-borrower to the two joint revolving credit facilities. These credit facilities can be used for working capital, as support for the combined commercial paper programs of the Companies and for other general corporate purposes.

Dominion Gas' share of commercial paper and letters of credit outstanding under its joint credit facilities with Dominion, Virginia Power and Questar Gas were as follows:

	Facility Limit(1)	Outstanding Commercial Paper	Outstanding Letters of Credit
(millions)			
At December 31, 2016			
Joint revolving credit facility(1)	**$1,000**	**$460**	**$—**
Joint revolving credit facility(1)	**500**	**—**	**—**
Total	**$1,500**	**$460(2)**	**$—**
At December 31, 2015			
Joint revolving credit facility(1)	$1,000	$391	$—
Joint revolving credit facility(1)	500	—	—
Total	$1,500	$391(2)	$—

(1) A maximum of a combined $1.5 billion of the facilities is available to Dominion Gas, assuming adequate capacity is available after giving effect to uses by co-borrowers Dominion, Virginia Power and Questar Gas. Sub-limits for Dominion Gas are set within the facility limit but can be changed at the option of the Companies multiple times per year. In November 2016, the aggregate sub-limit for Dominion Gas was decreased from $750 million to $500 million. If Dominion Gas has liquidity needs in excess of its sub-limit, the sub-limit may be changed or such needs may be satisfied through short-term intercompany borrowings from Dominion. In May 2016, the maturity dates for these facilities were extended from April 2019 to April 2020. These credit facilities can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $1.5 billion (or the sub-limit, whichever is less) of letters of credit.

(2) The weighted-average interest rate of the outstanding commercial paper supported by these credit facilities was 1.00% and 0.63% at December 31, 2016 and 2015, respectively.

NOTE 17. LONG-TERM DEBT

At December 31,	2016 Weighted-average Coupon[1]	2016	2015
(millions, except percentages)			
Dominion Gas Holdings, LLC:			
Unsecured Senior Notes:			
1.05% to 2.8%, due 2016 to 2020	**2.68%**	**$ 1,150**	$ 1,550
2.875% to 4.8%, due 2023 to 2044[2]	**3.90%**	**2,413**	1,750
Dominion Gas Holdings, LLC total principal		**$ 3,563**	$ 3,300
Securities due within one year		**—**	(400)
Unamortized discount and debt issuance costs		**(35)**	(31)
Dominion Gas Holdings, LLC total long-term debt		**$ 3,528**	$ 2,869
Virginia Electric and Power Company:			
Unsecured Senior Notes:			
1.2% to 8.625%, due 2016 to 2019	**4.93%**	**$ 1,804**	$ 2,261
2.75% to 8.875%, due 2022 to 2046	**4.59%**	**7,940**	6,292
Tax-Exempt Financings[3]:			
Variable rates, due 2016 to 2027	**1.22%**	**175**	194
1.75% to 5.6%, due 2023 to 2041	**2.25%**	**678**	678
Virginia Electric and Power Company total principal		**$10,597**	$ 9,425
Securities due within one year	**5.47%**	**(678)**	(476)
Unamortized discount, premium and debt issuances costs, net		**(67)**	(57)
Virginia Electric and Power Company total long-term debt		**$ 9,852**	$ 8,892
Dominion Resources, Inc.:			
Unsecured Senior Notes:			
Variable rate, due 2016		**$ —**	$ 600
1.25% to 6.4%, due 2016 to 2021	**2.83%**	**5,400**	3,900
2.75% to 7.0%, due 2022 to 2044	**4.68%**	**4,999**	4,599
Tax-Exempt Financing, variable rate, due 2041	**1.41%**	**75**	75
Unsecured Junior Subordinated Notes:			
2.962% and 4.104%, due 2019 and 2021	**3.53%**	**1,100**	—
Payable to Affiliated Trust, 8.4% due 2031	**8.40%**	**10**	10
Enhanced Junior Subordinated Notes:			
5.25% to 7.5%, due 2054 to 2076	**5.48%**	**1,485**	971
Variable rates, due 2066	**3.45%**	**422**	377
Remarketable Subordinated Notes, 1.07% to 2.0%, due 2019 to 2024	**1.79%**	**2,400**	2,100
Unsecured Debentures and Senior Notes:			
6.8% and 6.875%, due 2026 and 2027[4]	**6.81%**	**89**	89
Term Loan, variable rate, due 2017[5]	**1.85%**	**250**	—
Unsecured Senior and Medium-Term Notes[5]:			
5.31% to 6.85%, due 2017 and 2018	**5.84%**	**135**	—
2.98% to 7.20%, due 2024 to 2051	**4.57%**	**500**	—
Term Loan, variable rate, due 2023[6]	**4.75%**	**405**	—
Tax-Exempt Financing, 1.55%, due 2033[7]	**1.55%**	**27**	27
Dominion Midstream Partners, LP:			
Term Loan, variable rate, due 2019	**2.19%**	**300**	—
Unsecured Senior and Medium-Term Notes, 5.83% and 6.48%, due 2018[8]	**5.84%**	**255**	—
Unsecured Senior Notes, 4.875%, due 2041[8]	**4.88%**	**180**	—
Dominion Gas Holdings, LLC total principal (from above)		**3,563**	3,300
Virginia Electric and Power Company total principal (from above)		**10,597**	9,425
Dominion Resources, Inc. total principal		**$32,192**	$25,473
Fair value hedge valuation[9]		**(1)**	7
Securities due within one year[10]	**3.13%**	**(1,709)**	(1,825)
Unamortized discount, premium and debt issuance costs, net		**(251)**	(187)
Dominion Resources, Inc. total long-term debt		**$30,231**	$23,468

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2016.
(2) Beginning June 30, 2016, amount includes foreign currency remeasurement adjustments.
(3) These financings relate to certain pollution control equipment at Virginia Power's generating facilities. Certain variable rate tax-exempt financings are supported by a $100 million credit facility that terminates in April 2020.
(4) Represents debt assumed by Dominion from the merger of its former CNG subsidiary.

(5) Represents debt obligations of Dominion Questar or Questar Gas. See Note 3 for more information.
(6) Represents debt associated with SBL Holdco. The debt is nonrecourse to Dominion and is secured by SBL Holdco's interest in certain merchant solar facilities.
(7) Represents debt obligations of a DEI subsidiary.
(8) Represents debt obligations of Questar Pipeline. See Note 3 for more information.
(9) Represents the valuation of certain fair value hedges associated with Dominion's fixed rate debt.
(10) 2015 excludes $100 million of variable rate short-term notes that were purchased and cancelled in February 2016 using proceeds from the issuance of long-term debt. The notes would have otherwise matured in May 2016.

Based on stated maturity dates rather than early redemption dates that could be elected by instrument holders, the scheduled principal payments of long-term debt at December 31, 2016, were as follows:

	2017	2018	2019	2020	2021	Thereafter	Total
(millions, except percentages)							
Dominion Gas	**$ —**	**$ —**	**$ 450**	**$ 700**	**$ —**	**$ 2,413**	**$ 3,563**
Weighted-average Coupon			**2.50%**	**2.80%**		**3.90%**	
Virginia Power							
Unsecured Senior Notes	**$ 604**	**$ 850**	**$ 350**	**$ —**	**$ —**	**$ 7,940**	**$ 9,744**
Tax-Exempt Financings	**75**	**—**	**—**	**—**	**—**	**778**	**853**
Total	**$ 679**	**$ 850**	**$ 350**	**$ —**	**$ —**	**$ 8,718**	**$10,597**
Weighted-average Coupon	**5.47%**	**4.17%**	**5.00%**			**4.37%**	
Dominion							
Term Loans	**$ 268**	**$ 20**	**$ 321**	**$ 19**	**$ 19**	**$ 308**	**$ 955**
Unsecured Senior Notes	**1,368**	**3,275**	**2,500**	**700**	**900**	**16,122**	**24,865**
Tax-Exempt Financings	**75**	**—**	**—**	**—**	**—**	**880**	**955**
Unsecured Junior Subordinated Notes Payable to Affiliated Trusts	**—**	**—**	**—**	**—**	**—**	**10**	**10**
Unsecured Junior Subordinated Notes	**—**	**—**	**550**	**—**	**550**	**—**	**1,100**
Enhanced Junior Subordinated Notes	**—**	**—**	**—**	**—**	**—**	**1,907**	**1,907**
Remarketable Subordinated Notes	**—**	**—**	**—**	**1,000**	**700**	**700**	**2,400**
Total	**$1,711**	**$3,295**	**$3,371**	**$1,719**	**$2,169**	**$19,927**	**$32,192**
Weighted-average Coupon	**3.13%**	**3.62%**	**3.09%**	**2.07%**	**3.12%**	**4.38%**	

The Companies short-term credit facilities and long-term debt agreements contain customary covenants and default provisions. As of December 31, 2016, there were no events of default under these covenants.

In January 2017, Dominion issued $400 million of 1.875% senior notes and $400 million of 2.75% senior notes that mature in 2019 and 2022, respectively.

Senior Note Redemptions

As part of Dominion's Liability Management Exercise, in December 2014, Dominion redeemed five outstanding series of senior notes with an aggregate outstanding principal of $1.9 billion. The aggregate redemption price paid in December 2014 was $2.2 billion and represents the principal amount outstanding, accrued and unpaid interest and the applicable make-whole premium of $263 million. Total charges for the Liability Management Exercise of $284 million, including the make-whole premium, were recognized and recorded in interest expense in Dominion's Consolidated Statements of Income. Proceeds from Dominion's issuance of senior notes in November 2014 were used to offset the payment of the redemption price. Also see Convertible Securities called for redemption below.

Convertible Securities

As part of Dominion's Liability Management Exercise, in November 2014, Dominion provided notice to redeem all $22 million of outstanding contingent convertible senior notes. The senior notes were eligible for conversion during 2014. However, in lieu of redemption, holders elected to convert the remaining $22 million of notes in December 2014 into $26 million of common stock. Proceeds from Dominion's issuance of senior notes in November 2014 were used to offset the portion of the conversions paid in cash.

Enhanced Junior Subordinated Notes

In June 2006 and September 2006, Dominion issued $300 million of June 2006 hybrids and $500 million of September 2006 hybrids, respectively. Beginning June 30, 2016, the June 2006 hybrids bear interest at three-month LIBOR plus 2.825%, reset quarterly. Previously, interest was fixed at 7.5% per year. The September 2006 hybrids bear interest at the three-month LIBOR plus 2.3%, reset quarterly.

In June 2009, Dominion issued $685 million of 8.375% June 2009 hybrids. The June 2009 hybrids were listed on the NYSE under the symbol DRU.

In October 2014, Dominion issued $685 million of October 2014 hybrids that will bear interest at 5.75% per year until October 1, 2024. Thereafter, they will bear interest at the three-month LIBOR plus 3.057%, reset quarterly.

Dominion may defer interest payments on the hybrids on one or more occasions for up to 10 consecutive years. If the interest payments on the hybrids are deferred, Dominion may not make distributions related to its capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments during the deferral period. Also, during the deferral period, Dominion may not make any payments on or redeem or repurchase any debt securities that are equal in right of payment with, or subordinated to, the hybrids.

Dominion executed RCCs in connection with its issuance of the June 2006 hybrids, the September 2006 hybrids, and the June

2009 hybrids. Under the terms of the RCCs, Dominion covenants to and for the benefit of designated covered debtholders, as may be designated from time to time, that Dominion shall not redeem, repurchase, or defease all or any part of the hybrids, and shall not cause its majority owned subsidiaries to purchase all or any part of the hybrids, on or before their applicable RCC termination date, unless, subject to certain limitations, during the 180 days prior to such activity, Dominion has received a specified amount of proceeds as set forth in the RCCs from the sale of qualifying securities that have equity-like characteristics that are the same as, or more equity-like than the applicable characteristics of the hybrids at that time, as more fully described in the RCCs. In September 2011, Dominion amended the RCCs of the June 2006 hybrids and September 2006 hybrids to expand the measurement period for consideration of proceeds from the sale of common stock issuances from 180 days to 365 days. In July 2014, Dominion amended the RCC of the June 2009 hybrids to expand the measurement period for consideration of proceeds from the sale of common stock or other equity-like issuances from 180 days to 365 days. The proceeds Dominion receives from the replacement offering, adjusted by a predetermined factor, must equal or exceed the redemption or repurchase price.

As part of Dominion's Liability Management Exercise, in October 2014, Dominion redeemed all $685 million of the June 2009 hybrids plus accrued interest with the net proceeds from the issuance of the October 2014 hybrids. In 2015, Dominion purchased and cancelled $14 million and $3 million of the June 2006 hybrids and the September 2006 hybrids, respectively. In the first quarter of 2016, Dominion purchased and cancelled $38 million and $4 million of the June 2006 hybrids and the September 2006 hybrids, respectively. In July 2016, Dominion launched a tender offer to purchase up to $200 million in aggregate of additional June 2006 hybrids and September 2006 hybrids, which expired on August 1, 2016. In connection with the tender offer, Dominion purchased and cancelled $125 million and $74 million of the June 2006 hybrids and the September 2006 hybrids, respectively. All purchases were conducted in compliance with the applicable RCC. Also in July 2016, Dominion issued $800 million of 5.25% July 2016 hybrids. The proceeds were used for general corporate purposes, including to finance the tender offer. The July 2016 hybrids are listed on the NYSE under the symbol DRUA.

From time to time, Dominion may reduce its outstanding debt and level of interest expense through redemption of debt securities prior to maturity and repurchases in the open market, in privately negotiated transactions, through additional tender offers or otherwise.

Remarketable Subordinated Notes

In June 2013, Dominion issued $550 million of 2013 Series A 6.125% Equity Units and $550 million of 2013 Series B 6.0% Equity Units, initially in the form of Corporate Units. The Corporate Units were listed on the NYSE under the symbols DCUA and DCUB, respectively.

Each Corporate Unit consisted of a stock purchase contract and 1/20 interest in a RSN issued by Dominion. The stock purchase contracts obligated the holders to purchase shares of Dominion common stock at a future settlement date prior to the relevant RSN maturity date. The purchase price paid under the stock purchase contracts was $50 per Corporate Unit and the number of shares purchased was determined under a formula based upon the average closing price of Dominion common stock near the settlement date. The RSNs were pledged as collateral to secure the purchase of common stock under the related stock purchase contracts.

In March 2016 and May 2016, Dominion successfully remarketed the $550 million 2013 Series A 1.07% RSNs due 2021 and the $550 million 2013 Series B 1.18% RSNs due 2019, respectively, pursuant to the terms of the related 2013 Equity Units. In connection with the remarketings, the interest rate on the Series A and Series B junior subordinated notes was reset to 4.104% and 2.962%, respectively, payable on a semi-annual basis and Dominion ceased to have the ability to redeem the notes at its option or defer interest payments. At December 31, 2016, the securities are included in junior subordinated notes in Dominion's Consolidated Balance Sheets. Dominion did not receive any proceeds from the remarketings. Remarketing proceeds belonged to the investors holding the related 2013 Equity Units and were temporarily used to purchase a portfolio of treasury securities. Upon maturity of each portfolio, the proceeds were applied on behalf of investors on the related stock purchase contract settlement date to pay the purchase price to Dominion for issuance of 8.5 million shares of its common stock on both April 1, 2016 and July 1, 2016. See Issuance of Common Stock below for a description of common stock issued by Dominion in April 2016 and July 2016 under the stock purchase contracts.

In July 2014, Dominion issued $1.0 billion of 2014 Series A 6.375% Equity Units, initially in the form of Corporate Units. In August 2016, Dominion issued $1.4 billion of 2016 Series A 6.75% Equity Units, initially in the form of Corporate Units. The Corporate Units are listed on the NYSE under the symbols DCUC and DCUD, respectively. The net proceeds from the 2016 Equity Units were used to finance the Dominion Questar Combination. See Note 3 for more information.

Each 2014 Series A Corporate Unit consists of a stock purchase contract and 1/20 interest in a 2014 Series A RSN issued by Dominion. Each 2016 Series A Corporate Unit consists of a stock purchase contract, a 1/40 interest in a 2016 Series A-1 RSN issued by Dominion and a 1/40 interest in a 2016 Series A-2 RSN issued by Dominion. The stock purchase contracts obligate the holders to purchase shares of Dominion common stock at a future settlement date prior to the relevant RSN maturity date. The purchase price to be paid under the stock purchase contracts is $50 per Corporate Unit and the number of shares to be purchased will be determined under a formula based upon the average closing price of Dominion common stock near the settlement date. The RSNs are pledged as collateral to secure the purchase of common stock under the related stock purchase contracts.

Dominion makes quarterly interest payments on the RSNs and quarterly contract adjustment payments on the stock purchase contracts, at the rates described below. Dominion may defer payments on the stock purchase contracts and the RSNs for one or more consecutive periods but generally not beyond the purchase contract settlement date. If payments are deferred, Dominion may not make any cash distributions related to its capital stock, including dividends, redemptions, repurchases, liquidation payments or guarantee payments. Also, during the deferral period, Dominion may not make any payments on or redeem or repurchase any debt securities that are equal in right of payment with, or subordinated to, the RSNs.

Dominion has recorded the present value of the stock purchase contract payments as a liability offset by a charge to equity. Interest payments on the RSNs are recorded as interest expense and stock purchase contract payments are charged against the liability. Accretion of the stock purchase contract liability is recorded as imputed interest expense. In calculating diluted EPS, Dominion applies the treasury stock method to the Equity Units.

Pursuant to the terms of the 2014 Equity Units and 2016 Equity Units, Dominion expects to remarket the 2014 Series A RSNs during the second quarter of 2017 and both the 2016 Series A-1 and 2016 Series A-2 RSNs during the third quarter of 2019. Following a successful remarketing, the interest rate on the RSNs will be reset, interest will be payable on a semi-annual basis and Dominion will cease to have the ability to redeem the RSNs at its option or defer interest payments. Proceeds of each remarketing will belong to the investors in the related equity units and will be held and applied on their behalf at the settlement date of the related stock purchase contracts to pay the purchase price to Dominion for issuance of its common stock.

Under the terms of the stock purchase contracts, assuming no anti-dilution or other adjustments, Dominion will issue between 11.6 million and 14.5 million shares of its common stock in July 2017 and between 15.0 million and 18.7 million shares in August 2019. A total of 40.9 million shares of Dominion's common stock has been reserved for issuance in connection with the stock purchase contracts.

Selected information about Dominion's Equity Units is presented below:

Issuance Date	Units Issued	Total Net Proceeds	Total Long-term Debt	RSN Annual Interest Rate	Stock Purchase Contract Annual Rate	Stock Purchase Contract Liability[1]	Stock Purchase Settlement Date	RSN Maturity Date
(millions, except interest rates)								
7/1/2014	20	$ 982.0	$1,000.0	1.500%	4.875%	$142.8	7/1/2017	7/1/2020
8/15/2016[2]	28	$1,374.8	$1,400.0	2.000%[3]	4.750%	$190.6	8/15/2019	

(1) Payments of $94 million and $101 million were made in 2016 and 2015, respectively, including payments for the remarketed 2013 Series A and B notes. The stock purchase contract liability was $212 million and $115 million at December 31, 2016 and 2015, respectively.
(2) The maturity dates of the $700 million Series A-1 RSNs and $700 million Series A-2 RSNs are August 15, 2021 and August 15, 2024, respectively.
(3) Annual interest rate applies to each of the Series A-1 RSNs and Series A-2 RSNs.

Note 18. Preferred Stock

Dominion is authorized to issue up to 20 million shares of preferred stock; however, none were issued and outstanding at December 31, 2016 or 2015.

Virginia Power is authorized to issue up to 10 million shares of preferred stock, $100 liquidation preference. During 2014, Virginia Power redeemed 2.59 million shares, which represented all outstanding series of its preferred stock, some of which were redeemed as a part of Dominion's Liability Management Exercise in September 2014. Upon redemption, each series was no longer outstanding for any purpose and dividends ceased to accumulate. Virginia Power had no preferred stock issued and outstanding at December 31, 2016 or 2015.

Note 19. Equity

Issuance of Common Stock

Dominion

Dominion maintains Dominion Direct® and a number of employee savings plans through which contributions may be invested in Dominion's common stock. These shares may either be newly issued or purchased on the open market with proceeds contributed to these plans. In January 2014, Dominion began purchasing its common stock on the open market for these plans. In April 2014, Dominion began issuing new common shares for these direct stock purchase plans.

During 2016, Dominion received cash proceeds, net of fees and commissions, of $2.2 billion from the issuance of approximately 32 million shares of common stock through various programs resulting in approximately 628 million of shares of common stock outstanding at December 31, 2016. These proceeds include cash of $295 million received from the issuance of 4.0 million of such shares through Dominion Direct® and employee savings plans.

In December 2014, Dominion filed an SEC shelf registration for the sale of debt and equity securities including the ability to sell common stock through an at-the-market program. Also in December 2014, Dominion entered into four separate sales agency agreements to effect sales under the program and pursuant to which it may offer from time to time up to $500 million aggregate amount of its common stock. Sales of common stock can be made by means of privately negotiated transactions, as transactions on the NYSE at market prices or in such other transactions as are agreed upon by Dominion and the sales agents and in conformance with applicable securities laws. Following issuances during the first and second quarters of 2015, Dominion has the ability to issue up to approximately $200 million of stock under the 2014 sales agency agreements; however, no additional issuances occurred under these agreements in 2016.

In both April 2016 and July 2016, Dominion issued 8.5 million shares under the related stock purchase contracts entered into as part of Dominion's 2013 Equity Units and received $1.1 billion of total proceeds. Additionally, Dominion completed a market issuance of equity in April 2016 of 10.2 million shares and received proceeds of $756 million through a registered underwritten public offering. A portion of the net proceeds was used to finance the Dominion Questar Combination. See Note 3 for more information.

Virginia Power

In 2016, 2015 and 2014, Virginia Power did not issue any shares of its common stock to Dominion.

Shares Reserved for Issuance

At December 31, 2016, Dominion had approximately 63 million shares reserved and available for issuance for Dominion Direct®, employee stock awards, employee savings plans, director stock compensation plans and issuance in connection with stock purchase contracts. See Note 17 for more information.

Repurchase of Common Stock

Dominion did not repurchase any shares in 2016 or 2015 and does not plan to repurchase shares during 2017, except for shares tendered by employees to satisfy tax withholding obligations on vested restricted stock, which do not count against its stock repurchase authorization.

Purchase of Dominion Midstream Units

In September 2015, Dominion initiated a program to purchase from the market up to $50 million of common units representing limited partner interests in Dominion Midstream, which expired in September 2016. Dominion purchased approximately 658,000 common units for $17 million and 887,000 common units for $25 million for the years ended December 31, 2016 and 2015, respectively.

Issuance of Dominion Midstream Units

During the fourth quarter of 2016, Dominion Midstream received $482 million of proceeds from the issuance of common units and $490 million of proceeds from the issuance of convertible preferred units. The net proceeds were primarily used to finance a portion of the acquisition of Questar Pipeline from Dominion. See Note 3 for more information.

The holders of the convertible preferred units are entitled to receive cumulative quarterly distributions payable in cash or additional convertible preferred units, subject to certain conditions. The units are convertible into Dominion Midstream common units on a one-for-one basis, subject to certain adjustments, (i) in whole or in part at the option of the unitholders any time after December 1, 2018 or, (ii) in whole or in part at Dominion Midstream's option, subject to certain conditions, any time after December 1, 2019. The conversion of such units would result in a potential increase to Dominion's net income attributable to noncontrolling interests.

Accumulated Other Comprehensive Income (Loss)

Presented in the table below is a summary of AOCI by component:

At December 31,	2016	2015
(millions)		
Dominion		
Net deferred losses on derivatives-hedging activities, net of tax of $173 and $110	**$ (280)**	$(176)
Net unrealized gains on nuclear decommissioning trust funds, net of tax of $(318) and $(281)	**569**	504
Net unrecognized pension and other postretirement benefit costs, net of tax of $691 and $525	**(1,082)**	(797)
Other comprehensive loss from equity method investees, net of tax of $4 and $4	**(6)**	(5)
Total AOCI	**$ (799)**	$(474)
Virginia Power		
Net deferred losses on derivatives-hedging activities, net of tax of $5 and $4	**$ (8)**	$ (7)
Net unrealized gains on nuclear decommissioning trust funds, net of tax of $(35) and $(30)	**54**	47
Total AOCI	**$ 46**	$ 40
Dominion Gas		
Net deferred losses on derivatives-hedging activities, net of tax of $15 and $10	**$ (24)**	$ (17)
Net unrecognized pension costs, net of tax of $68 and $56	**(99)**	(82)
Total AOCI	**$ (123)**	$ (99)

Dominion

The following table presents Dominion's changes in AOCI by component, net of tax:

	Deferred gains and losses on derivatives-hedging activities	Unrealized gains and losses on investment securities	Unrecognized pension and other postretirement benefit costs	Other comprehensive loss from equity method investees	Total
(millions)					
Year Ended December 31, 2016					
Beginning balance	**$(176)**	**$504**	**$ (797)**	**$(5)**	**$(474)**
Other comprehensive income before reclassifications: gains (losses)	**55**	**93**	**(319)**	**(1)**	**(172)**
Amounts reclassified from AOCI: (gains) losses(1)	**(159)**	**(28)**	**34**	**—**	**(153)**
Net current period other comprehensive income (loss)	**(104)**	**65**	**(285)**	**(1)**	**(325)**
Ending balance	**$(280)**	**$569**	**$(1,082)**	**$(6)**	**$(799)**
Year Ended December 31, 2015					
Beginning balance	$(178)	$548	$ (782)	$(4)	$(416)
Other comprehensive income before reclassifications: gains (losses)	110	6	(66)	(1)	49
Amounts reclassified from AOCI: (gains) losses(1)	(108)	(50)	51	—	(107)
Net current period other comprehensive income (loss)	2	(44)	(15)	(1)	(58)
Ending balance	$(176)	$504	$ (797)	$(5)	$(474)

(1) See table below for details about these reclassifications.

The following table presents Dominion's reclassifications out of AOCI by component:

Details about AOCI components	Amounts reclassified from AOCI	Affected line item in the Consolidated Statements of Income
(millions)		
Year Ended December 31, 2016		
Deferred (gains) and losses on derivatives-hedging activities:		
Commodity contracts	**$(330)**	Operating revenue
	13	Purchased gas
	10	Electric fuel and other energy-related purchases
Interest rate contracts	**31**	Interest and related charges
Foreign currency contracts	**17**	Other Income
Total	**(259)**	
Tax	**100**	Income tax expense
Total, net of tax	**$(159)**	
Unrealized (gains) and losses on investment securities:		
Realized (gain) loss on sale of securities	**$ (66)**	Other income
Impairment	**23**	Other income
Total	**(43)**	
Tax	**15**	Income tax expense
Total, net of tax	**$ (28)**	
Unrecognized pension and other postretirement benefit costs:		
Prior-service costs (credits)	**$ (15)**	Other operations and maintenance
Actuarial losses	**71**	Other operations and maintenance
Total	**56**	
Tax	**(22)**	Income tax expense
Total, net of tax	**$ 34**	
Year Ended December 31, 2015		
Deferred (gains) and losses on derivatives-hedging activities:		
Commodity contracts	$(203)	Operating revenue
	15	Purchased gas
	1	Electric fuel and other energy-related purchases
Interest rate contracts	11	Interest and related charges
Total	(176)	
Tax	68	Income tax expense
Total, net of tax	$(108)	
Unrealized (gains) and losses on investment securities:		
Realized (gain) loss on sale of securities	$(110)	Other income
Impairment	31	Other income
Total	(79)	
Tax	29	Income tax expense
Total, net of tax	$ (50)	
Unrecognized pension and other postretirement benefit costs:		
Prior-service costs (credits)	$ (12)	Other operations and maintenance
Actuarial losses	98	Other operations and maintenance
Total	86	
Tax	(35)	Income tax expense
Total, net of tax	$ 51	

Virginia Power

The following table presents Virginia Power's changes in AOCI by component, net of tax:

	Deferred gains and losses on derivatives-hedging activities	Unrealized gains and losses on investment securities	Total
(millions)			
Year Ended December 31, 2016			
Beginning balance	**$(7)**	**$ 47**	**$ 40**
Other comprehensive income before reclassifications: gains (losses)	**(2)**	**11**	**9**
Amounts reclassified from AOCI: (gains) losses(1)	**1**	**(4)**	**(3)**
Net current period other comprehensive income (loss)	**(1)**	**7**	**6**
Ending balance	**$(8)**	**$ 54**	**$ 46**
Year Ended December 31, 2015			
Beginning balance	$(7)	$ 57	$ 50
Other comprehensive income before reclassifications: gains (losses)	(1)	(4)	(5)
Amounts reclassified from AOCI: (gains) losses(1)	1	(6)	(5)
Net current period other comprehensive income (loss)	—	(10)	(10)
Ending balance	$(7)	$ 47	$ 40

(1) See table below for details about these reclassifications.

The following table presents Virginia Power's reclassifications out of AOCI by component:

Details about AOCI components	Amounts reclassified from AOCI	Affected line item in the Consolidated Statements of Income
(millions)		
Year Ended December 31, 2016		
(Gains) losses on cash flow hedges:		
Interest rate contracts	**$ 1**	Interest and related charges
Total	**1**	
Tax	**—**	Income tax expense
Total, net of tax	**$ 1**	
Unrealized (gains) and losses on investment securities:		
Realized (gain) loss on sale of securities	**$ (9)**	Other income
Impairment	**3**	Other income
Total	**(6)**	
Tax	**2**	Income tax expense
Total, net of tax	**$ (4)**	
Year Ended December 31, 2015		
(Gains) losses on cash flow hedges:		
Commodity contracts	$ 1	Electric fuel and other energy-related purchases
Total	1	
Tax	—	Income tax expense
Total, net of tax	$ 1	
Unrealized (gains) and losses on investment securities:		
Realized (gain) loss on sale of securities	$(14)	Other income
Impairment	4	Other income
Total	(10)	
Tax	4	Income tax expense
Total, net of tax	$ (6)	

Dominion Gas

The following table presents Dominion Gas' changes in AOCI by component, net of tax:

	Deferred gains and losses on derivatives-hedging activities	Unrecognized pension costs	Total
(millions)			
Year Ended December 31, 2016			
Beginning balance	**$(17)**	**$(82)**	**$ (99)**
Other comprehensive income before reclassifications: losses	**(16)**	**(20)**	**(36)**
Amounts reclassified from AOCI(1): losses	**9**	**3**	**12**
Net current period other comprehensive loss	**(7)**	**(17)**	**(24)**
Ending balance	**$(24)**	**$(99)**	**$(123)**
Year Ended December 31, 2015			
Beginning balance	$(20)	$(66)	$ (86)
Other comprehensive income before reclassifications: gains (losses)	6	(20)	(14)
Amounts reclassified from AOCI(1): (gains) losses	(3)	4	1
Net current period other comprehensive income (loss)	3	(16)	(13)
Ending balance	$(17)	$(82)	$ (99)

(1) See table below for details about these reclassifications.

The following table presents Dominion Gas' reclassifications out of AOCI by component:

Details about AOCI components	Amounts reclassified from AOCI	Affected line item in the Consolidated Statements of Income
(millions)		
Year Ended December 31, 2016		
Deferred (gains) and losses on derivatives-hedging activities:		
Commodity contracts	**$ (4)**	Operating revenue
Interest rate contracts	**2**	Interest and related charges
Foreign currency contracts	**17**	Other income
Total	**15**	
Tax	**(6)**	Income tax expense
Total, net of tax	**$ 9**	
Unrecognized pension costs:		
Actuarial losses	**$ 5**	Other operations and maintenance
Total	**5**	
Tax	**(2)**	Income tax expense
Total, net of tax	**$ 3**	
Year Ended December 31, 2015		
Deferred (gains) and losses on derivatives-hedging activities:		
Commodity contracts	$ (6)	Operating revenue
Total	(6)	
Tax	3	Income tax expense
Total, net of tax	$ (3)	
Unrecognized pension costs:		
Actuarial losses	$ 7	Other operations and maintenance
Total	7	
Tax	(3)	Income tax expense
Total, net of tax	$ 4	

Stock-Based Awards

The 2005 and 2014 Incentive Compensation Plans permit stock-based awards that include restricted stock, performance grants, goal-based stock, stock options, and stock appreciation rights. The Non-Employee Directors Compensation Plan permits grants of restricted stock and stock options. Under provisions of these plans, employees and non-employee directors may be granted options to purchase common stock at a price not less than its fair market value at the date of grant with a maximum term of eight years. Option terms are set at the discretion of the CGN Committee of the Board of Directors or the Board of Directors itself, as provided under each plan. At December 31, 2016, approximately 24 million shares were available for future grants under these plans.

Dominion measures and recognizes compensation expense relating to share-based payment transactions over the vesting period based on the fair value of the equity or liability instruments issued. Dominion's results for the years ended December 31, 2016, 2015 and 2014 include $33 million, $39 million, and $39 million, respectively, of compensation costs and $11 million, $14 million, and $14 million, respectively of income tax benefits related to Dominion's stock-based compensation arrangements. Stock-based compensation cost is reported in other operations and maintenance expense in Dominion's Consolidated Statements of Income. Excess Tax Benefits are classified as a financing cash flow. Dominion realized less than $1 million and $3 million of Excess Tax Benefits from the vesting of restricted stock awards during the year ended December 31, 2016 and 2015, respectively, and less than $1 million during the year ended December 31, 2014.

Restricted Stock

Restricted stock grants are made to officers under Dominion's LTIP and may also be granted to certain key non-officer employees from time to time. The fair value of Dominion's restricted stock awards is equal to the closing price of Dominion's stock on the date of grant. New shares are issued for restricted stock awards on the date of grant and generally vest over a three-year service period. The following table provides a summary of restricted stock activity for the years ended December 31, 2016, 2015 and 2014:

	Shares	Weighted - average Grant Date Fair Value
	(thousands)	
Nonvested at December 31, 2013	1,007	$49.35
Granted	354	67.98
Vested	(278)	44.50
Cancelled and forfeited	(18)	53.61
Nonvested at December 31, 2014	1,065	$56.74
Granted	302	73.26
Vested	(510)	50.71
Cancelled and forfeited	(2)	62.62
Nonvested at December 31, 2015	855	$66.16
Granted	**372**	**71.67**
Vested	**(301)**	**56.83**
Cancelled and forfeited	**(40)**	**71.75**
Nonvested at December 31, 2016	**886**	**$71.40**

As of December 31, 2016, unrecognized compensation cost related to nonvested restricted stock awards totaled $31 million and is expected to be recognized over a weighted-average period of 1.9 years. The fair value of restricted stock awards that vested was $21 million, $37 million, and $19 million in 2016, 2015 and 2014, respectively. Employees may elect to have shares of restricted stock withheld upon vesting to satisfy tax withholding obligations. The number of shares withheld will vary for each employee depending on the vesting date fair market value of Dominion stock and the applicable federal, state and local tax withholding rates.

Goal-Based Stock

Goal-based stock awards are granted under Dominion's LTIP to officers who have not achieved a certain targeted level of share ownership, in lieu of cash-based performance grants. Current outstanding goal-based shares include awards granted to officers in February 2015 and February 2016.

The issuance of awards is based on the achievement of two performance metrics during a two-year period: TSR relative to that of companies listed as members of the Philadelphia Utility Index as of the end of the performance period and ROIC. The actual number of shares issued will vary between zero and 200% of targeted shares depending on the level of performance metrics achieved. The fair value of goal-based stock is determined on the date of grant. Awards to officers vest at the end of the two-year performance period. All goal-based stock awards are settled by issuing new shares.

The following table provides a summary of goal-based stock activity for the years ended December 31, 2016, 2015 and 2014:

	Targeted Number of Shares	Weighted - average Grant Date Fair Value
	(thousands)	
Nonvested at December 31, 2013	5	$53.85
Granted	13	68.83
Vested	(1)	52.48
Nonvested at December 31, 2014	17	$65.15
Granted	14	72.72
Vested	(7)	56.22
Nonvested at December 31, 2015	24	$72.27
Granted	**12**	**69.93**
Vested	**(10)**	**68.83**
Cancelled and forfeited	**(3)**	**68.83**
Nonvested at December 31, 2016	**23**	**$72.99**

At December 31, 2016, the targeted number of shares expected to be issued under the February 2015 and February 2016 awards was approximately 23 thousand. In January 2017, the CGN Committee determined the actual performance against metrics established for the February 2015 awards with a performance period that ended December 31, 2016. Based on that determination, the total number of shares to be issued under the February 2015 goal-based stock awards was approximately 9 thousand.

As of December 31, 2016, unrecognized compensation cost related to nonvested goal-based stock awards was not material.

Cash-Based Performance Grants

Cash-based performance grants are made to Dominion's officers under Dominion's LTIP. The actual payout of cash-based performance grants will vary between zero and 200% of the targeted amount based on the level of performance metrics achieved.

In February 2014, a cash-based performance grant was made to officers. The performance grant was paid out in January 2016 based on the achievement of two performance metrics during 2014 and 2015: TSR relative to that of companies listed as members of the Philadelphia Utility Index as of the end of the performance period and ROIC. The total of the payout under the grant was $10 million.

In February 2015, a cash-based performance grant was made to officers. Payout of the performance grant occurred in January 2017 based on the achievement of two performance metrics during 2015 and 2016: TSR relative to that of companies listed as members of the Philadelphia Utility Index as of the end of the performance period and ROIC. The total of the payout under the grant was $10 million.

In February 2016, a cash-based performance grant was made to officers. Payout of the performance grant is expected to occur by March 15, 2018 based on the achievement of two performance metrics during 2016 and 2017: TSR relative to that of companies listed as members of the Philadelphia Utility Index as of the end of the performance period and ROIC. At December 31, 2016, the targeted amount of the grant was $14 million and a liability of $6 million had been accrued for this award.

Note 20. Dividend Restrictions

The Virginia Commission may prohibit any public service company, including Virginia Power, from declaring or paying a dividend to an affiliate if found to be detrimental to the public interest. At December 31, 2016, the Virginia Commission had not restricted the payment of dividends by Virginia Power.

The Ohio Commission may prohibit any public service company, including East Ohio, from declaring or paying a dividend to an affiliate if found to be detrimental to the public interest. At December 31, 2016, the Ohio Commission had not restricted the payment of dividends by East Ohio.

The Utah Commission may prohibit any public service company, including Questar Gas, from declaring or paying a dividend to an affiliate if found to be detrimental to the public interest. At December 31, 2016, the Utah Commission had not restricted the payment of dividends by Questar Gas.

Certain agreements associated with the Companies' credit facilities contain restrictions on the ratio of debt to total capitalization. These limitations did not restrict the Companies' ability to pay dividends or receive dividends from their subsidiaries at December 31, 2016.

See Note 17 for a description of potential restrictions on dividend payments by Dominion in connection with the deferral of interest payments on certain junior subordinated notes and equity units, initially in the form of corporate units.

Note 21. Employee Benefit Plans

Dominion and Dominion Gas—Defined Benefit Plans

Dominion provides certain retirement benefits to eligible active employees, retirees and qualifying dependents. Dominion Gas participates in a number of the Dominion-sponsored retirement plans. Under the terms of its benefit plans, Dominion reserves the right to change, modify or terminate the plans. From time to time in the past, benefits have changed, and some of these changes have reduced benefits.

Dominion maintains qualified noncontributory defined benefit pension plans covering virtually all employees. Retirement benefits are based primarily on years of service, age and the employee's compensation. Dominion's funding policy is to contribute annually an amount that is in accordance with the provisions of ERISA. The pension programs also provide benefits to certain retired executives under company-sponsored nonqualified employee benefit plans. The nonqualified plans are funded through contributions to grantor trusts. Dominion also provides retiree healthcare and life insurance benefits with annual employee premiums based on several factors such as age, retirement date and years of service.

Pension benefits for Dominion Gas employees not represented by collective bargaining units are covered by the Dominion Pension Plan, a defined benefit pension plan sponsored by Dominion that provides benefits to multiple Dominion subsidiaries. Pension benefits for Dominion Gas employees represented by collective bargaining units are covered by separate pension plans for East Ohio and, for DTI, a plan that provides benefits to employees of both DTI and Hope. Employee compensation is the basis for allocating pension costs and obligations between DTI and Hope and determining East Ohio's share of total pension costs.

Retiree healthcare and life insurance benefits for Dominion Gas employees not represented by collective bargaining units are covered by the Dominion Retiree Health and Welfare Plan, a plan sponsored by Dominion that provides certain retiree healthcare and life insurance benefits to multiple Dominion subsidiaries. Retiree healthcare and life insurance benefits for Dominion Gas employees represented by collective bargaining units are covered by separate other postretirement benefit plans for East Ohio and, for DTI, a plan that provides benefits to both DTI and Hope. Employee headcount is the basis for allocating other postretirement benefit costs and obligations between DTI and Hope and determining East Ohio's share of total other postretirement benefit costs.

Pension and other postretirement benefit costs are affected by employee demographics (including age, compensation levels and years of service), the level of contributions made to the plans and earnings on plan assets. These costs may also be affected by changes in key assumptions, including expected long-term rates of return on plan assets, discount rates, healthcare cost trend rates, mortality rates and the rate of compensation increases.

Dominion uses December 31 as the measurement date for all of its employee benefit plans, including those in which Dominion Gas participates. Dominion uses the market-related value of pension plan assets to determine the expected return on plan assets, a component of net periodic pension cost, for all pension plans, including those in which Dominion Gas participates. The market-related value recognizes changes in fair value on a straight-line basis over a four-year period, which reduces year-to-year volatility. Changes in fair value are measured as the difference between the expected and actual plan asset returns, including dividends, interest and realized and unrealized investment gains and losses. Since the market-related value recognizes changes in fair value over a four-year period, the future market-related value of pension plan assets will be impacted as previously unrecognized changes in fair value are recognized.

Dominion's pension and other postretirement benefit plans hold investments in trusts to fund employee benefit payments. Dominion's pension and other postretirement plan assets experienced aggregate actual returns of $534 million in 2016 and aggregate actual losses of $72 million in 2015, versus expected returns of $691 million and $648 million, respectively. Dominion Gas' pension and other postretirement plan assets for employees represented by collective bargaining units experienced aggregate actual returns of $130 million in 2016 and aggregate actual losses of $13 million in 2015, versus expected returns of $157 million and $150 million, respectively. Differences between actual and expected returns on plan assets are accumulated and amortized during future periods. As such, any investment-related declines in these trusts will result in future increases in the net periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash to be contributed to the employee benefit plans.

In October 2014, the Society of Actuaries published new mortality tables and mortality improvement scales. Such tables and scales are used to develop mortality assumptions for use in determining pension and other postretirement benefit liabilities and expense. Following evaluation of the new tables, Dominion changed its assumption for mortality rates to reflect a generational improvement scale. This change in assumption increased net periodic benefit cost for Dominion and Dominion Gas (for employees represented by collective bargaining units) by $25 million and $3 million, respectively, for 2015.

During 2016, Dominion and Dominion Gas (for employees represented by collective bargaining units) engaged their actuary to conduct an experience study of their employees demographics over a five-year period as compared to significant assumptions that were being used to determine pension and other postretirement benefit obligations and periodic costs. These assumptions primarily included mortality, retirement rates, termination rates, and salary increase rates. The changes in assumptions implemented as a result of the experience study resulted in increases of $290 million and $38 million in the pension and other postretirement benefits obligations, respectively, at December 31, 2016 for Dominion and $24 million and $9 million in the pension and other postretirement benefits obligations, respectively, at December 31, 2016 for Dominion Gas. In addition, these changes will increase net periodic benefit costs for Dominion by $42 million for 2017. The increase in net periodic benefit costs for Dominion Gas for 2017 is immaterial.

Plan Amendments and Remeasurements

In the third quarter of 2016, Dominion remeasured an other postretirement benefit plan as a result of an amendment that changed post-65 retiree medical coverage for certain current and future Local 50 retirees effective April 1, 2017. The remeasurement resulted in a decrease in Dominion's accumulated postretirement benefit obligation of $37 million. The impact of the remeasurement on net periodic benefit credit was recognized prospectively from the remeasurement date and increased the net periodic benefit credit for 2016 by $9 million. The discount rate used for the remeasurement was 3.71% and the demographic and mortality assumptions were updated using plan-specific studies and mortality improvement scales. The expected long-term rate of return used was consistent with the measurement as of December 31, 2015.

In the third quarter of 2014, East Ohio remeasured its other postretirement benefit plan as a result of an amendment that changed medical coverage upon the attainment of age 65 for certain future retirees effective January 1, 2016. For employees represented by collective bargaining units, the remeasurement resulted in an increase in the accumulated postretirement benefit obligation of $22 million. The impact of the remeasurement on net periodic benefit credit was recognized prospectively from the remeasurement date and reduced net periodic benefit credit for 2014, for employees represented by collective bargaining units, by less than $1 million. The discount rate used for the remeasurement was 4.20% and the expected long-term rate of return used was 8.50%. All other assumptions used for the remeasurement were consistent with the measurement as of December 31, 2013.

Funded Status

The following table summarizes the changes in pension plan and other postretirement benefit plan obligations and plan assets and includes a statement of the plans' funded status for Dominion and Dominion Gas (for employees represented by collective bargaining units):

	Pension Benefits		Other Postretirement Benefits	
Year Ended December 31,	**2016**	2015	**2016**	2015
(millions, except percentages)				
Dominion				
Changes in benefit obligation:				
Benefit obligation at beginning of year	**$ 6,391**	$ 6,667	**$ 1,430**	$ 1,571
Dominion Questar Combination	**817**	—	**85**	—
Service cost	**118**	126	**31**	40
Interest cost	**317**	287	**65**	67
Benefits paid	**(286)**	(246)	**(83)**	(79)
Actuarial (gains) losses during the year	**784**	(443)	**166**	(138)
Plan amendments(1)	**—**	—	**(216)**	(31)
Settlements and curtailments(2)	**(9)**	—	**—**	—
Benefit obligation at end of year	**$ 8,132**	$ 6,391	**$ 1,478**	$ 1,430
Changes in fair value of plan assets:				
Fair value of plan assets at beginning of year	**$ 6,166**	$ 6,480	**$ 1,382**	$ 1,402
Dominion Questar Combination	**704**	—	**45**	—
Actual return (loss) on plan assets	**426**	(71)	**108**	(1)
Employer contributions	**15**	3	**12**	12
Benefits paid	**(286)**	(246)	**(35)**	(31)
Settlements(2)	**(9)**	—	**—**	—
Fair value of plan assets at end of year	**$ 7,016**	$ 6,166	**$ 1,512**	$ 1,382
Funded status at end of year	**$ (1,116)**	$ (225)	**$ 34**	$ (48)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Noncurrent pension and other postretirement benefit assets	**$ 930**	$ 931	**$ 148**	$ 12
Other current liabilities	**(43)**	(14)	**(5)**	(3)
Noncurrent pension and other postretirement benefit liabilities	**(2,003)**	(1,142)	**(109)**	(57)
Net amount recognized	**$ (1,116)**	$ (225)	**$ 34**	$ (48)
Significant assumptions used to determine benefit obligations as of December 31:				
Discount rate	**3.31%–4.50%**	4.96%–4.99%	**3.92%–4.47%**	4.93%–4.94%
Weighted average rate of increase for compensation	**4.09%**	4.22%	**3.29%**	4.22%
Dominion Gas				
Changes in benefit obligation:				
Benefit obligation at beginning of year	**$ 608**	$ 638	**$ 292**	$ 320
Service cost	**13**	15	**5**	7
Interest cost	**30**	27	**14**	14
Benefits paid	**(32)**	(29)	**(19)**	(18)
Actuarial (gains) losses during the year	**64**	(43)	**28**	(31)
Benefit obligation at end of year	**$ 683**	$ 608	**$ 320**	$ 292
Changes in fair value of plan assets:				
Fair value of plan assets at beginning of year	**$ 1,467**	$ 1,510	**$ 283**	$ 288
Actual return (loss) on plan assets	**107**	(14)	**23**	1
Employer contributions	**—**	—	**12**	12
Benefits paid	**(32)**	(29)	**(19)**	(18)
Fair value of plan assets at end of year	**$ 1,542**	$ 1,467	**$ 299**	$ 283
Funded status at end of year	**$ 859**	$ 859	**$ (21)**	$ (9)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Noncurrent pension and other postretirement benefit assets	**$ 859**	$ 859	**$ —**	$ —
Noncurrent pension and other postretirement benefit liabilities(3)	**—**	—	**(21)**	(9)
Net amount recognized	**$ 859**	$ 859	**$ (21)**	$ (9)
Significant assumptions used to determine benefit obligations as of December 31:				
Discount rate	**4.50%**	4.99%	**4.47%**	4.93%
Weighted average rate of increase for compensation	**4.11%**	3.93%	**n/a**	3.93%

(1) 2016 amount relates primarily to a plan amendment that changed post-65 retiree medical coverage for certain current and future Local 50 retirees effective April 1, 2017. 2015 amount relates primarily to a plan amendment that changed retiree medical benefits for certain nonunion employees after Medicare eligibility.

(2) Relates primarily to a settlement for certain executives.

(3) Reflected in other deferred credits and other liabilities in Dominion Gas' Consolidated Balance Sheets.

The ABO for all of Dominion's defined benefit pension plans was $7.3 billion and $5.8 billion at December 31, 2016 and 2015, respectively. The ABO for the defined benefit pension plans covering Dominion Gas employees represented by collective bargaining units was $640 million and $578 million at December 31, 2016 and 2015, respectively.

Under its funding policies, Dominion evaluates plan funding requirements annually, usually in the fourth quarter after receiving updated plan information from its actuary. Based on the funded status of each plan and other factors, Dominion determines the amount of contributions for the current year, if any, at that time. During 2016, Dominion and Dominion Gas made no contributions to the qualified defined benefit pension plans and no contributions are currently expected in 2017. In January 2017, Dominion made a $75 million contribution to Dominion Questar's qualified pension plan to satisfy a regulatory condition to closing of the Dominion Questar Combination. In July 2012, the MAP 21 Act was signed into law. This Act includes an increase in the interest rates used to determine plan sponsors' pension contributions for required funding purposes. In 2014, the HATFA of 2014 was signed into law. Similar to the MAP 21 Act, the HATFA of 2014 adjusts the rules for calculating interest rates used in determining funding obligations. It is estimated that the new interest rates will reduce required pension contributions through 2019. Dominion believes that required pension contributions will rise subsequent to 2019, resulting in an estimated $200 million reduction in net cumulative required contributions over a 10-year period.

Certain regulatory authorities have held that amounts recovered in utility customers' rates for other postretirement benefits, in excess of benefits actually paid during the year, must be deposited in trust funds dedicated for the sole purpose of paying such benefits. Accordingly, certain of Dominion's subsidiaries, including Dominion Gas, fund other postretirement benefit costs through VEBAs. Dominion's remaining subsidiaries do not prefund other postretirement benefit costs but instead pay claims as presented. Dominion's contributions to VEBAs, all of which pertained to Dominion Gas employees, totaled $12 million for both 2016 and 2015, and Dominion expects to contribute approximately $12 million to the Dominion VEBAs in 2017, all of which pertains to Dominion Gas employees.

Dominion and Dominion Gas do not expect any pension or other postretirement plan assets to be returned during 2017.

The following table provides information on the benefit obligations and fair value of plan assets for plans with a benefit obligation in excess of plan assets for Dominion and Dominion Gas (for employees represented by collective bargaining units):

	Pension Benefits		Other Postretirement Benefits	
As of December 31,	**2016**	2015	**2016**	2015
(millions)				
Dominion				
Benefit obligation	**$7,386**	$5,728	**$470**	$359
Fair value of plan assets	**5,340**	4,571	**356**	299
Dominion Gas				
Benefit obligation	**$ —**	$ —	**$320**	$292
Fair value of plan assets	**—**	—	**299**	283

The following table provides information on the ABO and fair value of plan assets for Dominion's pension plans with an ABO in excess of plan assets:

As of December 31,	**2016**	2015
(millions)		
Accumulated benefit obligation	**$5,987**	$5,198
Fair value of plan assets	**4,653**	4,571

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid for Dominion's and Dominion Gas' (for employees represented by collective bargaining units) plans:

	Estimated Future Benefit Payments	
	Pension Benefits	Other Postretirement Benefits
(millions)		
Dominion		
2017	**$380**	**$ 92**
2018	**361**	**96**
2019	**373**	**97**
2020	**398**	**99**
2021	**415**	**100**
2022-2026	**2,345**	**490**
Dominion Gas		
2017	**$ 33**	**$ 17**
2018	**35**	**18**
2019	**37**	**19**
2020	**38**	**19**
2021	**40**	**20**
2022-2026	**211**	**101**

Plan Assets

Dominion's overall objective for investing its pension and other postretirement plan assets is to achieve appropriate long-term rates of return commensurate with prudent levels of risk. As a participating employer in various pension plans sponsored by Dominion, Dominion Gas is subject to Dominion's investment policies for such plans. To minimize risk, funds are broadly diversified among asset classes, investment strategies and investment advisors. The strategic target asset allocations for Dominion's pension funds are 28% U.S. equity, 18% non-U.S. equity, 35% fixed income, 3% real estate and 16% other alternative investments. U.S. equity includes investments in large-cap, mid-cap and small-cap companies located in the U.S. Non-U.S. equity includes investments in large-cap and small-cap companies located outside of the U.S. including both developed and emerging markets. Fixed income includes corporate debt instruments of companies from diversified industries and U.S. Treasuries. The U.S. equity, non-U.S. equity and fixed income investments are in individual securities as well as mutual funds. Real estate includes equity real estate investment trusts and investments in partnerships. Other alternative investments include partnership investments in private equity, debt and hedge funds that follow several different strategies.

Dominion also utilizes common/collective trust funds as an investment vehicle for its defined benefit plans. A common/collective trust fund is a pooled fund operated by a bank or trust company for investment of the assets of various organizations and individuals in a well-diversified portfolio. Common/collective trust funds are funds of grouped assets that follow various investment strategies.

Strategic investment policies are established for Dominion's prefunded benefit plans based upon periodic asset/liability studies. Factors considered in setting the investment policy include employee demographics, liability growth rates, future discount rates, the funded status of the plans and the expected long-term rate of return on plan assets. Deviations from the plans' strategic allocation are a function of Dominion's assessments regarding short-term risk and reward opportunities in the capital markets and/or short-term market movements which result in the plans' actual asset allocations varying from the strategic target asset allocations. Through periodic rebalancing, actual allocations are brought back in line with the target. Future asset/liability studies will focus on strategies to further reduce pension and other postretirement plan risk, while still achieving attractive levels of returns. Financial derivatives may be used to obtain or manage market exposures and to hedge assets and liabilities.

For fair value measurement policies and procedures related to pension and other postretirement benefit plan assets, see Note 6.

The fair values of Dominion's and Dominion Gas' (for employees represented by collective bargaining units) pension plan assets by asset category are as follows:

At December 31,	2016				2015			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
(millions)								
Dominion								
Cash and cash equivalents	**$ 12**	**$ 2**	**$—**	**$ 14**	$ 16	$ —	$—	$ 16
Common and preferred stocks:								
U.S.	**1,705**	**—**	**—**	**1,705**	1,736	—	—	1,736
International	**928**	**—**	**—**	**928**	786	—	—	786
Insurance contracts	**—**	**334**	**—**	**334**	—	330	—	330
Corporate debt instruments	**35**	**682**	**—**	**717**	44	695	—	739
Government securities	**13**	**522**	**—**	**535**	85	390	—	475
Total recorded at fair value	**$2,693**	**$1,540**	**$—**	**$4,233**	$2,667	$1,415	$—	$4,082
Assets recorded at NAV[1]:								
Common/collective trust funds[2]				**1,960**				1,200
Alternative investments:								
Real estate funds				**121**				153
Private equity funds				**506**				465
Debt funds				**153**				170
Hedge funds				**25**				86
Total recorded at NAV				**$2,765**				$2,074
Total investments[3]				**$6,998**				$6,156
Dominion Gas								
Cash and cash equivalents	**$ 3**	**$ —**	**$—**	**$ 3**	$ 4	$ —	$—	$ 4
Common and preferred stocks:								
U.S.	**375**	**—**	**—**	**375**	413	—	—	413
International	**203**	**—**	**—**	**203**	187	—	—	187
Insurance contracts	**—**	**73**	**—**	**73**	—	78	—	78
Corporate debt instruments	**8**	**150**	**—**	**158**	10	165	—	175
Government securities	**3**	**115**	**—**	**118**	20	93	—	113
Total recorded at fair value	**$ 592**	**$ 338**	**$—**	**$ 930**	$ 634	$ 336	$—	$ 970
Assets recorded at NAV[1]:								
Common/collective trust funds[4]				**430**				286
Alternative investments:								
Real estate funds				**27**				36
Private equity funds				**111**				111
Debt funds				**34**				40
Hedge funds				**6**				21
Total recorded at NAV				**$ 608**				$ 494
Total investments[5]				**$1,538**				$1,464

(1) These investments that are measured at fair value using the NAV per share (or its equivalent) as a practical expedient are not required to be categorized in the fair value hierarchy.

(2) Also included in the common collective trust funds is the Northern Trust Collective Short-Term Investment Fund, totaling $167 million and $125 million at December 31, 2016 and 2015, respectively, which is comprised of money market instruments with short-term maturities used for temporary investment. Liquidity is emphasized to provide for redemption of units on any business day. Principal preservation is also a prime objective. Admissions and withdrawals are made daily. Interest is accrued daily and distributed monthly.

(3) Includes net assets related to pending sales of securities of $46 million, net accrued income of $19 million, and excludes net assets related to pending purchases of securities of $47 million at December 31, 2016. Includes net assets related to pending sales of securities of $112 million, net accrued income of $16 million, and excludes net assets related to pending purchases of securities of $118 million at December 31, 2015.

(4) Also included in the common collective trust funds is the Northern Trust Collective Short-Term Investment Fund, totaling $37 million and $30 million at December 31, 2016 and 2015, respectively, which is comprised of money market instruments with short-term maturities used for temporary investment. Liquidity is emphasized to provide for redemption of units on any business day. Principal preservation is also a prime objective. Admissions and withdrawals are made daily. Interest is accrued daily and distributed monthly.

(5) Includes net assets related to pending sales of securities of $10 million, net accrued income of $4 million, and excludes net assets related to pending purchases of securities of $10 million at December 31, 2016. Includes net assets related to pending sales of securities of $27 million, net accrued income of $4 million, and excludes net assets related to pending purchases of securities of $28 million at December 31, 2015.

The fair values of Dominion's and Dominion Gas' (for employees represented by collective bargaining units) other postretirement plan assets by asset category are as follows:

At December 31,	2016				2015			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
(millions)								
Dominion								
Cash and cash equivalents	**$ 1**	**$ 1**	**$—**	**$ 2**	$ 1	$ 1	$—	$ 2
Common and preferred stocks:								
U.S.	**571**	**—**	**—**	**571**	531	—	—	531
International	**143**	**—**	**—**	**143**	134	—	—	134
Insurance contracts	**—**	**19**	**—**	**19**	—	18	—	18
Corporate debt instruments	**2**	**40**	**—**	**42**	3	38	—	41
Government securities	**1**	**30**	**—**	**31**	4	22	—	26
Total recorded at fair value	**$718**	**$90**	**$—**	**$ 808**	$673	$79	$—	$ 752
Assets recorded at NAV(1):								
Common/collective trust funds(2)				**621**				543
Alternative investments:								
Real estate funds				**9**				14
Private equity funds				**59**				54
Debt funds				**12**				14
Hedge funds				**1**				5
Total recorded at NAV				**$ 702**				$ 630
Total investments(3)				**$1,510**				$1,382
Dominion Gas								
Common and preferred stocks:								
U.S.	**$121**	$—	$—	$ 121	$113	$—	$—	$ 113
International	**24**	—	—	24	24	—	—	24
Total recorded at fair value	**$145**	**$—**	**$—**	**$ 145**	$137	$—	$—	$ 137
Assets recorded at NAV(1):								
Common/collective trust funds(4)				**140**				132
Alternative investments:								
Real estate funds				**1**				2
Private equity funds				**12**				11
Debt funds				**1**				1
Total recorded at NAV				**$ 154**				$ 146
Total investments				**$ 299**				$ 283

(1) These investments that are measured at fair value using the NAV per share (or its equivalent) as a practical expedient are not required to be categorized in the fair value hierarchy.

(2) Also included in the common collective trust funds is the Northern Trust Collective Short-Term Investment Fund, totaling $16 million and $9 million at December 31, 2016 and 2015, respectively, which is comprised of money market instruments with short-term maturities used for temporary investment. Liquidity is emphasized to provide for redemption of units on any business day. Principal preservation is also a prime objective. Admissions and withdrawals are made daily. Interest is accrued daily and distributed monthly.

(3) Includes net assets related to pending sales of securities of $5 million, net accrued income of $2 million, and excludes net assets related to pending purchases of securities of $5 million at December 31, 2016.

(4) Also included in the common collective trust funds is the Northern Trust Collective Short-Term Investment Fund, totaling $2 million and $3 million at December 31, 2016 and 2015, respectively, which is comprised of money market instruments with short-term maturities used for temporary investment. Liquidity is emphasized to provide for redemption of units on any business day. Principal preservation is also a prime objective. Admissions and withdrawals are made daily. Interest is accrued daily and distributed monthly.

The Plan's investments are determined based on the fair values of the investments and the underlying investments, which have been determined as follows:

- *Cash and Cash Equivalents*—Investments are held primarily in short-term notes and treasury bills, which are valued at cost plus accrued interest.
- *Common and Preferred Stocks*—Investments are valued at the closing price reported on the active market on which the individual securities are traded.
- *Insurance Contracts*—Investments in Group Annuity Contracts with John Hancock were entered into after 1992 and are stated at fair value based on the fair value of the underlying securities as provided by the managers and include investments in U.S. government securities, corporate debt instruments, state and municipal debt securities.
- *Corporate Debt Instruments*—Investments are valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings. When quoted prices are not available for identical or similar instruments, the instrument is valued under a discounted cash flows approach that maximizes observable inputs, such as current yields of similar instruments, but includes adjustments for certain risks that may not be observable, such as credit and liquidity risks or a broker quote, if available.
- *Government Securities*—Investments are valued using pricing models maximizing the use of observable inputs for similar securities.
- *Common/Collective Trust Funds*—Common/collective trust funds invest in debt and equity securities and other instruments with characteristics similar to those of the funds' benchmarks. The primary objectives of the funds are to seek investment returns that approximate the overall performance of their benchmark indexes. These benchmarks are major equity indices, fixed income indices, and money market indices that focus on growth, income, and liquidity strategies, as applicable. Investments in common/collective trust funds are stated at the NAV as determined by the issuer of the common/collective trust funds and is based on the fair value of the underlying investments held by the fund less its liabilities. The NAV is used as a practical expedient to estimate fair value. The common/collective trust funds do not have any unfunded commitments, and do not have any applicable liquidation periods or defined terms/periods to be held. The majority of the common/collective trust funds have limited withdrawal or redemption rights during the term of the investment.
- *Alternative Investments*—Investments in real estate funds, private equity funds, debt funds and hedge funds are stated at fair value based on the NAV of the Plan's proportionate share of the partnership, joint venture or other alternative investment's fair value as determined by reference to audited financial statements or NAV statements provided by the investment manager. The NAV is used as a practical expedient to estimate fair value.

Net Periodic Benefit (Credit) Cost

Net periodic benefit (credit) cost is reflected in other operations and maintenance expense in the Consolidated Statements of Income. The components of the provision for net periodic benefit (credit) cost and amounts recognized in other comprehensive income and regulatory assets and liabilities for Dominion's and Dominion Gas' (for employees represented by collective bargaining units) plans are as follows:

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	**2016**	2015	2014	**2016**	2015	2014
(millions, except percentages)						
Dominion						
Service cost	**$ 118**	$ 126	$ 114	**$ 31**	$ 40	$ 32
Interest cost	**317**	287	290	**65**	67	67
Expected return on plan assets	**(573)**	(531)	(499)	**(118)**	(117)	(111)
Amortization of prior service (credit) cost	**1**	2	3	**(35)**	(27)	(28)
Amortization of net actuarial loss	**111**	160	111	**8**	6	2
Settlements and curtailments	**1**	—	1	**—**	—	—
Net periodic benefit (credit) cost	**$ (25)**	$ 44	$ 20	**$ (49)**	$ (31)	$ (38)
Changes in plan assets and benefit obligations recognized in other comprehensive income and regulatory assets and liabilities:						
Current year net actuarial (gain) loss	**$ 931**	$ 159	$ 784	**$ 178**	$ (18)	$ 183
Prior service (credit) cost	**—**	—	—	**(216)**	(31)	9
Settlements and curtailments	**(1)**	—	(1)	**—**	—	—
Less amounts included in net periodic benefit cost:						
Amortization of net actuarial loss	**(111)**	(160)	(111)	**(8)**	(6)	(2)
Amortization of prior service credit (cost)	**(1)**	(2)	(3)	**35**	27	28
Total recognized in other comprehensive income and regulatory assets and liabilities	**$ 818**	$ (3)	$ 669	**$ (11)**	$ (28)	$ 218
Significant assumptions used to determine periodic cost:						
Discount rate	**2.87%-4.99%**	4.40%	5.20%-5.30%	**3.56%-4.94%**	4.40%	4.20%-5.10%
Expected long-term rate of return on plan assets	**8.75%**	8.75%	8.75%	**8.50%**	8.50%	8.50%
Weighted average rate of increase for compensation	**4.22%**	4.22%	4.21%	**4.22%**	4.22%	4.22%
Healthcare cost trend rate(1)				**7.00%**	7.00%	7.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)(1)				**5.00%**	5.00%	5.00%
Year that the rate reaches the ultimate trend rate(1)(2)				**2020**	2019	2018
Dominion Gas						
Service cost	**$ 13**	$ 15	$ 12	**$ 5**	$ 7	$ 6
Interest cost	**30**	27	28	**14**	14	13
Expected return on plan assets	**(134)**	(126)	(115)	**(23)**	(24)	(23)
Amortization of prior service (credit) cost	**—**	1	1	**1**	(1)	(1)
Amortization of net actuarial loss	**13**	20	19	**1**	2	—
Net periodic benefit (credit) cost	**$ (78)**	$ (63)	$ (55)	**$ (2)**	$ (2)	$ (5)
Changes in plan assets and benefit obligations recognized in other comprehensive income and regulatory assets and liabilities:						
Current year net actuarial (gain) loss	**$ 91**	$ 97	$ 43	**$ 28**	$ (9)	$ 40
Prior service cost	**—**	—	—	**—**	—	10
Less amounts included in net periodic benefit cost:						
Amortization of net actuarial loss	**(13)**	(20)	(19)	**(1)**	(2)	—
Amortization of prior service credit (cost)	**—**	(1)	(1)	**(1)**	1	1
Total recognized in other comprehensive income and regulatory assets and liabilities	**$ 78**	$ 76	$ 23	**$ 26**	$ (10)	$ 51
Significant assumptions used to determine periodic cost:						
Discount rate	**4.99%**	4.40%	5.20%	**4.93%**	4.40%	4.20%-5.00%
Expected long-term rate of return on plan assets	**8.75%**	8.75%	8.75%	**8.50%**	8.50%	8.50%
Weighted average rate of increase for compensation	**3.93%**	3.93%	3.93%	**3.93%**	3.93%	3.93%
Healthcare cost trend rate(1)				**7.00%**	7.00%	7.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)(1)				**5.00%**	5.00%	5.00%
Year that the rate reaches the ultimate trend rate(1)(2)				**2020**	2019	2018

(1) Assumptions used to determine net periodic cost for the following year.

(2) The Society of Actuaries model used to determine healthcare cost trend rates was updated in 2014. The new model converges to the ultimate trend rate much more quickly than previous models.

The components of AOCI and regulatory assets and liabilities for Dominion's and Dominion Gas' (for employees represented by collective bargaining units) plans that have not been recognized as components of net periodic benefit (credit) cost are as follows:

	Pension Benefits		Other Postretirement Benefits	
At December 31,	**2016**	2015	**2016**	2015
(millions)				
Dominion				
Net actuarial loss	**$ 3,200**	$ 2,381	**$ 283**	$ 114
Prior service (credit) cost	**4**	5	**(419)**	(237)
Total(1)	**$3,204**	$2,386	**$(136)**	$(123)
Dominion Gas				
Net actuarial loss	**$ 458**	$ 380	**$ 60**	$ 33
Prior service (credit) cost	**—**	1	**7**	7
Total(2)	**$ 458**	$ 381	**$ 67**	$ 40

(1) As of December 31, 2016, of the $3.2 billion and $(136) million related to pension benefits and other postretirement benefits, $1.9 billion and $(103) million, respectively, are included in AOCI, with the remainder included in regulatory assets and liabilities. As of December 31, 2015, of the $2.4 billion and $(123) million related to pension benefits and other postretirement benefits, $1.4 billion and $(90) million, respectively, are included in AOCI, with the remainder included in regulatory assets and liabilities.

(2) As of December 31, 2016, of the $458 million related to pension benefits, $167 million is included in AOCI, with the remainder included in regulatory assets and liabilities; the $67 million related to other postretirement benefits is included entirely in regulatory assets and liabilities. As of December 31, 2015, of the $381 million related to pension benefits, $138 million is included in AOCI, with the remainder included in regulatory assets and liabilities; the $40 million related to other postretirement benefits is included entirely in regulatory assets and liabilities.

The following table provides the components of AOCI and regulatory assets and liabilities for Dominion's and Dominion Gas' (for employees represented by collective bargaining units) plans as of December 31, 2016 that are expected to be amortized as components of net periodic benefit (credit) cost in 2017:

	Pension Benefits	Other Postretirement Benefits
(millions)		
Dominion		
Net actuarial loss	**$161**	**$ 13**
Prior service (credit) cost	**1**	**(47)**
Dominion Gas		
Net actuarial loss	**$ 16**	**$ 2**
Prior service (credit) cost	**—**	**1**

The expected long-term rates of return on plan assets, discount rates, healthcare cost trend rates and mortality are critical assumptions in determining net periodic benefit (credit) cost. Dominion develops assumptions, which are then compared to the forecasts of an independent investment advisor (except for the expected long-term rates of return) to ensure reasonableness. An internal committee selects the final assumptions used for Dominion's pension and other postretirement plans, including those in which Dominion Gas participates, including discount rates, expected long-term rates of return, healthcare cost trend rates and mortality rates.

Dominion determines the expected long-term rates of return on plan assets for its pension plans and other postretirement benefit plans, including those in which Dominion Gas participates, by using a combination of:

- Expected inflation and risk-free interest rate assumptions;
- Historical return analysis to determine long term historic returns as well as historic risk premiums for various asset classes;
- Expected future risk premiums, asset volatilities and correlations;
- Forecasts of an independent investment advisor;
- Forward-looking return expectations derived from the yield on long-term bonds and the expected long-term returns of major stock market indices; and
- Investment allocation of plan assets.

Dominion determines discount rates from analyses of AA/Aa rated bonds with cash flows matching the expected payments to be made under its plans, including those in which Dominion Gas participates.

Mortality rates are developed from actual and projected plan experience for postretirement benefit plans. Dominion's actuary conducts an experience study periodically as part of the process to select its best estimate of mortality. Dominion considers both standard mortality tables and improvement factors as well as the plans' actual experience when selecting a best estimate. During 2016, Dominion conducted a new experience study as scheduled and, as a result, updated its mortality assumptions for all its plans, including those in which Dominion Gas participates.

Assumed healthcare cost trend rates have a significant effect on the amounts reported for Dominion's retiree healthcare plans, including those in which Dominion Gas participates. A one percentage point change in assumed healthcare cost trend rates would have had the following effects for Dominion's and Dominion Gas' (for employees represented by collective bargaining units) other postretirement benefit plans:

	Other Postretirement Benefits	
	One percentage point increase	One percentage point decrease
(millions)		
Dominion		
Effect on net periodic cost for 2017	**$ 23**	**$ (18)**
Effect on other postretirement benefit obligation at December 31, 2016	**152**	**(127)**
Dominion Gas		
Effect on net periodic cost for 2017	**$ 5**	**$ (4)**
Effect on other postretirement benefit obligation at December 31, 2016	**41**	**(34)**

Dominion Gas (Employees Not Represented by Collective Bargaining Units) and Virginia Power—Participation in Defined Benefit Plans

Virginia Power employees and Dominion Gas employees not represented by collective bargaining units are covered by the Dominion Pension Plan described above. As participating employers, Virginia Power and Dominion Gas are subject to Dominion's funding policy, which is to contribute annually an amount that is in accordance with ERISA. During 2016, Virginia Power and Dominion Gas made no contributions to the Dominion Pension Plan, and no contributions to this plan are currently expected in 2017. Virginia Power's net periodic pension cost related to this plan was $79 million, $97 million and $75 million in 2016, 2015 and 2014, respectively. Dominion Gas' net periodic pension credit related to this plan was $(45) million, $(38) million and $(37) million in 2016, 2015 and 2014, respectively. Net periodic pension (credit) cost is reflected in other operations and maintenance expense in their respective Consolidated Statements of Income. The funded status of various Dominion subsidiary groups and employee compensation are the basis for determining the share of total pension costs for participating Dominion subsidiaries. See Note 24 for Virginia Power and Dominion Gas amounts due to/from Dominion related to this plan.

Retiree healthcare and life insurance benefits, for Virginia Power employees and for Dominion Gas employees not represented by collective bargaining units, are covered by the Dominion Retiree Health and Welfare Plan described above. Virginia Power's net periodic benefit (credit) cost related to this plan was $(29) million, $(16) million and $(18) million in 2016, 2015 and 2014, respectively. Dominion Gas' net periodic benefit (credit) cost related to this plan was $(4) million, $(5) million and $(5) million for 2016, 2015 and 2014, respectively. Net periodic benefit (credit) cost is reflected in other operations and maintenance expenses in their respective Consolidated Statements of Income. Employee headcount is the basis for determining the share of total other postretirement benefit costs for participating Dominion subsidiaries. See Note 24 for Virginia Power and Dominion Gas amounts due to/from Dominion related to this plan.

Dominion holds investments in trusts to fund employee benefit payments for the pension and other postretirement benefit plans in which Virginia Power and Dominion Gas' employees participate. Any investment-related declines in these trusts will result in future increases in the net periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash that Virginia Power and Dominion Gas will provide to Dominion for their shares of employee benefit plan contributions.

Certain regulatory authorities have held that amounts recovered in rates for other postretirement benefits, in excess of benefits actually paid during the year, must be deposited in trust funds dedicated for the sole purpose of paying such benefits. Accordingly, Virginia Power and Dominion Gas fund other postretirement benefit costs through VEBAs. During 2016 and 2015, Virginia Power made no contributions to the VEBA and does not expect to contribute to the VEBA in 2017. Dominion Gas made no contributions to the VEBAs for employees not represented by collective bargaining units during 2016 and 2015 and does not expect to contribute in 2017.

Defined Contribution Plans

Dominion also sponsors defined contribution employee savings plans that cover substantially all employees. During 2016, 2015 and 2014, Dominion recognized $44 million, $43 million and $41 million, respectively, as employer matching contributions to these plans. Dominion Gas participates in these employee savings plans, both specific to Dominion Gas and that cover multiple Dominion subsidiaries. During 2016, 2015 and 2014, Dominion Gas recognized $7 million as employer matching contributions to these plans. Virginia Power also participates in these employee savings plans. During 2016, 2015 and 2014, Virginia Power recognized $19 million, $18 million and $17 million, respectively, as employer matching contributions to these plans.

Organizational Design Initiative

In the first quarter of 2016, the Companies announced an organizational design initiative that reduced their total workforces during 2016. The goal of the organizational design initiative was to streamline leadership structure and push decision making lower while also improving efficiency. For the year ended December 31, 2016, Dominion recorded a $65 million ($40 million after-tax) charge, including $33 million ($20 million after-tax) at Virginia Power and $8 million ($5 million after-tax) at Dominion Gas, primarily reflected in other operations and maintenance expense in their Consolidated Statements of Income due to severance pay and other costs related to the organizational design initiative. The terms of the severance under the organizational design initiative were consistent with the Companies' existing severance plans.

Note 22. Commitments And Contingencies

As a result of issues generated in the ordinary course of business, the Companies are involved in legal proceedings before various courts and are periodically subject to governmental examinations (including by regulatory authorities), inquiries and investigations. Certain legal proceedings and governmental examinations involve demands for unspecified amounts of damages, are in an initial procedural phase, involve uncertainty as to the outcome of pending appeals or motions, or involve significant factual issues that need to be resolved, such that it is not possible for the Companies to estimate a range of possible loss. For such matters for which the Companies cannot estimate a range of possible loss, a statement to this effect is made in the description of the matter. Other matters may have progressed sufficiently through the litigation or investigative processes such that the Companies are able to estimate a range of possible loss. For legal proceedings and governmental examinations for which the Companies are able to reasonably estimate a range of possible losses, an estimated range of possible loss is provided, in excess of the accrued liability (if any) for such matters. Any accrued liability is recorded on a gross basis with a receivable also recorded for any probable insurance recoveries. Estimated ranges of loss are inclusive of legal fees and net of any anticipated insurance recoveries. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the Companies' maximum possible loss exposure. The circumstances of such legal proceedings and governmental examinations will change from time to time and actual results may vary significantly from the current estimate. For current proceedings not specifically reported below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial position, liquidity or results of operations of the Companies.

Environmental Matters

The Companies are subject to costs resulting from a number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations.

Air

CAA

The CAA, as amended, is a comprehensive program utilizing a broad range of regulatory tools to protect and preserve the nation's air quality. At a minimum, states are required to establish regulatory programs to address all requirements of the CAA. However, states may choose to develop regulatory programs that are more restrictive. Many of the Companies' facilities are subject to the CAA's permitting and other requirements.

MATS

In December 2011, the EPA issued MATS for coal and oil-fired electric utility steam generating units. The rule establishes strict emission limits for mercury, particulate matter as a surrogate for toxic metals and hydrogen chloride as a surrogate for acid gases. The rule includes a limited use provision for oil-fired units with annual capacity factors under 8% that provides an exemption from emission limits, and allows compliance with operational work practice standards. Compliance was required by April 16, 2015, with certain limited exceptions. However, in June 2014, the VDEQ granted a one-year MATS compliance extension for two coal-fired units at Yorktown power station to defer planned retirements and allow for continued operation of the units to address reliability concerns while necessary electric transmission upgrades are being completed. These coal units will need to continue operating until at least April 2017 due to delays in transmission upgrades needed to maintain electric reliability. Therefore, in October 2015 Virginia Power submitted a request to the EPA for an additional one year compliance extension under an EPA Administrative Order. The order was signed by the EPA in April 2016 allowing the Yorktown units to operate for up to one additional year, as required to maintain reliable power availability while transmission upgrades are being made.

In June 2015, the U.S. Supreme Court issued a decision holding that the EPA failed to take cost into account when the agency first decided to regulate the emissions from coal- and oil-fired plants, and remanded the MATS rule back to the U.S. Court of Appeals for the D.C. Circuit. However, the Supreme Court did not vacate or stay the effective date and implementation of the MATS rule. In November 2015, in response to the Supreme Court decision, the EPA proposed a supplemental finding that consideration of cost does not alter the agency's previous conclusion that it is appropriate and necessary to regulate coal- and oil-fired electric utility steam generating units under Section 112 of the CAA. In December 2015, the U.S. Court of Appeals for the D.C. Circuit issued an order remanding the MATS rulemaking proceeding back to the EPA without setting aside judgment, noting that EPA had represented it was on track to issue a final finding regarding its consideration of cost. In April 2016, the EPA issued a final supplemental finding that consideration of costs does not alter its conclusion regarding appropriateness and necessity for the regulation. These actions do not change Virginia Power's plans to close coal units at Yorktown power station by April 2017 or the need to complete necessary electricity transmission upgrades which are expected to be in service approximately 20 months following receipt of all required permits and approvals for construction. Since the MATS rule remains in effect and Dominion is complying with the requirements of the rule, Dominion does not expect any adverse impacts to its operations at this time.

CSAPR

In July 2011, the EPA issued a replacement rule for CAIR, called CSAPR, that required 28 states to reduce power plant emissions that cross state lines. CSAPR established new SO_2 and NO_X emissions cap and trade programs that were completely independent of the current ARP. Specifically, CSAPR required reductions in SO_2 and NO_X emissions from fossil fuel-fired electric generating units of 25 MW or more through annual NO_X emissions caps, NO_X emissions caps during the ozone season (May 1 through September 30) and annual SO_2 emission caps with differing requirements for two groups of affected states. Following numerous petitions by industry participants for review and a successful motion for stay, in October 2014, the U.S. Court of Appeals for the D.C. Circuit ordered that the EPA's motion to lift the stay of CSAPR be granted. Further, the Court granted the EPA's request to shift the CSAPR compliance deadlines by three years, so that Phase 1 emissions budgets (which would have gone into effect in 2012 and 2013) applied in 2015 and 2016, and Phase 2 emissions budgets will apply in 2017 and beyond. CSAPR replaced CAIR beginning in January 2015. In September 2016, the EPA issued a revision to CSAPR that reduces the ozone season NO_X emission budgets in 22 states beginning in 2017. The cost to comply with CSAPR, including the recent revision to the CSAPR ozone season NO_X program, is not expected to be material to Dominion's or Virginia Power's Consolidated Financial Statements.

Ozone Standards

In October 2015, the EPA issued a final rule tightening the ozone standard from 75-ppb to 70-ppb. To comply with this standard, in April 2016 Virginia Power submitted the NO_X Reasonable Available Control Technology analysis for Unit 5 at Possum Point power station. In December 2016, the VDEQ determined that NO_X controls are required on Unit 5. Installation and operation of these NO_X controls including an associated water treatment system will be required by mid-2019 with an expected cost in the range of $25 to $35 million.

The EPA is expected to complete attainment designations for a new standard by December 2017 and states will have until 2020 or 2021 to develop plans to address the new standard. Until the states have developed implementation plans, the Companies are unable to predict whether or to what extent the new rules will ultimately require additional controls. However, if significant expenditures are required to implement additional controls, it could materially affect the Companies' results of operations and cash flows.

NO_x and VOC Emissions

In April 2016, the Pennsylvania Department of Environmental Protection issued final regulations, with an effective date of January 2017, to reduce NO_X and VOC emissions from combustion sources. To comply with the regulations, Dominion Gas is installing emission control systems on existing engines at several compressor stations in Pennsylvania. The compliance costs associated with engineering and installation of controls and compliance demonstration with the regulation are expected to be approximately $25 million.

NSPS

In August 2012, the EPA issued the first NSPS impacting new and modified facilities in the natural gas production and gathering sectors and made revisions to the NSPS for natural gas processing and transmission facilities. These rules establish equipment performance specifications and emissions standards for control of VOC emissions for natural gas production wells, tanks, pneumatic controllers, and compressors in the upstream sector. In June 2016, the EPA issued a final NSPS regulation, for the oil and natural gas sector, to regulate methane and VOC emissions from new and modified facilities in transmission and storage, gathering and boosting, production and processing facilities. All projects which commenced construction after September 2015 will be required to comply with this regulation. Dominion and Dominion Gas are still evaluating whether potential impacts on results of operations, financial condition and/or cash flows related to this matter will be material.

Climate Change Regulation

Carbon Regulations

In October 2013, the U.S. Supreme Court granted petitions filed by several industry groups, states, and the U.S. Chamber of Commerce seeking review of the U.S. Court of Appeals for the D.C. Circuit's June 2012 decision upholding the EPA's regulation of GHG emissions from stationary sources under the CAA's permitting programs. In June 2014, the U.S. Supreme Court ruled that the EPA lacked the authority under the CAA to require PSD or Title V permits for stationary sources based solely on GHG emissions. However, the Court upheld the EPA's ability to require BACT for GHG for sources that are otherwise subject to PSD or Title V permitting for conventional pollutants. In August 2016, the EPA issued a draft rule proposing to reaffirm that a source's obligation to obtain a PSD or Title V permit for GHGs is triggered only if such permitting requirements are first triggered by non-GHG, or conventional, pollutants that are regulated by the New Source Review program, and to set a significant emissions rate at 75,000 tons per year of CO_2 equivalent emissions under which a source would not be required to apply BACT for its GHG emissions. Until the EPA ultimately takes final action on this rulemaking, the Companies cannot predict the impact to their financial statements.

In July 2011, the EPA signed a final rule deferring the need for PSD and Title V permitting for CO_2 emissions for biomass projects. This rule temporarily deferred for a period of up to three years the consideration of CO_2 emissions from biomass projects when determining whether a stationary source meets the PSD and Title V applicability thresholds, including those for the application of BACT. The deferral policy expired in July 2014. In July 2013, the U.S. Court of Appeals for the D.C. Circuit vacated this rule; however, a mandate making this decision effective has not been issued. Virginia Power converted three coal-fired generating stations, Altavista, Hopewell and Southampton, to biomass during the CO_2 deferral period. It is unclear how the court's decision or the EPA's final policy regarding the treatment of specific feedstock will affect biomass sources that were permitted during the deferral period; however, the expenditures to comply with any new requirements could be material to Dominion's and Virginia Power's financial statements.

Methane Emissions

In July 2015, the EPA announced the next generation of its voluntary Natural Gas STAR Program, the Natural Gas STAR Methane Challenge Program. The program covers the entire natural gas sector from production to distribution, with more emphasis on transparency and increased reporting for both annual emissions and reductions achieved through implementation measures. In March 2016, East Ohio, Hope, DTI and Questar Gas (prior to the Dominion Questar Combination) joined the EPA as founding partners in the new Methane Challenge program and submitted implementation plans in September 2016. DCG joined the EPA's voluntary Natural Gas STAR Program in July 2016 and submitted an implementation plan in September 2016. Dominion and Dominion Gas do not expect the costs related to these programs to have a material impact on their results of operations, financial condition and/or cash flows.

Water

The CWA, as amended, is a comprehensive program requiring a broad range of regulatory tools including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms. The Companies must comply with applicable aspects of the CWA programs at their operating facilities.

In October 2014, the final regulations under Section 316(b) of the CWA that govern existing facilities and new units at existing facilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold became effective. The rule establishes a national standard for impingement based on seven compliance options, but forgoes the creation of a single technology standard for entrainment. Instead, the EPA has delegated entrainment technology decisions to state regulators. State regulators are to make case-by-case entrainment technology determinations after an examination of five mandatory facility-specific factors, including a social cost-benefit test, and six optional facility-specific factors. The rule governs all electric generating stations with water withdrawals above two MGD, with a heightened entrainment analysis for those facilities over 125 MGD. Dominion and Virginia Power have 14 and 11 facilities, respectively, that may be subject to the final regulations. Dominion anticipates that it will have to install impingement control technologies at many of these stations that have once-through cooling systems. Dominion and Virginia Power are currently evaluating the need or potential for entrainment controls under the final rule as these decisions will be made on a case-by-case basis after a thorough review of detailed biological, technology, cost and benefit studies. While the impacts of this rule could be material to Dominion's and Virginia Power's results of operations, financial condition and/or cash flows, the existing regulatory framework in Virginia provides rate recovery mechanisms that could substantially mitigate any such impacts for Virginia Power.

In September 2015, the EPA released a final rule to revise the Effluent Limitations Guidelines for the Steam Electric Power Generating Category. The final rule establishes updated standards for wastewater discharges that apply primarily at coal and oil steam generating stations. Affected facilities are required to convert from wet to dry or closed cycle coal ash management, improve existing wastewater treatment systems and/or install new wastewater treatment technologies in order to meet the new discharge limits. Virginia Power has eight facilities that may be subject to additional wastewater treatment requirements associated with the final rule. While the impacts of this rule could be material to Dominion's and Virginia Power's results of operations, financial condition and/or cash flows, the existing regulatory framework in Virginia provides rate recovery mechanisms that could substantially mitigate any such impacts for Virginia Power.

Solid and Hazardous Waste

The CERCLA, as amended, provides for immediate response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances into the environment and authorizes the U.S. government 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 the CERCLA, as amended, generators and transporters of hazardous substances, as well as past and present owners and operators of contaminated sites, can be jointly, severally and strictly liable for the cost of cleanup. These potentially responsible parties can be ordered to perform a cleanup, be sued for costs associated with an EPA-directed cleanup, voluntarily settle with the U.S. government concerning their liability for cleanup costs, or voluntarily begin a site investigation and site remediation under state oversight.

From time to time, Dominion, Virginia Power, or Dominion Gas may be identified as a potentially responsible party to a Superfund site. The EPA (or a state) can either allow such a party to conduct and pay for a remedial investigation, feasibility study and remedial action or conduct the remedial investigation and action itself and then seek reimbursement from the potentially responsible parties. Each party can be held jointly, severally and strictly liable for the cleanup costs. These parties can also bring contribution actions against each other and seek reimbursement from their insurance companies. As a result, Dominion, Virginia Power, or Dominion Gas may be responsible for the costs of remedial investigation and actions under the Superfund law or other laws or regulations regarding the remediation of waste. The Companies do not believe these matters will have a material effect on results of operations, financial condition and/or cash flows.

In September 2011, the EPA issued a UAO to Virginia Power and 22 other parties, pursuant to CERCLA, ordering specific remedial action of certain areas at the Ward Transformer Superfund site located in Raleigh, North Carolina. In September 2016, the U.S., on behalf of the EPA, lodged a proposed Remedial Design/Remedial Action Consent Decree with the U.S. District Court for the Eastern District of North Carolina, settling claims related to the site between the EPA and a number of parties, including Virginia Power. In November 2016, the court approved and entered the final Consent Decree and closed the case. The Consent Decree identifies Virginia Power as a non-performing cash-out party to the settlement and resolves Virginia Power's alleged liability under CERCLA with respect to the site, including liability pursuant to the UAO. Virginia Power's cash settlement for this case was less than $1 million.

Dominion has determined that it is associated with 19 former manufactured gas plant sites, three of which pertain to Virginia Power and 12 of which pertain to Dominion Gas. Studies conducted by other utilities at their former manufactured gas plant sites have indicated that those sites contain coal tar and other potentially harmful materials. None of the former sites with which the Companies are associated is under investigation by any state or federal environmental agency. At one of the former sites, Dominion is conducting a state-approved post closure groundwater monitoring program and an environmental land use restriction has been recorded. Another site has been accepted into a state-based voluntary remediation program. Virginia Power is currently evaluating the nature and extent of the contamination from this site as well as potential remedial options. Preliminary costs for options under evaluation for the site range from $1 million to $22 million. Due to the uncertainty surrounding the other sites, the Companies are unable to make an estimate of the potential financial statement impacts.

See below for discussion on ash pond and landfill closure costs.

Other Legal Matters

The Companies are defendants in a number of lawsuits and claims involving unrelated incidents of property damage and personal injury. Due to the uncertainty surrounding these matters, the Companies are unable to make an estimate of the potential financial statement impacts; however, they could have a material impact on results of operations, financial condition and/or cash flows.

Appalachian Gateway

Pipeline Contractor Litigation

Following the completion of the Appalachian Gateway project in 2012, DTI received multiple change order requests and other claims for additional payments from a pipeline contractor for the project. In July 2013, DTI filed a complaint in U.S. District Court for the Eastern District of Virginia for breach of contract as well as accounting and declaratory relief. The contractor filed a motion to dismiss, or in the alternative, a motion to transfer venue to Pennsylvania and/or West Virginia, where the pipelines were constructed. DTI filed an opposition to the contractor's motion in August 2013. In November 2013, the court granted the contractor's motion on the basis that DTI must first comply with the dispute resolution process. In July 2015, the contractor filed a complaint against DTI in U.S. District Court for the Western District of Pennsylvania. In August 2015, DTI filed a motion to dismiss, or in the alternative, a motion to transfer venue to Virginia. In March 2016, the Pennsylvania court granted the motion to dismiss and transferred the case to the U.S. District Court for the Eastern District of Virginia. In April 2016, the Virginia court issued an order staying the proceedings and ordering mediation. A mediation occurred in May 2016 but was unsuccessful. In July 2016, DTI filed a motion to dismiss. This case is pending. DTI has accrued a liability of $6 million for this matter. Dominion Gas cannot currently estimate additional financial statement impacts, but there could be a material impact to its financial condition and/or cash flows.

Gas Producers Litigation

In connection with the Appalachian Gateway project, Dominion Field Services, Inc. entered into contracts for firm purchase rights with a group of small gas producers. In June 2016, the gas producers filed a complaint in the Circuit Court of Marshall County, West Virginia against Dominion, DTI and Dominion Field Services, Inc., among other defendants, claiming that the contracts are unenforceable and seeking compensatory and punitive damages. During the third quarter of 2016, Dominion, DTI and Dominion Field Services, Inc. were served with the complaint. Also in the third quarter of 2016, Dominion and DTI, with the consent of the other defendants, removed the case to the U.S. District Court for the Northern District of West Virginia. In October 2016, the defendants filed a motion to dismiss and the plaintiffs filed a motion to remand. In February 2017, the U.S. District Court entered an order remanding the matter to the Circuit Court of Marshall County, West Virginia. This case is pending. Dominion and Dominion Gas cannot currently estimate financial statement impacts, but there could be a material impact to their financial condition and/or cash flows.

Ash Pond and Landfill Closure Costs

In September 2014, Virginia Power received a notice from the Southern Environmental Law Center on behalf of the Potomac Riverkeeper and Sierra Club alleging CWA violations at Possum Point power station. The notice alleges unpermitted discharges to surface water and groundwater from Possum Point power station's historical and active ash storage facilities. A similar notice from the Southern Environmental Law Center on behalf of the Sierra Club was subsequently received related to Chesapeake power station. In December 2014, Virginia Power offered to close all of its coal ash ponds and landfills at Possum Point power station, Chesapeake and Bremo power stations as settlement of the potential litigation. While the issue is open to potential further negotiations, the Southern Environmental Law Center declined the offer as presented in January 2015 and, in March 2015, filed a lawsuit related to its claims of the alleged CWA violations at Chesapeake power station. Virginia Power filed a motion to dismiss in April 2015, which was denied in November 2015. A trial was held in June 2016. This case is pending. As a result of the December 2014 settlement offer, Virginia Power recognized a charge of $121 million in other operations and maintenance expense in its Consolidated Statements of Income for the year ended December 31, 2014.

In April 2015, the EPA's final rule regulating the management of CCRs stored in impoundments (ash ponds) and landfills was published in the Federal Register. The final rule regulates CCR landfills, existing ash ponds that still receive and manage CCRs, and inactive ash ponds that do not receive, but still store CCRs. Virginia Power currently operates inactive ash ponds, existing ash ponds, and CCR landfills subject to the final rule at eight different facilities. The enactment of the final rule in April 2015 created a legal obligation for Virginia Power to retrofit or close all of its inactive and existing ash ponds over a certain period of time, as well as perform required monitoring, corrective action, and post-closure care activities as necessary. The CCR rule requires that groundwater impacts associated with ash ponds be remediated. It is too early in the implementation phase of the rule to determine the scope of any potential groundwater remediation, but the costs, if required, could be material.

In April 2016, the EPA announced a partial settlement with certain environmental and industry organizations that had challenged the final CCR rule in the U.S. Court of Appeals for the D.C. Circuit. As part of the settlement, certain exemptions included in the final rule for inactive ponds that closed by April 2018 will be removed, resulting in inactive ponds ultimately being subject to the same requirements as existing ponds. In June 2016, the court issued an order approving the settlement, which requires the EPA to modify provisions in the final CCR rule concerning inactive ponds. In August 2016, the EPA issued a final rule, effective October 2016, extending certain compliance deadlines in the final CCR rule for inactive ponds.

In February and March 2016, respectively, two parties filed administrative appeals in the Circuit Court for the City of Richmond challenging certain provisions, relating to ash pond dewatering activities, of Possum Point power station's wastewater discharge permit issued by the VDEQ in January 2016. One of those parties withdrew its appeal in June 2016. In November 2016, the court dismissed the remaining appeal.

In 2015, Virginia Power recorded a $386 million ARO related to future ash pond and landfill closure costs, which resulted in a $99 million incremental charge recorded in other operations and maintenance expense in its Consolidated Statement of Income, a $166 million increase in property, plant, and equipment associated with asset retirement costs, and a $121 million reduction in other noncurrent liabilities related to reversal of the contingent liability described above since the ARO obligation created by the final CCR rule represents similar activities. In 2016, Virginia Power recorded an increase to this ARO of $238 million, which resulted in a $197 million incremental charge recorded in other operations and maintenance expense in its Consolidated Statement of Income, a $17 million increase in property, plant, and equipment and a $24 million increase in regulatory assets. The actual AROs related to the CCR rule may vary substantially from the estimates used to record the obligation at December 31, 2016.

In December 2016, the U.S. Congress passed and the President signed legislation that creates a framework for EPA-approved state CCR permit programs. Under this legislation, an approved state CCR permit program functions in lieu of the self-implementing Federal CCR rule. The legislation allows states more flexibility in developing permit programs to implement the environmental criteria in the CCR rule. It is unknown how long it will take for the EPA to develop the framework for state program approvals. The EPA has enforcement authority until these new CCR rules are in place and state programs are approved. The EPA and states with approved programs both will have authority to enforce CCR requirements under their respective rules and programs. Dominion cannot forecast potential incremental impacts or costs related to existing coal ash sites until rules implementing the 2016 CCR legislation are in place.

Cove Point

Dominion is constructing the Liquefaction Project at the Cove Point facility, which would enable the facility to liquefy domestically-produced natural gas and export it as LNG. In September 2014, FERC issued an order granting authorization for Cove Point to construct, modify and operate the Liquefaction Project. In October 2014, several parties filed a motion with FERC to stay the order and requested rehearing. In May 2015, FERC denied the requests for stay and rehearing.

Two parties have separately filed petitions for review of the FERC order in the U.S. Court of Appeals for the D.C. Circuit, which petitions were consolidated. Separately, one party requested a stay of the FERC order until the judicial proceedings are complete, which the court denied in June 2015. In July 2016, the court denied one party's petition for review of the FERC order authorizing the Liquefaction Project. The court also issued a decision remanding the other party's petition for review of the FERC order to FERC for further explanation of FERC's decision that a previous transaction with an existing import shipper was not unduly discriminatory. Cove Point believes that on remand FERC will be able to justify its decision.

In September 2013, the DOE granted Non-FTA Authorization approval for the export of up to 0.77 bcfe/day of natural gas to countries that do not have an FTA for trade in natural gas. In June 2016, a party filed a petition for review of this approval in the U.S. Court of Appeals for the D.C. Circuit. This case is pending.

FERC

The FERC staff in the Office of Enforcement, Division of Investigations, is conducting a non-public investigation of Virginia Power's offers of combustion turbines generators into the PJM day-ahead markets from April 2010 through September 2014. The FERC staff notified Virginia Power of its preliminary findings relating to Virginia Power's alleged violation of FERC's rules in connection with these activities. Virginia Power has provided its response to the FERC staff's preliminary findings letter explaining why Virginia Power's conduct was lawful and refuting any allegation of wrongdoing. Virginia Power is cooperating fully with the investigation; however, it cannot currently predict whether or to what extent it may incur a material liability.

Greensville County

Virginia Power is constructing Greensville County and related transmission interconnection facilities. In July 2016, the Sierra Club filed an administrative appeal in the Circuit Court for the City of Richmond challenging certain provisions in Greensville County's PSD air permit issued by VDEQ in June 2016. Virginia Power is currently unable to make an estimate of the potential impacts to its consolidated financial statements related to this matter.

Nuclear Matters

In March 2011, a magnitude 9.0 earthquake and subsequent tsunami caused significant damage at the Fukushima Daiichi nuclear power station in northeast Japan. These events have resulted in significant nuclear safety reviews required by the NRC and industry groups such as the Institute of Nuclear Power Operations. Like other U.S. nuclear operators, Dominion has been gathering supporting data and participating in industry initiatives focused on the ability to respond to and mitigate the consequences of design-basis and beyond-design-basis events at its stations.

In July 2011, an NRC task force provided initial recommendations based on its review of the Fukushima Daiichi accident and in October 2011 the NRC staff prioritized these recommendations into Tiers 1, 2 and 3, with the Tier 1 recommendations consisting of actions which the staff determined should be started without unnecessary delay. In December 2011, the NRC Commissioners approved the agency staff's prioritization and recommendations, and that same month an appropriations act directed the NRC to require reevaluation of external hazards (not limited to seismic and flooding hazards) as soon as possible.

Based on the prioritized recommendations, in March 2012, the NRC issued orders and information requests requiring specific reviews and actions to all operating reactors, construction permit holders and combined license holders based on the lessons learned from the Fukushima Daiichi event. The orders applicable to Dominion requiring implementation of safety enhancements related to mitigation strategies to respond to extreme natural events resulting in the loss of power at plants, and enhancing spent fuel pool instrumentation have been implemented. The information requests issued by the NRC request each reactor to reevaluate the seismic and external flooding hazards at their site using present-day methods and information, conduct walkdowns of their facilities to ensure protection against the hazards in their current design basis, and to reevaluate their emergency communications systems and staffing levels. The walkdowns of each unit have been completed, audited by the NRC and found to be adequate. Reevaluation of the emergency communications systems and staffing levels was completed as part of the effort to comply with the orders. Reevaluation of the seismic and external flooding hazards is expected to continue through 2018. Dominion and Virginia Power do not currently expect that compliance with the NRC's information requests will materially impact their financial position, results of operations or cash flows during the implementation period. The NRC staff is evaluating the implementation of the longer term Tier 2 and Tier 3 recommendations. Dominion and Virginia Power do not expect material financial impacts related to compliance with Tier 2 and Tier 3 recommendations.

Nuclear Operations

Nuclear Decommissioning—Minimum Financial Assurance

The NRC requires nuclear power plant owners to annually update minimum financial assurance amounts for the future decommissioning of their nuclear facilities. Decommissioning involves the decontamination and removal of radioactive contaminants from a nuclear power station once operations have ceased, in accordance with standards established by the NRC. The 2016 calculation for the NRC minimum financial assurance amount, aggregated for Dominion's and Virginia Power's nuclear units, excluding joint owners' assurance amounts and Millstone Unit 1 and Kewaunee, as those units are in a decommissioning state, was $2.9 billion and $1.8 billion, respectively, and has been satisfied by a combination of the funds being collected and deposited in the nuclear decommissioning trusts and the real annual rate of return growth of the funds allowed by the NRC. The 2016 NRC minimum financial assurance amounts above were calculated using preliminary December 31, 2016 U.S. Bureau of Labor Statistics indices. Dominion believes that the amounts currently available in its decommissioning trusts and their expected earnings will be sufficient to cover expected decommissioning costs for the Millstone and Kewaunee units. Virginia Power also believes that the decommissioning funds and their expected earnings for the Surry and North Anna units will be sufficient to cover decommissioning costs, particularly when combined with future ratepayer collections and contributions to these decommissioning trusts, if such future collections and contributions are required. This reflects a positive long-term outlook for trust fund investment returns as the decommissioning of the units will not be complete for decades. Dominion and Virginia Power will continue to monitor these trusts to ensure they meet the NRC minimum financial assurance requirement, which may include, if needed, the use of parent company guarantees, surety bonding or other financial instruments recognized by the NRC. See Note 9 for additional information on nuclear decommissioning trust investments.

Nuclear Insurance

The Price-Anderson Amendments Act of 1988 provides the public up to $13.36 billion of liability protection per nuclear incident, via obligations required of owners of nuclear power plants, and allows for an inflationary provision adjustment every five years. Dominion and Virginia Power have purchased $375 million of coverage from commercial insurance pools for each reactor site with the remainder provided through a mandatory industry retrospective rating plan. In the event of a nuclear incident at any licensed nuclear reactor in the U.S., the Companies could be assessed up to $127 million for each of their licensed reactors not to exceed $19 million per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed. However, the NRC granted an exemption in March 2015 to remove Kewaunee from the Secondary Financial Protection program.

The current levels of nuclear property insurance coverage for Dominion's and Virginia Power's nuclear units is as follows:

	Coverage
(billions)	
Dominion	
Millstone	**$1.70**
Kewaunee	**1.06**
Virginia Power(1)	
Surry	**$1.70**
North Anna	**1.70**

(1) Surry and North Anna share a blanket property limit of $200 million.

Dominion's and Virginia Power's nuclear property insurance coverage for Millstone, Surry and North Anna exceeds the NRC minimum requirement for nuclear power plant licensees of $1.06 billion per reactor site. Kewaunee meets the NRC minimum requirement of $1.06 billion. This includes coverage for premature decommissioning and functional total loss. The NRC requires that the proceeds from this insurance be used first, to return the reactor to and maintain it in a safe and stable condition and second, to decontaminate the reactor and station site in accordance with a plan approved by the NRC. Nuclear property insurance is provided by NEIL, a mutual insurance company, and is subject to retrospective premium assessments in any policy year in which losses exceed the funds available to the insurance company. Dominion's and Virginia Power's maximum retrospective premium assessment for the current policy period is $87 million and $49 million, respectively. Based on the severity of the incident, the Board of Directors of the nuclear insurer has the discretion to lower or eliminate the maximum retrospective premium assessment. Dominion and Virginia Power have the financial responsibility for any losses that exceed the limits or for which insurance proceeds are not available because they must first be used for stabilization and decontamination.

Millstone and Virginia Power also purchase accidental outage insurance from NEIL to mitigate certain expenses, including replacement power costs, associated with the prolonged outage of a nuclear unit due to direct physical damage. Under this program, Dominion and Virginia Power are subject to a retrospective premium assessment for any policy year in which losses exceed funds available to NEIL. Dominion's and Virginia Power's maximum retrospective premium assessment for the current policy period is $23 million and $10 million, respectively.

ODEC, a part owner of North Anna, and Massachusetts Municipal and Green Mountain, part owners of Millstone's Unit 3, are responsible to Dominion and Virginia Power for their share of the nuclear decommissioning obligation and insurance premiums on applicable units, including any retrospective premium assessments and any losses not covered by insurance.

Spent Nuclear Fuel

Dominion and Virginia Power entered into contracts with the DOE for the disposal of spent nuclear fuel under provisions of the Nuclear Waste Policy Act of 1982. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by Dominion's and Virginia Power's contracts with the DOE. Dominion and Virginia Power have previously received damages award payments and settlement payments related to these contracts.

By mutual agreement of the parties, the settlement agreements are extendable to provide for resolution of damages incurred after 2013. The settlement agreements for the Surry, North Anna and Millstone plants have been extended to provide for periodic payments for damages incurred through December 31, 2016, and additional extensions are contemplated by the settlement agreements. Possible settlement of the Kewaunee claims for damages incurred after December 31, 2013 is being evaluated.

In 2016, Virginia Power and Dominion received payments of $30 million for resolution of claims incurred at North Anna and Surry for the period of January 1, 2014 through December 31, 2014, and $22 million for resolution of claims incurred at Millstone for the period of July 1, 2014 through June 30, 2015.

In 2015, Virginia Power and Dominion received payments of $8 million for resolution of claims incurred at North Anna and Surry for the period of January 1, 2013 through December 31, 2013, and $17 million for resolution of claims incurred at Millstone for the period of July 1, 2013 through June 30, 2014.

In 2014, Virginia Power and Dominion received payments of $27 million for the resolution of claims incurred at North Anna and Surry for the period January 1, 2011 through December 31, 2012 and $17 million for the resolution of claims incurred at Millstone for the period of July 1, 2012 through June 30, 2013. In 2014, Dominion also received payments totaling $7 million for the resolution of claims incurred at Kewaunee for periods from January 1, 2011 through December 31, 2013.

Dominion and Virginia Power continue to recognize receivables for certain spent nuclear fuel-related costs that they believe are probable of recovery from the DOE. Dominion's receivables for spent nuclear fuel-related costs totaled $56 million and $87 million at December 31, 2016 and 2015, respectively. Virginia Power's receivables for spent nuclear fuel-related costs totaled $37 million and $54 million at December 31, 2016 and 2015, respectively.

Pursuant to a November 2013 decision of the U.S Court of Appeals for the D.C. Circuit, in January 2014 the Secretary of the DOE sent a recommendation to the U.S. Congress to adjust to zero the current fee of $1 per MWh for electricity paid by civilian nuclear power generators for disposal of spent nuclear fuel. The processes specified in the Nuclear Waste Policy Act for adjustment of the fee have been completed, and as of May 2014, Dominion and Virginia Power are no longer required to pay the waste fee. In 2014, Dominion and Virginia Power recognized fees of $16 million and $10 million, respectively.

Dominion and Virginia Power will continue to manage their spent fuel until it is accepted by the DOE.

Long-Term Purchase Agreements

At December 31, 2016, Virginia Power had the following long-term commitments that are noncancelable or are cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services:

	2017	2018	2019	2020	2021	Thereafter	Total
(millions)							
Purchased electric capacity(1)	**$149**	**$93**	**$60**	**$52**	**$46**	**$—**	**$400**

(1) Commitments represent estimated amounts payable for capacity under power purchase contracts with qualifying facilities and independent power producers, the last of which ends in 2021. Capacity payments under the contracts are generally based on fixed dollar amounts per month, subject to escalation using broad-based economic indices. At December 31, 2016, the present value of Virginia Power's total commitment for capacity payments is $347 million. Capacity payments totaled $248 million, $305 million, and $330 million, and energy payments totaled $126 million, $198 million, and $304 million for the years ended 2016, 2015 and 2014, respectively.

Lease Commitments

The Companies lease real estate, vehicles and equipment primarily under operating leases. Payments under certain leases are escalated based on an index such as the consumer price index. Future minimum lease payments under noncancelable operating and capital leases that have initial or remaining lease terms in excess of one year as of December 31, 2016 are as follows:

	2017	2018	2019	2020	2021	Thereafter	Total
(millions)							
Dominion(1)	**$72**	**$69**	**$58**	**$39**	**$32**	**$238**	**$508**
Virginia Power	**$33**	**$30**	**$24**	**$20**	**$16**	**$ 32**	**$155**
Dominion Gas	**$27**	**$26**	**$21**	**$ 8**	**$ 5**	**$ 18**	**$105**

(1) Amounts include a lease agreement for the Dominion Questar corporate office, which is accounted for as a capital lease. At December 31, 2016, the Consolidated Balance Sheets include $30 million in property, plant and equipment and $35 million in other deferred credits and other liabilities. The Consolidated Statements of Income include less than $1 million recorded in depreciation, depletion and amortization for the year ended December 31, 2016.

Rental expense for Dominion totaled $104 million, $99 million, and $92 million for 2016, 2015 and 2014, respectively. Rental expense for Virginia Power totaled $52 million, $51 million, and $43 million for 2016, 2015, and 2014, respectively. Rental expense for Dominion Gas totaled $37 million, $37 million, and $35 million for 2016, 2015 and 2014, respectively. The majority of rental expense is reflected in other operations and maintenance expense in the Consolidated Statements of Income.

In July 2016, Dominion signed an agreement with a lessor to construct and lease a new corporate office property in Richmond, Virginia. The lessor is providing equity and has obtained financing commitments from debt investors, totaling $365 million, to fund the estimated project costs. The project is expected to be completed by mid-2019. Dominion has been appointed to act as the construction agent for the lessor, during which time Dominion will request cash draws from the lessor and debt investors to fund all project costs, which totaled $46 million as of December 31, 2016. If the project is terminated under certain events of default, Dominion could be required to pay up to 89.9% of the then funded amount. For specific full recourse events, Dominion could be required to pay up to 100% of the then funded amount.

The five-year lease term will commence once construction is substantially complete and the facility is able to be occupied. At the end of the initial lease term, Dominion can (i) extend the term of the lease for an additional five years, subject to the approval of the participants, at current market terms, (ii) purchase the property for an amount equal to the project costs or, (iii) subject to certain terms and conditions, sell the property to a third party using commercially reasonable efforts to obtain the highest cash purchase price for the property. If the project is sold and the proceeds from the sale are insufficient to repay the investors for the project costs, Dominion may be required to make a payment to the lessor, up to 87% of project costs, for the difference between the project costs and sale proceeds.

Guarantees, Surety Bonds and Letters of Credit

At December 31, 2016, Dominion had issued $48 million of guarantees, primarily to support equity method investees. No significant amounts related to these guarantees have been recorded.

Dominion also enters into guarantee arrangements on behalf of its consolidated subsidiaries, primarily to facilitate their commercial transactions with third parties. If any of these subsidiaries fail to perform or pay under the contracts and the counterparties seek performance or payment, Dominion would be obligated to satisfy such obligation. To the extent that a liability subject to a guarantee has been incurred by one of Dominion's consolidated subsidiaries, that liability is included in the Consolidated Financial Statements. Dominion is not required to recognize liabilities for guarantees issued on behalf of its subsidiaries unless it becomes probable that it will have to perform under the guarantees. Terms of the guarantees typically end once obligations have been paid. Dominion currently believes it is unlikely that it would be required to perform or otherwise incur any losses associated with guarantees of its subsidiaries' obligations.

At December 31, 2016, Dominion had issued the following subsidiary guarantees:

	Maximum Exposure
(millions)	
Commodity transactions(1)	**$2,074**
Nuclear obligations(2)	**169**
Cove Point(3)	**1,900**
Solar(4)	**1,130**
Other(5)	**545**
Total(6)	**$5,818**

(1) Guarantees related to commodity commitments of certain subsidiaries. These guarantees were provided to counterparties in order to facilitate physical and financial transaction related commodities and services.
(2) Guarantees related to certain DEI subsidiaries' regarding all aspects of running a nuclear facility.
(3) Guarantees related to Cove Point, in support of terminal services, transportation and construction. Cove Point has two guarantees that have no maximum limit and, therefore, are not included in this amount.
(4) Includes guarantees to facilitate the development of solar projects. Also includes guarantees entered into by DEI on behalf of certain subsidiaries to facilitate the acquisition and development of solar projects.
(5) Guarantees related to other miscellaneous contractual obligations such as leases, environmental obligations, construction projects and insurance programs. Due to the uncertainty of worker's compensation claims, the parental guarantee has no stated limit. Also included are guarantees related to certain DEI subsidiaries' obligations for equity capital contributions and energy generation associated with Fowler Ridge and NedPower. As of December 31, 2016, Dominion's maximum remaining cumulative exposure under these equity funding agreements is $36 million through 2019 and its maximum annual future contributions could range from approximately $4 million to $19 million.
(6) Excludes Dominion's guarantee for the construction of the new corporate office property discussed further within Lease Commitments above.

Additionally, at December 31, 2016, Dominion had purchased $149 million of surety bonds, including $71 million at Virginia Power and $22 million at Dominion Gas, and authorized the issuance of letters of credit by financial institutions of $85 million to facilitate commercial transactions by its subsidiaries with third parties. Under the terms of surety bonds, the Companies are obligated to indemnify the respective surety bond company for any amounts paid.

As of December 31, 2016, Virginia Power had issued $14 million of guarantees primarily to support tax-exempt debt issued through conduits. The related debt matures in 2031 and is included in long-term debt in Virginia Power's Consolidated Balance Sheets. In the event of default by a conduit, Virginia Power would be obligated to repay such amounts, which are limited to the principal and interest then outstanding.

Indemnifications

As part of commercial contract negotiations in the normal course of business, the Companies may sometimes agree to make payments to compensate or indemnify other parties for possible future unfavorable financial consequences resulting from specified events. The specified events may involve an adverse judgment in a lawsuit or the imposition of additional taxes due to a change in tax law or interpretation of the tax law. The Companies are unable to develop an estimate of the maximum potential amount of any other future payments under these contracts because events that would obligate them have not yet occurred or, if any such event has occurred, they have not been notified of its occurrence. However, at December 31, 2016, the Companies believe any other future payments, if any, that could ultimately become payable under these contract provisions, would not have a material impact on their results of operations, cash flows or financial position.

Note 23. Credit Risk

Credit risk is the risk of financial loss if counterparties fail to perform their contractual obligations. In order to minimize overall credit risk, credit policies are maintained, including the evaluation of counterparty financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. In addition, counterparties may make available collateral, including letters of credit or cash held as margin deposits, as a result of exceeding agreed-upon credit limits, or may be required to prepay the transaction.

The Companies maintain a provision for credit losses based on factors surrounding the credit risk of their customers, historical trends and other information. Management believes, based on credit policies and the December 31, 2016 provision for credit losses, that it is unlikely that a material adverse effect on financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

General

Dominion

As a diversified energy company, Dominion transacts primarily with major companies in the energy industry and with commercial and residential energy consumers. These transactions principally occur in the Northeast, mid-Atlantic, Midwest and Rocky Mountain regions of the U.S. Dominion does not believe that this geographic concentration contributes significantly to its overall exposure to credit risk. In addition, as a result of its large and diverse customer base, Dominion is not exposed to a significant concentration of credit risk for receivables arising from electric and gas utility operations.

Dominion's exposure to credit risk is concentrated primarily within its energy marketing and price risk management activities, as Dominion transacts with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Energy marketing and price risk management activities include marketing of merchant generation output, structured transactions and the use of financial contracts for enterprise-wide hedging purposes. Gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of any collateral. At December 31, 2016, Dominion's credit exposure totaled $98 million. Of this amount, investment grade counterparties, including those internally rated, represented 53%, and no single counterparty, whether investment grade or non-investment grade, exceeded $9 million of exposure.

Virginia Power

Virginia Power sells electricity and provides distribution and transmission services to customers in Virginia and northeastern North Carolina. Management believes that this geographic concentration risk is mitigated by the diversity of Virginia Power's customer base, which includes residential, commercial and industrial customers, as well as rural electric cooperatives and municipalities. Credit risk associated with trade accounts receivable from energy consumers is limited due to the large number of customers. Virginia Power's exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Virginia Power's gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on- or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. At December 31, 2016, Virginia Power's credit exposure totaled $42 million. Of this amount, investment grade counterparties, including those internally rated, represented 33%, and no single counterparty, whether investment grade or non-investment grade, exceeded $6 million of exposure.

Dominion Gas

Dominion Gas transacts mainly with major companies in the energy industry and with residential and commercial energy consumers. These transactions principally occur in the Northeast, mid-Atlantic and Midwest regions of the U.S. Dominion Gas does not believe that this geographic concentration contributes to its overall exposure to credit risk. In addition, as a result of its large and diverse customer base, Dominion Gas is not exposed to a significant concentration of credit risk for receivables arising from gas utility operations.

In 2016, DTI provided service to 289 customers with approximately 96% of its storage and transportation revenue being provided through firm services. The ten largest customers provided approximately 40% of the total storage and transportation revenue and the thirty largest provided approximately 70% of the total storage and transportation revenue.

East Ohio distributes natural gas to residential, commercial and industrial customers in Ohio using rates established by the Ohio Commission. Approximately 98% of East Ohio revenues are derived from its regulated gas distribution services. East Ohio's bad debt risk is mitigated by the regulatory framework established by the Ohio Commission. See Note 13 for further information about Ohio's PIPP and UEX Riders that mitigate East Ohio's overall credit risk.

Credit-Related Contingent Provisions

The majority of Dominion's derivative instruments contain credit-related contingent provisions. These provisions require Dominion to provide collateral upon the occurrence of specific events, primarily a credit downgrade. If the credit-related contingent features underlying these instruments that are in a liability position and not fully collateralized with cash were fully triggered as of December 31, 2016 and 2015, Dominion would have been required to post an additional $3 million and $12 million, respectively, of collateral to its counterparties. The collateral that would be required to be posted includes the impacts of any offsetting asset positions and any amounts already posted for derivatives, non-derivative contracts and derivatives elected under the normal purchases and normal sales exception, per contractual terms. Dominion had posted no collateral at December 31, 2016 and 2015, related to derivatives with credit-related contingent provisions that are in a liability position and not fully collateralized with cash. The collateral posted includes any amounts paid related to non-derivative contracts and derivatives elected under the normal purchases and normal sales exception, per contractual terms. The aggregate fair value of all derivative instruments with credit-related contingent provisions that are in a liability position and not fully collateralized with cash as of December 31, 2016 and 2015 was $9 million and $49 million, respectively, which does not include the impact of any offsetting asset positions. Credit-related contingent provisions for Virginia Power and Dominion Gas were not material as of December 31, 2016 and 2015. See Note 7 for further information about derivative instruments.

Note 24. Related-party Transactions

Virginia Power and Dominion Gas engage in related party transactions primarily with other Dominion subsidiaries (affiliates). Virginia Power's and Dominion Gas' receivable and payable balances with affiliates are settled based on contractual terms or on a monthly basis, depending on the nature of the underlying transactions. Virginia Power and Dominion Gas are included in Dominion's consolidated federal income tax return and, where applicable, combined income tax returns for Dominion are filed in various states. See Note 2 for further information. Dominion's transactions with equity method investments are described in Note 9. A discussion of significant related party transactions follows.

Virginia Power

Transactions with Affiliates

Virginia Power transacts with affiliates for certain quantities of natural gas and other commodities in the ordinary course of business. Virginia Power also enters into certain commodity derivative contracts with affiliates. Virginia Power uses these contracts, which are principally comprised of commodity swaps, to manage commodity price risks associated with purchases of natural gas. See Notes 7 and 19 for more information. As of December 31, 2016, Virginia Power's derivative assets and liabilities with affiliates were $41 million and $8 million, respectively. As of December 31, 2015, Virginia Power's derivative assets and liabilities with affiliates were $13 million and $22 million, respectively.

Virginia Power participates in certain Dominion benefit plans as described in Note 21. At December 31, 2016 and 2015, Virginia Power's amounts due to Dominion associated with the Dominion Pension Plan and reflected in noncurrent pension and other postretirement benefit liabilities in the Consolidated Balance Sheets were $396 million and $316 million, respectively. At December 31, 2016 and 2015, Virginia Power's amounts due from Dominion associated with the Dominion Retiree Health and Welfare Plan and reflected in noncurrent pension and other postretirement benefit assets in the Consolidated Balance Sheets were $130 million and $77 million, respectively.

DRS and other affiliates provide accounting, legal, finance and certain administrative and technical services to Virginia Power. In addition, Virginia Power provides certain services to affiliates, including charges for facilities and equipment usage.

The financial statements for all years presented include costs for certain general, administrative and corporate expenses assigned by DRS to Virginia Power on the basis of direct and allocated methods in accordance with Virginia Power's services agreements with DRS. Where costs incurred cannot be determined by specific identification, the costs are allocated based on the proportional level of effort devoted by DRS resources that is attributable to the entity, determined by reference to number of employees, salaries and wages and other similar measures for the relevant DRS service. Management believes the assumptions and methodologies underlying the allocation of general corporate overhead expenses are reasonable.

Presented below are significant transactions with DRS and other affiliates:

Year Ended December 31,	**2016**	2015	2014
(millions)			
Commodity purchases from affiliates	**$571**	$555	$543
Services provided by affiliates[(1)]	**454**	422	432
Services provided to affiliates	**22**	22	22

(1) Includes capitalized expenditures of $144 million, $143 million and $146 million for the year ended December 31, 2016, 2015, and 2014, respectively.

Virginia Power has borrowed funds from Dominion under short-term borrowing arrangements. There were $262 million and $376 million in short-term demand note borrowings from Dominion as of December 31, 2016 and 2015, respectively. The weighted-average interest rate of these borrowings was 0.97% and 0.60% at December 31, 2016 and 2015, respectively. Virginia Power had no outstanding borrowings, net of repayments under the Dominion money pool for its nonregulated subsidiaries as of December 31, 2016 and 2015. Interest charges related to Virginia Power's borrowings from Dominion were immaterial for the years ended December 31, 2016, 2015 and 2014.

There were no issuances of Virginia Power's common stock to Dominion in 2016, 2015 or 2014.

DOMINION GAS

Transactions with Related Parties

Dominion Gas transacts with affiliates for certain quantities of natural gas and other commodities at market prices in the ordinary course of business. Additionally, Dominion Gas provides transportation and storage services to affiliates. Dominion Gas also enters into certain other contracts with affiliates, which are presented separately from contracts involving commodities or services. As of December 31, 2016 and 2015, all of Dominion Gas' commodity derivatives were with affiliates. See Notes 7 and 19 for more information. See Note 9 for information regarding transactions with an affiliate.

Dominion Gas participates in certain Dominion benefit plans as described in Note 21. At December 31, 2016 and 2015, Dominion Gas' amounts due from Dominion associated with the Dominion Pension Plan and reflected in noncurrent pension and other postretirement benefit assets in the Consolidated Balance Sheets were $697 million and $652 million, respectively. At December 31, 2016 and 2015, Dominion Gas' amounts due from Dominion and liabilities due to Dominion associated with the Dominion Retiree Health and Welfare Plan were immaterial.

DRS and other affiliates provide accounting, legal, finance and certain administrative and technical services to Dominion Gas. Dominion Gas provides certain services to related parties, including technical services.

The financial statements for all years presented include costs for certain general, administrative and corporate expenses assigned by DRS to Dominion Gas on the basis of direct and allocated methods in accordance with Dominion Gas' services agreements with DRS. Where costs incurred cannot be determined by specific identification, the costs are allocated based on the proportional level of effort devoted by DRS resources that is attributable to the entity, determined by reference to number of employees, salaries and wages and other similar measures for the relevant DRS service. Management believes the assumptions and methodologies underlying the allocation of general corporate overhead expenses are reasonable. The costs of these services follow:

Year Ended December 31,	**2016**	2015	2014
(millions)			
Purchases of natural gas and transportation and storage services from affiliates	**$ 9**	$ 10	$ 34
Sales of natural gas and transportation and storage services to affiliates	**69**	69	84
Services provided by related parties[(1)]	**141**	133	106
Services provided to related parties[(2)]	**128**	101	17

(1) Includes capitalized expenditures of $49 million, $57 million and $49 million for the year ended December 31, 2016, 2015, and 2014, respectively.
(2) Amounts primarily attributable to Atlantic Coast Pipeline.

The following table presents affiliated and related party balances reflected in Dominion Gas' Consolidated Balance Sheets:

At December 31,	**2016**	2015
(millions)		
Other receivables[(1)]	**$10**	$ 7
Customer receivables from related parties	**1**	4
Imbalances receivable from affiliates	**2**	1
Imbalances payable to affiliates[(2)]	**4**	—
Affiliated notes receivable[(3)]	**18**	14

(1) Represents amounts due from Atlantic Coast Pipeline, a related party VIE.
(2) Amounts are presented in other current liabilities in Dominion Gas' Consolidated Balance Sheets.
(3) Amounts are presented in other deferred charges and other assets in Dominion Gas' Consolidated Balance Sheets.

Dominion Gas' borrowings under the IRCA with Dominion totaled $118 million and $95 million as of December 31, 2016 and 2015, respectively. The weighted-average interest rate of these borrowings was 1.08% and 0.65% at December 31, 2016 and 2015, respectively. Interest charges related to Dominion Gas' total borrowings from Dominion were immaterial for the years ended December 31, 2016 and 2015 and $4 million for the year ended December 31, 2014.

NOTE 25. OPERATING SEGMENTS

The Companies are organized primarily on the basis of products and services sold in the U.S. A description of the operations included in the Companies' primary operating segments is as follows:

Primary Operating Segment	Description of Operations	Dominion	Virginia Power	Dominion Gas
DVP	Regulated electric distribution	X	X	
	Regulated electric transmission	X	X	
Dominion Generation	Regulated electric fleet	X	X	
	Merchant electric fleet	X		
Dominion Energy	Gas transmission and storage	X(1)		X
	Gas distribution and storage	X		X
	Gas gathering and processing	X		X
	LNG import and storage	X		
	Nonregulated retail energy marketing	X		

(1) Includes remaining producer services activities.

In addition to the operating segments above, the Companies also report a Corporate and Other segment.

Dominion

The Corporate and Other Segment of Dominion includes its corporate, service company and other functions (including unallocated debt). In addition, Corporate and Other includes specific items attributable to Dominion's operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

In March 2014, Dominion exited the electric retail energy marketing business. As a result, the earnings impact from the electric retail energy marketing business has been included in the Corporate and Other Segment of Dominion for 2014 first quarter results of operations.

In the second quarter of 2013, Dominion commenced a restructuring of its producer services business, which aggregates natural gas supply, engages in natural gas trading and marketing activities and natural gas supply management and provides price risk management services to Dominion affiliates. The restructuring, which was completed in the first quarter of 2014, resulted in the termination of natural gas trading and certain energy marketing activities. As a result, the earnings impact from natural gas trading and certain energy marketing activities has been included in the Corporate and Other Segment of Dominion for 2014.

In 2016, Dominion reported after-tax net expenses of $484 million in the Corporate and Other segment, with $180 million of these net expenses attributable to specific items related to its operating segments.

The net expenses for specific items in 2016 primarily related to the impact of the following items:

- A $197 million ($122 million after-tax) charge related to future ash pond and landfill closure costs at certain utility generation facilities, attributable to Dominion Generation; and
- A $59 million ($36 million after-tax) charge related to an organizational design initiative, attributable to:
  - DVP ($5 million after-tax);
  - Dominion Energy ($12 million after-tax); and
  - Dominion Generation ($19 million after-tax).

In 2015, Dominion reported after-tax net expenses of $391 million in the Corporate and Other segment, with $136 million of these net expenses attributable to specific items related to its operating segments.

The net expenses for specific items in 2015 primarily related to the impact of the following items:

- A $99 million ($60 million after-tax) charge related to future ash pond and landfill closure costs at certain utility generation facilities, attributable to Dominion Generation; and
- An $85 million ($52 million after-tax) write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015, attributable to Dominion Generation.

In 2014, Dominion reported after-tax net expenses of $970 million in the Corporate and Other segment, with $544 million of these net expenses attributable to specific items related to its operating segments.

The net expenses for specific items in 2014 primarily related to the impact of the following items:

- $374 million ($248 million after-tax) in charges associated with Virginia legislation enacted in April 2014 relating to the development of a third nuclear unit located at North Anna and offshore wind facilities, attributable to Dominion Generation;
- A $319 million ($193 million after-tax) net loss related to the producer services business discussed above, attributable to Dominion Energy; and
- A $121 million ($74 million after-tax) charge related to a settlement offer to incur future ash pond closure costs at certain utility generation facilities, attributable to Dominion Generation.

The following table presents segment information pertaining to Dominion's operations:

Year Ended December 31,	DVP	Dominion Generation	Dominion Energy	Corporate and Other	Adjustments & Eliminations	Consolidated Total
(millions)						
2016						
Total revenue from external customers	**$2,210**	**$6,747**	**$2,069**	**$ (7)**	**$ 718**	**$11,737**
Intersegment revenue	**23**	**10**	**697**	**609**	**(1,339)**	**—**
Total operating revenue	**2,233**	**6,757**	**2,766**	**602**	**(621)**	**11,737**
Depreciation, depletion and amortization	**537**	**662**	**330**	**30**	**—**	**1,559**
Equity in earnings of equity method investees	**—**	**(16)**	**105**	**22**	**—**	**111**
Interest income	**—**	**74**	**34**	**36**	**(78)**	**66**
Interest and related charges	**244**	**290**	**38**	**516**	**(78)**	**1,010**
Income taxes	**308**	**279**	**431**	**(363)**	**—**	**655**
Net income (loss) attributable to Dominion	**484**	**1,397**	**726**	**(484)**	**—**	**2,123**
Investment in equity method investees	**—**	**228**	**1,289**	**44**	**—**	**1,561**
Capital expenditures	**1,320**	**2,440**	**2,322**	**43**	**—**	**6,125**
Total assets (billions)	**15.6**	**27.1**	**26.0**	**10.2**	**(7.3)**	**71.6**
2015						
Total revenue from external customers	$2,091	$7,001	$1,877	$ (27)	$ 741	$11,683
Intersegment revenue	20	15	695	554	(1,284)	—
Total operating revenue	2,111	7,016	2,572	527	(543)	11,683
Depreciation, depletion and amortization	498	591	262	44	—	1,395
Equity in earnings of equity method investees	—	(15)	60	11	—	56
Interest income	—	64	25	13	(44)	58
Interest and related charges	230	262	27	429	(44)	904
Income taxes	307	465	423	(290)	—	905
Net income (loss) attributable to Dominion	490	1,120	680	(391)	—	1,899
Investment in equity method investees	—	245	1,042	33	—	1,320
Capital expenditures	1,607	2,190	2,153	43	—	5,993
Total assets (billions)	14.7	25.6	15.2	8.9	(5.8)	58.6
2014						
Total revenue from external customers	$1,918	$7,135	$2,446	$ (12)	$ 949	$12,436
Intersegment revenue	18	34	880	572	(1,504)	—
Total operating revenue	1,936	7,169	3,326	560	(555)	12,436
Depreciation, depletion and amortization	462	514	243	73	—	1,292
Equity in earnings of equity method investees	—	(18)	54	10	—	46
Interest income	—	58	23	20	(33)	68
Interest and related charges	205	240	11	770	(33)	1,193
Income taxes	317	365	463	(693)	—	452
Net income (loss) attributable to Dominion	502	1,061	717	(970)	—	1,310
Capital expenditures	1,652	2,466	1,329	104	—	5,551

Intersegment sales and transfers for Dominion are based on contractual arrangements and may result in intersegment profit or loss that is eliminated in consolidation.

Virginia Power

The majority of Virginia Power's revenue is provided through tariff rates. Generally, such revenue is allocated for management reporting based on an unbundled rate methodology among Virginia Power's DVP and Dominion Generation segments.

The Corporate and Other Segment of Virginia Power primarily includes specific items attributable to its operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or in allocating resources.

In 2016, Virginia Power reported after-tax net expenses of $173 million for specific items attributable to its operating segments in the Corporate and Other segment.

The net expenses for specific items in 2016 primarily related to the impact of the following item:

- A $197 million ($121 million after-tax) charge related to future ash pond and landfill closure costs at certain utility generation facilities, attributable to Dominion Generation.

In 2015, Virginia Power reported after-tax net expenses of $153 million for specific items attributable to its operating segments in the Corporate and Other segment.

The net expenses for specific items in 2015 primarily related to the impact of the following items:

- A $99 million ($60 million after-tax) charge related to future ash pond and landfill closure costs at certain utility generation facilities, attributable to Dominion Generation; and
- An $85 million ($52 million after-tax) write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015, attributable to Dominion Generation.

In 2014, Virginia Power reported after-tax net expenses of $342 million for specific items attributable to its operating segments in the Corporate and Other segment.

The net expenses for specific items in 2014 primarily related to the impact of the following items:

- $374 million ($248 million after-tax) in charges associated with Virginia legislation enacted in April 2014 relating to the development of a third nuclear unit located at North Anna and offshore wind facilities, attributable to Dominion Generation; and
- A $121 million ($74 million after-tax) charge related to a settlement offer to incur future ash pond closure costs at certain utility generation facilities, attributable to Dominion Generation.

The following table presents segment information pertaining to Virginia Power's operations:

Year Ended December 31,	DVP	Dominion Generation	Corporate and Other	Adjustments & Eliminations	Consolidated Total
(millions)					
2016					
Operating revenue	**$2,217**	**$5,390**	**$ (19)**	**$ —**	**$7,588**
Depreciation and amortization	**537**	**488**	**—**	**—**	**1,025**
Interest income	**—**	**—**	**—**	**—**	**—**
Interest and related charges	**244**	**219**	**—**	**(2)**	**461**
Income taxes	**307**	**524**	**(104)**		**727**
Net income (loss)	**482**	**909**	**(173)**	**—**	**1,218**
Capital expenditures	**1,313**	**1,336**	**—**	**—**	**2,649**
Total assets (billions)	**15.6**	**17.8**	**—**	**(0.1)**	**33.3**
2015					
Operating revenue	$2,099	$5,566	$ (43)	$ —	$7,622
Depreciation and amortization	498	453	2	—	953
Interest income	—	7	—	—	7
Interest and related charges	230	210	4	(1)	443
Income taxes	308	437	(86)		659
Net income (loss)	490	750	(153)	—	1,087
Capital expenditures	1,569	1,120	—	—	2,689
Total assets (billions)	14.7	17.0	—	(0.1)	31.6
2014					
Operating revenue	$1,928	$5,651	$ —	$ —	$7,579
Depreciation and amortization	462	416	37	—	915
Interest income	—	8	—	—	8
Interest and related charges	205	203	3	—	411
Income taxes	317	416	(185)	—	548
Net income (loss)	509	691	(342)	—	858
Capital expenditures	1,651	1,456	—	—	3,107

DOMINION GAS

The Corporate and Other Segment of Dominion Gas primarily includes specific items attributable to Dominion Gas' operating segment that are not included in profit measures evaluated by executive management in assessing the segment's performance or in allocating resources and the effect of certain items recorded at Dominion Gas as a result of Dominion's basis in the net assets contributed.

In 2016, Dominion Gas reported after-tax net expenses of $3 million in its Corporate and Other segment, with $7 million of these net expenses attributable to its operating segment.

The net expense for specific items in 2016 primarily related to the impact of the following item:

- An $8 million ($5 million after-tax) charge related to an organizational design initiative.

In 2015, Dominion Gas reported after-tax net expenses of $21 million in its Corporate and Other segment, with $13 million of these net expenses attributable to specific items related to its operating segment.

The net expenses for specific items in 2015 primarily related to the impact of the following item:

- $16 million ($10 million after-tax) ceiling test impairment charge.

In 2014, Dominion Gas reported after-tax net expenses of $9 million in its Corporate and Other segment, with none of these net expenses attributable to specific items related to its operating segment.

The following table presents segment information pertaining to Dominion Gas' operations:

Year Ended December 31,	Dominion Energy	Corporate and Other	Consolidated Total
(millions)			
2016			
Operating revenue	**$1,638**	**$ —**	**$1,638**
Depreciation and amortization	**214**	**(10)**	**204**
Equity in earnings of equity method investees	**21**	**—**	**21**
Interest income	**1**	**—**	**1**
Interest and related charges	**92**	**2**	**94**
Income taxes	**237**	**(22)**	**215**
Net income (loss)	**395**	**(3)**	**392**
Investment in equity method investees	**98**	**—**	**98**
Capital expenditures	**854**	**—**	**854**
Total assets (billions)	**10.5**	**0.6**	**11.1**
2015			
Operating revenue	$1,716	$ —	$1,716
Depreciation and amortization	213	4	217
Equity in earnings of equity method investees	23	—	23
Interest income	1	—	1
Interest and related charges	72	1	73
Income taxes	296	(13)	283
Net income (loss)	478	(21)	457
Investment in equity method investees	102	—	102
Capital expenditures	795	—	795
Total assets (billions)	9.7	0.6	10.3
2014			
Operating revenue	$1,898	$ —	$1,898
Depreciation and amortization	197	—	197
Equity in earnings of equity method investees	21	—	21
Interest income	1	—	1
Interest and related charges	27	—	27
Income taxes	340	(6)	334
Net income (loss)	521	(9)	512
Capital expenditures	719	—	719

Note 26. Quarterly Financial and Common Stock Data (Unaudited)

A summary of the Companies' quarterly results of operations for the years ended December 31, 2016 and 2015 follows. Amounts reflect all adjustments necessary in the opinion of management for a fair statement of the results for the interim periods. Results for interim periods may fluctuate as a result of weather conditions, changes in rates and other factors.

Dominion

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
(millions, except per share amounts)					
2016					
Operating revenue	**$ 2,921**	**$ 2,598**	**$ 3,132**	**$ 3,086**	**$11,737**
Income from operations	**882**	**781**	**1,145**	**819**	**3,627**
Net income including noncontrolling interests	**531**	**462**	**728**	**491**	**2,212**
Net income attributable to Dominion	**524**	**452**	**690**	**457**	**2,123**
Basic EPS:					
Net income attributable to Dominion	**0.88**	**0.73**	**1.10**	**0.73**	**3.44**
Diluted EPS:					
Net income attributable to Dominion	**0.88**	**0.73**	**1.10**	**0.73**	**3.44**
Dividends declared per share	**0.7000**	**0.7000**	**0.7000**	**0.7000**	**2.8000**
Common stock prices (intraday high-low)	**$75.18 - 66.25**	**$77.93 - 68.71**	**$78.97 - 72.49**	**$77.32 - 69.51**	**$78.97 - 66.25**

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
(millions, except per share amounts)					
2015					
Operating revenue	$ 3,409	$ 2,747	$ 2,971	$ 2,556	$11,683
Income from operations	1,002	773	1,123	638	3,536
Net income including noncontrolling interests	540	418	599	366	1,923
Net income attributable to Dominion	536	413	593	357	1,899
Basic EPS:					
Net income attributable to Dominion	0.91	0.70	1.00	0.60	3.21
Diluted EPS:					
Net income attributable to Dominion	0.91	0.70	1.00	0.60	3.20
Dividends declared per share	0.6475	0.6475	0.6475	0.6475	2.5900
Common stock prices (intraday high-low)	$79.89 - 68.25	$74.34 - 66.52	$76.59 - 66.65	$74.88 - 64.54	$79.89 - 64.54

Dominion's 2016 results include the impact of the following significant item:

- Fourth quarter results include a $122 million after-tax charge related to future ash pond and landfill closure costs at certain utility generation facilities.

There were no significant items impacting Dominion's 2015 quarterly results.

Virginia Power

Virginia Power's quarterly results of operations were as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
(millions)					
2016					
Operating revenue	**$1,890**	**$1,776**	**$2,211**	**$1,711**	**$7,588**
Income from operations	**514**	**553**	**914**	**369**	**2,350**
Net income	**263**	**280**	**503**	**172**	**1,218**
2015					
Operating revenue	$2,137	$1,813	$2,058	$1,614	$7,622
Income from operations	525	481	741	374	2,121
Net income	269	246	385	187	1,087

Virginia Power's 2016 results include the impact of the following significant item:

- Fourth quarter results include a $121 million after-tax charge related to future ash pond and landfill closure costs at certain utility generation facilities.

Virginia Power's 2015 results include the impact of the following significant items:

- Fourth quarter results include a $32 million after-tax charge related to incremental future ash pond and landfill closure costs at certain utility generation facilities.
- Second quarter results include a $28 million after-tax charge related to incremental future ash pond and landfill closure costs at certain utility generation facilities due to the enactment of the final CCR rule in April 2015.
- First quarter results include a $52 million after-tax write-off of deferred fuel costs associated with Virginia legislation enacted in February 2015.

Dominion Gas

Dominion Gas' quarterly results of operations were as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
(millions)					
2016					
Operating revenue	**$431**	**$368**	**$382**	**$457**	**$1,638**
Income from operations	**175**	**186**	**133**	**175**	**669**
Net income	**98**	**105**	**83**	**106**	**392**
2015					
Operating revenue	$531	$395	$365	$425	$1,716
Income from operations	271	153	202	163	789
Net income	161	85	111	100	457

There were no significant items impacting Dominion Gas' 2016 quarterly results.

Dominion Gas' 2015 results include the impact of the following significant items:

- Third quarter results include a $29 million after-tax gain from an agreement to convey shale development rights underneath a natural gas storage field.
- First quarter results include a $43 million after-tax gain from agreements to convey shale development rights underneath several natural gas storage fields.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Dominion

Senior management, including Dominion's CEO and CFO, evaluated the effectiveness of Dominion's disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, Dominion's CEO and CFO have concluded that Dominion's disclosure controls and procedures are effective. There were no changes in Dominion's internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, Dominion's internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

Management of Dominion understands and accepts responsibility for Dominion's financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). Dominion continuously strives to identify opportunities to enhance the effectiveness and efficiency of internal control, just as Dominion does throughout all aspects of its business.

Dominion maintains a system of internal control designed to provide reasonable assurance, at a reasonable cost, that its assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel and internal audits.

The Audit Committee of the Board of Directors of Dominion, composed entirely of independent directors, meets periodically with the independent registered public accounting firm, the internal auditors and management to discuss auditing, internal control, and financial reporting matters of Dominion and to ensure that each is properly discharging its responsibilities. Both the independent registered public accounting firm and the internal auditors periodically meet alone with the Audit Committee and have free access to the Committee at any time.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act of 2002 require Dominion's 2016 Annual Report to contain a management's report and a report of the independent registered public accounting firm regarding the effectiveness of internal control. As a basis for the report, Dominion tested and evaluated the design and operating effectiveness of internal controls. Based on its assessment as of December 31, 2016, Dominion makes the following assertions:

Management is responsible for establishing and maintaining effective internal control over financial reporting of Dominion.

There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.

Management evaluated Dominion's internal control over financial reporting as of December 31, 2016. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that Dominion maintained effective internal control over financial reporting as of December 31, 2016.

Dominion's independent registered public accounting firm is engaged to express an opinion on Dominion's internal control over financial reporting, as stated in their report which is included herein.

In September 2016, Dominion acquired Dominion Questar. Dominion excluded all of the acquired Dominion Questar's business from the scope of management's assessment of the effectiveness of Dominion's internal control over financial reporting as of December 31, 2016. Dominion Questar constituted 3% of Dominion's total revenues for 2016 and 6% of Dominion's total assets as of December 31, 2016.

February 28, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
Dominion Resources, Inc.
Richmond, Virginia

We have audited the internal control over financial reporting of Dominion Resources, Inc. and subsidiaries ("Dominion") as of December 31, 2016, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Management's Annual Report on Internal Control over Financial Reporting, management excluded from its assessment the internal control over financial reporting the acquired Dominion Questar businesses which were acquired on September 16, 2016 and who constitute 3% of total revenues and 6% of total assets of the consolidated financial statement amounts at and for the year ended December 31, 2016. Accordingly, our audit did not include the internal control over financial reporting of Questar businesses. Dominion's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on Dominion's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Dominion maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2016 of Dominion and our report dated February 28, 2017 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP
Richmond, Virginia
February 28, 2017

Virginia Power

Senior management, including Virginia Power's CEO and CFO, evaluated the effectiveness of Virginia Power's disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, Virginia Power's CEO and CFO have concluded that Virginia Power's disclosure controls and procedures are effective. There were no changes in Virginia Power's internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, Virginia Power's internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

Management of Virginia Power understands and accepts responsibility for Virginia Power's financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). Virginia Power continuously strives to identify opportunities to enhance the effectiveness and efficiency of internal control, just as it does throughout all aspects of its business.

Virginia Power maintains a system of internal control designed to provide reasonable assurance, at a reasonable cost, that its assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel and internal audits.

The Board of Directors also serves as Virginia Power's Audit Committee and meets periodically with the independent registered public accounting firm, the internal auditors and management to discuss Virginia Power's auditing, internal accounting control and financial reporting matters and to ensure that each is properly discharging its responsibilities.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act require Virginia Power's 2016 Annual Report to contain a management's report regarding the effectiveness of internal control. As a basis for the report, Virginia Power tested and evaluated the design and operating effectiveness of internal controls. Based on the assessment as of December 31, 2016, Virginia Power makes the following assertions:

Management is responsible for establishing and maintaining effective internal control over financial reporting of Virginia Power.

There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.

Management evaluated Virginia Power's internal control over financial reporting as of December 31, 2016. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that Virginia Power maintained effective internal control over financial reporting as of December 31, 2016.

This annual report does not include an attestation report of Virginia Power's independent registered public accounting firm regarding internal control over financial reporting. Management's report is not subject to attestation by Virginia Power's independent registered public accounting firm pursuant to a permanent exemption under the Dodd-Frank Act.

February 28, 2017

Dominion Gas

Senior management, including Dominion Gas' CEO and CFO, evaluated the effectiveness of Dominion Gas' disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, Dominion Gas' CEO and CFO have concluded that Dominion Gas' disclosure controls and procedures are effective. There were no changes in Dominion Gas' internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, Dominion Gas' internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

Management of Dominion Gas understands and accepts responsibility for Dominion Gas' financial statements and related disclosures and the effectiveness of internal control over financial reporting (internal control). Dominion Gas continuously strives to identify opportunities to enhance the effectiveness and efficiency of internal control, just as it does throughout all aspects of its business.

Dominion Gas maintains a system of internal control designed to provide reasonable assurance, at a reasonable cost, that its assets are safeguarded against loss from unauthorized use or disposition and that transactions are executed and recorded in accordance with established procedures. This system includes written policies, an organizational structure designed to ensure appropriate segregation of responsibilities, careful selection and training of qualified personnel and internal audits.

The Board of Directors also serves as Dominion Gas' Audit Committee and meets periodically with the independent registered public accounting firm, the internal auditors and management to discuss Dominion Gas' auditing, internal accounting control and financial reporting matters and to ensure that each is properly discharging its responsibilities.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act require Dominion Gas' 2016 Annual Report to contain a management's report regarding the effectiveness of internal control. As a basis for the report, Dominion Gas tested and evaluated the design and operating effectiveness of internal controls. Based on the assessment as of December 31, 2016, Dominion Gas makes the following assertions:

Management is responsible for establishing and maintaining effective internal control over financial reporting of Dominion Gas.

There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.

Management evaluated Dominion Gas' internal control over financial reporting as of December 31, 2016. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that Dominion Gas maintained effective internal control over financial reporting as of December 31, 2016.

This annual report does not include an attestation report of Dominion Gas' independent registered public accounting firm regarding internal control over financial reporting. Management's report is not subject to attestation by Dominion Gas' independent registered public accounting firm pursuant to a permanent exemption under the Dodd-Frank Act.

February 28, 2017

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Dominion

The following information for Dominion is incorporated by reference from the Dominion 2017 Proxy Statement, which will be filed on or around March 20, 2017:

- Information regarding the directors required by this item is found under the heading *Election of Directors*.
- Information regarding compliance with Section 16 of the Securities Exchange Act of 1934, as amended, required by this item is found under the heading *Section 16(a) Beneficial Ownership Reporting Compliance*.
- Information regarding the Dominion Audit Committee Financial expert(s) required by this item is found under the heading *Board of Directors Committees—Audit Committee*.
- Information regarding the Dominion Audit Committee required by this item is found under the headings *Board of Directors Committees—Audit Committee* and *Audit Committee Report*.
- Information regarding Dominion's Code of Ethics required by this item is found under the heading *Corporate Governance and Board Matters*.

The information concerning the executive officers of Dominion required by this item is included in Part I of this Form 10-K under the caption *Executive Officers of Dominion*. Each executive officer of Dominion is elected annually.

Item 11. Executive Compensation

Dominion

The following information about Dominion is contained in the 2017 Proxy Statement and is incorporated by reference: the information regarding executive compensation contained under the headings *Compensation Discussion and Analysis* and *Executive Compensation*; the information regarding Compensation Committee interlocks contained under the heading *Compensation Committee Interlocks and Insider Participation*; *The Compensation, Governance and Nominating Committee Report*; and the information regarding director compensation contained under the heading *Compensation of Non-Employee Directors.*

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Dominion

The information concerning stock ownership by directors, executive officers and five percent beneficial owners contained under the heading *Securities Ownership* in the 2017 Proxy Statement is incorporated by reference.

The information regarding equity securities of Dominion that are authorized for issuance under its equity compensation plans contained under the heading *Executive Compensation-Equity Compensation Plans* in the 2017 Proxy Statement is incorporated by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Dominion

The information regarding related party transactions required by this item found under the heading *Other Information-Related Party Transactions,* and information regarding director independence found under the heading *Corporate Governance and Board Matters-Independence of Directors,* in the 2017 Proxy Statement is incorporated by reference.

Item 14. Principal Accountant Fees and Services

Dominion

The information concerning principal accountant fees and services contained under the heading *Auditor Fees and Pre-Approval Policy* in the 2017 Proxy Statement is incorporated by reference.

Virginia Power and Dominion Gas

The following table presents fees paid to Deloitte & Touche LLP for services related to Virginia Power and Dominion Gas for the fiscal years ended December 31, 2016 and 2015.

Type of Fees	2016	2015
(millions)		
Virginia Power		
Audit fees	**$1.82**	$1.87
Audit-related fees	**—**	—
Tax fees	**—**	—
All other fees	**—**	—
Total Fees	**$1.82**	$1.87
Dominion Gas		
Audit fees	**$1.05**	$1.06
Audit-related fees	**0.16**	0.19
Tax fees	**—**	—
All other fees	**—**	—
Total Fees	**$1.21**	$1.25

Audit fees represent fees of Deloitte & Touche LLP for the audit of Virginia Power's and Dominion Gas' annual consolidated financial statements, the review of financial statements included in Virginia Power's and Dominion Gas' quarterly Form 10-Q reports, and the services that an independent auditor would customarily provide in connection with subsidiary audits, statutory requirements, regulatory filings, and similar engagements for the fiscal year, such as comfort letters, attest services, consents, and assistance with review of documents filed with the SEC.

Audit-related fees consist of assurance and related services that are reasonably related to the performance of the audit or review of Virginia Power's and Dominion Gas' consolidated financial statements or internal control over financial reporting. This category may include fees related to the performance of audits and attest services not required by statute or regulations, due diligence related to mergers, acquisitions, and investments, and accounting consultations about the application of GAAP to proposed transactions.

Virginia Power's and Dominion Gas' Boards of Directors have adopted the Dominion Audit Committee pre-approval policy for their independent auditor's services and fees and have delegated the execution of this policy to the Dominion Audit Committee. In accordance with this delegation, each year the Dominion Audit Committee pre-approves a schedule that details the services to be provided for the following year and an estimated charge for such services. At its January 2017 meeting, the Dominion Audit Committee approved Virginia Power's and Dominion Gas' schedules of services and fees for 2017. In accordance with the pre-approval policy, any changes to the pre-approved schedule may be pre-approved by the Dominion Audit Committee or a delegated member of the Dominion Audit Committee.

Part IV
Item 15. Exhibits and Financial Statement Schedules

(a) Certain documents are filed as part of this Form 10-K and are incorporated by reference and found on the pages noted.

1. Financial Statements
   See Index on page 60.

2. All schedules are omitted because they are not applicable, or the required information is either not material or is shown in the financial statements or the related notes.

3. Exhibits (incorporated by reference unless otherwise noted)

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
3.1.a	Dominion Resources, Inc. Articles of Incorporation as amended and restated, effective May 20, 2010 (Exhibit 3.1, Form 8-K filed May 20, 2010, File No. 1-8489).	X		
3.1.b	Virginia Electric and Power Company Amended and Restated Articles of Incorporation, as in effect on October 30, 2014 (Exhibit 3.1.b, Form 10-Q filed November 3, 2014, File No. 1-2255).		X	
3.1.c	Articles of Organization of Dominion Gas Holdings, LLC (Exhibit 3.1, Form S-4 filed April 4, 2014, File No. 333-195066).			X
3.2.a	Dominion Resources, Inc. Amended and Restated Bylaws, effective December 17, 2015 (Exhibit 3.1, Form 8-K filed December 17, 2015, File No. 1-8489).	X		
3.2.b	Virginia Electric and Power Company Amended and Restated Bylaws, effective June 1, 2009 (Exhibit 3.1, Form 8-K filed June 3, 2009, File No. 1-2255).		X	
3.2.c	Operating Agreement of Dominion Gas Holdings, LLC dated as of September 12, 2013 (Exhibit 3.2, Form S-4 filed April 4, 2014, File No. 333-195066).			X
4	Dominion Resources, Inc., Virginia Electric and Power Company and Dominion Gas Holdings, LLC agree to furnish to the Securities and Exchange Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of any of their total consolidated assets.	X	X	X
4.1.a	See Exhibit 3.1.a above.	X		
4.1.b	See Exhibit 3.1.b above.		X	
4.2	Indenture of Mortgage of Virginia Electric and Power Company, dated November 1, 1935, as supplemented and modified by Fifty-Eighth Supplemental Indenture (Exhibit 4(ii), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-2255); Ninety-Second Supplemental Indenture, dated as of July 1, 2012 (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2012 filed August 1, 2012, File No. 1-2255).	X	X	
4.3	Form of Senior Indenture, dated June 1, 1998, between Virginia Electric and Power Company and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4(iii), Form S-3 Registration Statement filed February 27, 1998, File No. 333-47119); Form of Twelfth Supplemental Indenture, dated January 1, 2006 (Exhibit 4.2, Form 8-K filed January 12, 2006, File No. 1-2255); Form of Thirteenth Supplemental Indenture, dated as of January 1, 2006 (Exhibit 4.3, Form 8-K filed January 12, 2006, File No. 1-2255); Form of Fourteenth Supplemental Indenture, dated May 1, 2007 (Exhibit 4.2, Form 8-K filed May 16, 2007, File No. 1-2255); Form of Fifteenth Supplemental Indenture, dated September 1, 2007 (Exhibit 4.2, Form 8-K filed September 10, 2007, File No. 1-2255); Form of Seventeenth Supplemental Indenture, dated November 1, 2007 (Exhibit 4.3, Form 8-K filed November 30, 2007, File No. 1-2255); Form of Eighteenth Supplemental Indenture, dated April 1, 2008 (Exhibit 4.2, Form 8-K filed April 15, 2008, File No. 1-2255); Form of Nineteenth Supplemental and Amending Indenture, dated November 1, 2008 (Exhibit 4.2, Form 8-K filed November 5, 2008, File No. 1-2255); Form of Twentieth Supplemental Indenture, dated June 1, 2009 (Exhibit 4.3, Form 8-K filed June 24, 2009, File No. 1-2255); Form of Twenty-First Supplemental Indenture, dated August 1, 2010 (Exhibit 4.3, Form 8-K filed September 1, 2010, File No. 1-2255); Twenty-Second Supplemental Indenture, dated as of January 1, 2012 (Exhibit 4.3, Form 8-K filed January 12, 2012, File	X	X	

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
	No. 1-2255); Twenty-Third Supplemental Indenture, dated as of January 1, 2013 (Exhibit 4.3, Form 8-K filed January 8, 2013, File No. 1-2255); Twenty-Fourth Supplemental Indenture, dated as of January 1, 2013 (Exhibit 4.4, Form 8-K filed January 8, 2013, File No. 1-2255); Twenty-Fifth Supplemental Indenture, dated as of March 1, 2013 (Exhibit 4.3, Form 8-K filed March 14, 2013, File No. 1-2255); Twenty-Sixth Supplemental Indenture, dated as of August 1, 2013 (Exhibit 4.3, Form 8-K filed August 15, 2013, File No. 1-2255); Twenty-Seventh Supplemental Indenture, dated February 1, 2014 (Exhibit 4.3, Form 8-K filed February 7, 2014, File No. 1-2255); Twenty-Eighth Supplemental Indenture, dated February 1, 2014 (Exhibit 4.4, Form 8-K filed February 7, 2014, File No. 1-2255); Twenty-Ninth Supplemental Indenture, dated May 1, 2015 (Exhibit 4.3, Form 8-K filed May 13, 2015, File No. 1-02255); Thirtieth Supplemental Indenture, dated May 1, 2015 (Exhibit 4.4, Form 8-K filed May 13, 2015, File No. 1-02255); Thirty-First Supplemental Indenture, dated January 1, 2016 (Exhibit 4.3, Form 8-K filed January 14, 2016, File No. 000-55337); Thirty-Second Supplemental Indenture, dated November 1, 2016 (Exhibit 4.3, Form 8-K filed November 16, 2016, File No. 000-55337); Thirty-Third Supplemental Indenture, dated November 1, 2016 (Exhibit 4.4, Form 8-K filed November 16, 2016, File No. 000-55337).			
4.4	Indenture, Junior Subordinated Debentures, dated December 1, 1997, between Dominion Resources, Inc. and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)) as supplemented by a Form of Second Supplemental Indenture, dated January 1, 2001 (Exhibit 4.6, Form 8-K filed January 12, 2001, File No. 1-8489).	X		
4.5	Indenture, dated April 1, 1995, between Consolidated Natural Gas Company and The Bank of New York Mellon (as successor trustee to United States Trust Company of New York) (Exhibit (4), Certificate of Notification No. 1 filed April 19, 1995, File No. 70-8107); Securities Resolution No. 2 effective as of October 16, 1996 (Exhibit 2, Form 8-A filed October 18, 1996, File No. 1-3196 and relating to the 6 7/8% Debentures Due October 15, 2026); Securities Resolution No. 4 effective as of December 9, 1997 (Exhibit 2, Form 8-A filed December 12, 1997, File No. 1-3196 and relating to the 6.80% Debentures Due December 15, 2027).	X		
4.6	Form of Senior Indenture, dated June 1, 2000, between Dominion Resources, Inc. and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4(iii), Form S-3 Registration Statement filed December 21, 1999, File No. 333-93187); Form of Sixteenth Supplemental Indenture, dated December 1, 2002 (Exhibit 4.3, Form 8-K filed December 13, 2002, File No. 1-8489); Form of Twenty-First Supplemental Indenture, dated March 1, 2003 (Exhibits 4.3, Form 8-K filed March 4, 2003, File No. 1-8489); Form of Twenty-Second Supplemental Indenture, dated July 1, 2003 (Exhibit 4.2, Form 8-K filed July 22, 2003, File No. 1-8489); Form of Twenty-Ninth Supplemental Indenture, dated June 1, 2005 (Exhibit 4.3, Form 8-K filed June 17, 2005, File No. 1-8489); Forms of Thirty-Fifth and Thirty-Sixth Supplemental Indentures, dated June 1, 2008 (Exhibits 4.2 and 4.3, Form 8-K filed June 16, 2008, File No. 1-8489); Form of Thirty-Ninth Supplemental Indenture, dated August 1, 2009 (Exhibit 4.3, Form 8-K filed August 12, 2009, File No. 1-8489); Forty-First Supplemental Indenture, dated March 1, 2011 (Exhibit 4.3, Form 8-K, filed March 7, 2011, File No. 1-8489); Forty-Third Supplemental Indenture, dated August 1, 2011 (Exhibit 4.3, Form 8-K, filed August 5, 2011, File No. 1-8489); Forty-Fourth Supplemental Indenture, dated August 1, 2011 (Exhibit 4.3, Form 8-K, filed August 15, 2011, File No. 1-8489); Forty-Fifth Supplemental Indenture, dated September 1, 2012 (Exhibit 4.3, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Sixth Supplemental Indenture, dated September 1, 2012 (Exhibit 4.4, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Seventh Supplemental Indenture, dated September 1, 2012 (Exhibit 4.5, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Eighth Supplemental Indenture, dated March 1, 2014 (Exhibit 4.3, Form 8-K, filed March 24, 2014, File No. 1-8489); Forty-Ninth Supplemental Indenture, dated November 1, 2014 (Exhibit 4.3, Form 8-K, filed November 25, 2014, File No. 1-8489); Fiftieth Supplemental Indenture, dated November 1, 2014 (Exhibit 4.4, Form 8-K, filed November 25, 2014, File No. 1-8489); Fifty-First Supplemental Indenture, dated November 1, 2014 (Exhibit 4.5, Form 8-K, filed November 25, 2014, File No. 1-8489).	X		

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
4.7	Indenture, dated as of June 1, 2015, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Trustee (Exhibit 4.1, Form 8-K filed June 15, 2015, File No. 1-8489); First Supplemental Indenture, dated as of June 1, 2015 (Exhibit 4.2, Form 8-K filed June 15, 2015, File No. 1-8489); Second Supplemental Indenture, dated as of September 1, 2015 (Exhibit 4.2, Form 8-K filed September 24, 2015, File No. 1-8489); Third Supplemental Indenture, dated as of February 1, 2016 (Exhibit 4.7, Form 10-K for the fiscal year ended December 31, 2015 filed February 26, 2016, File No. 1-8489); Fourth Supplemental Indenture, dated as of August 1, 2016 (Exhibit 4.2, Form 8-K filed August 9, 2016, File No. 1-8489); Fifth Supplemental Indenture, dated as of August 1, 2016 (Exhibit 4.3, Form 8-K filed August 9, 2016, File No. 1-8489); Sixth Supplemental Indenture, dated as of August 1, 2016 (Exhibit 4.4, Form 8-K filed August 9, 2016, File No. 1-8489); Seventh Supplemental Indenture, dated as of September 1, 2016 (Exhibit 4.1, Form 10-Q filed November 9, 2016, File No. 1-8489); Eighth Supplemental Indenture, dated as of December 1, 2016 (filed herewith); Ninth Supplemental Indenture, dated as of January 1, 2017 (Exhibit 4.2, Form 8-K filed January 12, 2017, File No. 1-8489); Tenth Supplemental Indenture, dated as of January 1, 2017 (Exhibit 4.3, Form 8-K filed January 12, 2017, File No. 1-8489).	X		
4.8	Junior Subordinated Indenture II, dated June 1, 2006, between Dominion Resources, Inc. and The Bank of New York Mellon (successor to JPMorgan Chase Bank, N.A.), as Trustee (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489); First Supplemental Indenture dated as of June 1, 2006 (Exhibit 4.2, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489); Second Supplemental Indenture, dated as of September 1, 2006 (Exhibit 4.2, Form 10-Q for the quarter ended September 30, 2006 filed November 1, 2006, File No. 1-8489); Fourth Supplemental Indenture, dated as of June 1, 2013 (Exhibit 4.3, Form 8-K filed June 7, 2013, File No. 1-8489); Fifth Supplemental Indenture, dated as of June 1, 2013 (Exhibit 4.4, Form 8-K filed June 7, 2013, File No. 1-8489); Sixth Supplemental Indenture, dated as of June 1, 2014 (Exhibit 4.3, Form 8-K filed July 1, 2014, File No. 1-8489); Seventh Supplemental Indenture, dated as of September 1, 2014 (Exhibit 4.3, Form 8-K filed October 3, 2013, File No. 1-8489); Eighth Supplemental Indenture, dated March 7, 2016 (Exhibit 4.4, Form 8-K filed March 7, 2016, File No. 1-8489); Ninth Supplemental Indenture, dated May 26, 2016 (Exhibit 4.4, Form 8-K filed May 26, 2016, File No. 1-8489); Tenth Supplemental Indenture, dated July 1, 2016 (Exhibit 4.3, Form 8-K filed July 19, 2016, File No. 1-8489); Eleventh Supplemental Indenture, dated August 1, 2016 (Exhibit 4.3, Form 8-K filed August 15, 2016, File No. 1-8489); Twelfth Supplemental Indenture, dated August 1, 2016 (Exhibit 4.4, Form 8-K filed August 15, 2016, File No. 1-8489).	X		
4.9	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated June 23, 2006 (Exhibit 4.3, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489), as amended by Amendment No. 1 to Replacement Capital Covenant dated September 26, 2011 (Exhibit 4.2, Form 10-Q for the quarter ended September 30, 2011 filed October 28, 2011, File No. 1-8489).	X		
4.10	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated September 29, 2006 (Exhibit 4.3, Form 10-Q for the quarter ended September 30, 2006 filed November 1, 2006, File No. 1-8489), as amended by Amendment No. 1 to Replacement Capital Covenant dated September 26, 2011 (Exhibit 4.3, Form 10-Q for the quarter ended September 30, 2011 filed October 28, 2011, File No. 1-8489).	X		
4.11	Series A Purchase Contract and Pledge Agreement, dated as of June 7, 2013, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.7, Form 8-K filed June 7, 2013, File No. 1-8489).	X		
4.12	Series B Purchase Contract and Pledge Agreement, dated as of June 7, 2013, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.8, Form 8-K filed June 7, 2013, File No. 1-8489).	X		
4.13	2014 Series A Purchase Contract and Pledge Agreement, dated as of July 1, 2014, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.5, Form 8-K filed July 1, 2014, File No. 1-8489).	X		

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
4.14	2016 Series A Purchase Contract and Pledge Agreement, dated August 15, 2016, between the Company and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.7, Form 8-K filed August 15, 2016, File No. 1-8489).	X		
4.15	Indenture, dated as of October 1, 2013, between Dominion Gas Holdings, LLC and Deutsche Bank Trust Company Americas, as Trustee (Exhibit 4.1, Form S-4 filed April 4, 2014, File No. 333-195066); First Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.2, Form S-4 filed April 4, 2014, File No. 333-195066); Second Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.3, Form S-4 filed April 4, 2014, File No. 333-195066); Third Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.4, Form S-4 filed April 4, 2014, File No. 333-195066); Fourth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.2, Form 8-K filed December 8, 2014, File No. 333-195066); Fifth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.3, Form 8-K filed December 8, 2014, File No. 333-195066); Sixth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.4, Form 8-K filed December 8, 2014, File No. 333-195066); Seventh Supplemental Indenture, dated as of November 1, 2015 (Exhibit 4.2, Form 8-K filed November 17, 2015, File No. 001-37591); Eighth Supplemental Indenture, dated as of May 1, 2016 (Exhibit 4.1.a, Form 10-Q filed August 3, 2016, File No. 1-37591); Ninth Supplemental Indenture, dated as of June 1, 2016 (Exhibit 4.1.b, Form 10-Q filed August 3, 2016, File No. 1-37591); Tenth Supplemental Indenture, dated as of June 1, 2016 (Exhibit 4.1.c, Form 10-Q filed August 3, 2016, File No. 1-37591).	X		X
10.1	$5,000,000,000 Second Amended and Restated Revolving Credit Agreement, dated November 10, 2016, among Dominion Resources, Inc., Virginia Electric and Power Company, Dominion Gas Holdings, LLC, Questar Gas Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Mizuho Bank, Ltd., Bank of America, N.A., Barclays Bank PLC and Wells Fargo Bank, N.A., as Syndication Agents, and other lenders named therein (Exhibit 10.1, Form 8-K filed November 11, 2016, File No. 1-8489).	X	X	X
10.2	$500,000,000 Second Amended and Restated Revolving Credit Agreement, dated November 10, 2016, among Dominion Resources, Inc., Virginia Electric and Power Company, Dominion Gas Holdings, LLC, Questar Gas Company, KeyBank National Association, as Administrative Agent, U.S. Bank National Association, as Syndication Agent, and other lenders named therein (Exhibit 10.2, Form 8-K filed November 11, 2016, File No. 1-8489).	X	X	X
10.3	DRS Services Agreement, dated January 1, 2003, between Dominion Resources, Inc. and Dominion Resources Services, Inc. (Exhibit 10.1, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489).	X		
10.4	DRS Services Agreement, dated January 1, 2012, between Dominion Resources Services, Inc. and Virginia Electric and Power Company (Exhibit 10.2, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489 and File No. 1-2255).		X	
10.5	DRS Services Agreement, dated September 12, 2013, between Dominion Gas Holdings, LLC and Dominion Resources Services, Inc. (Exhibit 10.3, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.6	DRS Services Agreement, dated January 1, 2003, between Dominion Transmission Inc. and Dominion Resources Services, Inc. (Exhibit 10.4, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.7	DRS Services Agreement, dated January 1, 2003, between The East Ohio Company and Dominion Resources Services, Inc. (Exhibit 10.5, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.8	DRS Services Agreement, dated January 1, 2003, between Dominion Iroquois, Inc. and Dominion Resources Services, Inc. (Exhibit 10.6, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.9	Agreement between PJM Interconnection, L.L.C. and Virginia Electric and Power Company (Exhibit 10.1, Form 8-K filed April 26, 2005, File No. 1-2255 and File No. 1-8489).	X	X	

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.10	Form of Settlement Agreement in the form of a proposed Consent Decree among the United States of America, on behalf of the United States Environmental Protection Agency, the State of New York, the State of New Jersey, the State of Connecticut, the Commonwealth of Virginia and the State of West Virginia and Virginia Electric and Power Company (Exhibit 10, Form 10-Q for the quarter ended March 31, 2003 filed May 9, 2003, File No. 1-8489 and File No. 1-2255).	X	X	
10.11*	Dominion Resources, Inc. Executive Supplemental Retirement Plan, as amended and restated effective December 17, 2004 (Exhibit 10.5, Form 8-K filed December 23, 2004, File No. 1-8489), as amended September 26, 2014 (Exhibit 10.1, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.12*	Form of Employment Continuity Agreement for certain officers of Dominion Resources, Inc. and Virginia Electric and Power Company, amended and restated July 15, 2003 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2003 filed August 11, 2003, File No. 1-8489 and File No. 1-2255), as amended March 31, 2006 (Exhibit 10.1, Form 8-K filed April 4, 2006, File No. 1-8489).	X	X	X
10.13*	Form of Employment Continuity Agreement for certain officers of Dominion Resources, Inc. and Virginia Electric and Power Company dated January 24, 2013 (effective for certain officers elected subsequent to February 1, 2013) (Exhibit 10.9, Form 10-K for the fiscal year ended December 31, 2013 filed February 27, 2014, File No. 1-8489 and File No. 1-2255).	X	X	X
10.14*	Dominion Resources, Inc. Retirement Benefit Restoration Plan, as amended and restated effective December 17, 2004 (Exhibit 10.6, Form 8-K filed December 23, 2004, File No. 1-8489), as amended September 26, 2014 (Exhibit 10.2, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.15*	Dominion Resources, Inc. Executives' Deferred Compensation Plan, amended and restated effective December 31, 2004 (Exhibit 10.7, Form 8-K filed December 23, 2004, File No. 1-8489).	X	X	X
10.16*	Dominion Resources, Inc. New Executive Supplemental Retirement Plan, as amended and restated effective July 1, 2013 (Exhibit 10.2, Form 10-Q for the quarter ended June 30, 2013 filed August 6, 2013 File No. 1-8489), as amended September 26, 2014 (Exhibit 10.3, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.17*	Dominion Resources, Inc. New Retirement Benefit Restoration Plan, as amended and restated effective January 1, 2009 (Exhibit 10.17, Form 10-K for the fiscal year ended December 31, 2008 filed February 26, 2009, File No. 1-8489 and Exhibit 10.20, Form 10-K for the fiscal year ended December 31, 2008 filed February 26, 2009, File No. 1-2255), as amended September 26, 2014 (Exhibit 10.4, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.18*	Dominion Resources, Inc. Stock Accumulation Plan for Outside Directors, amended as of February 27, 2004 (Exhibit 10.15, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-8489) as amended effective December 31, 2004 (Exhibit 10.1, Form 8-K filed December 23, 2004, File No. 1-8489).	X		
10.19*	Dominion Resources, Inc. Directors Stock Compensation Plan, as amended February 27, 2004 (Exhibit 10.16, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-8489) as amended effective December 31, 2004 (Exhibit 10.2, Form 8-K filed December 23, 2004, File No. 1-8489).	X		
10.20*	Dominion Resources, Inc. Non-Employee Directors' Compensation Plan, effective January 1, 2005, as amended and restated effective December 17, 2009 (Exhibit 10.18, Form 10-K filed for the fiscal year ended December 31, 2009 filed February 26, 2010, File No. 1-8489).	X		
10.21*	Dominion Resources, Inc. Executive Stock Purchase Tool Kit, effective September 1, 2001, amended and restated May 7, 2014 (Exhibit 10.4, Form 10-Q for the fiscal quarter ended June 30, 2014 filed July 30, 2014, File No. 1-8489 and File No. 1-2250).	X	X	X

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.22*	Dominion Resources, Inc. Security Option Plan, effective January 1, 2003, amended December 31, 2004 and restated effective January 1, 2005 (Exhibit 10.13, Form 8-K filed December 23, 2004, File No. 1-8489).	X	X	X
10.23*	Letter agreement between Dominion Resources, Inc. and Thomas F. Farrell II, dated February 27, 2003 (Exhibit 10.24, Form 10-K for the fiscal year ended December 31, 2002 filed March 20, 2003, File No. 1-8489), as amended December 16, 2005 (Exhibit 10.1, Form 8-K filed December 16, 2005, File No. 1-8489).	X	X	X
10.24*	Employment agreement dated February 13, 2007 between Dominion Resources Services, Inc. and Mark F. McGettrick (Exhibit 10.34, Form 10-K for the fiscal year ended December 31, 2006 filed February 28, 2007, File No. 1-8489).	X	X	X
10.25*	Supplemental Retirement Agreement dated October 22, 2003 between Dominion Resources, Inc. and Paul D. Koonce (Exhibit 10.18, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-2255).	X	X	X
10.26*	Supplemental Retirement Agreement dated December 12, 2000, between Dominion Resources, Inc. and David A. Christian (Exhibit 10.25, Form 10-K for the fiscal year ended December 31, 2001 filed March 11, 2002, File No. 1-2255).	X	X	X
10.27*	Form of Advancement of Expenses for certain directors and officers of Dominion Resources, Inc., approved by the Dominion Resources, Inc. Board of Directors on October 24, 2008 (Exhibit 10.2, Form 10-Q for the quarter ended September 30, 2008 filed October 30, 2008, File No. 1-8489 and Exhibit 10.3, Form 10-Q for the quarter ended September 30, 2008 filed October 30, 2008, File No. 1-2255).	X	X	X
10.28*	Dominion Resources, Inc. 2005 Incentive Compensation Plan, originally effective May 1, 2005, as amended and restated effective December 20, 2011 (Exhibit 10.32, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489 and File No. 1-2255).	X	X	X
10.29*	Supplemental Retirement Agreement with Mark F. McGettrick effective May 19, 2010 (Exhibit 10.1, Form 8-K filed May 20, 2010, File No. 1-8489).	X	X	X
10.30*	Form of Restricted Stock Award Agreement for Mark F. McGettrick, Paul D. Koonce and David A. Christian approved December 17, 2012 (Exhibit 10.1, Form 8-K filed December 21, 2012, File No. 1-8489).	X	X	X
10.31*	Form of Restricted Stock Award Agreement under the 2012 Long-Term Incentive Program approved January 19, 2012 (Exhibit 10.2, Form 8-K filed January 20, 2012, File No. 1-8489).	X	X	X
10.32*	2013 Performance Grant Plan under the 2013 Long-Term Incentive Program approved January 24, 2013 (Exhibit 10.1, Form 8-K filed January 25, 2013, File No. 1-8489).	X	X	X
10.33*	Form of Restricted Stock Award Agreement under the 2013 Long-Term Incentive Program approved January 24, 2013 (Exhibit 10.2, Form 8-K filed January 25, 2013, File No. 1-8489).	X	X	X
10.34*	Restricted Stock Award Agreement for Thomas F. Farrell II, dated December 17, 2010 (Exhibit 10.1, Form 8-K filed December 17, 2010, File No. 1-8489).	X	X	X
10.35*	2014 Performance Grant Plan under the 2014 Long-Term Incentive Program approved January 16, 2014 (Exhibit 10.40, Form 10-K for the fiscal year ended December 31, 2013 filed February 28, 2014, File No. 1-8489).	X	X	X
10.36*	Form of Restricted Stock Award Agreement under the 2014 Long-Term Incentive Program approved January 16, 2014 (Exhibit 10.41, Form 10-K for the fiscal year ended December 31, 2013 filed February 28, 2014, File No. 1-8489).	X	X	X
10.37*	Form of Special Performance Grant for Thomas F. Farrell II and Mark F. McGettrick approved January 16, 2014 (Exhibit 10.42, Form 10-K for the fiscal year ended December 31, 2013 filed February 28, 2014, File No. 1-8489).	X	X	X
10.38*	Dominion Resources, Inc. 2014 Incentive Compensation Plan, effective May 7, 2014 (Exhibit 10.1, Form 8-K filed May 7, 2014, File No. 1-8489).	X	X	X

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.39	Registration Rights Agreement, dated as of October 22, 2013, by and among Dominion Gas Holdings, LLC and RBC Capital Markets, LLC, RBS Securities Inc. and Scotia Capital (USA) Inc., as the initial purchasers of the Notes (Exhibit 10.1, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.40	Inter-Company Credit Agreement, dated October 17, 2013, between Dominion Resources, Inc. and Dominion Gas Holdings, LLC (Exhibit 10.2, Form S-4 filed April 4, 2014, File No. 333-195066).	X		X
10.41*	2015 Performance Grant Plan under 2015 Long-Term Incentive Program approved January 22, 2015 (Exhibit 10.42, Form 10-K for the fiscal year ended December 31, 2014 filed February 27, 2015, File No. 1-8489).	X	X	X
10.42*	Form of Restricted Stock Award Agreement under the 2015 Long-Term Incentive Program approved January 22, 2015 (Exhibit 10.43, Form 10-K for the fiscal year ended December 31, 2014 filed February 27, 2015, File No. 1-8489).	X	X	X
10.43*	2016 Performance Grant Plan under the 2016 Long-Term Incentive Program approved January 21, 2016 (Exhibit 10.47, Form 10-K for the fiscal year ended December 31, 2015 filed February 26, 2016, File No. 1-8489).	X	X	X
10.44*	Form of Restricted Stock Award Agreement under the 2016 Long-Term Incentive Program approved January 21, 2016 (Exhibit 10.48, Form 10-K for the fiscal year ended December 31, 2015 filed February 26, 2016, File No. 1-8489).	X	X	X
10.45*	2017 Performance Grant Plan under the 2017 Long-Term Incentive Program approved January 24, 2017 (filed herewith).	X	X	X
10.46*	Form of Restricted Stock Award Agreement under the 2017 Long-Term Incentive Program approved January 24, 2017 (filed herewith).	X	X	X
10.47*	Base salaries for named executive officers of Dominion Resources, Inc. (filed herewith).	X		
10.48*	Non-employee directors’ annual compensation for Dominion Resources, Inc. (filed herewith).	X		
12.a	Ratio of earnings to fixed charges for Dominion Resources, Inc. (filed herewith).	X		
12.b	Ratio of earnings to fixed charges for Virginia Electric and Power Company (filed herewith).		X	
12.c	Ratio of earnings to fixed charges for Dominion Gas Holdings, LLC (filed herewith).			X
21	Subsidiaries of Dominion Resources, Inc. (filed herewith).	X		
23	Consent of Deloitte & Touche LLP (filed herewith).	X	X	X
31.a	Certification by Chief Executive Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).	X		
31.b	Certification by Chief Financial Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).	X		
31.c	Certification by Chief Executive Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).		X	
31.d	Certification by Chief Financial Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).		X	
31.e	Certification by Chief Executive Officer of Dominion Gas Holdings, LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).			X
31.f	Certification by Chief Financial Officer of Dominion Gas Holdings, LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).			X

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
32.a	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Resources, Inc. as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).	X		
32.b	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Virginia Electric and Power Company as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).		X	
32.c	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Gas Holdings, LLC as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).			X
101	The following financial statements from Dominion Resources, Inc. and Virginia Electric and Power Company Annual Report on Form 10-K for the year ended December 31, 2016, filed on February 28, 2017, formatted in XBRL: (i) Consolidated Statements of Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Common Shareholders' Equity (iv) Consolidated Statements of Comprehensive Income (v) Consolidated Statements of Cash Flows, and (vi) the Notes to Consolidated Financial Statements.	X	X	X

* *Indicates management contract or compensatory plan or arrangement*

Item 16. Form 10-K Summary

None.

Signatures

Dominion

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DOMINION RESOURCES, INC.

By: /s/ Thomas F. Farrell II

(Thomas F. Farrell II, Chairman, President and Chief Executive Officer)

Date: February 28, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 28th day of February, 2017.

Signature	Title
/s/ Thomas F. Farrell II **Thomas F. Farrell II**	Chairman of the Board of Directors, President and Chief Executive Officer
/s/ William P. Barr **William P. Barr**	Director
/s/ Helen E. Dragas **Helen E. Dragas**	Director
/s/ James O. Ellis, Jr. **James O. Ellis, Jr.**	Director
/s/ Ronald W. Jibson **Ronald W. Jibson**	Director
/s/ John W. Harris **John W. Harris**	Director
/s/ Mark J. Kington **Mark J. Kington**	Director
/s/ Joseph M. Rigby **Joseph M. Rigby**	Director
/s/ Pamela J. Royal **Pamela J. Royal**	Director
/s/ Robert H. Spilman, Jr. **Robert H. Spilman, Jr.**	Director
/s/ Susan N. Story **Susan N. Story**	Director
/s/ Michael E. Szymanczyk **Michael E. Szymanczyk**	Director
/s/ David A. Wollard **David A. Wollard**	Director
/s/ Mark F. McGettrick **Mark F. McGettrick**	Executive Vice President and Chief Financial Officer
/s/ Michele L. Cardiff **Michele L. Cardiff**	Vice President, Controller and Chief Accounting Officer

Virginia Power

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VIRGINIA ELECTRIC AND POWER COMPANY

By: /s/ Thomas F. Farrell II

(Thomas F. Farrell II, Chairman of the Board of Directors and Chief Executive Officer)

Date: February 28, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 28th day of February, 2017.

Signature	Title
/s/ Thomas F. Farrell II **Thomas F. Farrell II**	Chairman of the Board of Directors and Chief Executive Officer
/s/ Mark F. McGettrick **Mark F. McGettrick**	Director, Executive Vice President and Chief Financial Officer
/s/ Mark O. Webb **Mark O. Webb**	Director
/s/ Michele L. Cardiff **Michele L. Cardiff**	Vice President, Controller and Chief Accounting Officer

Dominion Gas

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DOMINION GAS HOLDINGS, LLC

By: /s/ Thomas F. Farrell II

(Thomas F. Farrell II, Chairman of the Board of Directors and Chief Executive Officer)

Date: February 28, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 28th day of February, 2017.

Signature	Title
/s/ Thomas F. Farrell II **Thomas F. Farrell II**	Chairman of the Board of Directors and Chief Executive Officer
/s/ Mark F. McGettrick **Mark F. McGettrick**	Director, Executive Vice President and Chief Financial Officer
/s/ Mark O. Webb **Mark O. Webb**	Director
/s/ Michele L. Cardiff **Michele L. Cardiff**	Vice President, Controller and Chief Accounting Officer

Exhibit Index

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
3.1.a	Dominion Resources, Inc. Articles of Incorporation as amended and restated, effective May 20, 2010 (Exhibit 3.1, Form 8-K filed May 20, 2010, File No. 1-8489).	X		
3.1.b	Virginia Electric and Power Company Amended and Restated Articles of Incorporation, as in effect on October 30, 2014 (Exhibit 3.1.b, Form 10-Q filed November 3, 2014, File No. 1-2255).		X	
3.1.c	Articles of Organization of Dominion Gas Holdings, LLC (Exhibit 3.1, Form S-4 filed April 4, 2014, File No. 333-195066).			X
3.2.a	Dominion Resources, Inc. Amended and Restated Bylaws, effective December 17, 2015 (Exhibit 3.1, Form 8-K filed December 17, 2015, File No. 1-8489).	X		
3.2.b	Virginia Electric and Power Company Amended and Restated Bylaws, effective June 1, 2009 (Exhibit 3.1, Form 8-K filed June 3, 2009, File No. 1-2255).		X	
3.2.c	Operating Agreement of Dominion Gas Holdings, LLC dated as of September 12, 2013 (Exhibit 3.2, Form S-4 filed April 4, 2014, File No. 333-195066).			X
4	Dominion Resources, Inc., Virginia Electric and Power Company and Dominion Gas Holdings, LLC agree to furnish to the Securities and Exchange Commission upon request any other instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of any of their total consolidated assets.	X	X	X
4.1.a	See Exhibit 3.1.a above.	X		
4.1.b	See Exhibit 3.1.b above.		X	
4.2	Indenture of Mortgage of Virginia Electric and Power Company, dated November 1, 1935, as supplemented and modified by Fifty-Eighth Supplemental Indenture (Exhibit 4(ii), Form 10-K for the fiscal year ended December 31, 1985, File No. 1-2255); Ninety-Second Supplemental Indenture, dated as of July 1, 2012 (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2012 filed August 1, 2012, File No. 1-2255).	X	X	
4.3	Form of Senior Indenture, dated June 1, 1998, between Virginia Electric and Power Company and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4(iii), Form S-3 Registration Statement filed February 27, 1998, File No. 333-47119); Form of Twelfth Supplemental Indenture, dated January 1, 2006 (Exhibit 4.2, Form 8-K filed January 12, 2006, File No. 1-2255); Form of Thirteenth Supplemental Indenture, dated as of January 1, 2006 (Exhibit 4.3, Form 8-K filed January 12, 2006, File No. 1-2255); Form of Fourteenth Supplemental Indenture, dated May 1, 2007 (Exhibit 4.2, Form 8-K filed May 16, 2007, File No. 1-2255); Form of Fifteenth Supplemental Indenture, dated September 1, 2007 (Exhibit 4.2, Form 8-K filed September 10, 2007, File No. 1-2255); Form of Seventeenth Supplemental Indenture, dated November 1, 2007 (Exhibit 4.3, Form 8-K filed November 30, 2007, File No. 1-2255); Form of Eighteenth Supplemental Indenture, dated April 1, 2008 (Exhibit 4.2, Form 8-K filed April 15, 2008, File No. 1-2255); Form of Nineteenth Supplemental and Amending Indenture, dated November 1, 2008 (Exhibit 4.2, Form 8-K filed November 5, 2008, File No. 1-2255); Form of Twentieth Supplemental Indenture, dated June 1, 2009 (Exhibit 4.3, Form 8-K filed June 24, 2009, File No. 1-2255); Form of Twenty-First Supplemental Indenture, dated August 1, 2010 (Exhibit 4.3, Form 8-K filed September 1, 2010, File No. 1-2255); Twenty-Second Supplemental Indenture, dated as of January 1, 2012 (Exhibit 4.3, Form 8-K filed January 12, 2012, File No. 1-2255); Twenty-Third Supplemental Indenture, dated as of January 1, 2013 (Exhibit 4.3, Form 8-K filed January 8, 2013, File No. 1-2255); Twenty-Fourth Supplemental Indenture, dated as of January 1, 2013 (Exhibit 4.4, Form 8-K filed January 8, 2013, File No. 1-2255); Twenty-Fifth Supplemental Indenture, dated as of March 1, 2013 (Exhibit 4.3, Form 8-K filed March 14, 2013, File No. 1-2255); Twenty-Sixth Supplemental Indenture, dated as of August 1, 2013 (Exhibit 4.3, Form 8-K filed August 15, 2013, File No. 1-2255); Twenty-Seventh Supplemental Indenture, dated February 1, 2014 (Exhibit 4.3, Form 8-K filed February 7, 2014, File No. 1-2255); Twenty-Eighth Supplemental Indenture, dated February 1, 2014 (Exhibit 4.4, Form 8-K filed February 7, 2014, File No. 1-2255); Twenty-Ninth Supplemental Indenture,	X	X	

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
	dated May 1, 2015 (Exhibit 4.3, Form 8-K filed May 13, 2015, File No. 1-02255); Thirtieth Supplemental Indenture, dated May 1, 2015 (Exhibit 4.4, Form 8-K filed May 13, 2015, File No. 1-02255); Thirty-First Supplemental Indenture, dated January 1, 2016 (Exhibit 4.3, Form 8-K filed January 14, 2016, File No. 000-55337); Thirty-Second Supplemental Indenture, dated November 1, 2016 (Exhibit 4.3, Form 8-K filed November 16, 2016, File No. 000-55337); Thirty-Third Supplemental Indenture, dated November 1, 2016 (Exhibit 4.4, Form 8-K filed November 16, 2016, File No. 000-55337).			
4.4	Indenture, Junior Subordinated Debentures, dated December 1, 1997, between Dominion Resources, Inc. and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)) as supplemented by a Form of Second Supplemental Indenture, dated January 1, 2001 (Exhibit 4.6, Form 8-K filed January 12, 2001, File No. 1-8489).	X		
4.5	Indenture, dated April 1, 1995, between Consolidated Natural Gas Company and The Bank of New York Mellon (as successor trustee to United States Trust Company of New York) (Exhibit (4), Certificate of Notification No. 1 filed April 19, 1995, File No. 70-8107); Securities Resolution No. 2 effective as of October 16, 1996 (Exhibit 2, Form 8-A filed October 18, 1996, File No. 1-3196 and relating to the 6 7/8% Debentures Due October 15, 2026); Securities Resolution No. 4 effective as of December 9, 1997 (Exhibit 2, Form 8-A filed December 12, 1997, File No. 1-3196 and relating to the 6.80% Debentures Due December 15, 2027).	X		
4.6	Form of Senior Indenture, dated June 1, 2000, between Dominion Resources, Inc. and The Bank of New York Mellon (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4(iii), Form S-3 Registration Statement filed December 21, 1999, File No. 333-93187); Form of Sixteenth Supplemental Indenture, dated December 1, 2002 (Exhibit 4.3, Form 8-K filed December 13, 2002, File No. 1-8489); Form of Twenty-First Supplemental Indenture, dated March 1, 2003 (Exhibits 4.3, Form 8-K filed March 4, 2003, File No. 1-8489); Form of Twenty-Second Supplemental Indenture, dated July 1, 2003 (Exhibit 4.2, Form 8-K filed July 22, 2003, File No. 1-8489); Form of Twenty-Ninth Supplemental Indenture, dated June 1, 2005 (Exhibit 4.3, Form 8-K filed June 17, 2005, File No. 1-8489); Forms of Thirty-Fifth and Thirty-Sixth Supplemental Indentures, dated June 1, 2008 (Exhibits 4.2 and 4.3, Form 8-K filed June 16, 2008, File No. 1-8489); Form of Thirty-Ninth Supplemental Indenture, dated August 1, 2009 (Exhibit 4.3, Form 8-K filed August 12, 2009, File No. 1-8489); Forty-First Supplemental Indenture, dated March 1, 2011 (Exhibit 4.3, Form 8-K, filed March 7, 2011, File No. 1-8489); Forty-Third Supplemental Indenture, dated August 1, 2011 (Exhibit 4.3, Form 8-K, filed August 5, 2011, File No. 1-8489); Forty-Fourth Supplemental Indenture, dated August 1, 2011 (Exhibit 4.3, Form 8-K, filed August 15, 2011, File No. 1-8489); Forty-Fifth Supplemental Indenture, dated September 1, 2012 (Exhibit 4.3, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Sixth Supplemental Indenture, dated September 1, 2012 (Exhibit 4.4, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Seventh Supplemental Indenture, dated September 1, 2012 (Exhibit 4.5, Form 8-K, filed September 13, 2012, File No. 1-8489); Forty-Eighth Supplemental Indenture, dated March 1, 2014 (Exhibit 4.3, Form 8-K, filed March 24, 2014, File No. 1-8489); Forty-Ninth Supplemental Indenture, dated November 1, 2014 (Exhibit 4.3, Form 8-K, filed November 25, 2014, File No. 1-8489); Fiftieth Supplemental Indenture, dated November 1, 2014 (Exhibit 4.4, Form 8-K, filed November 25, 2014, File No. 1-8489); Fifty-First Supplemental Indenture, dated November 1, 2014 (Exhibit 4.5, Form 8-K, filed November 25, 2014, File No. 1-8489).	X		
4.7	Indenture, dated as of June 1, 2015, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Trustee (Exhibit 4.1, Form 8-K filed June 15, 2015, File No. 1-8489); First Supplemental Indenture, dated as of June 1, 2015 (Exhibit 4.2, Form 8-K filed June 15, 2015, File No. 1-8489); Second Supplemental Indenture, dated as of September 1, 2015 (Exhibit 4.2, Form 8-K filed September 24, 2015, File No. 1-8489); Third Supplemental Indenture, dated as of February 1, 2016 (Exhibit 4.7, Form 10-K for the fiscal year ended December 31, 2015 filed February 26, 2016, File No. 1-8489); Fourth Supplemental Indenture, dated as of August 1, 2016 (Exhibit 4.2, Form 8-K filed August 9, 2016, File No. 1-8489); Fifth Supplemental Indenture, dated as of August 1, 2016 (Exhibit 4.3, Form 8-K filed August 9, 2016, File No. 1-8489); Sixth Supplemental Indenture, dated as of August 1,	X		

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
	2016 (Exhibit 4.4, Form 8-K filed August 9, 2016, File No. 1-8489); Seventh Supplemental Indenture, dated as of September 1, 2016 (Exhibit 4.1, Form 10-Q filed November 9, 2016, File No. 1-8489); Eighth Supplemental Indenture, dated as of December 1, 2016 (filed herewith); Ninth Supplemental Indenture, dated as of January 1, 2017 (Exhibit 4.2, Form 8-K filed January 12, 2017, File No. 1-8489); Tenth Supplemental Indenture, dated as of January 1, 2017 (Exhibit 4.3, Form 8-K filed January 12, 2017, File No. 1-8489).			
4.8	Junior Subordinated Indenture II, dated June 1, 2006, between Dominion Resources, Inc. and The Bank of New York Mellon (successor to JPMorgan Chase Bank, N.A.), as Trustee (Exhibit 4.1, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489); First Supplemental Indenture dated as of June 1, 2006 (Exhibit 4.2, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489); Second Supplemental Indenture, dated as of September 1, 2006 (Exhibit 4.2, Form 10-Q for the quarter ended September 30, 2006 filed November 1, 2006, File No. 1-8489); Fourth Supplemental Indenture, dated as of June 1, 2013 (Exhibit 4.3, Form 8-K filed June 7, 2013, File No. 1-8489); Fifth Supplemental Indenture, dated as of June 1, 2013 (Exhibit 4.4, Form 8-K filed June 7, 2013, File No. 1-8489); Sixth Supplemental Indenture, dated as of June 1, 2014 (Exhibit 4.3, Form 8-K filed July 1, 2014, File No. 1-8489); Seventh Supplemental Indenture, dated as of September 1, 2014 (Exhibit 4.3, Form 8-K filed October 3, 2013, File No. 1-8489); Eighth Supplemental Indenture, dated March 7, 2016 (Exhibit 4.4, Form 8-K filed March 7, 2016, File No. 1-8489); Ninth Supplemental Indenture, dated May 26, 2016 (Exhibit 4.4, Form 8-K filed May 26, 2016, File No. 1-8489); Tenth Supplemental Indenture, dated July 1, 2016 (Exhibit 4.3, Form 8-K filed July 19, 2016, File No. 1-8489); Eleventh Supplemental Indenture, dated August 1, 2016 (Exhibit 4.3, Form 8-K filed August 15, 2016, File No. 1-8489); Twelfth Supplemental Indenture, dated August 1, 2016 (Exhibit 4.4, Form 8-K filed August 15, 2016, File No. 1-8489).	X		
4.9	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated June 23, 2006 (Exhibit 4.3, Form 10-Q for the quarter ended June 30, 2006 filed August 3, 2006, File No. 1-8489), as amended by Amendment No. 1 to Replacement Capital Covenant dated September 26, 2011 (Exhibit 4.2, Form 10-Q for the quarter ended September 30, 2011 filed October 28, 2011, File No. 1-8489).	X		
4.10	Replacement Capital Covenant entered into by Dominion Resources, Inc. dated September 29, 2006 (Exhibit 4.3, Form 10-Q for the quarter ended September 30, 2006 filed November 1, 2006, File No. 1-8489), as amended by Amendment No. 1 to Replacement Capital Covenant dated September 26, 2011 (Exhibit 4.3, Form 10-Q for the quarter ended September 30, 2011 filed October 28, 2011, File No. 1-8489).	X		
4.11	Series A Purchase Contract and Pledge Agreement, dated as of June 7, 2013, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.7, Form 8-K filed June 7, 2013, File No. 1-8489).	X		
4.12	Series B Purchase Contract and Pledge Agreement, dated as of June 7, 2013, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.8, Form 8-K filed June 7, 2013, File No. 1-8489).	X		
4.13	2014 Series A Purchase Contract and Pledge Agreement, dated as of July 1, 2014, between Dominion Resources, Inc. and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.5, Form 8-K filed July 1, 2014, File No. 1-8489).	X		
4.14	2016 Series A Purchase Contract and Pledge Agreement, dated August 15, 2016, between the Company and Deutsche Bank Trust Company Americas, as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (Exhibit 4.7, Form 8-K filed August 15, 2016, File No. 1-8489).	X		

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
4.15	Indenture, dated as of October 1, 2013, between Dominion Gas Holdings, LLC and Deutsche Bank Trust Company Americas, as Trustee (Exhibit 4.1, Form S-4 filed April 4, 2014, File No. 333-195066); First Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.2, Form S-4 filed April 4, 2014, File No. 333-195066); Second Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.3, Form S-4 filed April 4, 2014, File No. 333-195066); Third Supplemental Indenture, dated as of October 1, 2013 (Exhibit 4.4, Form S-4 filed April 4, 2014, File No. 333-195066); Fourth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.2, Form 8-K filed December 8, 2014, File No. 333-195066); Fifth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.3, Form 8-K filed December 8, 2014, File No. 333-195066); Sixth Supplemental Indenture, dated as of December 1, 2014 (Exhibit 4.4, Form 8-K filed December 8, 2014, File No. 333-195066); Seventh Supplemental Indenture, dated as of November 1, 2015 (Exhibit 4.2, Form 8-K filed November 17, 2015, File No. 001-37591); Eighth Supplemental Indenture, dated as of May 1, 2016 (Exhibit 4.1.a, Form 10-Q filed August 3, 2016, File No. 1-37591); Ninth Supplemental Indenture, dated as of June 1, 2016 (Exhibit 4.1.b, Form 10-Q filed August 3, 2016, File No. 1-37591); Tenth Supplemental Indenture, dated as of June 1, 2016 (Exhibit 4.1.c, Form 10-Q filed August 3, 2016, File No. 1-37591).	X		X
10.1	$5,000,000,000 Second Amended and Restated Revolving Credit Agreement, dated November 10, 2016, among Dominion Resources, Inc., Virginia Electric and Power Company, Dominion Gas Holdings, LLC, Questar Gas Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Mizuho Bank, Ltd., Bank of America, N.A., Barclays Bank PLC and Wells Fargo Bank, N.A., as Syndication Agents, and other lenders named therein (Exhibit 10.1, Form 8-K filed November 11, 2016, File No. 1-8489).	X	X	X
10.2	$500,000,000 Second Amended and Restated Revolving Credit Agreement, dated November 10, 2016, among Dominion Resources, Inc., Virginia Electric and Power Company, Dominion Gas Holdings, LLC, Questar Gas Company, KeyBank National Association, as Administrative Agent, U.S. Bank National Association, as Syndication Agent, and other lenders named therein (Exhibit 10.2, Form 8-K filed November 11, 2016, File No. 1-8489).	X	X	X
10.3	DRS Services Agreement, dated January 1, 2003, between Dominion Resources, Inc. and Dominion Resources Services, Inc. (Exhibit 10.1, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489).	X		
10.4	DRS Services Agreement, dated January 1, 2012, between Dominion Resources Services, Inc. and Virginia Electric and Power Company (Exhibit 10.2, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489 and File No. 1-2255).		X	
10.5	DRS Services Agreement, dated September 12, 2013, between Dominion Gas Holdings, LLC and Dominion Resources Services, Inc. (Exhibit 10.3, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.6	DRS Services Agreement, dated January 1, 2003, between Dominion Transmission Inc. and Dominion Resources Services, Inc. (Exhibit 10.4, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.7	DRS Services Agreement, dated January 1, 2003, between The East Ohio Company and Dominion Resources Services, Inc. (Exhibit 10.5, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.8	DRS Services Agreement, dated January 1, 2003, between Dominion Iroquois, Inc. and Dominion Resources Services, Inc. (Exhibit 10.6, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.9	Agreement between PJM Interconnection, L.L.C. and Virginia Electric and Power Company (Exhibit 10.1, Form 8-K filed April 26, 2005, File No. 1-2255 and File No. 1-8489).	X	X	
10.10	Form of Settlement Agreement in the form of a proposed Consent Decree among the United States of America, on behalf of the United States Environmental Protection Agency, the State of New York, the State of New Jersey, the State of Connecticut, the Commonwealth of Virginia and the State of West Virginia and Virginia Electric and Power Company (Exhibit 10, Form 10-Q for the quarter ended March 31, 2003 filed May 9, 2003, File No. 1-8489 and File No. 1-2255).	X	X	

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.11*	Dominion Resources, Inc. Executive Supplemental Retirement Plan, as amended and restated effective December 17, 2004 (Exhibit 10.5, Form 8-K filed December 23, 2004, File No. 1-8489), as amended September 26, 2014 (Exhibit 10.1, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.12*	Form of Employment Continuity Agreement for certain officers of Dominion Resources, Inc. and Virginia Electric and Power Company, amended and restated July 15, 2003 (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2003 filed August 11, 2003, File No. 1-8489 and File No. 1-2255), as amended March 31, 2006 (Exhibit 10.1, Form 8-K filed April 4, 2006, File No. 1-8489).	X	X	X
10.13*	Form of Employment Continuity Agreement for certain officers of Dominion Resources, Inc. and Virginia Electric and Power Company dated January 24, 2013 (effective for certain officers elected subsequent to February 1, 2013) (Exhibit 10.9, Form 10-K for the fiscal year ended December 31, 2013 filed February 27, 2014, File No. 1-8489 and File No. 1-2255).	X	X	X
10.14*	Dominion Resources, Inc. Retirement Benefit Restoration Plan, as amended and restated effective December 17, 2004 (Exhibit 10.6, Form 8-K filed December 23, 2004, File No. 1-8489), as amended September 26, 2014 (Exhibit 10.2, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.15*	Dominion Resources, Inc. Executives' Deferred Compensation Plan, amended and restated effective December 31, 2004 (Exhibit 10.7, Form 8-K filed December 23, 2004, File No. 1-8489).	X	X	X
10.16*	Dominion Resources, Inc. New Executive Supplemental Retirement Plan, as amended and restated effective July 1, 2013 (Exhibit 10.2, Form 10-Q for the quarter ended June 30, 2013 filed August 6, 2013 File No. 1-8489), as amended September 26, 2014 (Exhibit 10.3, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.17*	Dominion Resources, Inc. New Retirement Benefit Restoration Plan, as amended and restated effective January 1, 2009 (Exhibit 10.17, Form 10-K for the fiscal year ended December 31, 2008 filed February 26, 2009, File No. 1-8489 and Exhibit 10.20, Form 10-K for the fiscal year ended December 31, 2008 filed February 26, 2009, File No. 1-2255), as amended September 26, 2014 (Exhibit 10.4, Form 10-Q for the fiscal quarter ended September 30, 2014 filed November 3, 2014).	X	X	X
10.18*	Dominion Resources, Inc. Stock Accumulation Plan for Outside Directors, amended as of February 27, 2004 (Exhibit 10.15, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-8489) as amended effective December 31, 2004 (Exhibit 10.1, Form 8-K filed December 23, 2004, File No. 1-8489).	X		
10.19*	Dominion Resources, Inc. Directors Stock Compensation Plan, as amended February 27, 2004 (Exhibit 10.16, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-8489) as amended effective December 31, 2004 (Exhibit 10.2, Form 8-K filed December 23, 2004, File No. 1-8489).	X		
10.20*	Dominion Resources, Inc. Non-Employee Directors' Compensation Plan, effective January 1, 2005, as amended and restated effective December 17, 2009 (Exhibit 10.18, Form 10-K filed for the fiscal year ended December 31, 2009 filed February 26, 2010, File No. 1-8489).	X		
10.21*	Dominion Resources, Inc. Executive Stock Purchase Tool Kit, effective September 1, 2001, amended and restated May 7, 2014 (Exhibit 10.4, Form 10-Q for the fiscal quarter ended June 30, 2014 filed July 30, 2014, File No. 1-8489 and File No. 1-2250).	X	X	X
10.22*	Dominion Resources, Inc. Security Option Plan, effective January 1, 2003, amended December 31, 2004 and restated effective January 1, 2005 (Exhibit 10.13, Form 8-K filed December 23, 2004, File No. 1-8489).	X	X	X
10.23*	Letter agreement between Dominion Resources, Inc. and Thomas F. Farrell II, dated February 27, 2003 (Exhibit 10.24, Form 10-K for the fiscal year ended December 31, 2002 filed March 20, 2003, File No. 1-8489), as amended December 16, 2005 (Exhibit 10.1, Form 8-K filed December 16, 2005, File No. 1-8489).	X	X	X

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.24*	Employment agreement dated February 13, 2007 between Dominion Resources Services, Inc. and Mark F. McGettrick (Exhibit 10.34, Form 10-K for the fiscal year ended December 31, 2006 filed February 28, 2007, File No. 1-8489).	X	X	X
10.25*	Supplemental Retirement Agreement dated October 22, 2003 between Dominion Resources, Inc. and Paul D. Koonce (Exhibit 10.18, Form 10-K for the fiscal year ended December 31, 2003 filed March 1, 2004, File No. 1-2255).	X	X	X
10.26*	Supplemental Retirement Agreement dated December 12, 2000, between Dominion Resources, Inc. and David A. Christian (Exhibit 10.25, Form 10-K for the fiscal year ended December 31, 2001 filed March 11, 2002, File No. 1-2255).	X	X	X
10.27*	Form of Advancement of Expenses for certain directors and officers of Dominion Resources, Inc., approved by the Dominion Resources, Inc. Board of Directors on October 24, 2008 (Exhibit 10.2, Form 10-Q for the quarter ended September 30, 2008 filed October 30, 2008, File No. 1-8489 and Exhibit 10.3, Form 10-Q for the quarter ended September 30, 2008 filed October 30, 2008, File No. 1-2255).	X	X	X
10.28*	Dominion Resources, Inc. 2005 Incentive Compensation Plan, originally effective May 1, 2005, as amended and restated effective December 20, 2011 (Exhibit 10.32, Form 10-K for the fiscal year ended December 31, 2011 filed February 28, 2012, File No. 1-8489 and File No. 1-2255).	X	X	X
10.29*	Supplemental Retirement Agreement with Mark F. McGettrick effective May 19, 2010 (Exhibit 10.1, Form 8-K filed May 20, 2010, File No. 1-8489).	X	X	X
10.30*	Form of Restricted Stock Award Agreement for Mark F. McGettrick, Paul D. Koonce and David A. Christian approved December 17, 2012 (Exhibit 10.1, Form 8-K filed December 21, 2012, File No. 1-8489).	X	X	X
10.31*	Form of Restricted Stock Award Agreement under the 2012 Long-Term Incentive Program approved January 19, 2012 (Exhibit 10.2, Form 8-K filed January 20, 2012, File No. 1-8489).	X	X	X
10.32*	2013 Performance Grant Plan under the 2013 Long-Term Incentive Program approved January 24, 2013 (Exhibit 10.1, Form 8-K filed January 25, 2013, File No. 1-8489).	X	X	X
10.33*	Form of Restricted Stock Award Agreement under the 2013 Long-Term Incentive Program approved January 24, 2013 (Exhibit 10.2, Form 8-K filed January 25, 2013, File No. 1-8489).	X	X	X
10.34*	Restricted Stock Award Agreement for Thomas F. Farrell II, dated December 17, 2010 (Exhibit 10.1, Form 8-K filed December 17, 2010, File No. 1-8489).	X	X	X
10.35*	2014 Performance Grant Plan under the 2014 Long-Term Incentive Program approved January 16, 2014 (Exhibit 10.40, Form 10-K for the fiscal year ended December 31, 2013 filed February 28, 2014, File No. 1-8489).	X	X	X
10.36*	Form of Restricted Stock Award Agreement under the 2014 Long-Term Incentive Program approved January 16, 2014 (Exhibit 10.41, Form 10-K for the fiscal year ended December 31, 2013 filed February 28, 2014, File No. 1-8489).	X	X	X
10.37*	Form of Special Performance Grant for Thomas F. Farrell II and Mark F. McGettrick approved January 16, 2014 (Exhibit 10.42, Form 10-K for the fiscal year ended December 31, 2013 filed February 28, 2014, File No. 1-8489).	X	X	X
10.38*	Dominion Resources, Inc. 2014 Incentive Compensation Plan, effective May 7, 2014 (Exhibit 10.1, Form 8-K filed May 7, 2014, File No. 1-8489).	X	X	X
10.39	Registration Rights Agreement, dated as of October 22, 2013, by and among Dominion Gas Holdings, LLC and RBC Capital Markets, LLC, RBS Securities Inc. and Scotia Capital (USA) Inc., as the initial purchasers of the Notes (Exhibit 10.1, Form S-4 filed April 4, 2014, File No. 333-195066).			X
10.40	Inter-Company Credit Agreement, dated October 17, 2013, between Dominion Resources, Inc. and Dominion Gas Holdings, LLC (Exhibit 10.2, Form S-4 filed April 4, 2014, File No. 333-195066).	X		X

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
10.41*	2015 Performance Grant Plan under 2015 Long-Term Incentive Program approved January 22, 2015 (Exhibit 10.42, Form 10-K for the fiscal year ended December 31, 2014 filed February 27, 2015, File No. 1-8489).	X	X	X
10.42*	Form of Restricted Stock Award Agreement under the 2015 Long-Term Incentive Program approved January 22, 2015 (Exhibit 10.43, Form 10-K for the fiscal year ended December 31, 2014 filed February 27, 2015, File No. 1-8489).	X	X	X
10.43*	2016 Performance Grant Plan under the 2016 Long-Term Incentive Program approved January 21, 2016 (Exhibit 10.47, Form 10-K for the fiscal year ended December 31, 2015 filed February 26, 2016, File No. 1-8489).	X	X	X
10.44*	Form of Restricted Stock Award Agreement under the 2016 Long-Term Incentive Program approved January 21, 2016 (Exhibit 10.48, Form 10-K for the fiscal year ended December 31, 2015 filed February 26, 2016, File No. 1-8489).	X	X	X
10.45*	2017 Performance Grant Plan under the 2017 Long-Term Incentive Program approved January 24, 2017 (filed herewith).	X	X	X
10.46*	Form of Restricted Stock Award Agreement under the 2017 Long-Term Incentive Program approved January 24, 2017 (filed herewith).	X	X	X
10.47*	Base salaries for named executive officers of Dominion Resources, Inc. (filed herewith).	X		
10.48*	Non-employee directors' annual compensation for Dominion Resources, Inc. (filed herewith).	X		
12.a	Ratio of earnings to fixed charges for Dominion Resources, Inc. (filed herewith).	X		
12.b	Ratio of earnings to fixed charges for Virginia Electric and Power Company (filed herewith).		X	
12.c	Ratio of earnings to fixed charges for Dominion Gas Holdings, LLC (filed herewith).			X
21	Subsidiaries of Dominion Resources, Inc. (filed herewith).	X		
23	Consent of Deloitte & Touche LLP (filed herewith).	X	X	X
31.a	Certification by Chief Executive Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).	X		
31.b	Certification by Chief Financial Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).	X		
31.c	Certification by Chief Executive Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).		X	
31.d	Certification by Chief Financial Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).		X	
31.e	Certification by Chief Executive Officer of Dominion Gas Holdings, LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).			X
31.f	Certification by Chief Financial Officer of Dominion Gas Holdings, LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).			X
32.a	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Resources, Inc. as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).	X		
32.b	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Virginia Electric and Power Company as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).		X	
32.c	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Gas Holdings, LLC as required by Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).			X

Exhibit Number	Description	Dominion	Virginia Power	Dominion Gas
101	The following financial statements from Dominion Resources, Inc. and Virginia Electric and Power Company Annual Report on Form 10-K for the year ended December 31, 2016, filed on February 28, 2017, formatted in XBRL: (i) Consolidated Statements of Income, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Common Shareholders' Equity (iv) Consolidated Statements of Comprehensive Income (v) Consolidated Statements of Cash Flows, and (vi) the Notes to Consolidated Financial Statements.	X	X	X

* *Indicates management contract or compensatory plan or arrangement*