Spectra Energy Corp.
Form 10-K
February 27, 2015

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K

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

For the fiscal year ended December 31, 2014 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 1-33007

SPECTRA ENERGY CORP
(Exact name of registrant as specified in its charter)

Delaware	20-5413139
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
5400 Westheimer Court, Houston, Texas	77056
(Address of principal executive offices)	(Zip Code)

713-627-5400
(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.001	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. ¨

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.

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

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

Estimated aggregate market value of the common equity held by nonaffiliates of the registrant June 30, 2014: $28,000,000,000

Number of shares of Common Stock, $0.001 par value, outstanding at January 31, 2015: 671,089,528

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2015 Annual Meeting of Shareholders are incorporated by reference in Part III.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This document includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements represent management's intentions, plans, expectations, assumptions and beliefs about future events. These forward-looking statements are identified by terms and phrases such as: anticipate, believe, intend, estimate, expect, continue, should, could, may, plan, project, predict, will, potential, forecast, and similar expressions. Forward-looking statements are subject to risks, uncertainties and other factors, many of which are outside our control and could cause actual results to differ materially from the results expressed or implied by those forward-looking statements. Factors used to develop these forward-looking statements and that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- state, provincial, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an effect on rate structure, and affect the speed at and degree to which competition enters the natural gas and oil industries;
- outcomes of litigation and regulatory investigations, proceedings or inquiries;
- weather and other natural phenomena, including the economic, operational and other effects of hurricanes and storms;
- the timing and extent of changes in commodity prices, interest rates and foreign currency exchange rates;
- general economic conditions, including the risk of a prolonged economic slowdown or decline, or the risk of delay in a recovery, which can affect the long-term demand for natural gas and oil and related services;
- potential effects arising from terrorist attacks and any consequential or other hostilities;
- changes in environmental, safety and other laws and regulations;
- the development of alternative energy resources;
- results and costs of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general market and economic conditions;
- increases in the cost of goods and services required to complete capital projects;
- declines in the market prices of equity and debt securities and resulting funding requirements for defined benefit pension plans;
- growth in opportunities, including the timing and success of efforts to develop U.S. and Canadian pipeline, storage, gathering, processing and other related infrastructure projects and the effects of competition;
- the performance of natural gas and oil transmission and storage, distribution, and gathering and processing facilities;
- the extent of success in connecting natural gas and oil supplies to gathering, processing and transmission systems and in connecting to expanding gas and oil markets;
- the effects of accounting pronouncements issued periodically by accounting standard-setting bodies;
- conditions of the capital markets during the periods covered by forward-looking statements; and
- the ability to successfully complete merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger, acquisition or divestiture; and the success of the business following a merger, acquisition or divestiture.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than Spectra Energy Corp has described. Spectra Energy Corp undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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Item 1. Business.

The terms “we,” “our,” “us” and “Spectra Energy” as used in this report refer collectively to Spectra Energy Corp and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Spectra Energy. The term “Spectra Energy Partners” refers to our Spectra Energy Partners operating segment. The term “SEP” refers to Spectra Energy Partners, LP, our master limited partnership.

General

Spectra Energy Corp, through its subsidiaries and equity affiliates, owns and operates a large and diversified portfolio of complementary natural gas-related energy assets and is one of North America’s leading natural gas infrastructure companies. We also own and operate a crude oil pipeline system that connects Canadian and U.S. producers to refineries in the U.S. Rocky Mountain and Midwest regions. For over a century, we and our predecessor companies have developed critically important pipelines and related energy infrastructure connecting natural gas supply sources to premium markets. We currently operate in three key areas of the natural gas industry: gathering and processing, transmission and storage, and distribution. We provide transmission and storage of natural gas to customers in various regions of the northeastern and southeastern United States, the Maritime Provinces in Canada, the Pacific Northwest in the United States and Canada, and in the province of Ontario, Canada. We also provide natural gas sales and distribution services to retail customers in Ontario, and natural gas gathering and processing services to customers in western Canada. We also own a 50% interest in DCP Midstream, LLC (DCP Midstream), based in Denver, Colorado, one of the leading natural gas gatherers in the United States based on wellhead volumes, and one of the largest U.S. producers and marketers of natural gas liquids (NGLs). Our internet website is http://www.spectraenergy.com.

Our natural gas pipeline systems consist of approximately 21,000 miles of transmission pipelines. Our storage facilities provide approximately 295 billion cubic feet (Bcf) of net storage capacity in the United States and Canada. Our crude oil pipeline system, Express-Platte, consists of over 1,700 miles of transmission pipeline comprised of the Express pipeline and the Platte pipeline systems.

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Businesses

We manage our business in four reportable segments: Spectra Energy Partners, Distribution, Western Canada Transmission & Processing, and Field Services. The remainder of our business operations is presented as “Other,” and consists of unallocated corporate costs, employee benefit plan assets and liabilities, 100%-owned captive insurance subsidiaries, and other miscellaneous activities. The following sections describe the operations of each of our businesses. For financial information on our business segments, see Part II. Item 8. Financial Statements and Supplementary Data, Note 4 of Notes to Consolidated Financial Statements.

SPECTRA ENERGY PARTNERS

We currently own an 82% equity interest in SEP, a natural gas, crude oil and NGL infrastructure master limited partnership, which owns 100% of Texas Eastern Transmission, LP (Texas Eastern), 100% of Algonquin Gas Transmission, LLC (Algonquin), 100% of East Tennessee Natural Gas, LLC (East Tennessee), 100% of Express-Platte, 100% of Saltville Gas Storage Company L.L.C. (Saltville), 100% of Ozark Gas Gathering, L.L.C. (Ozark Gas Gathering) and Ozark Gas Transmission, L.L.C. (Ozark Gas Transmission), 100% of Big Sandy Pipeline, LLC (Big Sandy), 100% of Market Hub Partners Holding (Market Hub), 100% of Bobcat Gas Storage (Bobcat), 78% of Maritimes & Northeast Pipeline, L.L.C. (M&N U.S.), 49.9% of Southeast Supply Header, LLC (SESH), 33% of DCP Sand Hills Pipeline, LLC (Sand Hills), 33% of DCP Southern Hills Pipeline, LLC (Southern Hills), 50% of Steckman Ridge, LP (Steckman Ridge) and 50% of Gulfstream Natural Gas System, L.L.C. (Gulfstream). We own another 4% indirect interest in Sand Hills and 4% indirect interest in Southern Hills through our ownership interest in DCP Midstream, which is considered our Field Services segment.

SEP is a publicly traded entity which trades on the New York Stock Exchange (NYSE) under the symbol “SEP.” See Part II. Item 8. Financial Statements and Supplementary Data, Note 2 of Notes to Consolidated Financial Statements for further discussion of SEP.

Our Spectra Energy Partners business primarily provides transmission, storage and gathering of natural gas, as well as the transportation and storage of crude oil and NGLs through interstate pipeline systems for customers in various regions of the midwestern, northeastern and southeastern United States and Canada. Its pipeline systems consist of approximately 17,000 miles of transmission and transportation pipelines. The pipeline systems in our Spectra Energy Partners business receive natural gas and crude oil from major North American producing regions for delivery to their respective markets. A majority of contracted transportation volumes are under long-term firm service agreements, where customers reserve capacity in the pipeline. Interruptible services, where customers can use capacity if it is available at the time of the request, are provided on a short-term or seasonal basis.

Demand on the natural gas pipeline and storage systems is seasonal, with the highest throughput occurring during colder periods in the first and fourth quarters, and storage injections occurring primarily during the summer periods. Actual throughput and storage injections/withdrawals do not have a significant effect on revenues or earnings.

Most of Spectra Energy Partners’ pipeline and storage operations are regulated by the Federal Energy Regulatory Commission (FERC) and are subject to the jurisdiction of various federal, state and local environmental agencies. FERC is the U.S. agency that regulates the transportation of natural gas and crude oil in interstate commerce. The National Energy Board (NEB) is the Canadian agency that regulates the transportation of crude oil in Canada.

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Texas Eastern

We have an effective 82% ownership interest in Texas Eastern through our ownership of SEP. The Texas Eastern natural gas transmission system extends approximately 1,700 miles from producing fields in the Gulf Coast region of Texas and Louisiana to Ohio, Pennsylvania, New Jersey and New York. It consists of two parallel systems, one with one to four large-diameter parallel pipelines and the other with one to three large-diameter pipelines. Texas Eastern's onshore system consists of approximately 8,600 miles of pipeline and associated compressor stations (facilities that increase the pressure of gas to facilitate its pipeline transmission). Texas Eastern also owns and operates two offshore Louisiana pipeline systems, which extend approximately 100 miles into the Gulf of Mexico and include approximately 400 miles of pipeline. Texas Eastern has two storage facilities in Pennsylvania held through joint ventures and one 100%-owned and operated storage facility in Maryland. Texas Eastern's total working joint venture capacity in these three facilities is 74 Bcf. In addition, Texas Eastern's system is connected to Steckman Ridge, a 12 Bcf joint venture storage facility in Pennsylvania, and three affiliated storage facilities in Texas and Louisiana, aggregating 74 Bcf, owned by Market Hub and Bobcat.

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Algonquin

We have an effective 82% ownership interest in Algonquin through our ownership of SEP. The Algonquin natural gas transmission system connects with Texas Eastern's facilities in New Jersey and extends approximately 250 miles through New Jersey, New York, Connecticut, Rhode Island and Massachusetts where it connects to the Maritimes & Northeast Pipeline. The system consists of approximately 1,130 miles of pipeline with associated compressor stations.

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East Tennessee

We have an effective 82% ownership interest in East Tennessee through our ownership of SEP. East Tennessee's natural gas transmission system crosses Texas Eastern's system at two locations in Tennessee and consists of two mainline systems totaling approximately 1,500 miles of pipeline in Tennessee, Georgia, North Carolina and Virginia, with associated compressor stations. East Tennessee has a liquefied natural gas (LNG, natural gas that has been converted to liquid form) storage facility in Tennessee with a total working capacity of 1 Bcf. East Tennessee also connects to the Saltville storage facilities in Virginia that have a working gas capacity of approximately 5 Bcf.

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Maritimes & Northeast Pipeline

We have an effective 64% ownership interest in M&N U.S. through our ownership of SEP. M&N U.S. is owned 78% directly by SEP, with affiliates of Emera, Inc. and Exxon Mobil Corporation directly owning the remaining 13% and 9% interests, respectively. M&N U.S. is an approximately 350-mile mainline interstate natural gas transmission system which extends from the border of Canada near Baileyville, Maine to northeastern Massachusetts. M&N U.S. is connected to the Canadian portion of the Maritimes & Northeast Pipeline system, Maritimes & Northeast Pipeline Limited Partnership (M&N Canada), which is owned 78% by us as part of our Western Canada Transmission & Processing segment. M&N U.S. facilities include compressor stations, with a market delivery capability of approximately 0.8 Bcf/d of natural gas. The pipeline's location and key interconnects with our transmission system link regional natural gas supplies to the northeast U.S. markets.

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Ozark

We have an effective 82% ownership interest in Ozark Gas Transmission and Ozark Gas Gathering through our ownership of SEP. Ozark Gas Transmission consists of an approximately 530-mile natural gas transmission system extending from southeastern Oklahoma through Arkansas to southeastern Missouri. Ozark Gas Gathering consists of an approximately 365-mile natural gas gathering system, with associated compressor stations, that primarily serves Arkoma basin producers in eastern Oklahoma.

On April 28, 2014, Ozark Gas Transmission entered into an agreement with Magellan Midstream Partners, L.P. (Magellan) to lease an approximately 159-mile stretch of natural gas pipeline to Magellan and perform the necessary conversion work to allow for the transportation of petroleum liquids. Ozark Gas Transmission expects to receive approval from the FERC and begin the necessary conversion work by mid 2015.

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Big Sandy

We have an effective 82% ownership interest in Big Sandy, which was acquired in 2011, through our ownership of SEP. Big Sandy is an approximately 70-mile natural gas transmission system, with associated compressor stations, located in eastern Kentucky. Big Sandy's interconnection with the Tennessee Gas Pipeline system links the Huron Shale and Appalachian Basin natural gas supplies to the mid-Atlantic and northeast markets.

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Gulfstream

We have an effective 41% investment in Gulfstream through our ownership of SEP. Gulfstream is an approximately 745-mile interstate natural gas transmission system, with associated compressor stations, operated jointly by us and The Williams Companies, Inc. (Williams). Gulfstream transports natural gas from Mississippi, Alabama, Louisiana and Texas, crossing the Gulf of Mexico to markets in central and southern Florida. Gulfstream is owned 50% directly by SEP and 50% by affiliates of Williams. Our investment in Gulfstream is accounted for under the equity method of accounting.

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SESH

We have an effective 41% total investment in SESH, an approximately 290-mile natural gas transmission system, with associated compressor stations, operated jointly by Spectra Energy and CenterPoint Energy Southeastern Pipelines Holding, LLC (CenterPoint). SESH extends from the Perryville Hub in northeastern Louisiana where the emerging shale gas production of eastern Texas, northern Louisiana and Arkansas, along with conventional production, is reached from five major interconnections. SESH extends to Alabama, interconnecting with 14 major north-south pipelines and three high-deliverability storage facilities. SESH is owned 49.9% directly by SEP and 0.1% directly by Spectra Energy as part of our "Other" segment, with the remaining 50% owned by CenterPoint and Enable Midstream Partners, LP, collectively. Spectra Energy expects to contribute its remaining 0.1% interest in SESH to SEP in November 2015. Our investment in SESH is accounted for under the equity method of accounting.

Market Hub

We have an effective 82% ownership interest in Market Hub through our ownership of SEP. Market Hub owns and operates two natural gas storage facilities, Moss Bluff and Egan, with a total storage capacity of approximately 48 Bcf. The Moss Bluff facility consists of four salt dome storage caverns located in southeast Texas, with access to five pipeline systems including the Texas Eastern system. The Egan facility consists of four salt dome storage caverns located in south central Louisiana, with access to eight pipeline systems, including the Texas Eastern system.

Saltville

We have an effective 82% ownership interest in Saltville through our ownership of SEP. Saltville owns and operates natural gas storage facilities in Virginia with a total storage capacity of approximately 5 Bcf, interconnecting with East Tennessee's system. This salt cavern facility offers high-deliverability capabilities and is strategically located near markets in Tennessee, Virginia and North Carolina.

Bobcat

We have an effective 82% ownership interest in Bobcat through our ownership of SEP. Bobcat, an approximately 26 Bcf salt dome facility acquired in 2010, is strategically located on the Gulf Coast near Henry Hub, interconnecting with five major interstate pipelines, including Texas Eastern.

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Steckman Ridge

We have an effective 41% investment in Steckman Ridge through our ownership of SEP. Steckman Ridge is an approximately 12 Bcf depleted reservoir storage facility located in south central Pennsylvania that interconnects with the Texas Eastern and Dominion Transmission, Inc. systems. Steckman Ridge is owned 50% directly by SEP and 50% by NJR Steckman Ridge Storage Company. Our investment in Steckman Ridge is accounted for under the equity method of accounting.

Express-Platte

We have an effective 82% ownership interest in Express-Platte, acquired in March 2013, through our ownership of SEP. The Express-Platte pipeline system, an approximately 1,700-mile crude oil transportation system, which begins in Hardisty, Alberta, and terminates in Wood River, Illinois, is comprised of both the Express and Platte crude oil pipelines. The Express pipeline carries crude oil to U.S. refining markets in the Rockies area, including Montana, Wyoming, Colorado and Utah. The Platte pipeline, which interconnects with the Express pipeline in Casper, Wyoming, transports crude oil predominantly from the Bakken shale and western Canada to refineries in the Midwest.

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Sand Hills / Southern Hills

In 2012, we acquired direct one-third ownership interests in Sand Hills and Southern Hills. DCP Midstream Partners, LP (DCP Partners) (DCP Midstream's publicly traded master limited partnership) and Phillips 66 also each own a direct one-third interest in each of the two pipelines. With our effective 82% ownership interest of SEP and our 50% ownership interest of DCP Midstream, we have 31% effective ownership interests in Sand Hills and Southern Hills. Our investments in Sand Hills and Southern Hills are accounted for under the equity method of accounting.

The Sand Hills pipeline is an approximately 900 mile pipeline engaged in the business of transporting NGLs and provides takeaway service from the Permian and Eagle Ford basins to fractionation facilities along the Texas Gulf Coast and the Mont Belvieu, Texas market hub. The Southern Hills pipeline is also an approximately 900 mile pipeline engaged in the business of transporting NGLs and provides takeaway service from the Midcontinent to fractionation facilities along the Texas Gulf Coast and the Mont Belvieu, Texas market hub. The Sand Hills and Southern Hills pipelines were placed into service in the second quarter of 2013.

Competition

Spectra Energy Partners' natural gas transmission and storage businesses compete with similar facilities that serve our supply and market areas in the transmission and storage of natural gas. The principal elements of competition are location, rates, terms of service, and flexibility and reliability of service.

The natural gas transported in our transmission business competes with other forms of energy available to our customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other forms of energy, levels of business activity, long-term economic conditions, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Spectra Energy Partners' crude oil transportation business competes with pipelines, rail, truck and barge facilities that transport crude oil from production areas to refinery markets. The principal elements of competition are location, rates, terms of service, flexibility and reliability of service.

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In transporting NGLs, Sand Hills and Southern Hills compete with a number of major interstate and intrastate pipelines, including those affiliated with major integrated oil companies, and rail and truck fleet operations. In general, Sand Hills and Southern Hills compete with these entities in terms of transportation fees, reliability and quality of customer service.

Customers and Contracts

In general, Spectra Energy Partners' natural gas pipelines provide transmission and storage services for local distribution companies (LDCs, companies that obtain a major portion of their revenues from retail distribution systems for the delivery of natural gas for ultimate consumption), electric power generators, exploration and production companies, and industrial and commercial customers, as well as energy marketers. Transmission and storage services are generally provided under firm agreements where customers reserve capacity in pipelines and storage facilities. The vast majority of these agreements provide for fixed reservation charges that are paid monthly regardless of the actual volumes transported on the pipelines or injected or withdrawn from our storage facilities, plus a small variable component that is based on volumes transported, injected or withdrawn, which is intended to recover variable costs.

Spectra Energy Partners also provides interruptible transmission and storage services where customers can use capacity if it is available at the time of the request. Interruptible revenues depend on the amount of volumes transported or stored and the associated rates for this interruptible service. New projects placed into service may initially have higher levels of interruptible services at inception. Storage operations also provide a variety of other value-added services including natural gas parking, loaning and balancing services to meet our customers' needs.

Customers on the Express-Platte system are primarily refineries located in the Rocky Mountain and Midwestern states of the United States. Other customers include oil producers and marketing entities. Express capacity is typically contracted under long-term committed contracts where customers reserve capacity and pay commitment charges based on a contracted volume even if they do not ship. A small amount of Express capacity and all Platte capacity is used by uncommitted shippers who only pay for the pipeline capacity that is actually used in a given month.

Sand Hills and Southern Hills generate the majority of their revenues from fee-based arrangements. The revenues earned by Sand Hills and Southern Hills are for long-term contracts relating to the transportation of NGLs and generally are not dependent on commodity prices.

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DISTRIBUTION

We provide distribution services in Canada through our subsidiary, Union Gas Limited (Union Gas). Union Gas is a major Canadian natural gas storage, transmission and distribution company based in Ontario with over 100 years of experience and service to customers. The distribution business serves approximately 1.4 million residential, commercial and industrial customers in more than 400 communities across northern, southwestern and eastern Ontario. Union Gas' storage and transmission business offers storage and transmission services to customers at the Dawn Hub, the largest integrated underground storage facility in Canada and one of the largest in North America. It offers customers an important link in the movement of natural gas from western Canada and U.S. supply basins to markets in central Canada and the northeast United States.

Union Gas' distribution system consists of approximately 40,000 miles of main and service pipelines. Distribution pipelines carry natural gas from the point of local supply to customers. Union Gas' underground natural gas storage facilities have a working capacity of approximately 160 Bcf in 25 underground facilities located in depleted gas fields. Its transmission system consists of approximately 3,000 miles of high-pressure pipeline and associated mainline compressor stations.

Competition

Union Gas' distribution system is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the Ontario Energy Board Act (1998) and is subject to regulation in a number of areas, including rates. Union Gas is not generally subject to third-party competition within its distribution franchise area. However, physical bypass of Union Gas' system may be permitted, even within Union Gas' distribution franchise area. In addition, other companies could enter Union Gas' markets or regulations could change.

Union Gas provides storage services to customers outside its franchise area and new storage services under a framework established by the OEB that supports unregulated storage investments and allows Union Gas to compete with third-party storage providers on bases of price, terms of service, and flexibility and reliability of service. Existing storage services to customers within Union Gas' franchise area, however, have continued to be provided at cost-based rates and are not subject to third-party competition.

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Union Gas competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include weather, price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, and other factors.

Customers and Contracts

Most of Union Gas' power generation customers, industrial and large commercial customers, and a portion of residential customers, purchase their natural gas directly from suppliers or marketers. Because Union Gas earns income from the distribution of natural gas and not from the sale of the natural gas commodity, gas distribution margins are not affected by either the source of customers' gas supply or its price, except to the extent that prices affect actual customer usage.

Union Gas provides its in-franchise customers with regulated distribution, transmission and storage services. Union Gas also provides unregulated natural gas storage and regulated transmission services for other utilities and energy market participants, including large natural gas transmission and distribution companies. A substantial amount of Union Gas' annual transportation and storage revenue is generated by fixed demand charges.

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WESTERN CANADA TRANSMISSION & PROCESSING

Our Western Canada Transmission & Processing business is comprised of the BC Pipeline, BC Field Services, Canadian Midstream and Empress NGL operations, and M&N Canada.

BC Pipeline and BC Field Services provide fee-based natural gas transmission and gas gathering and processing services. BC Pipeline is regulated by the NEB under full cost-of-service regulation. BC Pipeline transports processed natural gas from facilities primarily in northeast British Columbia (BC) to markets in BC, Alberta and the U.S. Pacific Northwest. BC Pipeline has approximately 1,750 miles of transmission pipeline in BC and Alberta, as well as associated mainline compressor stations. Throughput for the BC Pipeline totaled 801 trillion British thermal units (TBtu) in 2014, compared to 699 TBtu in 2013 and 662 TBtu in 2012.

The BC Field Services business, which is regulated by the NEB under a “light-handed” regulatory model, consists of raw gas gathering pipelines and gas processing facilities, primarily in northeast BC. These facilities provide services to natural gas producers to remove impurities from the raw gas stream including water, carbon dioxide, hydrogen sulfide and other substances. Where required, these facilities also remove various NGLs for subsequent sale by the producers. NGLs are liquid hydrocarbons extracted during the processing of natural gas. Principal commercial NGLs include butanes, propane, natural gasoline and ethane. The BC Field Services business includes nine gas processing plants located in BC, associated field compressor stations and approximately 1,400 miles of gathering pipelines.

The Canadian Midstream business provides similar gas gathering and processing services in BC and Alberta and consists of 11 natural gas processing plants and approximately 700 miles of gathering pipelines. This business is primarily regulated by the province where the assets are located, either BC or Alberta.

The Empress NGL business provides NGL extraction, fractionation, transportation, storage and marketing services to western Canadian producers and NGL customers throughout Canada and the northern tier of the United States. Assets include a majority ownership interest in an NGL extraction plant, an integrated NGL fractionation facility, an NGL transmission pipeline, ten terminals where NGLs are loaded for shipping or transferred into product sales pipelines, two NGL storage facilities and an NGL marketing business. The Empress extraction and fractionation plant is located in Empress, Alberta.

We own approximately 78% of M&N Canada, with affiliates of Emera, Inc. and Exxon Mobil Corporation directly owning the remaining 13% and 9% interests, respectively. M&N Canada is an approximately 550-mile mainline interprovincial natural gas transmission system which extends from Goldboro, Nova Scotia to the U.S. border near Baileyville, Maine. M&N Canada is connected to the U.S. portion of the Maritimes & Northeast Pipeline system, M&N U.S., which is directly owned by SEP (part of our Spectra Energy Partners segment) and affiliates of Exxon Mobil Corporation and Emera, Inc. M&N Canada facilities include associated compressor stations and has a market delivery capability of approximately 0.6 Bcf/d of natural gas. The pipeline’s location and key interconnects with Spectra Energy’s transmission system link regional natural gas supplies to the northeast U.S. and Atlantic Canadian markets.

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Competition

Western Canada Transmission & Processing businesses compete with third-party midstream companies, exploration and production companies, and pipelines in the gathering, processing and transmission of natural gas and the extraction and marketing of NGL products. The principal elements of competition are location, rates, terms of service, and flexibility and reliability of service. Customer demands for toll certainty and lower cost-tailored services have promoted increased competition from other midstream service companies and producers.

Natural gas competes with other forms of energy available to Western Canada Transmission & Processing's customers and end-users, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas, NGLs and other forms of energy, levels of business activity, long-term economic conditions, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors affect the demand for natural gas in the areas that Western Canada Transmission & Processing serves.

In addition to the fee-for-service pipeline and gathering and processing businesses, we compete with other NGL extraction facilities at Empress, Alberta for the right to extract and purchase NGLs from natural gas shippers on the TransCanada pipeline system. To extract and acquire NGLs, we must be competitive in the prices or fees we pay to gas shippers and suppliers. We also compete with other NGL marketers in the various product sales markets we serve.

Customers & Contracts

BC Pipeline provides: (i) transmission services from the outlet of natural gas processing plants primarily in northeast BC to LDCs, end-use industrial and commercial customers, marketers, and exploration and production companies requiring transmission services to the nearest natural gas trading hub; and (ii) transmission services primarily to downstream markets in the Pacific Northwest (both in the United States and Canada) using the southern portion of the transmission pipeline and markets in Alberta through pipeline interconnects in northern British Columbia with Nova Gas Transmission Ltd. (Nova). The majority of transportation services are provided under firm agreements, which provide for fixed reservation charges that are paid monthly regardless of actual volumes transported on the pipeline, plus a small variable component that is based on volumes transported to recover variable costs. BC Pipeline also provides interruptible transmission services where customers can use capacity if it is available at the time of request. Payments under these services are based on volumes transported.

The BC Field Services and Canadian Midstream operations in western Canada provide raw natural gas gathering and processing services to exploration and production companies under agreements which are fee-for-service contracts which do not expose us to direct commodity-price risk. However, a sustained decline in natural gas prices has impacted our ability to negotiate and renew expiring service contracts with customers in certain areas of our operations. The BC Field Services and Canadian Midstream operations provide both firm and interruptible services.

The NGL extraction operation at Empress, Alberta is jointly owned with a partner and has capacity to produce approximately 63,000 Bbls/d (our share is approximately 58,000 Bbls/d at full capacity). At Empress, we extract and purchase NGLs from natural gas shippers on the Nova/TransCanada pipeline system. In addition to paying shippers a negotiated extraction fee, we keep the shipper whole by returning an equivalent amount of natural gas for the NGLs that were extracted. After NGLs are extracted, we fractionate the NGLs into ethane, propane, butanes and condensate, and sell these products into the marketplace. All ethane is sold to Alberta-based petrochemical companies. In addition to paying for natural gas shrinkage, the ethane buyers pay us a negotiated cost-of-service price or a negotiated fixed price. We sell the remaining products—propane, butane and condensate—at market prices. The majority of propane is sold to propane retailers. Butane is sold mainly into the motor gasoline refinery market and condensate is sold to the crude blending and crude diluent markets. Profit margins are driven by the market prices of NGL products, extraction premiums paid to shippers, shrinkage make-up natural gas prices and other operating costs. Empress' customers are U.S.-based and Canadian-based.

Operating results at Empress are significantly affected by changes in average NGL and natural gas prices, which have fluctuated significantly over the last several years. We continue to closely monitor the risks associated with these price changes.

We employ policies and procedures to manage Spectra Energy's risks associated with Empress' commodity price fluctuations, which may include the use of forward physical transactions as well as commodity derivatives. Effective January 2014, we implemented a commodity hedging program at Empress in an effort to mitigate a large portion of commodity risk.

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FIELD SERVICES

Field Services consists of our 50% investment in DCP Midstream, which is accounted for as an equity investment. DCP Midstream gathers, compresses, treats, processes, transports, stores and sells natural gas. In addition, this segment produces, fractionates, transports, stores and sells NGLs, recovers and sells condensate and trades and markets natural gas and NGLs. Phillips 66 owns the other 50% interest in DCP Midstream. DCP Midstream currently owns a 22% interest in DCP Partners, a publicly traded master limited partnership which trades on the NYSE under the symbol "DPM." As its general partner, DCP Midstream accounts for its investment in DCP Partners as a consolidated subsidiary.

DCP Midstream owns or operates assets in 17 states in the United States. DCP Midstream's gathering systems include connections to several interstate and intrastate natural gas and NGL pipeline systems, one natural gas storage facility and one NGL storage facility. DCP Midstream operates in a diverse number of regions, including the Permian Basin, Eagle Ford, Niobrara/DJ Basin and Midcontinent. DCP Midstream owns or operates approximately 68,000 miles of gathering and transmission pipeline.

As of December 31, 2014, DCP Midstream owned or operated 64 natural gas processing plants, which separate raw natural gas that has been gathered on DCP Midstream's and third-party systems into condensate, NGLs and residue gas.

The NGLs separated from the raw natural gas are either sold and transported as NGL raw mix or further separated through a fractionation process into their individual components (ethane, propane, butane and natural gasoline) and then sold as components. As of December 31, 2014, DCP Midstream owned or operated 12 fractionators. In addition, DCP Midstream operates a propane wholesale marketing business and a seven million barrel propane and butane storage facility in the northeastern United States.

The residue natural gas (gas that has had associated NGLs removed) separated from the raw natural gas is sold at market-based prices to marketers and end-users, including large industrial customers and natural gas and electric utilities serving individual consumers. DCP Midstream also stores residue natural gas at its 14 Bcf Southeast Texas natural gas storage facility located near Beaumont, Texas.

DCP Midstream uses NGL trading and storage at its Mont Belvieu, Texas and Conway, Kansas NGL market centers to manage price risk and to provide additional services to its customers. Asset-based gas trading and marketing activities are

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supported by ownership of the Southeast Texas storage facility and various intrastate pipelines which provide access to market centers/hubs such as Katy, Texas and the Houston Ship Channel.

DCP Partners owns direct one-third ownership interests in the Sand Hills and Southern Hills NGL pipelines; SEP also owns direct one-third ownership interests. With our 50% ownership of DCP Midstream and our 82% ownership interest of SEP, we have 31% effective ownership interests in Sand Hills and Southern Hills. See "Business - Businesses - Spectra Energy Partners" for further discussion of Sand Hills and Southern Hills.

DCP Midstream's operating results are significantly affected by changes in average NGL, natural gas and crude oil prices, which have fluctuated significantly over the last several years. DCP Midstream closely monitors the risks associated with these price changes. See Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Quantitative and Qualitative Disclosures About Market Risk for a discussion of DCP Midstream's exposure to changes in commodity prices.

Competition

In gathering, processing, transporting and storing natural gas, as well as producing, marketing and transporting NGLs, DCP Midstream competes with major integrated oil companies, major interstate and intrastate pipelines, national and local natural gas gatherers and processors, NGL transporters and brokers, marketers and distributors of natural gas supplies. Competition for natural gas supplies is based mostly on the reputation, efficiency and reliability of operations, the availability of gathering and transportation to high-demand markets, pricing arrangements offered by the gatherer/processor and the ability of the gatherer/processor to obtain a satisfactory price for the producer's residue natural gas and extracted NGLs. Competition for sales to customers is based mostly upon reliability, services offered and the prices of delivered natural gas and NGLs.

Customers and Contracts

DCP Midstream sells a portion of its NGLs to Phillips 66 and Chevron Phillips Chemical Company LLC (CPChem). In addition, DCP Midstream purchases NGLs from CPChem. Prior to December 31, 2014 approximately 35% of DCP Midstream's NGL production was committed to Phillips 66 and CPChem under 15-year contracts, the primary production commitment of which began a wind down period in December 2014, and expires in January 2019. DCP Midstream anticipates continuing to purchase and sell commodities with ConocoPhillips as a third-party and with Phillips 66 and CPChem as related parties, in the ordinary course of business.

The residual natural gas, primarily methane, that results from processing raw natural gas is sold at market-based prices to marketers and end-users, including large industrial companies, natural gas distribution companies and electric utilities. DCP Midstream purchases or takes custody of substantially all of its raw natural gas from producers, principally under the following types of contractual arrangements. More than 70% of the volumes of gas that are gathered and processed are under percentage-of-proceeds contracts.

- Percentage-of-proceeds/index arrangements. In general, DCP Midstream purchases natural gas from producers at the wellhead or other receipt points, gathers the wellhead natural gas through its gathering system, treats and processes it, and then sells the residue natural gas and NGLs based on index prices from published index market prices. DCP Midstream remits to the producers either an agreed-upon percentage of the actual proceeds received by DCP Midstream from the sale of the residue natural gas, NGLs and condensate, or an agreed-upon percentage of the proceeds based on index-related prices or contractual recoveries for the natural gas, NGLs and condensate, regardless of the actual amount of sales proceeds which DCP Midstream receives. DCP Midstream keeps the difference between the proceeds received and the amount remitted back to the producer. Under percentage-of-liquids arrangements, DCP Midstream does not keep any amounts related to the residue natural gas proceeds and only keeps amounts related to the difference between the proceeds received and the amount remitted back to the producer related to NGLs and condensate. Certain of these arrangements may also result in the producer retaining title to all or a portion of the residue natural gas and/or the NGLs in lieu of DCP Midstream returning sales proceeds to the producer. Additionally, these arrangements may include fee-based components. DCP Midstream's revenues from percentage-of-proceeds/index arrangements are directly related to the prices of natural gas, NGLs or condensate. DCP Midstream's revenues under percentage-of-liquids arrangements are directly related to the price of NGLs and condensate.
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Fee-based arrangements. DCP Midstream receives a fee or fees for one or more of the following services: gathering, compressing, treating, processing, transporting or storing natural gas, and fractionating, storing and transporting NGLs. Fee-based arrangements include natural gas arrangements pursuant to which DCP Midstream obtains natural gas at the wellhead or other receipt points at an index-related price at the delivery point less a specified amount, generally the same as the transportation fees it would otherwise charge for transportation of the natural gas from the wellhead location to the delivery point. The revenue DCP Midstream earns from these arrangements is directly related

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to the volume of natural gas or NGLs that flows through its systems and is not dependent on commodity prices. However, to the extent that a sustained decline in commodity prices results in a decline in volumes, DCP Midstream's revenues from these arrangements would be reduced.

- Keep-whole and wellhead purchase arrangements. DCP Midstream gathers raw natural gas from producers for processing, the NGLs and condensate are sold and the residue natural gas is returned to the producer with a Btu content equivalent to the Btu content of the natural gas gathered. This arrangement keeps the producer whole to the thermal value of the natural gas received. Under the terms of a wellhead purchase contract, DCP Midstream purchases natural gas from the producer at the wellhead or defined receipt point for processing and markets the resulting NGLs and residue natural gas at market prices. Under these types of contracts, DCP Midstream is exposed to the difference between the value of the NGLs extracted from processing and the value of the Btu-equivalent of the residue natural gas, or frac spread. DCP Midstream benefits in periods when NGL prices are higher relative to natural gas prices, where that frac spread exceeds our cost.

As defined by the terms of the above arrangements, DCP Midstream also sells condensate, which is generally similar to crude oil and is produced in association with natural gas gathering and processing. The revenues that DCP Midstream earns from the sale of condensate correlate directly with crude oil prices.

Supplies and Raw Materials

We purchase a variety of manufactured equipment and materials for use in operations and expansion projects. The primary equipment and materials utilized in operations and project execution processes are steel pipe, compression engines, pumps, valves, fittings, polyethylene plastic pipe, gas meters and other consumables.

We operate a North American supply chain management network with employees dedicated to this function in the United States and Canada. Our supply chain management group uses economies-of-scale to maximize the efficiency of supply networks where applicable. The price of equipment and materials may vary however, perhaps substantially, from year to year. DCP Midstream performs its own supply chain management function.

Regulations

Most of our U.S. gas transmission, crude oil pipeline and storage operations are regulated by the FERC. The FERC regulates natural gas transmission in U.S. interstate commerce including the establishment of rates for services. The FERC also regulates the construction of U.S. interstate natural gas pipelines and storage facilities, including the extension, enlargement and abandonment of facilities. In addition, certain operations are subject to oversight by state regulatory commissions. The FERC may propose and implement new rules and regulations affecting interstate natural gas transmission and storage companies, which remain subject to the FERC's jurisdiction. These initiatives may also affect certain transmission of gas by intrastate pipelines.

Our Spectra Energy Partners and DCP Midstream operations are subject to the jurisdiction of the Environmental Protection Agency (EPA) and various other federal, state and local environmental agencies. See "Environmental Matters" for a discussion of environmental regulation. Our U.S. interstate natural gas pipelines and certain of DCP Midstream's gathering and transmission pipelines are also subject to the regulations of the U.S. Department of Transportation (DOT) concerning pipeline safety.

Express-Platte pipeline system rates and tariffs are subject to regulation by the NEB in Canada and the FERC in the United States. In addition, the Platte pipeline also operates as an intrastate pipeline in Wyoming and is subject to jurisdiction by the Wyoming Public Service Commission.

The intrastate natural gas and NGL pipelines owned by us and DCP Midstream are subject to state regulation. To the extent that the natural gas intrastate pipelines that transport natural gas in interstate commerce provide services under Section 311 of the Natural Gas Policy Act of 1978, they are subject to FERC regulation. DCP Midstream's interstate natural gas pipeline operations are also subject to regulation by the FERC. The natural gas gathering and processing activities of DCP Midstream are not subject to FERC regulation.

Our Canadian operations are governed by various federal and provincial agencies with respect to pipeline safety, including the NEB and the Transportation Safety Board, the British Columbia Oil and Gas Commission, the Alberta Energy Regulator and the Ontario Technical Standards and Safety Authority.

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Our Canadian natural gas transmission and distribution operations and approximately two-thirds of the storage operations in Canada, are subject to regulation by the NEB or the provincial agencies in Canada, such as the OEB. These agencies have jurisdiction similar to the FERC for regulating rates, the terms and conditions of service, the construction of additional facilities and acquisitions. Our BC Field Services business in western Canada is regulated by the NEB pursuant to a framework for light-handed regulation under which the NEB acts on a complaints-basis for rates associated with that business. Similarly, the rates charged by our Canadian Midstream operations for gathering and processing services in western Canada are regulated on a complaints-basis by applicable provincial regulators. Our Empress NGL business is not under any form of rate regulation.

Environmental Matters

We are subject to various U.S. federal, state and local laws and regulations, as well as Canadian federal and provincial regulations, regarding air and water quality, hazardous and solid waste disposal and other environmental matters. Environmental laws and regulations affecting our U.S.-based operations include, but are not limited to:

- The Clean Air Act (CAA) and the 1990 amendments to the CAA, as well as state laws and regulations affecting air emissions (including State Implementation Plans related to existing and new national ambient air quality standards), which may limit new sources of air emissions. Our natural gas processing, transmission and storage assets are considered sources of air emissions and are thereby subject to the CAA. Owners and/or operators of air emission sources, like us, are responsible for obtaining permits for existing and new sources of air emissions and for annual compliance and reporting.
- The Federal Water Pollution Control Act (Clean Water Act), which requires permits for facilities that discharge wastewaters into the environment. The Oil Pollution Act (OPA) amended parts of the Clean Water Act and other statutes as they pertain to the prevention of and response to oil spills. The OPA imposes certain spill prevention, control and countermeasure requirements. Although we are primarily a natural gas business, the OPA affects our business primarily because of the presence of liquid hydrocarbons (condensate) in our offshore pipelines.
- The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which imposes liability for remediation costs associated with environmentally contaminated sites. Under CERCLA, any individual or entity that currently owns or in the past owned or operated a disposal site can be held liable and required to share in remediation costs, as well as transporters or generators of hazardous substances sent to a disposal site. Because of the geographical extent of our operations, we have disposed of waste at many different sites and therefore have CERCLA liabilities.
- The Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act, which requires certain solid wastes, including hazardous wastes, to be managed pursuant to a comprehensive regulatory regime. As part of our business, we generate solid waste within the scope of these regulations and therefore must comply with such regulations.
- The Toxic Substances Control Act, which requires that polychlorinated biphenyl (PCB) contaminated materials be managed in accordance with a comprehensive regulatory regime. Because of the historical use of lubricating oils containing PCBs, the internal surfaces of some of our pipeline systems are contaminated with PCBs, and liquids and other materials removed from these pipelines must be managed in compliance with such regulations.
- The National Environmental Policy Act, which requires federal agencies to consider potential environmental effects in their decisions, including site approvals. Many of our capital projects require federal agency review, and therefore the environmental effects of proposed projects are a factor in determining whether we will be permitted to complete proposed projects.

Environmental laws and regulations affecting our Canadian-based operations include, but are not limited to:

- The Fisheries Act (Canada), which regulates activities near any body of water in Canada.
- The Environmental Management Act (British Columbia), the Environmental Protection and Enhancement Act (Alberta) and the Environmental Protection Act (Ontario) are provincial laws governing various aspects, including permitting and site remediation obligations, of our facilities and operations in those provinces.
- The Canadian Environmental Protection Act, which, among other things, requires the reporting of greenhouse gas (GHG) emissions from our operations in Canada. Additional regulations to be promulgated under this Act may require the reduction of GHGs, nitrogen oxides, sulphur oxides, volatile organic compounds and particulate matter.

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- The Alberta Climate Change and Emissions Management Act (The Act) which, as of 2007, required certain facilities to meet reductions in emission intensity. The Act was applicable to our Empress facility in Alberta beginning in 2008.

For more information on environmental matters, including possible liability and capital costs, see Part II. Item 8. Financial Statements and Supplementary Data, Notes 5 and 20, of Notes to Consolidated Financial Statements.

Except to the extent discussed in Notes 5 and 20, compliance with international, federal, state, provincial and local provisions regulating the discharge of materials into the environment, or otherwise protecting the environment, is incorporated into the routine cost structure of our various business units and is not expected to have a material effect on our competitive position or consolidated results of operations, financial position or cash flows.

Geographic Regions

For a discussion of our Canadian operations and the risks associated with them, see Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Quantitative and Qualitative Disclosures About Market Risk—Foreign Currency Risk, and Notes 4 and 19 of Notes to Consolidated Financial Statements.

Employees

We had approximately 5,900 employees as of December 31, 2014, including approximately 3,600 employees in Canada. In addition, DCP Midstream employed approximately 3,500 employees as of such date. Approximately 1,400 of our Canadian employees are subject to collective bargaining agreements governing their employment with us. Approximately 38% of those employees are covered under agreements that either have expired or will expire by December 31, 2015.

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Executive and Other Officers

The following table sets forth information regarding our executive and other officers.

Name	Age	Position
Gregory L. Ebel	50	President and Chief Executive Officer, Director
J. Patrick Reddy	62	Chief Financial Officer
Dorothy M. Ables	57	Chief Administrative Officer
Guy G. Buckley	54	Chief Development Officer
Julie A. Dill	55	Chief Communications Officer
Reginald D. Hedgebeth	47	General Counsel
William T. Yardley	50	President, U.S. Transmission and Storage
Allen C. Capps	44	Vice President and Controller
Laura Buss Sayavedra	47	Vice President and Treasurer

Gregory L. Ebel assumed his current position as President and Chief Executive Officer on January 1, 2009. He previously served as Group Executive and Chief Financial Officer since January 2007. Mr. Ebel currently serves as the Chairman of the Board of Directors of Spectra Energy Corp and on the Board of Directors of Spectra Energy Partners GP, LLC and DCP Midstream, LLC.

J. Patrick Reddy joined Spectra Energy in January 2009 as Chief Financial Officer. Mr. Reddy served as Senior Vice President and Chief Financial Officer at Atmos Energy Corporation from 2000 to 2008. Mr. Reddy currently serves on the Board of Directors of DCP Midstream, LLC.

Dorothy M. Ables assumed her current position as Chief Administrative Officer in November 2008. Prior to then, she served as Vice President of Audit Services and Chief Ethics and Compliance Officer from January 2007. Ms. Ables currently serves on the Board of Directors of Spectra Energy Partners GP, LLC.

Guy G. Buckley assumed his current position as Chief Development Officer in January 2014. He previously served as Treasurer and Group Vice President-Mergers and Acquisitions from January 2012 to December 2013, and as Group Vice President, Corporate Strategy and Development from December 2008 to December 2011. Mr. Buckley currently serves on the Board of Directors of DCP Midstream, LLC.

Julie A. Dill assumed her current position as Chief Communications Officer on January 1, 2014. Ms. Dill previously served as Group Vice President - Strategy from January 2013 to December 2013, as President and Chief Executive Officer of Spectra Energy Partners, GP, LLC from January 2012 to October 2013 and as President of Union Gas Limited from December 2006 through December 2011. Ms. Dill currently serves on the Board of Directors of Spectra Energy Partners GP, LLC.

Reginald D. Hedgebeth assumed his current position as General Counsel in March 2009. He previously served as Senior Vice President, General Counsel and Secretary with Circuit City Stores, Inc. from July 2005 to March 2009.

William T. Yardley assumed his current position as President, U.S. Transmission and Storage in January 2013. Prior to then, he served as Group Vice President of Northeastern U.S. Assets and Operations since 2007. Mr. Yardley's currently serves on the Board of Directors of Spectra Energy Partners GP, LLC.

Allen C. Capps assumed his current position as Vice President and Controller in January 2012. He previously served as Vice President, Business Development, Storage and Transmission, for Union Gas from April 2010. Prior to then, Mr. Capps served as Vice President and Treasurer for Spectra Energy Corp from December 2007 until April 2010.

Laura Buss Sayavedra assumed her current position as Vice President and Treasurer on January 1, 2014. Ms. Sayavedra previously served as Vice President - Strategy from March 2013 to December 2013, as Vice President and Chief Financial Officer of Spectra Energy Partners, GP, LLC from July 2008 to February 2013, and as Vice President, Strategic Development and Analysis of Spectra Energy Corp from January 2007 to June 2008.

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Additional Information

We were incorporated on July 28, 2006 as a Delaware corporation. Our principal executive offices are located at 5400 Westheimer Court, Houston, Texas 77056 and our telephone number is 713-627-5400. We electronically file various reports with the Securities and Exchange Commission (SEC), including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and amendments to such reports. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at http://www.sec.gov. Additionally, information about us, including our reports filed with the SEC, is available through our website at http://www.spectraenergy.com. Such reports are accessible at no charge through our website and are made available as soon as reasonably practicable after such material is filed with or furnished to the SEC. Our website and the information contained on that site, or connected to that site, are not incorporated by reference into this report.

Item 1A. Risk Factors.

Discussed below are the material risk factors relating to Spectra Energy.

Reductions in demand for natural gas and oil, and low market prices of commodities adversely affect our operations and cash flows.

Our regulated businesses are generally economically stable; they are not significantly affected in the short-term by changing commodity prices. However, our businesses can all be negatively affected in the long term by sustained downturns in the economy or long-term conservation efforts, which could affect long-term demand and market prices for natural gas, oil and NGLs. These factors are beyond our control and could impair the ability to meet long-term goals.

Most of our revenues are based on regulated tariff rates, which include the recovery of certain fuel costs. However, lower overall economic output could reduce the volume of natural gas and NGLs transported and distributed or gathered and processed at our plants, and the volume of oil transported, resulting in lower earnings and cash flows. This decline would primarily affect distribution revenues in the short term. Transmission revenues could be affected by long-term economic declines, resulting in the non-renewal of long-term contracts at the time of expiration.

Lower demand along with lower prices for natural gas, oil and NGLs could result from multiple factors that affect the markets where we operate, including:

- weather conditions, such as abnormally mild winter or summer weather, resulting in lower energy usage for heating or cooling purposes, respectively;
- supply of and demand for energy commodities, including any decrease in the production of natural gas and oil which could negatively affect our processing and transmission businesses due to lower throughput;
- capacity and transmission service into, or out of, our markets; and
- petrochemical demand for NGLs.

The lack of availability of natural gas and oil resources may cause customers to seek alternative energy resources, which could materially affect our revenues, earnings and cash flows.

Our natural gas and oil businesses are dependent on the continued availability of natural gas and oil production and reserves. Prices for natural gas and oil, regulatory limitations on the development of natural gas and oil supplies, or a shift in supply sources could adversely affect development of additional reserves and production that are accessible by our pipeline, gathering, processing and distribution assets. Lack of commercial quantities of natural gas and oil available to these assets could cause customers to seek alternative energy resources, thereby reducing their reliance on our services, which in turn would materially affect our revenues, earnings and cash flows.

Investments and projects located in Canada expose us to fluctuations in currency rates that may affect our results of operations, cash flows and compliance with debt covenants.

We are exposed to foreign currency risk from our Canadian operations. An average 10% devaluation in the Canadian dollar exchange rate during 2014 would have resulted in an estimated net loss on the translation of local currency earnings of approximately $44 million on our Consolidated Statement of Operations. In addition, if a 10% devaluation had occurred on December 31, 2014, the Consolidated Balance Sheet would have been negatively impacted by $499 million through a cumulative translation adjustment in Accumulated Other Comprehensive Income (AOCI). At December 31, 2014, one U.S. dollar translated into 1.16 Canadian dollars.

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In addition, we maintain credit facilities that typically include financial covenants which limit the amount of debt that can be outstanding as a percentage of total capital for Spectra Energy or of a specific subsidiary. Failure to maintain these covenants could preclude us from issuing commercial paper or letters of credit, or borrowing under our revolving credit facilities, and could require other affiliates to immediately pay down any outstanding drawn amounts under other revolving credit agreements, which could affect cash flows or restrict business. Foreign currency fluctuations have a direct impact on our ability to maintain certain of these financial covenants.

Natural gas gathering and processing, NGL processing and marketing, and market-based storage operations are subject to commodity price risk, which could result in a decrease in our earnings and reduced cash flows.

We have gathering and processing operations that consist of contracts to buy and sell commodities, including contracts for natural gas, NGLs and other commodities that are settled by the delivery of the commodity or cash. We are exposed to market price fluctuations of NGLs and natural gas primarily in Field Services and at Empress in our Western Canada Transmission & Processing segment, and to oil primarily in our Field Services segment. The effect of commodity price fluctuations on our earnings could be material. Effective January 2014, we implemented a commodity hedging program at Empress in order to manage risks associated with Empress' commodity price fluctuations. The commodity hedging program helps manage the fluctuations in the Conway/Mont Belvieu index prices. However, it does not manage potential fluctuations in pricing differentials between the Empress market and index prices. The changes in pricing differentials may be material and may adversely affect results.

We have market-based rates for some of our storage operations and sell our storage services based on natural gas market spreads and volatility. If natural gas market spreads or volatility deviate from historical norms or there is significant growth in the amount of storage capacity available to natural gas markets relative to demand, our approach to managing our market-based storage contract portfolio may not protect us from significant variations in storage revenues, including possible declines, as contracts renew.

Our business is subject to extensive regulation that affects our operations and costs.

Our U.S. assets and operations are subject to regulation by various federal, state and local authorities, including regulation by the FERC and by various authorities under federal, state and local environmental laws. Our natural gas assets and operations in Canada are also subject to regulation by federal, provincial and local authorities, including the NEB and the OEB, and by various federal and provincial authorities under environmental laws. Regulation affects almost every aspect of our business, including, among other things, the ability to determine terms and rates for services provided by some of our businesses, make acquisitions, construct, expand and operate facilities, issue equity or debt securities, and pay dividends.

In addition, regulators in both the U.S. and Canada have taken actions to strengthen market forces in the gas pipeline industry, which have led to increased competition. In a number of key markets, natural gas pipeline and storage operators are facing competitive pressure from a number of new industry participants, such as alternative suppliers, as well as traditional pipeline competitors. Increased competition driven by regulatory changes could have a material effect on our business, earnings, financial condition and cash flows.

Execution of our capital projects subjects us to construction risks, increases in labor and material costs, and other risks that may affect our financial results.

A significant portion of our growth is accomplished through the construction of new pipelines and storage facilities as well as the expansion of existing facilities. Construction of these facilities is subject to various regulatory, development, operational and market risks, including:

- the ability to obtain necessary approvals and permits by regulatory agencies on a timely basis and on acceptable terms and to maintain those approvals and permits issued and satisfy the terms and conditions imposed therein;
- the availability of skilled labor, equipment, and materials to complete expansion projects;
- potential changes in federal, state and local statutes and regulations, including environmental requirements, that may prevent a project from proceeding or increase the anticipated cost of the project;
- impediments on our ability to acquire rights-of-way or land rights on a timely basis and on acceptable terms;

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- the ability to construct projects within anticipated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials or labor, weather, geologic conditions or other factors beyond our control, that may be material; and
- general economic factors that affect the demand for natural gas infrastructure.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated cost. As a result, new facilities may not achieve their expected investment return, which could affect our earnings, financial position and cash flows.

Gathering and processing, natural gas transmission and storage, crude oil transportation and storage, and gas distribution activities involve numerous risks that may result in accidents or otherwise affect our operations.

There are a variety of hazards and operating risks inherent in natural gas gathering and processing, transmission, storage, and distribution activities, and crude oil transportation and storage, such as leaks, explosions, mechanical problems, activities of third parties and damage to pipelines, facilities and equipment caused by hurricanes, tornadoes, floods, fires and other natural disasters, that could cause substantial financial losses. In addition, these risks could result in significant injury, loss of life, significant damage to property, environmental pollution and impairment of operations, any of which could result in substantial losses. For pipeline and storage assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damage resulting from these risks could be greater. We do not maintain insurance coverage against all of these risks and losses, and any insurance coverage we might maintain may not fully cover the damages caused by those risks and losses. Therefore, should any of these risks materialize, it could have a material effect on our business, earnings, financial condition and cash flows.

Our operations are subject to pipeline safety laws and regulations, compliance with which may require significant capital expenditures, increase our cost of operations and affect or limit our business plans.

Our interstate pipeline operations are subject to pipeline safety laws and regulations administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the DOT. These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. These regulations, among other things, include requirements to monitor and maintain the integrity of our pipelines. The regulations determine the pressures at which our pipelines can operate.

In 2010, serious pipeline incidents on systems unrelated to ours focused the attention of Congress and the public on pipeline safety. Legislative proposals were introduced in Congress to strengthen the PHMSA's enforcement and penalty authority, and expand the scope of its oversight. In 2011, PHMSA initiated an Advance Notice of Proposed Rulemaking announcing its consideration of substantial revisions in its regulations to increase pipeline safety. In January 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 was signed into law. This Act (the 2012 PSA Amendments) amends the Pipeline Safety Act in a number of significant ways, including:

- Authorizing PHMSA to assess higher penalties for violations of its regulations,
- Requiring PHMSA to adopt appropriate regulations within two years requiring the use of automatic or remote-controlled shutoff valves on new or rebuilt pipeline facilities and to perform a study on the application of such technology to existing pipeline facilities in High Consequence Areas (HCAs),
- Requiring operators of pipelines to verify maximum allowable operating pressure and report exceedances within five days,
- Requiring PHMSA to study and report on the adequacy of soil cover requirements in HCAs, and
- Requiring PHMSA to evaluate in detail whether integrity management requirements should be expanded to pipeline segments outside of HCAs (where the requirements currently apply).

Many of these legislative changes, such as increasing penalties, have been completed, while others are substantially in progress with resolution expected in 2015. Additionally, Congress is tasked with reauthorization of the Pipeline Safety Act during fiscal year 2015. PHMSA is designing an Integrity Verification Process intended to create standards to verify maximum allowable operating pressure, and to improve and expand integrity management processes. There remains uncertainty as to how these standards will be implemented, but it is expected that the changes will impose additional costs on new pipeline projects as well as on existing operations. In this climate of increasingly stringent regulation, pipeline failures or failures to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by PHMSA, which would reduce

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available capacity on our pipelines. Should any of these risks materialize, it may have an adverse effect on our operations, earnings, financial condition and cash flows.

In Canada, our interprovincial and international pipeline operations are subject to pipeline safety regulations overseen by the NEB. Applicable legislation and regulation require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interprovincial and international pipelines. Among other obligations, this regulatory framework imposes requirements to monitor and maintain the integrity of our pipelines.

As in the U.S., several legislative changes addressing pipeline safety in Canada have recently come into force. The changes evidence an increased focus on the implementation of management systems to address key areas such as emergency management, integrity management, safety, security and environmental protection. Other legislative changes have created authority for the NEB to impose administrative monetary penalties for non-compliance with the regulatory regime it administers.

Compliance with these legislative changes may impose additional costs on new Canadian pipeline projects as well as on existing operations. Failure to comply with applicable regulations could result in a number of consequences which may have an adverse effect on our operations, earnings, financial condition and cash flows.

Our operations are subject to numerous environmental laws and regulations, compliance with which may require significant capital expenditures, increase our cost of operations and affect or limit our business plans, or expose us to environmental liabilities.

We are subject to numerous environmental laws and regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations can result in increased capital, operating and other costs. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations can require significant expenditures, including expenditures for cleanup costs and damages arising out of contaminated properties. In particular, compliance with major Clean Air Act regulatory programs may cause us to incur significant capital expenditures to obtain permits, evaluate offsite impacts of our operations, install pollution control equipment, and otherwise assure compliance. The precise nature of these compliance obligations at each of our facilities has not been finally determined and may depend in part on future regulatory changes. In addition, compliance with new and emerging environmental regulatory programs is likely to significantly increase our operating costs compared to historical levels.

Failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting our operating assets. In addition, changes in environmental laws and regulations or the enactment of new environmental laws or regulations could result in a material increase in our cost of compliance with such laws and regulations. We may not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operating assets or development projects. If there is a delay in obtaining any required environmental regulatory approvals, if we fail to obtain or comply with them or if environmental laws or regulations change or are administered in a more stringent manner, the operations of facilities or the development of new facilities could be prevented, delayed or become subject to additional costs. No assurance can be made that the costs that may be incurred to comply with environmental regulations in the future will not have a significant effect on our earnings and cash flows.

The enactment of climate change legislation or the adoption of regulations under the existing Clean Air Act could result in increased operating costs and delays in obtaining necessary permits for our capital projects.

The current international climate framework, the United Nations-sponsored Kyoto Protocol, prescribed specific targets to reduce GHG emissions for developed countries for the 2008-2012 period. The Kyoto Protocol expired in 2012 and had not been signed by the U.S.; however, at the Copenhagen Climate Change Summit in 2009, the U.S. indicated it would reduce carbon dioxide emissions by 17% below 2005 levels by 2020. The United Nations-sponsored international negotiations held in Durban, South Africa in 2011 resulted in a non-binding agreement (Durban Agreement) to develop a roadmap aimed at creating a global agreement on climate action to be implemented by 2020. The U.S. is a party to the Durban agreement. In the interim period before 2020, the Kyoto

Protocol will continue in effect, although it is expected that not all of the current parties will choose to commit for this extended period.

In the U.S., climate change action is evolving at state, regional and federal levels. The Supreme Court decision in Massachusetts v. EPA in 2007 established that GHGs were pollutants subject to regulation under the Clean Air Act. Pursuant to federal regulations, we are currently subject to an obligation to report our GHG emissions at our largest emitting facilities, but are not generally subject to limits on emissions of GHGs, (except to the extent that some GHGs consist of volatile organic compounds and nitrous oxides that are subject to emission limits). Proposed regulation may extend our reporting obligations to additional facilities and activities. In addition, a number of Canadian provinces and U.S. states have joined regional greenhouse gas initiatives, and a number are developing their own programs that would mandate reductions in GHG emissions. Public interest groups are increasingly focusing on the emission of methane associated with natural gas development and transmission as a source of GHG emissions. However, as the key details of future GHG restrictions and compliance mechanisms remain undefined, the likely future effects on our business are highly uncertain.

In 2010, the EPA issued the Prevention of Significant Deterioration (PSD) and the Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). Beginning in 2011, the Tailoring Rule required that construction of new or modification of existing major sources of GHG emissions be subject to the PSD air permitting program (and later, the Title V permitting program), although the regulation also significantly increased the emissions thresholds that would subject facilities to these regulations. The scope of the Tailoring rule was limited by a 2015 U.S. Supreme Court decision, which determined that sources which are major sources only for GHGs (Step 2 sources) are no longer subject to the PSD permitting process. EPA followed with guidance indicating it will not enforce PSD permitting against these Step 2 sources. However, some states incorporated GHG permitting into their state regulations, and may continue to enforce these requirements. We anticipate that in the future, some new capital projects or projects to modify existing facilities could be subject to additional state-required permitting requirements related to GHG emissions that may result in delays in completing such projects. In 2014, the EPA proposed revising regulations to the National Ambient Air Quality Standards (NAAQS) that would lower the existing standard from 75 parts per billion (ppb) set in 2008, to a standard between 65 and 70 ppb. This may increase the non-attainment areas along our system and the number of affected facilities. These facilities may require pollution control or replacement of equipment to comply with tightened standards and may face a less certain permitting process. In 2015, the Obama Administration issued its intention to regulate methane emissions from new and modified natural gas transmission and storage sources, and its expectation for voluntary emission decreases from existing sources. While uncertainty remains as to how this blueprint will be implemented, we anticipate that additional controls or costs may be incurred.

Due to the speculative outlook regarding any U.S. federal and state policies and the uncertainty of the Canadian federal and provincial policies, we cannot estimate the potential effect of proposed GHG policies on our future consolidated results of operations, financial position or cash flows. However, such legislation or regulation could materially increase our operating costs, require material capital expenditures or create additional permitting, which could delay proposed construction projects.

We are involved in numerous legal proceedings, the outcome of which are uncertain, and resolutions adverse to us could negatively affect our earnings, financial condition and cash flows.

We are subject to numerous legal proceedings. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters with assurance. It is reasonably possible that the final resolution of some of the matters in which we are involved could require additional expenditures, in excess of established reserves, over an extended period of time and in a range of amounts that could have a material effect on our earnings and cash flows.

We rely on access to short-term and long-term capital markets to finance capital requirements and support liquidity needs, and access to those markets can be affected, particularly if we or our rated subsidiaries are unable to maintain an investment-grade credit rating, which could affect our cash flows or restrict business.

Our business is financed to a large degree through debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from assets. Accordingly, we rely on access to both short-term and long-term capital markets as a source of liquidity for capital requirements not satisfied by cash flows from operations and to fund investments originally financed through debt. Our senior unsecured long-term debt is currently rated investment-grade by various rating agencies. If the rating agencies were to rate us or our rated subsidiaries below investment-grade, our borrowing costs would increase, perhaps significantly. Consequently, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources could decrease.

We maintain revolving credit facilities to provide back-up for commercial paper programs for borrowings and/or letters of credit at various entities. These facilities typically include financial covenants which limit the amount of debt that can be outstanding as a percentage of the total capital for the specific entity. Failure to maintain these covenants at a particular entity could preclude that entity from issuing commercial paper or letters of credit or borrowing under the revolving credit facility and could require other affiliates to immediately pay down any outstanding drawn amounts under other revolving credit agreements, which could affect cash flows or restrict business. Furthermore, if Spectra Energy’s short-term debt rating were to be below tier 2 (for example, A-2 for Standard and Poor’s, P-2 for Moody’s Investor Service and F2 for Fitch Ratings), access to the commercial paper market could be significantly limited. Although this would not affect our ability to draw under our credit facilities, borrowing costs could be significantly higher.

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If we are not able to access capital at competitive rates, our ability to finance operations and implement our strategy may be affected. Restrictions on our ability to access financial markets may also affect our ability to execute our business plan as scheduled. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for future growth. Any downgrade or other event negatively affecting the credit ratings of our subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could increase our need to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing the liquidity and borrowing availability of the consolidated group.

We may be unable to secure renewals of long-term transportation agreements, which could expose our transportation volumes and revenues to increased volatility.

We may be unable to secure renewals of long-term transportation agreements in the future for our natural gas transmission and crude oil transportation businesses as a result of economic factors, lack of commercial gas supply available to our systems, changing gas supply flow patterns in North America, increased competition or changes in regulation. Without long-term transportation agreements, our revenues and contract volumes would be exposed to increased volatility. The inability to secure these agreements would materially affect our business, earnings, financial condition and cash flows.

We are exposed to the credit risk of our customers.

We are exposed to the credit risk of our customers in the ordinary course of our business. Generally, our customers are rated investment-grade, are otherwise considered creditworthy or provide us security to satisfy credit concerns. A significant amount of our credit exposures for transmission, storage, and gathering and processing services are with customers who have an investment-grade rating (or the equivalent based on our evaluation) or are secured by collateral. However, we cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including possible declines in our customers' creditworthiness. As a result of future capital projects for which natural gas producers may be the primary customer, our credit exposure with below investment-grade customers may increase. While we monitor these situations carefully and take appropriate measures when deemed necessary, it is possible that customer payment defaults, if significant, could have a material effect on our earnings and cash flows.

Native land claims have been asserted in British Columbia and Alberta, which could affect future access to public lands, and the success of these claims could have a significant effect on natural gas production and processing.

Certain aboriginal groups have claimed aboriginal and treaty rights over a substantial portion of public lands on which our facilities in British Columbia and Alberta, and the gas supply areas served by those facilities, are located. The existence of these claims, which range from the assertion of rights of limited use to aboriginal title, has given rise to some uncertainty regarding access to public lands for future development purposes. Such claims, if successful, could have a significant effect on natural gas production in British Columbia and Alberta, which could have a material effect on the volume of natural gas processed at our facilities and of NGLs and other products transported in the associated pipelines. In addition, various aboriginal groups in Ontario have claimed aboriginal and treaty rights in areas where Union Gas' facilities, and the gas supply areas served by those facilities, are located. The existence of these claims could give rise to future uncertainty regarding land tenure depending upon their negotiated outcomes. We cannot predict the outcome of any of these claims or the effect they may ultimately have on our business and operations.

Protecting against potential terrorist activities requires significant capital expenditures and a successful terrorist attack could affect our business.

Acts of terrorism and any possible reprisals as a consequence of any action by the U.S. and its allies could be directed against companies operating in the U.S. This risk is particularly high for companies, like us, operating in any energy infrastructure industry that handles volatile gaseous and liquid hydrocarbons. The potential for terrorism, including cyber-terrorism, has subjected our operations to increased risks that could have a material effect on our business. In particular, we may experience increased capital and operating costs to implement increased security for our facilities and pipelines, such as additional physical facility and pipeline security, and additional security personnel. Moreover, any physical damage to high profile facilities resulting from acts of terrorism may not be covered, or covered fully, by insurance. We may be required to expend material amounts of capital to repair any facilities, the expenditure of which could affect our business and cash flows.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

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Poor investment performance of our pension plan holdings and other factors affecting pension plan costs could affect our earnings, financial position and liquidity.

Our costs of providing defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates used to measure pension liabilities, actuarial gains and losses, future government regulation and our contributions made to the plans. Without sustained growth in the pension plan investments over time to increase the value of our plan assets, and depending upon the other factors impacting our costs as listed above, we could experience net asset, expense and funding volatility. This volatility could have a material effect on our earnings and cash flows.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

At December 31, 2014, we had over 100 primary facilities located in the United States and Canada. We generally own sites associated with our major pipeline facilities, such as compressor stations. However, we generally operate our transmission and distribution pipelines using rights of way pursuant to easements to install and operate pipelines, but we do not own the land. Except as described in Part II. Item 8. Financial Statements and Supplementary Data, Note 16 of Notes to Consolidated Financial Statements, none of our properties were secured by mortgages or other material security interests at December 31, 2014.

Our corporate headquarters are located at 5400 Westheimer Court, Houston, Texas 77056, which is a leased facility. The lease expires in 2026. We also maintain offices in, among other places, Calgary, Alberta and Chatham, Ontario. For a description of our material properties, see Item 1. Business.

Item 3. Legal Proceedings.

We have no material pending legal proceedings that are required to be disclosed hereunder. See Note 20 of Notes to Consolidated Financial Statements for discussions of other legal proceedings.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

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

Our common stock is traded on the NYSE under the symbol "SE." As of January 31, 2015, there were approximately 114,000 holders of record of our common stock and approximately 534,000 beneficial owners.

Common Stock Data by Quarter

2014	Dividends Per Common Share	Stock Price Range (a) High	Low
First Quarter	$ 0.335	$38.73	$34.23
Second Quarter	0.335	42.61	37.17
Third Quarter	0.335	43.12	38.55
Fourth Quarter	0.370	40.00	32.50
2013			
First Quarter	0.305	30.94	26.86
Second Quarter	0.305	34.83	29.62
Third Quarter	0.305	37.11	32.57
Fourth Quarter	0.305	36.16	32.80

(a) Stock prices represent the intra-day high and low price.

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Stock Performance Graph

The following graph reflects the comparative changes in the value from January 1, 2010 through December 31, 2014 of $100 invested in (1) Spectra Energy's common stock, (2) the Standard & Poor's 500 Stock Index, and (3) the Standard & Poor's 500 Oil & Gas Storage & Transportation Index. The amounts included in the table were calculated assuming the reinvestment of dividends at the time dividends were paid.

	January 1,	December 31,				
	2010	2010	2011	2012	2013	2014
Spectra Energy Corp	$100.00	$127.46	$163.20	$151.07	$204.03	$215.48
S&P 500 Stock Index	100.00	115.06	117.49	136.30	180.44	205.14
S&P 500 Storage & Transportation Index	100.00	127.40	188.45	211.53	254.69	295.23

Dividends

Our near-term objective is to increase our cash dividend by $0.14 per year through 2017. We expect to continue our policy of paying regular cash dividends. The declaration and payment of dividends are subject to the sole discretion of our Board of Directors and will depend upon many factors, including the financial condition, earnings and capital requirements of our operating subsidiaries, covenants associated with certain debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by our Board of Directors.

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Item 6. Selected Financial Data.

The following selected financial data should be read in conjunction with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data.

	2014	2013	2012	2011	2010
	(dollars in millions, except per-share amounts)				
Statements of Operations					
Operating revenues	$5,903	$5,518	$5,075	$5,351	$4,945
Operating income	1,924	1,666	1,575	1,763	1,674
Income from continuing operations	1,283	1,159	1,045	1,257	1,123
Net income—noncontrolling interests	201	121	107	98	80
Net income—controlling interests	1,082	1,038	940	1,184	1,049
Ratio of Earnings to Fixed Charges	3.6	2.9	2.8	3.4	3.1
Common Stock Data					
Earnings per share from continuing operations					
Basic	$1.61	$1.55	$1.44	$1.78	$1.61
Diluted	1.61	1.55	1.43	1.77	1.60
Earnings per share					
Basic	1.61	1.55	1.44	1.82	1.62
Diluted	1.61	1.55	1.43	1.81	1.61
Dividends per share	1.375	1.22	1.145	1.06	1.00

	December 31,				
	2014	2013	2012	2011	2010
	(in millions)				
Balance Sheets					
Total assets	$34,040	$33,533	$30,587	$28,138	$26,686
Long-term debt including capital leases, less current maturities	12,769	12,488	10,653	10,146	10,169

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

INTRODUCTION

Management's Discussion and Analysis should be read in conjunction with Item 8. Financial Statements and Supplementary Data.

EXECUTIVE OVERVIEW

Throughout 2014, we continued to successfully execute the long-term strategies we outlined for our shareholders—meeting the needs of our customers, generating strong earnings and cash flows from our fee-based assets, executing capital expansion plans that underlie our growth objectives, and maintaining our investment-grade balance sheet. These results, combined with future growth opportunities, led our Board of Directors to approve an increase in our quarterly dividend effective with the fourth quarter of 2014 to $0.37 per share, which represents an increase in our annual dividend by $0.14 per share.

During 2014, our earnings benefited from expansion projects and the acquisition of Express-Platte at Spectra Energy Partners, higher earnings from our Empress NGL business at Western Canada Transmission & Processing, and higher customer usage due primarily to colder weather at Distribution. These favorable results were partially offset by a weaker Canadian dollar at Distribution and Western Canada Transmission & Processing, and an increase in net income attributable to noncontrolling interests as a result of growth in DCP Partners' operation and the effects of dropdown hedges and lower commodity prices at Field Services.

We reported net income from controlling interests of $1,082 million and $1.61 of diluted earnings per share for 2014 compared to net income from controlling interests of $1,038 million and $1.55 of diluted earnings per share for 2013. Earnings highlights for 2014 compared to 2013 include the following:

- Spectra Energy Partners' earnings increased mainly due to expansion projects, primarily at Texas Eastern, higher earnings from the continued ramp up of volumes at Sand Hills and Southern Hills, the acquisition of Express-Platte in March 2013, higher natural gas transportation revenues due to new contracts, and an increase in crude oil transportation revenues for both Express and Platte pipelines mainly as a result of increased tariff rates and higher revenue volumes, partially offset by lower storage revenues due to lower rates and lower allowance for funds used during construction (AFUDC) due to decreased capital spending.
- Distribution's earnings decreased mainly due to a weaker Canadian dollar, lower storage revenues due to lower prices and 2014 earnings to be shared with customers under the new incentive regulation framework, partially offset by higher customer usage primarily as a result of colder weather and increased customer growth.
- Western Canada Transmission & Processing's earnings benefited from higher earnings at the Empress NGL business mainly due to non-cash mark-to-market gains associated with the risk management program implemented in early 2014 and higher propane prices, and higher gathering and processing revenues, partially offset by higher plant turnaround and maintenance costs and the effect of a weaker Canadian dollar.
- Field Services' earnings decreased, reflecting mainly an increase in net income attributable to noncontrolling interests as a result of growth in DCP Partners' operations and the effects of dropdown hedges, lower commodity prices, higher operating costs, losses on sales of assets and a goodwill impairment in 2014 compared to gains on sales of assets in 2013, and lower gains associated with the issuance of partnership units by DCP Partners, partially offset by increased gathering and processing margins due to asset growth and higher volumes, and favorable results from trading and marketing and DCP Partners' mark-to-market activity.

We invested $2.3 billion of capital and investment expenditures in 2014, including $1.5 billion of expansion and investment capital expenditures. Successful execution of our 2014 projects allowed us to continue to achieve aggregate returns over the past several years consistent with our targeted return on capital employed range. Return on capital employed as it relates to expansion projects is calculated by us as incremental earnings before interest and taxes, generated by a project divided by the total cost of the project. We continue to foresee significant expansion capital spending over the next several years, with approximately $2.7 billion planned for 2015. Concurrently, we executed on identified opportunities leveraging our asset footprint to capture incremental growth, connecting large diverse markets with growing supply throughout North America.

We are committed to an investment-grade balance sheet and continued prudent financial management of our capital structure. Therefore, financing these growth activities will continue to be based on our strong and growing fee-based earnings and cash flows as well as the issuance of debt and equity securities. In 2015, we plan to issue approximately $1.7 billion of

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combined long-term debt and commercial paper, including the refinancing of approximately $0.3 billion of long-term debt maturities. As of December 31, 2014, our four revolving credit facilities consisted of Spectra Energy Capital, LLC's (Spectra Capital's) $1.0 billion facility, SEP's $2.0 billion facility, Westcoast Energy, Inc.'s (Westcoast's) 400 million Canadian dollar facility, and Union Gas' 500 million Canadian dollar facility. These facilities are used principally as back-stops for commercial paper programs. At December 31, 2014 and 2013, our debt-to-capitalization ratio was 58%.

Our Strategy. Our strategy is to create superior and sustainable value for our investors, customers, employees and communities by delivering natural gas, liquids and crude oil infrastructure to premium markets. We will grow our business through organic growth, greenfield expansions and strategic acquisitions, with a focus on safety, reliability, customer responsiveness and profitability. We intend to accomplish this by:

- Building off the strength of our asset base.
- Maximizing that base through sector leading operations and service.
- Effectively executing the projects we have secured.
- Securing new growth opportunities that add value for our investors within each of our business segments.
- Expanding our value chain participation into complementary infrastructure assets.

Natural gas supply dynamics continue to rapidly change, and there is general recognition that natural gas can be an effective solution for meeting the energy needs of North America and beyond. This causes us to be optimistic about future growth opportunities. Identified opportunities include growth in natural gas-fired generation, growth in industrial markets, incremental gathering and processing requirements in western Canada, LNG exports in North America, growth related to moving new sources of gas supplies to markets and significant new liquids pipeline infrastructure. With our advantage of providing continuous access from leading supply regions through to the last mile of pipe in growing natural gas, NGL and crude oil markets, we expect to continue expanding our assets and operations to meet the evolving needs of our customers.

Crude oil supply dynamics also continue to evolve as North American production increases. Growing North American crude oil production is displacing imports from overseas and driving increased demand for crude oil transportation and logistics. Although recent decreases in global crude oil prices may dampen near-term growth in North American oil production, we remain confident about the long-term proposition and our ability to capture future opportunities and grow our crude oil pipeline business.

Successful execution of our strategy will be determined by such key factors as the continued production of, and the consumption of, natural gas, NGLs and crude oil within the United States and Canada, our ability to provide creative solutions for customers' evolving energy needs, maintaining leadership as a safe and reliable operator, and continued successful execution on our capital projects.

We continue to be actively engaged in the national discussions in both the United States and Canada regarding energy policy and have taken a lead role in shaping policy as it relates to pipeline safety and operations.

Significant Economic Factors For Our Business. Our regulated businesses are generally economically stable and are not significantly affected in the short-term by changing commodity prices. However, all of our businesses can be negatively affected in the long term by sustained downturns in the economy or prolonged decreases in the demand for crude oil, natural gas and/or NGLs, all of which are beyond our control and could impair our ability to meet long-term goals.

Most of our revenues are based on regulated tariff rates, which include the recovery of certain fuel costs. Lower overall economic output would reduce the volume of natural gas and NGLs transported and distributed or gathered and processed at our plants, and the volume of crude oil transported, resulting in lower earnings and cash flows. This decline would primarily affect distribution revenues and gathering and processing revenues, potentially in the short term. Transmission revenues could be affected by long-term economic declines resulting in the non-renewal of long-term contracts at the time of expiration. Pipeline transportation and storage customers continue to renew most contracts as they expire. Gathering and processing revenues and the earnings and cash distributions from our Field Services segment are also affected by volumes of natural gas made available to our systems, which are primarily driven by levels of natural gas drilling activity. While experiencing a decline in production from conventional gas wells, natural gas exploration and drilling activity in the areas that affect our Western Canada Transmission &

Processing and Field Services segments remain stable, primarily driven by recent positive “supply push” developments around unconventional gas reserves production in numerous locations within North America as discussed further below and by “demand pull” projects in British Columbia and the Pacific Northwest.

Our combined key natural gas markets—the northeastern and the southeastern United States, the Pacific Northwest, British Columbia and Ontario—are projected to continue to exhibit higher than average annual growth in natural gas demand versus the North American and continental United States average growth rates through 2019. This demand growth is primarily driven by the natural gas-fired electricity generation sector and other new industrial gas demands, including LNG. The natural gas industry is currently experiencing a significant shift in the sources of supply, and this dramatic change is affecting our growth strategies. Traditionally, supply to our markets has come from the Gulf Coast region, both onshore and offshore, as well as from natural gas reserves in western and eastern Canada. The national supply profile is shifting to new sources of gas from natural gas shale basins in the Rockies, Midcontinent, Appalachia, Texas and Louisiana. Also, significant supply sources continue to be identified for development in western Canada. These supply shifts are shaping the growth strategies that we will pursue, and therefore, will affect the nature of the projects anticipated in the capital and investment expenditure increases discussed below in “Liquidity and Capital Resources.”

Recent community and political pressures have arisen around the production processes associated with extracting natural gas from the natural gas shale basins. Although we continue to believe that natural gas will remain a viable energy solution for the United States and Canada, these pressures could increase costs and/or cause a slowdown in the production of natural gas from these basins, and therefore, could negatively affect our growth plans.

Our key crude oil markets include the Rocky Mountain and Midwest states with growing connectivity to the Gulf Coast and West Coast of the United States. Growth in our business is dependent on growing crude oil supply from North American sources and the ability of that supply to displace imported crude oil from overseas. The recent decline in crude oil prices may adversely affect the availability and cost-competitiveness of North American crude oil supply and sustained low oil prices could have a negative impact on our current business and associated growth opportunities.

In certain areas of Western Canada Transmission & Processing’s operations, lower natural gas prices resulting from increasing North American gas production have reduced producer demand for expansions of the British Columbia gas processing plants as well as renewals of existing gas processing contracts, and could continue to do so as long as gas prices remain below historical norms.

DCP Midstream’s business has commodity price exposure as a result of being compensated for certain services in the form of commodities rather than cash. Commodity prices have declined substantially, and experienced significant volatility during the latter part of 2014. The price of crude oil has continued to decline in the first part of 2015. If commodity prices remain weak for a sustained period, DCP Midstream’s natural gas throughput and NGL volumes will be negatively impacted, particularly as producers are curtailing or redirecting drilling. Drilling activity levels vary by geographic area, but in general, DCP Midstream has observed decreases in drilling activity with lower commodity prices. Furthermore a sustained decline in commodity prices could result in a decrease in exploration and development activities in the fields served by DCP Midstream's gas gathering and residue gas and NGL pipeline transportation systems, and DCP Midstream's natural gas treating and processing plants, which could lead to reduced utilization of these assets.

The shift to and increase in natural gas supply have resulted in declines in the price of natural gas in North America. As a result, there has been a shift to extracting gas in richer, “wet” gas areas, like the Marcellus shale. This has depressed activity in “dry” fields like the Fayetteville shale where our Ozark gathering and transmission assets are located. As the balance of supply and demand evolves, we expect activity in these areas to push prices higher. However, should the activity in the region continue to decline, our businesses there may be subject to possible impairment. The supply increase has also had a negative impact on the seasonal price spreads historically seen between the summer and winter months. As a result, the value of storage assets and contracts has declined in recent years, negatively impacting the results of our storage facilities. While we expect storage values to stabilize and strengthen in the future, should these market factors continue to keep downward pressure on the seasonality spread and re-contracting, we could be subject to further reduced value and possible impairment of our storage assets.

Our businesses in the United States and Canada are subject to laws and regulations on the federal, state and provincial levels. Regulations applicable to the natural gas transmission, crude oil transportation and storage industries have a significant effect on the nature of the businesses and the manner in which they operate. Changes to regulations are ongoing and we cannot predict the future course of changes in the regulatory environment or the ultimate effect that any future changes will have on our businesses.

These laws and regulations can result in increased capital, operating and other costs. Environmental laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations can require significant expenditures, including expenditures for cleanup costs and damages arising out of contaminated properties. In particular, compliance with major Clean Air Act regulatory programs may cause us to incur significant capital expenditures to obtain permits, evaluate offsite impacts of our operations, install pollution control equipment, and otherwise assure compliance.

Our interstate pipeline operations are subject to pipeline safety laws and regulations administered by PHMSA of the U.S. Department of Transportation. These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. In January 2012, the Pipeline Safety, Regulatory

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Certainty, and Job Creation Act of 2011 was signed into law. This Act amends the Pipeline Safety Act in a number of significant ways, including the assessing of higher penalties for violations.

Many of the changes to the Pipeline Safety Act have been completed, while others are substantially in progress with resolution expected in 2015. Additionally, Congress is tasked with reauthorization of the Pipeline Safety Act during fiscal year 2015. PHMSA is designing an Integrity Verification Process intended to create standards to verify maximum allowable operating pressure, and to improve and expand integrity management processes. There remains uncertainty as to how these standards will be implemented, but it is expected that the changes will impose additional costs on new pipeline projects as well as on existing operations. In this climate of increasingly stringent regulation, pipeline failures or failures to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by PHMSA, which would reduce available capacity on our pipelines. Should any of these risks materialize, it may have an adverse effect on our operations, earnings, financial condition or cash flows.

Additionally, investments and projects located in Canada expose us to risks related to Canadian laws, taxes, economic conditions, fluctuations in currency rates, political conditions and policies of the Canadian government. During the past several years, the Canadian dollar has fluctuated compared to the U.S. dollar, which affected earnings to varying degrees for brief periods. Changes in the exchange rate or any other factors are difficult to predict and may affect our future results.

Certain of our segments’ earnings are affected by fluctuations in commodity prices, especially the earnings of Field Services and our Empress NGL business at Western Canada Transmission & Processing, which are most sensitive to changes in NGL prices. DCP Midstream manages its direct exposure to these market prices separate from Specta Energy, and utilizes various risk management strategies, including the use of commodity derivatives. We evaluate the risks associated with commodity price volatility on an ongoing basis and implemented a commodity hedging program at Western Canada Transmission & Processing’s Empress NGL business effective January 2014. We have elected to not apply cash flow hedge accounting.

Based on current projections, our expected effective income tax rate will approximate 21%–22% for 2015. Our overall expected tax rate largely depends on the proportion of earnings in the United States to the earnings of our Canadian operations. Our earnings in the United States are subject to a combined federal and state statutory tax rate of approximately 37%. Our earnings in Canada are subject to a combined federal and provincial statutory tax rate of approximately 26%, but we anticipate an effective Canadian tax rate of approximately 6% for 2015, driven primarily by the recognition of certain regulatory tax benefits. See “Liquidity and Capital Resources” for further discussion about the tax impact of repatriating funds generated from our Canadian operations to Spectra Energy Corp (the U.S. parent).

Our strategic objectives include a critical focus on capital expansion projects that will require access to capital markets. An inability to access capital at competitive rates could affect our ability to implement our strategy. Market disruptions or a downgrade in our credit ratings may increase the cost of borrowings or affect our ability to access one or more sources of liquidity.

During the past few years, capital expansion projects have been exposed to cost pressures associated with the availability of skilled labor, the pricing of materials and challenges associated with ensuring the protection of our environment and continual safety enhancements to our facilities. We maintain a strong focus on project management activities to address these pressures as we move forward with planned expansion opportunities. Significant cost increases could negatively affect the returns ultimately earned on current and future expansions.

For further information related to management’s assessment of our risk factors, see Part I. Item 1A. Risk Factors.

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RESULTS OF OPERATIONS

	2014	2013	2012
	(in millions)		
Operating revenues	$5,903	$5,518	$5,075
Operating expenses	3,979	3,852	3,500
Operating income	1,924	1,666	1,575
Other income and expenses	420	569	465
Interest expense	679	657	625
Earnings from continuing operations before income taxes	1,665	1,578	1,415
Income tax expense from continuing operations	382	419	370
Income from continuing operations	1,283	1,159	1,045
Income from discontinued operations, net of tax	—	—	2
Net income	1,283	1,159	1,047
Net income—noncontrolling interests	201	121	107
Net income—controlling interests	$1,082	$1,038	$940

2014 Compared to 2013

Operating Revenues. The $385 million, or 7%, increase was driven by:

- revenues from expansion projects primarily at Texas Eastern, the acquisition of Express-Platte in March 2013, higher natural gas transportation revenues due to new contracts and an increase in crude oil transportation revenues for both Express and Platte Pipeline mainly as a result of increased tariff rates and higher volumes, and higher processing revenues, net of lower storage revenues due to lower rates at Spectra Energy Partners,
- higher sales volumes of residual natural gas, non-cash mark-to-market gains associated with the risk management program implemented in early 2014 and higher propane sales prices, net of lower sales volumes of NGLs at the Empress operations, and an increase in gathering and processing revenues at Western Canada Transmission & Processing, and
- higher customer usage of natural gas primarily as a result of colder weather, higher natural gas prices passed through to customers and growth in the number of customers, net of lower storage revenues due to lower prices and 2014 earnings to be shared with customers under the new incentive regulation framework at Distribution, partially offset by
- the effects of a weaker Canadian dollar at Distribution and Western Canada Transmission & Processing.

Operating Expenses. The $127 million, or 3%, increase was driven by:

- increased volumes of natural gas purchases for extraction and make-up, and a non-cash charge to reduce the value of propane inventory to net realizable value at the Empress operations, higher plant turnaround and maintenance costs, and higher plant fuel costs due to higher prices at the Empress operations at Western Canada Transmission & Processing,
- higher volumes of natural gas sold due to colder weather, higher natural gas prices passed through to customers and growth in the number of customers at Distribution, and
- expansion projects, primarily at Texas Eastern, and the acquisition of Express-Platte at Spectra Energy Partners, partially offset by
- the effects of a weaker Canadian dollar at Distribution and Western Canada Transmission & Processing.

Operating Income. The $258 million increase was driven by higher earnings from expansion projects, primarily at Texas Eastern, the acquisition of Express-Platte in March 2013, higher natural gas transportation revenues due to new contracts and an increase in crude oil transportation revenues for both Express and Platte pipelines mainly as a result of increased tariff rates and higher volumes, net of lower storage revenues due to lower rates at Spectra Energy Partners. The increase was also attributable to non-cash mark-to-market gains associated with the risk management program implemented in early 2014 and higher propane prices from the Empress NGL business, and higher gathering and processing revenues, net of higher plant turnaround and maintenance costs at Western Canada Transmission & Processing. Furthermore, the increase reflected higher customer usage primarily as a result of colder weather and increased growth in the number of customers, net of lower storage revenues due to lower prices and 2014 earnings to be shared with customers under the new incentive regulation framework at

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Distribution. These increases were partially offset by the effects of a weaker Canadian dollar at Distribution and Western Canada Transmission & Processing.

Other Income and Expenses. The $149 million decrease was attributable to lower equity earnings from Field Services mainly due to an increase in net income attributable to noncontrolling interests as a result of growth in DCP Partners' operations and the effects of dropdown hedges, lower commodity prices, higher operating costs due to increased spending on reliability programs and growth in operations, losses on sales of assets and a goodwill impairment charge in 2014 compared to gains on sales of assets in 2013 and lower gains associated with the issuance of partnership units by DCP Partners, net of increased gathering and processing margins due to asset growth and higher volumes, favorable results from trading and marketing and DCP Partners' mark-to-market activity. Lower AFUDC due to decreased capital spending at Spectra Energy Partners also contributed to the decrease. These decreases were partially offset by higher earnings from Sand Hills and Southern Hills at Spectra Energy Partners.

Interest Expense. The $22 million increase was mainly due to lower capitalized interest from projects placed in service in 2013 and higher average debt balances, partially offset by a weaker Canadian dollar.

Income Tax Expense from Continuing Operations. The $37 million decrease was mainly due to a lower effective state tax rate in 2014 and the 2013 revaluation of our accumulated deferred state taxes as a result of Spectra Energy's contribution of substantially all of its remaining U.S. transmission, storage and liquids assets to SEP on November 1, 2013 (U.S. Assets Dropdown), partially offset by the reversal of tax reserves in 2013 as a result of favorable Canadian income tax legislation.

The effective tax rate for income from continuing operations was 23% in 2014 compared to 27% in 2013. See Note 6 of Notes to Consolidated Financial Statements for reconciliations of our effective tax rates to the statutory tax rate.

Net Income-Noncontrolling Interests. The $80 million increase was driven by higher earnings from Spectra Energy Partners, partially offset by the effects of a decrease in the average ownership percentage of SEP held by the public, primarily as a result of the issuance of SEP partnership units to Spectra Energy in November 2013 associated with the U.S. Assets Dropdown.

2013 Compared to 2012

Operating Revenues. The $443 million, or 9%, increase was driven by:

- revenues from Express-Platte acquired in March 2013, net of lower recoveries of electric power and other costs passed through to customers, and lower storage revenues at Spectra Energy Partners,
- higher customer usage of natural gas as a result of colder weather, higher natural gas prices passed through to customers, higher distribution rates, an adjustment in 2012 related to an unfavorable OEB decision affecting transportation revenues, and growth in the number of customers, net of lower short-term transportation and storage revenues at Distribution,
- higher revenues from expansion projects at Western Canada Transmission & Processing and Spectra Energy Partners, and
- higher NGL sales prices and volumes at the Empress operations, net of lower contracted volumes in the conventional gathering and processing business at Western Canada Transmission & Processing, partially offset by
- the effects of a weaker Canadian dollar at Western Canada Transmission & Processing and Distribution.

Operating Expenses. The $352 million, or 10%, increase was driven by:

- an increase in volumes of natural gas sold due to colder weather, higher natural gas prices passed through to customers, increased gas purchased due to growth in the number of customers and higher operating fuel costs at Distribution,
- operating costs from Express-Platte, net of lower electric power and other costs passed through to customers at Spectra Energy Partners,
- increased volumes of natural gas purchases for extraction and make-up at the Empress operations, higher depreciation expense from expansion projects, scheduled plant turnarounds in 2013, increased operating costs of new facilities and higher benefit and labor costs, net of lower production costs due primarily to lower extraction premiums and a noncash charge in 2012 to write down propane inventory at the Empress operations, at Western Canada Transmission & Processing, and

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- higher corporate costs driven primarily by transaction costs associated with the U.S. Assets Dropdown and higher employee benefit costs, partially offset by
- the effects of a weaker Canadian dollar at Distribution and Western Canada Transmission & Processing.

Operating Income. The $91 million increase was driven by the acquisition of Express-Platte and Texas Eastern expansion projects at Spectra Energy Partners, and higher NGL earnings at the Empress operations due mainly to lower production costs and higher sales prices, net of lower contracted volumes in the conventional gathering and processing business and higher operating and maintenance costs at Western Canada Transmission & Processing. In addition, higher distribution rates, a 2012 adjustment related to an unfavorable decision by the OEB affecting transportation revenues and colder weather, net of lower transportation and storage revenues at Distribution contributed to the increase in the Operating Income. These increases were partially offset by the effects of a weaker Canadian dollar and higher corporate costs.

Other Income and Expenses. The $104 million increase was attributable to higher equity earnings from Field Services mainly due to the gains associated with the issuance of partnership units by DCP Partners and lower operating costs, partially offset by higher interest expense and the effects of asset dropdowns from DCP Midstream to DCP Partners. The increase was also due to higher AFUDC resulting from increased capital spending on expansion projects at Spectra Energy Partners, partially offset by lower AFUDC at Western Canada Transmission & Processing due to decreased capital spending on expansion projects.

Interest Expense. The $32 million increase was mainly due to higher average debt balances related to the acquisition of Express-Platte, partially offset by a weaker Canadian dollar.

Income Tax Expense from Continuing Operations. The $49 million increase was mainly attributable to higher earnings, the revaluation of accumulated deferred state taxes as a result of the U.S. Assets Dropdown and the non-deductibility of transaction costs, partially offset by favorable enacted Canadian federal income tax legislation and the recognition of certain regulatory tax benefits. The effective tax rate for income from continuing operations was 27% in 2013 compared to 26% in 2012. See Note 6 of Notes to Consolidated Financial Statements for reconciliations of our effective tax rates to the statutory tax rate.

Net Income-Noncontrolling Interests. The $14 million increase was driven by higher earnings from Spectra Energy Partners, the issuances of partnerships units by SEP to the public in 2012 and 2013, and the dropdown of a 38.76% interest in M&N U.S. to SEP in 2012, partially offset by the issuances of partnerships units by SEP to Spectra Energy in November 2013 in association with the U.S. Assets Dropdown.

For a more detailed discussion of earnings drivers, see the segment discussions that follow.

Segment Results

Management evaluates segment performance based on earnings from continuing operations before interest, taxes, and depreciation and amortization (EBITDA) transactions. Cash, cash equivalents and short-term investments are managed at the parent-company levels, so the gains and losses on foreign currency transactions and interest and dividend income are excluded from the segments' EBITDA. We consider segment EBITDA to be a good indicator of each segment's operating performance from its continuing operations, as it represents the results of our operations without regard to financing methods or capital structures. Our segment EBITDA may not be comparable to similarly titled measures of other companies because other companies may not calculate EBITDA in the same manner.

Spectra Energy Partners provides transmission, storage and gathering of natural gas for customers in various regions of the northeastern and southeastern United States and operates a crude oil pipeline system that connects Canadian and U.S. producers to refineries in the U.S. Rocky Mountain and Midwest regions.

Distribution provides retail natural gas distribution services in Ontario, Canada, as well as natural gas transmission and storage services to other utilities and energy market participants.

Western Canada Transmission & Processing provides transmission of natural gas, natural gas gathering and processing services, and NGL extraction, fractionation, transportation, storage and marketing to customers in western Canada, the northern tier of the U.S. and the Maritime Provinces in Canada.

Field Services gathers, compresses, treats, processes, transports, stores and sells natural gas; produces, fractionates, transports, stores and sells NGLs; recovers and sells condensate; and trades and markets natural gas and NGLs. It conducts operations through DCP Midstream, which is owned 50% by us and 50% by Phillips 66. DCP Midstream operates in a diverse number of regions, including the Permian Basin, Eagle Ford, Niobrara/DJ Basin and the Midcontinent. As of December 31,

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2014 DCP Midstream had an approximate 22% ownership interest in DCP Partners, a publicly-traded master limited partnership.

Segment EBITDA is summarized in the following table. Detailed discussions follow.

EBITDA by Business Segment

	2014	2013	2012
	(in millions)		
Spectra Energy Partners	$1,669	$1,433	$1,259
Distribution	552	574	587
Western Canada Transmission & Processing	754	736	694
Field Services	217	343	279
Total reportable segment EBITDA	3,192	3,086	2,819
Other	(58)	(86)	(36)
Total reportable segment and other EBITDA	3,134	3,000	2,783
Depreciation and amortization	796	772	746
Interest expense	679	657	625
Interest income and other	6	7	3
Earnings from continuing operations before income taxes	$1,665	$1,578	$1,415

The amounts discussed below include intercompany transactions that are eliminated in the Consolidated Financial Statements.

Spectra Energy Partners

	2014	2013	Increase (Decrease)	2012	Increase (Decrease)
	(in millions, except where noted)				
Operating revenues	$2,269	$1,965	$304	$1,754	$211
Operating expenses					
Operating, maintenance and other	781	715	66	626	89
Other income and expenses	181	183	(2)	131	52
EBITDA	$1,669	$1,433	$236	$1,259	$174
Express pipeline revenue receipts, MBbl/d (a,b)	223	219	4	N/A	N/A
Platte PADD II deliveries, MBbl/d (b)	170	168	2	N/A	N/A

(a) Thousand barrels per day.

(b) Data includes only activity since March 14, 2013, the date of the acquisition of Express-Platte.

2014 Compared to 2013

Operating Revenues. The $304 million increase was driven by:

- a $168 million increase due to expansion projects, primarily at Texas Eastern,
- a $68 million increase primarily due to the acquisition of Express-Platte in March 2013,
- a $44 million increase due to higher natural gas transportation revenues due to new contracts, mainly at Texas Eastern and Algonquin,
- a $26 million increase in crude oil transportation revenues for both Express and Platte pipelines mainly as a result of increased tariff rates and higher revenue volumes, and
- a $19 million increase due to higher processing revenues mainly due to volume, partially offset by
- a $25 million decrease in gas storage revenues due to lower rates.

Operating, Maintenance and Other. The $66 million increase was driven by:

- a $33 million increase from expansion projects, primarily at Texas Eastern,

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- a $25 million increase due to the acquisition of Express-Platte, and
- a $10 million increase in operating costs mostly due to repairs and maintenance, partially offset by
- an $11 million decrease mostly due to 2013 transaction costs related to the U.S. Assets Dropdown to SEP.

Other Income and Expenses. The $2 million decrease was primarily due to lower AFUDC resulting from decreased capital spending, mostly offset by higher equity earnings due to the continued ramp up of volumes at Sand Hills and Southern Hills.

EBITDA. The $236 million increase was driven by expansions, primarily at Texas Eastern, higher earnings from Sand Hills and Southern Hills, the acquisition of Express-Platte, higher natural gas transportation revenues due to new contracts mainly at Texas Eastern and Algonquin, an increase in crude oil transportation revenues for both Express and Platte pipelines mainly as a result of increased tariff rates and higher revenue volumes, and higher processing revenues, partially offset by lower storage revenues due to lower rates and lower AFUDC due to decreased capital spending.

2013 Compared to 2012

Operating Revenues. The $211 million increase was driven by:

- a $286 million increase due to the acquisition of Express-Platte in March 2013 and expansion projects primarily at Texas Eastern, partially offset by
- a $42 million decrease in recoveries of electric power and other costs passed through to customers,
- a $24 million decrease due to lower storage revenues as a result of lower contract renewal rates, and
- an $8 million decrease from lower processing revenues.

Operating, Maintenance and Other. The $89 million increase was driven by:

- a $115 million increase from the acquisition of Express-Platte and expansion projects primarily at Texas Eastern,
- a $10 million increase due to higher employee benefit costs and ad valorem taxes, net of lower software amortization, and
- a $7 million charge for transaction costs related to the U.S. Assets Dropdown to SEP, partially offset by
- a $42 million decrease in electric power and other costs passed through to customers.

Other Income and Expenses. The $52 million increase was primarily due to higher AFUDC resulting from increased capital spending on expansion projects.

EBITDA. The $174 million increase was driven by the acquisition of Express-Platte and higher earnings from expansions at Texas Eastern, partially offset by lower storage revenues, higher operating costs and lower processing revenues.

Matters Affecting Future Spectra Energy Partners Results

Spectra Energy Partners plans to continue earnings growth through capital efficient projects, such as transportation and storage expansion to support a two-pronged “supply push” / “market pull” strategy, as well as continued focus on optimizing the performance of the existing operations through organizational efficiencies and cost control. “Supply push” is when producers agree to pay to transport specified volumes of natural gas in order to support the construction of new pipelines or the expansion of existing pipelines. “Market pull” is taking gas away from established liquid supply points and building pipeline transportation capacity to satisfy end-user demand in new markets or demand growth in existing markets.

Future earnings growth will be dependent on the success of our expansion plans in both the market and supply areas of the pipeline network, which includes, among other things, shale gas exploration and development areas, the ability to continue renewing service contracts and continued regulatory stability. Natural gas storage prices have recently been challenged as a result of increasing natural gas supply and narrower seasonal price spreads. Gas supply and demand dynamics continue to change as a result of the development of new non-conventional shale gas supplies. The increase in natural gas supply has resulted in declines in the price of natural gas in North America. As a result, there has been a shift to extracting gas in richer, “wet” gas areas, like the Marcellus shale. This has depressed activity in “dry” fields like the Fayetteville shale where our Ozark gathering and transmission assets are located. As the balance of supply and demand evolves, we expect activity in these areas to push prices higher. However, should the activity in the region continue to decline, our businesses there may be subject to possible impairment.

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The supply increase has also had a negative impact on the seasonal price spreads historically seen between the summer and winter months. The value of storage assets and contracts has declined in recent years, negatively affecting the results of our storage facilities. While we expect storage values to stabilize and strengthen in the future, should these market factors continue to keep downward pressure on the seasonality spread and re-contracting, we could be subject to further reduced value and possible impairment of our storage assets.

Spectra Energy Partners plans to continue earnings growth by maximizing throughput on all sections of the pipeline systems. On the Express-Platte system, this entails connecting where possible to rail or barge terminals to extend the market reach of the pipeline to refinery-customers beyond the end of the pipeline. This also includes optimizing pipeline and storage operations and expanding terminal operations where appropriate. On the Southern Hills and Sand Hills NGL pipelines, volumes will continue to increase as NGL supply increases behind the system and new extraction plants are connected to the pipeline. Extensions may be added to the lines and pumps may be added to increase capacity.

Future earnings growth will be dependent on the success in renewing existing contracts or in securing new supply and market for all pipelines. This will require ongoing increases in supply of both crude oil and NGL and continued access to attractive markets. For the NGL pipelines, continued growth is dependent on successful execution of expansion projects to attach new supply.

Spectra Energy Partners interstate pipeline operations are subject to pipeline safety regulations administered by PHMSA of the U.S. Department of Transportation. These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. In January 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 was signed into law. This Act amends the Pipeline Safety Act in a number of significant ways, including the assessing of higher penalties for violations. Many of the changes to the Pipeline Safety Act have been completed, while others are substantially in progress with resolution expected in 2015. Additionally, Congress is tasked with reauthorization of the Pipeline Safety Act during fiscal year 2015. PHMSA is designing an Integrity Verification Process intended to create standards to verify maximum allowable operating pressure, and to improve and expand integrity management processes. There remains uncertainty as to how these standards will be implemented, but it is expected that the changes will impose additional costs on new pipeline projects as well as on existing operations. In this climate of increasingly stringent regulation, pipeline failures or failures to comply with applicable regulations could result in a reduction of allowable operating pressures as authorized by PHMSA, which would reduce available capacity on our pipelines. Should any of these risks materialize, it may have an adverse effect on our operations, earnings, financial condition or cash flows.

Distribution

	2014	2013	Increase (Decrease)	2012	Increase (Decrease)
	(in millions, except where noted)				
Operating revenues	$1,843	$1,848	$(5)	$1,666	$182
Operating expenses					
Natural gas purchased	879	826	53	638	188
Operating, maintenance and other	411	448	(37)	441	7
Other income and expenses	(1)	—	(1)	—	—
EBITDA	$552	$574	$(22)	$587	$(13)
Number of customers, thousands	1,420	1,399	21	1,379	20
Heating degree days, Fahrenheit	8,111	7,540	571	6,385	1,155
Pipeline throughput, TBtu	713	907	(194)	818	89
Canadian dollar exchange rate, average	1.10	1.03	0.07	1.00	0.03

2014 Compared to 2013

Operating Revenues. The $5 million decrease was driven by:

- a $147 million decrease resulting from a weaker Canadian dollar,
- an $8 million decrease in storage revenues primarily due to lower storage prices, and

- a $7 million decrease due to 2014 earnings to be shared with customers under the new incentive regulation framework, partially offset by

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- an $81 million increase in customer usage of natural gas primarily due to weather that was more than 7% colder than in 2013,
- a $34 million increase from higher natural gas prices passed through to customers. Prices charged to customers are adjusted quarterly based on the 12 months New York Mercantile Exchange (NYMEX) forecasts,
- a $34 million increase from growth in the number of customers, and
- a $10 million increase, net of 2012 earnings sharing, as a result of a decision by the OEB in 2014 primarily regarding certain 2012 revenues realized from the optimization of upstream transportation contracts being treated as utility earnings.

Natural Gas Purchased. The $53 million increase was driven by:

- a $65 million increase due to higher volumes of natural gas sold primarily due to colder weather,
- a $34 million increase from higher natural gas prices passed through to customers, and
- a $25 million increase from growth in the number of customers, partially offset by
- a $73 million decrease resulting from a weaker Canadian dollar.

Operating, Maintenance and Other. The $37 million decrease was driven by:

- a $30 million decrease resulting from a weaker Canadian dollar, and
- a $7 million decrease resulting from the deferral of pension expense approved by the OEB for recovery from customers.

EBITDA. The $22 million decrease was largely the result of a weaker Canadian dollar, lower storage revenues and 2014 earnings to be shared with customers under the new incentive regulation framework, partially offset by higher customer usage due to colder weather, increased revenues, net of 2012 earnings sharing, as a result of a decision by the OEB in 2014 primarily regarding certain 2012 revenues realized from the optimization of upstream transportation contracts being treated as utility earnings and increased customer growth.

2013 Compared to 2012

Operating Revenues. The $182 million increase was driven by:

- a $129 million increase in customer usage of natural gas primarily due to weather that was more than 18% colder than 2012,
- a $59 million increase from higher natural gas prices passed through to customers. Prices charged to customers are adjusted quarterly based on the 12 month NYMEX forecast,
- a $41 million increase from higher distribution rates approved by the OEB,
- a $38 million increase due to an adjustment in 2012 as a result of an unexpected decision from the OEB in November 2012 requiring certain revenues realized from the optimization of upstream transportation contracts be refunded to customers, and
- a $36 million increase from growth in the number of customers, partially offset by
- a $55 million decrease resulting from a weaker Canadian dollar,
- a $28 million decrease mainly in short-term transportation revenues due to lower exchange service revenues, net of a settlement received from the termination of a transportation contract,
- a $21 million decrease in storage revenues primarily due to lower prices, and
- a $20 million decrease as a result of the sharing of revenues realized from the optimization of upstream transportation contracts in accordance with an OEB rate order effective January 1, 2013.

Natural Gas Purchased. The $188 million increase was driven by:

- a $103 million increase due to higher volumes of natural gas sold due to colder weather,
- a $59 million increase from higher natural gas prices passed through to customers,
- a $28 million increase from growth in the number of customers, and

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- $15 million increase in operating fuel costs primarily due to gas measurement variances, partially offset by
- $24 million decrease resulting from a weaker Canadian dollar.

Operating, Maintenance and Other. The $7 million increase was driven by:

- $20 million increase primarily driven by higher employee benefit costs, partially offset by
- $14 million decrease resulting from a weaker Canadian dollar.

EBITDA. The $13 million decrease was largely the result of lower transportation and storage revenues, higher employee benefit costs, a weaker Canadian dollar and higher operating fuel costs, partially offset by an increase in distribution rates, an adjustment in 2012 related to an unfavorable decision by the OEB affecting transportation revenues and higher customer usage due to colder weather.

Matters Affecting Future Distribution Results

Distribution plans to continue to expand the Dawn-Parkway transmission system in response to increased customer demand to access new supplies at Dawn. These expansions will consist of both compression and pipeline projects, and will lead to increased earnings. The current 2015 Parkway site and compression expansion is under construction while the 2015 Brantford-Kirkwall pipeline and ancillary facilities are dependent on approval of a third party project, the approval of which is expected in mid 2015. We expect that the long-term demand for natural gas in Ontario will remain relatively stable with continued growth in peak-day demands. Some modest growth driven by low natural gas prices is expected to continue with specific interest coming from communities that are not currently serviced by natural gas, given the significant price advantage relative to their alternative energy options.

Natural gas storage prices have recently been compressed as a result of increasing natural gas supply and narrower seasonal price spreads. Gas supply and demand dynamics continue to change as a result of the development of new unconventional shale gas supplies. These market factors will continue to affect Union Gas' unregulated storage and regulated transportation revenues in the near term. Going forward, Union Gas expects unregulated storage values to stabilize and strengthen.

During the past several years, the Canadian dollar has fluctuated compared to the U.S. dollar, which affected earnings to varying degrees for brief periods. Changes in the exchange rate or any other factors are difficult to predict and may affect future results.

Western Canada Transmission & Processing

	2014	2013	Increase (Decrease)	2012	Increase (Decrease)
	(in millions, except where noted)				
Operating revenues	$1,902	$1,767	$135	$1,679	$88
Operating expenses					
Natural gas and petroleum products purchased	466	391	75	437	(46)
Operating, maintenance and other	687	649	38	585	64
Other income and expenses	5	9	(4)	37	(28)
EBITDA	$754	$736	$18	$694	$42
Pipeline throughput, TBtu	934	780	154	745	35
Volumes processed, TBtu	721	704	17	665	39
Canadian dollar exchange rate, average	1.10	1.03	0.07	1.00	0.03

2014 Compared to 2013

Operating Revenues. The $135 million increase was driven by:

- $112 million increase due primarily to higher sales volumes of residual natural gas at the Empress operations,
- an $85 million increase from non-cash mark-to-market gains associated with the risk management program implemented in early 2014,
- $41 million increase due to higher propane prices associated with the Empress NGL business,

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- a $19 million increase in gathering and processing revenues from new facilities in the Horn River and Montney unconventional development areas,
- a $17 million increase in gathering and processing revenues from existing facilities,
- a $17 million increase from settlement gains associated with the risk management program implemented in early 2014,
- a $13 million increase in transmission revenues due primarily to higher tolls at BC Pipeline,
- an $8 million increase primarily in interruptible transmission revenues due to a new supply source connected to the M&N Canada system, and
- a $6 million increase in carbon and other non-income tax expense recovered from customers, partially offset by
- a $143 million decrease as a result of a weaker Canadian dollar, and
- a $43 million decrease due to lower sales volumes of NGLs from decreased demand in the market at the Empress operations.

Natural Gas and Petroleum Products Purchased. The $75 million increase was driven by:

- a $98 million increase due primarily to higher volumes of natural gas purchases for extraction and make-up at Empress, and
- a $19 million non-cash charge to reduce the value of propane inventory at the Empress operations to net realizable value at December 31, 2014, partially offset by
- a $36 million decrease as a result of a weaker Canadian dollar, and
- an $8 million decrease primarily as a result of lower costs of NGL purchases at the Empress facility.

Operating, Maintenance and Other. The $38 million increase was driven by:

- a $38 million increase in plant turnaround and repair costs,
- a $9 million increase in Empress plant fuel costs due primarily to higher prices,
- an $8 million increase in maintenance expense,
- a $6 million increase primarily in costs passed through to customers at M&N Canada,
- a $6 million increase in carbon and other non-income tax expense,
- a $6 million increase in operating costs of new facilities, and
- a $5 million increase due to software support services, partially offset by
- a $48 million decrease as a result of a weaker Canadian dollar.

Other Income and Expenses. The $4 million decrease was driven primarily by lower AFUDC resulting from decreased capital spending on expansion projects.

EBITDA. The $18 million increase was driven by higher earnings at the Empress NGL business due mainly to non-cash mark-to-market gains associated with the risk management program implemented in early 2014 and higher propane sales prices and higher gathering and processing revenues, partially offset by higher plant turnaround and maintenance expenses and the effect of a weaker Canadian dollar.

2013 Compared to 2012

Operating Revenues. The $88 million increase was driven by:

- a $59 million increase in gathering and processing revenues due primarily to expansion in unconventional areas for Horn River and Montney development,
- a $39 million increase due to higher sales prices associated with the Empress NGL business,
- a $35 million increase due primarily to higher sales volumes of residual natural gas at the Empress operations,
- a $22 million increase in transmission revenues due primarily to expansion on the T-North Pipeline,
- a $17 million increase in NGL sales volumes at Empress,

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- a $9 million increase in carbon and other non-income tax expense recovered from customers, and
- a $9 million increase primarily driven by interruptible transmission revenues and higher 2013 tolls charged to customers at M&N Canada, partially offset by
- a $58 million decrease as a result of a weaker Canadian dollar, and
- a $44 million decrease in conventional gathering and processing revenues due primarily to lower contracted volumes.

Natural Gas and Petroleum Products Purchased. The $46 million decrease was driven by:

- a $53 million decrease as a result of lower production costs for the Empress facility caused primarily by lower extraction premiums,
- a $14 million decrease as a result of a weaker Canadian dollar, and
- a $14 million noncash charge in 2012 to write down propane inventory at the Empress operations, partially offset by
- a $35 million increase in volumes of natural gas purchases for extraction and make-up at Empress.

Operating, Maintenance and Other. The $64 million increase was driven by:

- a $20 million increase due to scheduled plant turnarounds in 2013,
- a $16 million increase due to operating costs of the new facilities at Dawson and Fort Nelson North,
- a $14 million increase due to higher benefit and labor costs,
- a $12 million increase primarily in costs passed through to customers at M&N Canada,
- a $9 million increase in carbon and other non-income tax expense, and
- a $6 million increase in Empress plant fuel and electricity costs due to higher prices, partially offset by
- a $21 million decrease as a result of a weaker Canadian dollar.

Other Income and Expenses. The $28 million decrease was driven primarily by lower AFUDC resulting from decreased capital spending on expansion projects.

EBITDA. The $42 million increase was driven by higher earnings at the Empress NGL business due mainly to lower production costs and higher sales prices, and earnings from expansions, partially offset by lower contracted volumes in the conventional gathering and processing business, higher operating and maintenance costs and the effect of a weaker Canadian dollar.

Matters Affecting Future Western Canada Transmission & Processing Results

Western Canada Transmission & Processing plans to continue earnings growth through capital efficient “supply push” and “demand pull” initiatives. “Supply push” growth projects are associated with gathering and processing expansions and incremental transportation capacity to support drilling activity in northern British Columbia. “Demand pull” growth projects are associated with both small and large scale LNG exports as well as new natural gas-fired electricity generation, methanol, and fertilizer plants in British Columbia and the Pacific Northwest. Earnings can fluctuate from period to period as a result of the timing of processing plant turnarounds that reduce revenues while a plant is out of service and increase operating costs as a result of the turnaround maintenance work. Western Canada Transmission & Processing’s processing plants are generally scheduled for turnaround work every three to four years, with the work being staggered to prevent significant outages at any given time in a single geographic area. Future earnings will also be affected by the ability to renew service contracts and regulatory stability. Earnings from processing services will be affected by the ability to access additional natural gas reserves. In addition, the Empress NGL business will be affected by NGL prices, gas flows eastbound beyond Empress and costs of acquiring natural gas, NGL extraction rights and NGLs.

During the past several years, the Canadian dollar has fluctuated compared to the U.S. dollar, which affected earnings to varying degrees for brief periods. Changes in the exchange rate are difficult to predict and may affect future results.

In certain areas of Western Canada Transmission & Processing’s operations, lower natural gas prices resulting from increasing North American gas production have reduced producer demand for both expansions of the British Columbia gas processing plants as well as renewals of existing gas processing contracts, and could continue to do so as long as gas prices remain below historical norms.

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Field Services

	2014	2013	Increase (Decrease)	2012	Increase (Decrease)
	(in millions, except where noted)				
Equity in earnings of unconsolidated affiliates	$217	$343	$(126)	$279	$64
EBITDA	$217	$343	$(126)	$279	$64
Natural gas gathered and processed/transported, TBtu/d (a,b)	7.3	7.1	0.2	7.1	—
NGL production, MBbl/d (a)	454	426	28	402	24
Average natural gas price per MMBtu (c,d)	$4.41	$3.65	$0.76	$2.79	$0.86
Average NGL price per gallon (e)	$0.89	$0.90	$(0.01)	$0.82	$0.08
Average crude oil price per barrel (f)	$93.06	$98.04	$(4.98)	$94.16	$3.88

(a) Reflects 100% of volumes.
(b) Trillion British thermal units per day.
(c) Average price based on NYMEX Henry Hub.
(d) Million British thermal units.
(e) Does not reflect results of commodity hedges. 2013 NGL prices have been revised to reflect the impact of ethane rejection.
(f) Average price based on NYMEX calendar month.

2014 Compared to 2013

EBITDA. Lower equity earnings of $126 million were mainly the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

- a $78 million decrease resulting from increased net income attributable to noncontrolling interests as a result of growth in DCP Partners' operations, as well as the effects of dropdown hedges,
- a $45 million decrease from commodity-sensitive processing arrangements, due to the impact of higher transportation and fractionation costs on our realized prices and decreased crude oil prices, partially offset by increased natural gas prices,
- a $43 million decrease primarily attributable to higher operating expenses as a result of increased spending on reliability programs, as well as growth in Field Services' operations,
- a $26 million decrease primarily as a result of losses on sales of assets and a goodwill impairment charge in 2014 compared to gains on sales of assets in 2013,
- a $25 million decrease in gains associated with issuances of partnership units by DCP Partners in 2014 compared to 2013,
- a $19 million decrease mainly due to higher interest expense as a result of higher interest rates from newly issued debt and lower capitalized interest on certain projects which were placed in service in 2013, and
- a $17 million decrease primarily attributable to higher depreciation expense as a result of growth in Field Services' business, partially offset by
- an $83 million increase in gathering and processing margins as a result of asset growth and higher volumes in certain of our geographic regions, and
- a $43 million increase as a result of DCP Partners' favorable results from third-party mark-to-market on derivative instruments used to mitigate a portion of its expected commodity cash flow risk, favorable results from Sand Hills and Southern Hills, and favorable results from NGL trading and gas marketing, partially offset by unfavorable results from wholesale propane.

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2013 Compared to 2012

EBITDA. Higher equity earnings of $64 million were mainly the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

- a $62 million increase in gains associated with the issuance of partnership units by DCP Partners in 2013 compared to 2012,
- a $13 million increase primarily attributable to lower operating costs as a result of a cost reduction initiative and lower benefit costs,
- a $10 million increase due to gains from sales of assets,
- a $12 million increase attributable to the favorable results from NGL trading, and
- a $9 million increase from commodity-sensitive processing arrangements due to higher natural gas and crude oil prices, net of lower NGL prices, partially offset by
- a $26 million decrease primarily attributable to higher interest expense due to higher interest rates as a result of newly issued debt and lower capitalized interest on certain projects which were placed in service in 2013, and
- a $15 million decrease primarily attributable to incremental dropdowns to DCP Partners, which increased net income attributable to noncontrolling interests.

Supplemental Data

Below is supplemental information for DCP Midstream’s operating results (presented at 100%):

	2014	2013	2012
	(in millions)		
Operating revenues	$14,013	$12,038	$10,171
Operating expenses	13,262	11,230	9,427
Operating income	751	808	744
Other income and expenses	83	35	34
Interest expense, net	287	249	193
Income tax expense	11	10	2
Net income	536	584	583
Net income—noncontrolling interests	248	93	97
Net income attributable to members’ interests	$288	$491	$486

Matters Affecting Future Field Services Results

The oil and gas industry is cyclical, with the operating results of companies in the industry significantly affected by the drilling activity, which may be impacted by prevailing commodity prices. DCP Midstream’s business has commodity price exposure as a result of being compensated for certain services in the form of commodities rather than cash. Commodity prices have declined substantially, and experienced significant volatility during the latter part of 2014. The price of crude oil has continued to decline in the first part of 2015. If commodity prices remain weak for a sustained period, DCP Midstream’s natural gas throughput and NGL volumes will be negatively impacted, particularly as producers are curtailing or redirecting drilling. Drilling activity levels vary by geographic area, but in general, DCP Midstream has observed decreases in drilling activity with lower commodity prices. Furthermore a sustained decline in commodity prices could result in a decrease in exploration and development activities in the fields served by DCP Midstream's gas gathering and residue gas and NGL pipeline transportation systems, and DCP Midstream's natural gas treating and processing plants, which could lead to reduced utilization of these assets. Despite recent short-term weakness, DCP Midstream’s long-term view is that commodity prices will be at levels that DCP Midstream believes will support continued growth in natural gas, condensate and NGL production. DCP Midstream believes that future commodity prices will be influenced by North American supply deliverability, the severity of winter and summer weather, the level of North American production and drilling activity by exploration and production companies and balance of trade between imports and exports of LNG and NGLs. NGL prices are impacted by the demand from petrochemical and refining industries and export facilities. The petrochemical industry is making significant investment in building or expanding facilities to convert chemical plants from a heavier oil-based feedstock to lighter NGL-based feedstocks, including ethane. This increased demand in future years as such facilities come into service should provide support for the increasing supply of ethane. Prior to those facilities commencing operations ethane prices could remain weak with supply in excess of demand. In addition, export facilities are being expanded or built, which provide support for the increasing supply of NGLs.

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Although there can be, and has been, near-term volatility in NGL prices, longer term DCP Midstream believes that there will be sufficient demand in NGLs to support increasing supply.

Other

	2014	2013	Increase (Decrease)	2012	Increase (Decrease)
	(in millions)				
Operating revenues	$72	$72	$—	$89	$(17)
Operating expenses					
Operating, maintenance and other	141	185	(44)	140	45
Other income and expenses	11	27	(16)	15	12
EBITDA	$(58)	$(86)	$28	$(36)	$(50)

2014 Compared to 2013

EBITDA. The $28 million increase reflects lower transaction costs associated with the U.S. Assets Dropdown and lower employee benefit costs, partially offset by a 2013 benefit from the reversal of an uncertain tax position related to matters prior to the spin-off of Spectra Energy in 2007.

2013 Compared to 2012

EBITDA. The $50 million decrease was driven mainly by transaction costs associated with the U.S. Assets Dropdown, higher employee benefit costs, and a 2012 gain related to an early termination notice by Westcoast for capacity contracts held on Vector Pipeline, partially offset by a reversal of an uncertain tax position related to matters prior to the spin-off of Spectra Energy in 2007.

Matters Affecting Future Other Results

Future results will continue to include corporate and business services we provide for our operations, and will also include operating costs and self-insured losses associated with our captive insurance entities. The results for Other could be affected by the number and severity of insured property losses.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The application of accounting policies and estimates is an important process that continues to evolve as our operations change and accounting guidance is issued. We have identified a number of critical accounting policies and estimates that require the use of significant estimates and judgments.

We base our estimates and judgments on historical experience and on other assumptions that we believe are reasonable at the time of application. These estimates and judgments may change as time passes and more information becomes available. If estimates are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. We discuss our critical accounting policies and estimates and other significant accounting policies with our Audit Committee.

Regulatory Accounting

We account for certain of our operations under accounting for regulated entities. As a result, we record assets and liabilities that result from the regulated ratemaking process that may not be recorded under generally accepted accounting principles for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers or for instances where the regulator provides current rates that are intended to recover costs that are expected to be incurred in the future. We continually assess whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Based on this assessment, we believe our existing regulatory assets, which primarily relate to the future collection of deferred income tax costs for our Canadian regulated operations, are probable of recovery. This assessment reflects the current political and regulatory climate at the state, provincial and federal levels, and is subject to change in the future. If future recovery of costs ceases to be probable, regulatory asset write-offs would be required. Additionally, regulatory agencies can provide flexibility in the manner and timing of the depreciation of property, plant and equipment and amortization of regulatory assets. Total regulatory assets were $1,494 million as of December 31, 2014 and $1,376 million as of December 31, 2013. Total regulatory liabilities were $430 million as of December 31, 2014 and $502 million as of December 31, 2013.

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Impairment of Goodwill

We had goodwill balances of $4,714 million at December 31, 2014 and $4,810 million at December 31, 2013. The decrease in goodwill in 2014 was the result of foreign currency translation, partially offset by an adjustment related to the acquisition of Express-Platte. See Note 3 of Notes to Consolidated Financial Statements for further discussion.

The majority of our goodwill relates to the acquisition of Westcoast in 2002, which owns substantially all of our Canadian operations. As of the acquisition date or upon a change in reporting units, we allocate goodwill to a reporting unit, which we define as an operating segment or one level below an operating segment.

As permitted under the accounting guidance on testing goodwill for impairment, we perform either a qualitative assessment or a quantitative assessment of each of our reporting units based on management's judgment. With respect to our qualitative assessments, we consider events and circumstances specific to us, such as macroeconomic conditions, industry and market considerations, cost factors and overall financial performance, when evaluating whether it is more likely than not that the fair values of our reporting units are less than their respective carrying amounts.

In connection with our quantitative assessments, we primarily use a discounted cash flow analysis to determine fair values of those reporting units. The long-term growth rates used for the reporting units that we quantitatively assess reflect continued expansion of our assets, driven by new natural gas supplies such as shale gas in North America and increasing demand for natural gas transmission capacity on our pipeline systems primarily as a result of forecasted growth in natural gas-fired power plants and increasing demand for crude oil and NGL transportation capacity on our pipeline systems. For our regulated businesses in Canada, if an increase in the cost of capital occurred, we assumed that the effect on the corresponding reporting unit's fair value would be ultimately offset by a similar increase in the reporting unit's regulated revenues since those rates include a component that is based on the reporting unit's cost of capital.

We performed a qualitative assessment for all of our reporting units to determine whether it is more likely than not that the respective fair values of these reporting units are less than their carrying amounts, including goodwill as of April 1, 2014 (our annual testing date). Based on that assessment, we determined that this condition, for all reporting units, does not exist. As such, performing the first step of the two-step impairment test for these reporting units was unnecessary. No triggering events occurred during the period from April 1, 2014 through December 31, 2014 that warranted re-testing for goodwill impairment.

Revenue Recognition

Revenues from the transmission, storage, processing, distribution and sales of natural gas, from the transportation and storage of crude oil, and from the sales of NGLs, are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month. These estimates are generally based on contract data, regulatory information, estimated distribution usage based on historical data adjusted for heating degree days, commodity prices and preliminary throughput and allocation measurements. Final bills for the current month are billed and collected in the following month. Differences between actual and estimated unbilled revenues are immaterial.

Pension and Other Post-Retirement Benefits

The calculations of pension and other post-retirement expense and liabilities require the use of numerous assumptions. Changes in these assumptions can result in different reported expense and liability amounts, and future actual demographic and economic outcomes can differ from the assumptions. We believe that the most critical assumptions used in the accounting for pension and other post-retirement benefits are the expected long-term rate of return on plan assets, the assumed discount rate, and the medical and prescription drug cost trend rate assumptions.

Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in our pension and post-retirement plans will impact future pension expense and funding.

The expected return on plan assets is important, as certain of our pension and other post-retirement benefit plans are partially funded. Expected long-term rates of return on plan assets are developed by using a weighted average of expected returns for each asset class to which the plan assets are allocated. For 2014, the assumed average return was 8.00% for the U.S. pension plan assets, 7.40% for the Canadian pension plan assets and 6.98% for the U.S. other post-retirement benefit assets. A change in the rate of return of 25 basis points for these assets would impact annual benefit expense by approximately $1 million before tax for U.S. plans, and by approximately $3 million before tax for Canadian plans. The Canadian other post-retirement benefit plans are not funded.

Since pension and other post-retirement benefit cost and obligations are measured on a discounted basis, the net periodic benefit cost and benefit obligation discount rates are significant assumptions. Discount rates used for our defined benefit and other post-retirement benefit plans are based on the yields constructed from a portfolio of high-quality bonds for which the timing and amount of cash outflows approximate the estimated payouts of the plans. Discount rates of 4.35% for the U.S. plans and 4.80% for the Canadian plans were used to calculate the 2014 net periodic benefit cost, and represent a weighted average of the applicable rates for all U.S. and Canadian plans, respectively. A 25 basis-point change in the discount rates would impact annual before-tax net periodic benefit cost by less than $1 million for U.S. plans and $4 million for Canadian plans. Discount rates of 4.09% for the U.S. plans and 4.00% for the Canadian plans were used to calculate the 2014 year-end benefit obligations and represent a weighted average of the applicable rates for all U.S. and Canadian plans, respectively. The weighted average discount rates used to determine the benefit obligation decreased approximately 0.26% for the U.S. plans and approximately 0.80% for the Canadian plans during 2014. The decrease to the benefit obligation discount rates resulted in an increase in benefit liabilities at December 31, 2014 compared to December 31, 2013.

See Note 25 of Notes to Consolidated Financial Statements for more information on pension and other post-retirement benefits.

LIQUIDITY AND CAPITAL RESOURCES

Known Trends and Uncertainties

As of December 31, 2014, we had negative working capital of $1,477 million. This balance includes commercial paper liabilities totaling $1,583 million and current maturities of long-term debt of $327 million. We will rely upon cash flows from operations and various financing transactions, which may include debt and/or equity issuances, to fund our liquidity and capital requirements for 2015. SEP is expected to be self-funding through its cash flows from operations, use of its revolving credit facility and its access to capital markets. We receive cash distributions from SEP in accordance with the partnership agreement, which considers our level of ownership and incentive distribution rights.

As of December 31, 2014, our four revolving credit facilities consisted of Spectra Capital's $1.0 billion facility, SEP's $2.0 billion facility, Westcoast's 400 million Canadian dollar facility and Union Gas' 500 million Canadian dollar facility. These facilities are used principally as back-stops for commercial paper programs. At Spectra Capital, SEP and Westcoast, we primarily use commercial paper for temporary funding of capital expenditures. At Union Gas, we primarily use commercial paper to support short-term working capital fluctuations. We also utilize commercial paper, other variable-rate debt and interest rate swaps to achieve our desired mix of fixed and variable-rate debt. See Note 16 of Notes to Consolidated Financial Statements for a discussion of available credit facilities and Financing Cash Flows and Liquidity for a discussion of effective shelf registrations.

Our consolidated capital structure includes commercial paper, long-term debt (including current maturities), preferred stock of subsidiaries and total equity. As of December 31, 2014, our capital structure was 58% debt, 33% common equity of controlling interests and 9% noncontrolling interests and preferred stock of subsidiaries.

Cash flows from operations for our 100%-owned and majority-owned businesses are fairly stable given that approximately 90% of revenues are derived from fee-based services, of which most are regulated. However, total operating cash flows are subject to a number of factors, including, but not limited to, earnings sensitivities to weather, commodity prices, distributions from our equity affiliates, including DCP Midstream and Gulfstream, and the timing of cost recoveries pursuant to regulatory approvals. See Part I. Item 1A. Risk Factors for further discussion.

Cash distributions from our equity affiliate, DCP Midstream, can fluctuate, mostly as a result of earnings sensitivities to commodity prices, as well as its level of capital expenditures and other investing activities. DCP Midstream funds its operations and investing activities mostly from its operating cash flows, third-party debt and equity transactions associated with DCP Partners. DCP Midstream is required to make quarterly tax distributions to us based on allocated taxable income. In addition to tax distributions, periodic distributions are determined by DCP Midstream's board of directors based on its earnings, operating cash flows and other factors, including capital expenditures and other investing activities, commodity prices outlook and the credit environment. We received total tax and periodic distributions from DCP Midstream of $237 million in 2014, $215 million in 2013 and $203 million in 2012. These distributions are classified within Operating Cash Flows. We continue to assess the effect of lower commodity prices and other activities at DCP Midstream on cash expected to be received from DCP Midstream and adjust our expansion or other activities as necessary.

In addition, cash flows from our Canadian operations are generally used to fund the ongoing Canadian businesses and future Canadian growth. At December 31, 2014, $160 million of Cash and Cash Equivalents was held by our Canadian subsidiaries. Historically, we have reinvested a substantial portion of our Canadian operations' earnings in Canada. Earnings not needed by our Canadian operations have been distributed to Spectra Energy Corp (the U.S. parent) with minimal incremental U.S. tax liability. We anticipate continued substantial reinvestment of our future Canadian earnings in Canada; however, future distributions to Spectra Energy Corp may incur incremental U.S. tax at the U.S. statutory rate without the

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ability to use foreign tax credits. The timing of when distributions may incur such incremental U.S. tax depends on many factors, such as the amount of future capital expansions in Canada, the tax characterization of our distributions as returns of capital or dividends, the impacts of tax planning on merger and acquisition activities and tax legislation at the time of the distributions.

As we execute on our strategic objectives around organic growth and expansion projects, expansion expenditures are expected to approximate $2.7 billion in 2015 and will continue to average approximately $2.8 billion through 2016. The timing and extent of these expenditures are likely to vary significantly from year to year, depending mostly on general economic conditions and market requirements. Given that we expect to continue to pursue expansion and earnings growth opportunities over the next several years and also given the scheduled maturities of our existing debt instruments, capital resources will continue to include long-term borrowings and possibly securing additional sources of capital including debt and/or equity securities. We remain committed to maintaining a capital structure and liquidity profile that continue to support an investment-grade credit rating.

Cash Flow Analysis

The following table summarizes the changes in cash flows for each of the periods presented:

	Years Ended December 31,		
	2014	2013	2012
	(in millions)		
Net cash provided by (used in):			
Operating activities	$2,221	$2,030	$1,938
Investing activities	(2,003)	(3,236)	(2,674)
Financing activities	(199)	1,316	654
Effect of exchange rate changes on cash	(5)	(3)	2
Net increase (decrease) in cash and cash equivalents	14	107	(80)
Cash and cash equivalents at beginning of the period	201	94	174
Cash and cash equivalents at end of the period	$215	$201	$94

Operating Cash Flows

Net cash provided by operating activities increased $191 million to $2,221 million in 2014 compared to 2013. This change was driven mostly by:

- higher earnings, and
- distributions from unconsolidated affiliates, partially offset by
- changes in working capital.

Net cash provided by operating activities increased $92 million to $2,030 million in 2013 compared to 2012. This change was driven mostly by:

- lower net tax payments in 2013, partially offset by
- changes in working capital.

Investing Cash Flows

Net cash flows used in investing activities decreased $1,233 million to $2,003 million in 2014 compared to 2013. This change was driven mostly by:

- a $1,254 million net cash outlay for the acquisition of Express-Platte in March 2013, and
- a $179 million increase in distributions from unconsolidated affiliates in 2014, comprised mostly of a $200 million distribution from SESH with proceeds from a SESH debt offering, partially offset by
- $6 million of net purchases of available-for-sale securities in 2014 compared to $146 million of net proceeds in 2013, and
- a $28 million increase in capital and investment expenditures in 2014. Capital and investment expenditures include a $189 million investment in SESH, used by SESH to retire debt.

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Net cash flows used in investing activities increased $562 million to $3,236 million in 2013 compared to 2012. This change was driven mostly by:

- a $1,254 million net cash outlay for the acquisition of Express-Platte, partially offset by
- $513 million of initial and subsequent investments in Sand Hills and Southern Hills in 2012 compared to investments of $267 million in 2013, and
- $146 million of net proceeds of available-for-sale securities in 2013 compared to $130 million of net purchases in 2012.

Capital and Investment Expenditures by Business Segment

Capital and investment expenditures are detailed by business segment in the following table. Capital and investment expenditures presented below include expenditures from both continuing and discontinued operations.

	Years Ended December 31,		
	2014	2013	2012
	(in millions)		
Spectra Energy Partners (a,b)	$1,241	$1,299	$1,443
Distribution	427	357	276
Western Canada Transmission & Processing	473	561	760
Total reportable segments	2,141	2,217	2,479
Other	146	42	66
Total consolidated	$2,287	$2,259	$2,545

(a) Excludes the $1,254 million net cash outlay for the acquisition of Express-Platte in March 2013 and $30 million paid in 2012 for amounts previously withheld from the purchase price consideration of the acquisition of Bobcat in 2010. See Note 3 of Notes to Consolidated Financial Statements for further discussions.

(b) Excludes a $71 million loan to an unconsolidated affiliate in 2013.

In March 2013, we acquired Express-Platte for $1.5 billion, consisting of $1.25 billion in cash and $260 million of acquired debt, before working capital adjustments. The acquisition was primarily funded through the issuance of stock in 2012
and debt. See Note 3 of Notes to Consolidated Financial Statements for further discussion of the acquisition of Express-Platte.

Capital and investment expenditures for 2014 totaled $2,287 million and included $1,358 million for expansion projects, $740 million for maintenance and other projects and a $189 million investment in SESH ($94 million at Spectra Energy Partners and $95 million at "Other"). SESH used the funds, along with its funds received from its other partners, to retire maturing debt.

We project 2015 capital and investment expenditures of approximately $3.4 billion, consisting of approximately $2.4 billion for Spectra Energy Partners, $0.6 billion for Distribution and $0.4 billion for Western Canada Transmission & Processing. Total projected 2015 capital and investment expenditures include approximately $2.7 billion of expansion capital expenditures and $0.7 billion for maintenance and upgrades of existing plants, pipelines and infrastructure to serve growth.

Capital expansion projects are developed and executed using results-proven project management processes. We evaluate the strategic fit and commercial and execution risks, and continuously measure performance compared to plan. Ongoing communications between project teams and senior leadership ensure we maintain the right focus and deliver the expected results.

Expansion capital expenditures included several key projects placed into service in 2014, including:

- North Montney Development - 211 MMcf/d of new gathering and processing service and 159 MMcf/d of renewed gathering and processing service. The project includes various processing plant modifications, including reactivation of the existing Aitken Creek plant. This project was placed in-service during the first quarter of 2014.
- Buffalo Terminal Expansion - Buffalo expansion consists of two additional 150,000 bbl above ground storage tanks along with delivery pump and piping facilities to supply crude oil to the Cenex Harvest States Front Range pipeline.

This project was placed in-service during the third quarter of 2014.

- TEAM 2014 - A 600 MMcf/d expansion of the Texas Eastern pipeline system consisting of new pipeline construction. The project is designed to transport gas produced in the Marcellus Shale to U.S. markets in the Northeast, Midwest and Gulf Coast. This project was placed in-service during the fourth quarter of 2014.

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- Bobcat Storage Expansion - The project as a whole is designed to expand the storage capacity and capabilities of the Bobcat facility. Cavern Well 4 increases the working gas capacity by 9.9 Bcf, and was placed in-service during the fourth quarter of 2014.
- Kingsport - An additional 61 MMcf/d on the East Tennessee system to support a customer's multi-year project to convert five coal-fired power plant boilers to natural gas. The project was placed in-service during the fourth quarter of 2014.

Significant 2015 expansion projects expenditures are expected to include:

- Dawn-Parkway 2015 - A 681 MMcfd expansion of the Dawn-Parkway transmission system consisting of the Parkway West project which includes the development of a new Greenfield compressor site west of Toronto and the installation of a new compressor and associated infrastructure; the Parkway D compressor unit and the Brantford-Kirkwall NPS 48 pipeline loop.
- OPEN - A 550 MMcf/d expansion of the Texas Eastern pipeline system consisting of new pipeline, a new compressor station and other associated facility upgrades. The project is designed to transport gas produced in the Utica Shale and Marcellus Shale to U.S. markets in the Midwest, Southeast and Gulf Coast. In-service is scheduled by the fourth quarter of 2015.
- AIM - A 342 MMcf/d expansion of the Algonquin system consisting of replacement pipeline, new pipeline, new and modified meter station facilities and additional compression at existing stations. The project is designed to transport gas from existing interconnects in New Jersey and New York to LDC markets in the northeast. In-service is scheduled by the fourth quarter of 2016.
- Gulf Market Expansion - This Texas Eastern system expansion project connects growth markets (Gulf Coast LNG and industrials) with diverse, growing shale supply. The project consists of installing up to seven compressor stations to provide up to 650 MMcf/d. The project will be executed in two phases. Phase 1, due to go in-service in the fourth quarter of 2016, will provide north to south compression at five stations. Phase 2 due to go in-service in the fourth quarter of 2017 will provide north to south compression at two stations.
- Sabal Trail - 1,100 MMcf/d of new capacity to access onshore shale gas supplies. Facilities include a new 465-mile pipeline, laterals and various compressor stations. In-service is scheduled by the second quarter of 2017.
- Salem Lateral - An expansion of the Algonquin system for delivery of 115 MMcf/d of natural gas to the Footprint Salem Harbor Power Station in Salem, Massachusetts. In-service is scheduled by the first quarter 2016.
- Uniontown to Gas City - The project will provide shippers with 425 MMcf/d of firm transportation service from the supply-rich area west of Uniontown, Pennsylvania to a new delivery meter with Panhandle Eastern Pipe Line near Gas City, Indiana for further redelivery to markets in the Midwest. These five shippers combine to contract for the full 425 MMcf/d of capacity under the project. In-service is scheduled by the fourth quarter of 2015.
- DCP Sand Hills - Red Lake - The project includes the construction of two lateral pipelines with a combined length of 170 miles to connect a DCP gas processing plant and two third-party gas processing plants to the Sand Hills Pipeline. The project extends the reach of the Sand Hills Pipeline into a fast growing region of the Permian basin and enhances long-term throughput on the pipeline. It is expected to be in-service in the second half of 2015.
- Ozark Conversion - The project includes abandonment of portions of the Ozark Gas Transmission system from natural gas service and leasing of the abandoned lines to Magellan to transport approximately 75,000 Bbls/d of refined products. In-service is scheduled by the third quarter of 2015.

Financing Cash Flows and Liquidity

Net cash used in financing activities totaled $199 million in 2014 compared to $1,316 million provided by financing activities in 2013. This $1,515 million change was driven mostly by:

- $156 million of net redemptions of long-term debt in 2014 compared to $2,233 million of net issuances in 2013 which were mostly used to fund the acquisition of Express-Platte and the U.S. Assets Dropdown, partially offset by
- $574 million of net commercial paper issuances in 2014 compared to $206 million of net commercial paper repayments in 2013,
- $327 million in proceeds from SEP's at-the-market program in 2014 compared to $214 million in proceeds from SEP's issuance of units in 2013, and

- $145 million of contributions from noncontrolling interest in 2014 compared to $23 million in 2013.

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Net cash provided by financing activities increased $662 million to $1,316 million in 2013 compared to 2012. This change was driven mostly by:

- a $1,457 million net increase in long-term debt issuances in 2013 compared to 2012, mostly used to fund the acquisition of Express-Platte and the U.S. Assets Dropdown, partially offset by
- $206 million of net repayments of commercial paper in 2013 compared to $199 million of proceeds from commercial paper in 2012, and
- proceeds of $382 million from the issuance of Spectra Energy common stock in 2012.

Significant Financing Activities—2014

Debt Issuances. The following long-term debt issuances were completed during 2014 as part of our overall financing plan to fund capital expenditures, to refinance maturing debt obligations and for other corporate purposes:

	Amount (in millions)		Interest Rate	Due Date
Spectra Capital	$ 300		variable	2018
Westcoast	316	(a)	3.43 %	2024
Union Gas	229	(a)	4.20 %	2044
Union Gas	183	(a)	2.76 %	2021

(a) U.S. dollar equivalent at time of issuance.

In November 2013, SEP entered into an equity distribution agreement under which it may sell and issue common units up to an aggregate amount of $400 million. This at-the-market offering program allows SEP to offer and sell its common units, representing limited partner interests, at prices it deems appropriate through a sales agent. Sales of common units, if any, will be made by means of ordinary brokers' transactions on the NYSE, in block transactions, or as otherwise agreed to between SEP and the sales agent.

SEP issued 6.4 million limited partner units to the public in 2014 under its at-the-market program and 132,000 general partner units to Spectra Energy. Total net proceeds to SEP were $334 million (net proceeds to Spectra Energy were $327 million). The net proceeds were used for SEP's general partnership purposes, which may have included debt repayments, future acquisitions, capital expenditures and/or additions to working capital. In 2015 through the date of this report, SEP has issued 184,000 common units to the public and 4,000 general partner units to Spectra Energy, for total net proceeds to SEP of $10 million (net proceeds to Spectra Energy were $10 million).

Significant Financing Activities—2013

Debt Issuances. The following long-term debt issuances were completed during 2013:

	Amount (in millions)		Interest Rate	Due Date
Spectra Capital	$ 1,200	(a)	variable	N/A
Spectra Capital	650		3.30 %	2023
SEP	1,000		4.75 %	2024
SEP	500		2.95 %	2018
SEP	400		5.95 %	2043
SEP	400		variable	2018
Union Gas	237	(b)	3.79 %	2023

(a) Repaid in the fourth quarter of 2013.
(b) U.S. dollar equivalent at time of issuance.

SEP Common Unit Issuances. SEP issued 0.6 million common units to the public in 2013 under its at-the-market program, for total net proceeds of $24 million.

In April 2013, SEP issued 5.2 million common units to the public, representing limited partner interests, and 0.1 million general partner units to Spectra Energy. Total net proceeds to SEP were $193 million (net proceeds to Spectra Energy were $190 million). Net proceeds to SEP were temporarily invested in restricted available-for-sale securities until the Express-Platte

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dropdown, at which time the funds were partially used to pay for a portion of the transaction. See Note 2 of Notes to Consolidated Financial Statements for a discussion of the Express-Platte transaction with SEP.

Significant Financing Activities—2012

Debt Issuances. The following long-term debt issuances were completed during 2012:

	Amount (in millions)		Interest Rate		Due Date
Algonquin	$350		3.51	%	2024
Texas Eastern	500		2.80	%	2022
East Tennessee	200		3.10	%	2024
Westcoast	251	(a)	3.12	%	2022

(a) U.S. dollar equivalent at time of issuance.

Spectra Energy Common Stock Issuances. In 2012, Spectra Energy issued 14.7 million common shares to the public. Total net proceeds to Spectra Energy were $382 million, used to fund acquisitions and capital expenditures and for other general corporate purposes.

SEP Common Unit Issuances. In 2012, SEP issued 5.5 million common units to the public, representing limited partner interests, and 0.1 million general partner units to Spectra Energy. Total net proceeds to SEP were $148 million (net proceeds to Spectra Energy were $145 million) and were restricted for the purpose of funding SEP's capital expenditures and acquisitions.

Available Credit Facilities and Restrictive Debt Covenants

	Expiration Date	Total Credit Facilities Capacity	Commercial Paper Outstanding at December 31, 2014	Available Credit Facilities Capacity
		(in millions)		
Spectra Capital (a)	2019	$1,000	$398	$602
SEP (b)	2019	2,000	907	1,093
Westcoast (c)	2019	344	46	298
Union Gas (d)	2019	430	232	198
Total		$3,774	$1,583	$2,191

(a) Revolving credit facility contains a covenant requiring the Spectra Energy Corp consolidated debt-to-total capitalization ratio, as defined in the agreement, to not exceed 65%. Per the terms of the agreement, collateralized debt is excluded from the calculation of the ratio. This ratio was 58% at December 31, 2014.

(b) Revolving credit facility contains a covenant that requires SEP to maintain a ratio of total Consolidated Indebtedness-to-Consolidated EBITDA, as defined in the agreement, of 5.0 to 1 or less. As of December 31, 2014, this ratio was 3.7 to 1.

(c) U.S. dollar equivalent at December 31, 2014. The revolving credit facility is 400 million Canadian dollars and contains a covenant that requires the Westcoast non-consolidated debt-to-total capitalization ratio to not exceed 75%. The ratio was 35% at December 31, 2014.

(d) U.S. dollar equivalent at December 31, 2014. The revolving credit facility is 500 million Canadian dollars and contains a covenant that requires the Union Gas debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 68% at December 31, 2014.

On December 10, 2014, we amended the Westcoast and Union Gas revolving credit agreements. The Westcoast revolving credit facility was increased to 400 million Canadian dollars, and the Union Gas revolving credit facility was increased to 500 million Canadian dollars. Both facilities expire in December 2019.

On December 11, 2014, we amended the Spectra Capital and SEP revolving credit agreements. The expiration date of both credit facilities was extended one year, with both facilities expiring in December 2019.

The issuances of commercial paper, letters of credit and revolving borrowings reduce the amounts available under the credit facilities. As of December 31, 2014, there were no letters of credit issued or revolving borrowings outstanding under the credit facilities.

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Our credit agreements contain various covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2014, we were in compliance with those covenants. In addition, our credit agreements allow for acceleration of payments or termination of the agreements due to nonpayment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. Our debt and credit agreements do not contain provisions that trigger an acceleration of indebtedness based solely on the occurrence of a material adverse change in our financial condition or results of operations.

As noted above, the terms of our Spectra Capital credit agreement requires our consolidated debt-to-total-capitalization ratio, as defined in the agreement, to be 65% or lower. Per the terms of the agreement, collateralized debt is excluded from the calculation of the ratio. This ratio was 58% at December 31, 2014. Our equity, and as a result, this ratio, is sensitive to significant movements of the Canadian dollar relative to the U.S. dollar due to the significance of our Canadian operations as discussed in "Quantitative and Qualitative Disclosures About Market Risk—Foreign Currency Risk." Based on the strength of our total capitalization as of December 31, 2014, however, it is not likely that a material adverse effect would occur as a result of a weakened Canadian dollar.

Term Loan Agreements. In November 2013, Spectra Capital entered into a five-year $300 million senior unsecured delayed-draw term loan agreement which allowed for up to one borrowing prior to January 15, 2014. The full $300 million available under the agreement was borrowed in January 2014. These borrowings are due in November 2018.

In November 2013, SEP entered into and borrowed $400 million under a senior unsecured five-year term loan agreement. A portion of the proceeds from the borrowing was used to pay Spectra Energy for the U.S. Assets Dropdown.

In 2012, Spectra Capital entered into a three-year $1.2 billion unsecured delayed-draw term loan agreement which allowed for up to four borrowings prior to March 1, 2013. The full $1.2 billion available under the agreement was borrowed in the first quarter of 2013. Proceeds from borrowings under the term loan were used for general corporate purposes, including acquisitions and to refinance existing indebtedness. Borrowings under this term loan agreement were repaid on November 1, 2013 with proceeds received from SEP from the U.S. Assets Dropdown, and the loan agreement was terminated.

Dividends. Our near-term objective is to increase our cash dividend by $0.14 per year through 2017. We expect to continue our policy of paying regular cash dividends. The declaration and payment of dividends are subject to the sole discretion of our Board of Directors and will depend upon many factors, including the financial condition, earnings and capital requirements of our operating subsidiaries, covenants associated with certain debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by our Board of Directors. We declared a quarterly cash dividend of $0.37 per common share on January 5, 2015 payable on March 10, 2015 to shareholders of record at the close of business on February 13, 2015.

Other Financing Matters. Spectra Energy Corp and Spectra Capital have an effective shelf registration statement on file with the SEC to register the issuance of unspecified amounts of various equity and debt securities. SEP has an effective shelf registration statement on file with the SEC to register the issuance of unspecified amounts of limited partner common units and various debt securities. SEP also has $143 million available as of December 31, 2014 for the issuance of limited partner common units and various debt securities under an additional shelf registration statement on file with the SEC related to its at-the-market program. Westcoast and Union Gas have an aggregate 2.5 billion Canadian dollars (approximately $2.2 billion) available as of December 31, 2014 for the issuance of debt securities in the Canadian market under debt shelf prospectuses.

In January 2015, SEP filed a registration statement with the SEC to register an additional $500 million of limited partner units. This shelf registration became effective on February 2, 2015.

Off-Balance Sheet Arrangements

We enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See Note 21 of Notes to Consolidated Financial Statements for further discussion of guarantee arrangements.

Most of the guarantee arrangements that we enter into enhance the credit standings of certain subsidiaries, non-consolidated entities or less than 100%-owned entities, enabling them to conduct business. As such, these guarantee arrangements involve elements of performance and credit risk which are not included on our Consolidated Balance Sheets. The possibility of us having to honor our contingencies is largely dependent upon the future operations of our subsidiaries, investees and other third parties, or the occurrence of certain future events.

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Issuance of these guarantee arrangements is not required for the majority of our operations. As such, if we discontinued issuing these guarantee arrangements, there would not be a material impact to our consolidated results of operations, financial position or cash flows.

We do not have any other material off-balance sheet financing entities or structures, except for normal operating lease arrangements, guarantee arrangements and financings entered into by DCP Midstream and our other equity investments. For additional information on these commitments, see Notes 20 and 21 of Notes to Consolidated Financial Statements.

Contractual Obligations

We enter into contracts that require payment of cash at certain periods based on certain specified minimum quantities and prices. The following table summarizes our contractual cash obligations for each of the periods presented. The table below excludes all amounts classified as Total Current Liabilities on the December 31, 2014 Consolidated Balance Sheet other than Current Maturities of Long-Term Debt. It is expected that the majority of Total Current Liabilities will be paid in cash in 2015.

Contractual Obligations as of December 31, 2014

	Payments Due By Period				
	Total	2015	2016 & 2017	2018 & 2019	2020 & Beyond
	(in millions)				
Long-term debt (a)	$19,646	$974	$2,499	$4,115	$12,058
Operating leases (b)	352	50	86	68	148
Purchase Obligations: (c)					
Firm capacity payments (d)	2,727	287	412	151	1,877
Energy commodity contracts (e)	507	457	50	—	—
Other purchase obligations (f)	820	219	468	78	55
Other long-term liabilities on the Consolidated Balance Sheet (g)	55	55	—	—	—
Total contractual cash obligations	$24,107	$2,042	$3,515	$4,412	$14,138

(a) See Note 16 of Notes to Consolidated Financial Statements. Amounts include principal payments and estimated scheduled interest payments over the life of the associated debt and capital lease obligations.

(b) See Note 20.

(c) Purchase obligations reflected in the Consolidated Balance Sheets have been excluded from the above table.

(d) Includes firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage.

(e) Includes contractual obligations to purchase physical quantities of NGLs and natural gas. Amounts include certain hedges as defined by applicable accounting standards. For contracts where the price paid is based on an index, the amount is based on forward market prices at December 31, 2014.

(f) Includes contracts for software and consulting or advisory services. Amounts also include contractual obligations for engineering, procurement and construction costs for pipeline projects. Amounts exclude certain open purchase orders for services that are provided on demand, where the timing of the purchase cannot be determined.

(g) Includes estimated 2015 retirement plan contributions (see Notes 25). We are unable to estimate retirement plan contributions beyond 2015 due primarily to uncertainties about market performance of plan assets. Excludes cash obligations for asset retirement activities (see Note 15) because the amount of cash flows to be paid to settle the asset retirement obligations is not known with certainty as we may use internal or external resources to perform retirement activities. Amounts also exclude reserves for litigation and environmental remediation (see Note 20) and regulatory liabilities (see Note 5) because we are uncertain as to the amount and/or timing of when cash payments will be required. Amounts also exclude deferred income taxes and investment tax credits on the Consolidated Balance Sheets since cash payments for income taxes are determined primarily by taxable income for each discrete fiscal year.

Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks associated with commodity prices, credit exposure, interest rates, equity prices and foreign currency exchange rates. We have established comprehensive risk management policies to monitor and manage these market risks. Our Chief Financial Officer is responsible for the overall governance of managing credit risk and commodity price risk, including monitoring exposure limits.

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Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of NGLs and natural gas purchased as a result of our investment in DCP Midstream, and the ownership of the NGL marketing operations in western Canada and processing associated with certain of our U.S. pipeline assets. Price risk represents the potential risk of loss from adverse changes in the market price of these energy commodities. Our exposure to commodity price risk is influenced by a number of factors, including contract size, length, market liquidity, location and unique or specific contract terms.

Within the Western Canada Transmission & Processing segment, we employ policies and procedures to manage Spectra Energy's risks associated with Empress' commodity price fluctuations, which may include the use of forward physical transactions as well as commodity derivatives. Effective January 2014, we implemented a commodity hedging program at Empress and have elected to not apply cash flow hedge accounting.

DCP Midstream manages its direct exposure to market prices separate from Spectra Energy, and utilizes various risk management strategies, including the use of commodity derivatives.

We are exposed to market price fluctuations of NGLs, natural gas and oil in our Field Services segment. Based on a sensitivity analysis as of December 31, 2014 and 2013, a 10¢ per-gallon change in NGL prices would affect our annual pre-tax earnings by approximately $55 million in 2015 and $59 million in 2014 for Field Services. For the same periods, a 50¢ per-MMBtu change in natural gas prices would affect our annual pre-tax earnings by approximately $23 million and $21 million, and a $10 per-barrel change in oil prices would affect our annual pre-tax earnings by approximately $25 million and $27 million, respectively.

Within the Western Canada Transmission & Processing segment, we have NGL marketing operations with contracts to buy and sell commodities, including natural gas, NGLs and other commodities that are settled by the delivery of the commodity or cash. With respect to the Empress assets in Western Canada Transmission & Processing, a 10¢ per-gallon change in NGL prices, primarily propane prices, would affect our annual pre-tax earnings by approximately $21 million in 2015. For the same period, a 50¢ per-MMBtu change in natural gas prices would affect our annual pre-tax earnings by approximately $6 million. These estimates do not include the effects of commodity derivatives or variability in business activity that may occur as a result of such things as changes in the demand for our products or changes in plant operations. Empress is also exposed to changes in the fair value of our commodity derivatives as a result of fluctuations in the market price of NGLs. At December 31, 2014, a 10¢ per-gallon movement in underlying commodity NGL prices would affect the estimated fair value of commodity derivatives by approximately $16 million.

These hypothetical calculations consider estimated production levels, but do not consider other potential effects that might result from such changes in commodity prices. The actual effect of commodity price changes on our earnings could be significantly different than these estimates.

See also Notes 1 and 19 of Notes to Consolidated Financial Statements.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. Our principal customers for natural gas transmission, storage, and gathering and processing services are industrial end-users, marketers, exploration and production companies, LDCs and utilities located throughout the United States and Canada. Customers on the Express-Platte system are primarily refineries located in the Rocky Mountain and Midwestern states of the United States. Other customers include oil producers and marketing entities. We have concentrations of receivables from natural gas utilities and their affiliates, industrial customers and marketers throughout these regions, as well as retail distribution customers in Canada. These concentrations of customers may affect our overall credit risk in that risk factors can negatively affect the credit quality of the entire sector. Credit risk associated with gas distribution services are primarily affected by general economic conditions in the service territory.

Where exposed to credit risk, we analyze the customers' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We also obtain parental guarantees, cash deposits or letters of credit from customers to provide credit support, where appropriate, based on our financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each contract. A significant amount of our credit exposures for transmission, storage, and gathering and processing services are with customers who have an investment-grade rating (or the equivalent based on our evaluation) or are secured by collateral. However, we cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including possible declines in our customers' creditworthiness. As a result of future capital projects for which natural gas producers may be the primary customer, our credit exposure with below investment-grade customers may increase.

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We manage cash and restricted cash positions to maximize value while assuring appropriate amounts of cash are available, as required. We invest our available cash in high-quality money market securities. Such money market securities are designed for safety of principal and liquidity, and accordingly, do not include equity-based securities. Based on our policies for managing credit risk, our current exposures and our credit and other reserves, we do not anticipate a material effect on our consolidated financial position or results of operations as a result of non-performance by any counterparty.

Interest Rate Risk

We are exposed to risk resulting from changes in interest rates as a result of our issuance of variable and fixed-rate debt and commercial paper. We manage our interest rate exposure by limiting our variable-rate exposures to percentages of total debt and by monitoring the effects of market changes in interest rates. We also enter into financial derivative instruments, including, but not limited to, interest rate swaps and rate lock agreements to manage and mitigate interest rate risk exposure. See also Notes 1, 16 and 19 of Notes to Consolidated Financial Statements.

As of December 31, 2014, we had interest rate hedges in place for various purposes. We are party to “pay floating—receive fixed” interest rate swaps with a total notional amount of $1,208 million to hedge against changes in the fair value of our fixed-rate debt that arise as a result of changes in market interest rates. These swaps also allow us to transform a portion of the underlying interest payments related to our long-term fixed-rate debt securities into variable-rate interest payments in order to achieve our desired mix of fixed and variable-rate debt.

Based on a sensitivity analysis as of December 31, 2014, it was estimated that if short-term interest rates average 100 basis points higher (lower) in 2015 than in 2014, interest expense, net of offsetting interest income, would fluctuate by $32 million. Comparatively, based on a sensitivity analysis as of December 31, 2013, had short-term interest rates averaged 100 basis points higher (lower) in 2014 than in 2013, it was estimated that interest expense, net of offsetting interest income, would have fluctuated by approximately $24 million. These amounts were estimated by considering the effect of the hypothetical interest rates on variable-rate debt outstanding, adjusted for interest rate hedges, short term investments, and cash and cash equivalents outstanding as of December 31, 2014 and 2013.

Equity Price Risk

Our cost of providing non-contributory defined benefit retirement and postretirement benefit plans are dependent upon, among other things, rates of return on plan assets. These plan assets expose us to price fluctuations in equity markets. In addition, our captive insurance companies maintain various investments to fund certain business risks and losses. Those investments may, from time to time, include investments in equity securities. Volatility of equity markets, particularly declines, will not only impact our cost of providing retirement and postretirement benefits, but will also impact the funding level requirements of those benefits.

We manage equity price risk by, among other things, diversifying our investments in equity investments, setting target allocations of investment types, periodically reviewing actual asset allocations and rebalancing allocations if warranted, and utilizing external investment advisors.

Foreign Currency Risk

We are exposed to foreign currency risk from our Canadian operations. To mitigate risks associated with foreign currency fluctuations, contracts may be denominated in or indexed to the U.S. dollar and/or local inflation rates, or investments may be naturally hedged through debt denominated or issued in the foreign currency.

To monitor our currency exchange rate risks, we use sensitivity analysis, which measures the effect of devaluation of the Canadian dollar. An average 10% devaluation in the Canadian dollar exchange rate during 2014 would have resulted in an estimated net loss on the translation of local currency earnings of approximately $44 million on our Consolidated Statement of Operation. In addition, if a 10% devaluation had occurred on December 31, 2014, the Consolidated Balance Sheet would have been negatively impacted by $499 million through a cumulative translation adjustment in AOCI. At December 31, 2014, one U.S. dollar translated into 1.16 Canadian dollars.

As discussed earlier, we maintain credit facilities that typically include financial covenants which limit the amount of debt that can be outstanding as a percentage of total capital for Spectra Energy or of a specific subsidiary. Failure to maintain these covenants could preclude us from issuing commercial paper or letters of credit or borrowing under our revolving credit facilities and could require other affiliates to immediately pay down any outstanding drawn amounts under other revolving credit agreements, which could adversely affect cash flows or restrict business. As a result of the impact of foreign currency

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fluctuations on our consolidated equity, these fluctuations have a direct impact on our ability to maintain certain of these financial covenants.

OTHER ISSUES

For information on other issues, see Notes 5 and 20 of Notes to Consolidated Financial Statements.

New Accounting Pronouncements

See Note 1 of Notes to Consolidated Financial Statements for discussion.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

See Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Quantitative and Qualitative Disclosures About Market Risk for discussion.

Item 8. Financial Statements and Supplementary Data.

Management’s Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining an adequate system of internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with generally accepted accounting principles. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

Our management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2014 based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting was effective at the reasonable assurance level as of December 31, 2014.

Deloitte & Touche LLP, our independent registered public accounting firm, has audited and issued a report on the effectiveness of our internal control over financial reporting. Their report is included herein.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Spectra Energy Corp

We have audited the accompanying consolidated balance sheets of Spectra Energy Corp and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedule and an opinion on the Company's internal control over financial reporting 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Spectra Energy Corp and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring

Organizations of the Treadway Commission.
/s/ DELOITTE & TOUCHE LLP
Houston, Texas
February 27, 2015

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SPECTRA ENERGY CORP
CONSOLIDATED STATEMENTS OF OPERATIONS
(In millions, except per-share amounts)

	Years Ended December 31,		
	2014	2013	2012
Operating Revenues			
Transportation, storage and processing of natural gas	$3,291	$3,128	$3,149
Distribution of natural gas	1,583	1,577	1,366
Sales of natural gas liquids	497	440	401
Transportation of crude oil	302	224	—
Other	230	149	159
Total operating revenues	5,903	5,518	5,075
Operating Expenses			
Natural gas and petroleum products purchased	1,219	1,139	1,037
Operating, maintenance and other	1,571	1,568	1,380
Depreciation and amortization	796	772	746
Property and other taxes	393	373	337
Total operating expenses	3,979	3,852	3,500
Operating Income	1,924	1,666	1,575
Other Income and Expenses			
Equity in earnings of unconsolidated affiliates	361	445	382
Other income and expenses, net	59	124	83
Total other income and expenses	420	569	465
Interest Expense	679	657	625
Earnings From Continuing Operations Before Income Taxes	1,665	1,578	1,415
Income Tax Expense From Continuing Operations	382	419	370
Income From Continuing Operations	1,283	1,159	1,045
Income From Discontinued Operations, net of tax	—	—	2
Net Income	1,283	1,159	1,047
Net Income — Noncontrolling Interests	201	121	107
Net Income — Controlling Interests	$1,082	$1,038	$940
Common Stock Data			
Weighted-average shares outstanding			
Basic	671	669	653
Diluted	672	671	656
Earnings per share			
Basic	$1.61	$1.55	$1.44
Diluted	$1.61	$1.55	$1.43
Dividends per share	$1.375	$1.22	$1.145

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY CORP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Years Ended December 31,		
	2014	2013	2012
Net Income	$1,283	$1,159	$1,047
Other comprehensive income (loss):			
Foreign currency translation adjustments	(548)	(494)	215
Non-cash mark-to-market net gain on hedges	4	7	6
Reclassification of cash flow hedges into earnings	5	7	9
Pension and benefits impact (net of tax benefit (expense) of $14, $(88) and $6, respectively)	(47)	203	9
Other	—	2	—
Total other comprehensive income (loss)	(586)	(275)	239
Total Comprehensive Income, net of tax	697	884	1,286
Less: Comprehensive Income — Noncontrolling Interests	194	114	110
Comprehensive Income — Controlling Interests	$503	$770	$1,176

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY CORP
CONSOLIDATED BALANCE SHEETS
(In millions)

	December 31, 2014	2013
ASSETS		
Current Assets		
Cash and cash equivalents	$215	$201
Receivables (net of allowance for doubtful accounts of $11 and $10 at December 31, 2014 and 2013, respectively)	1,336	1,336
Inventory	313	263
Fuel tracker	102	28
Other	366	253
Total current assets	2,332	2,081
Investments and Other Assets		
Investments in and loans to unconsolidated affiliates	2,966	3,043
Goodwill	4,714	4,810
Other	327	385
Total investments and other assets	8,007	8,238
Property, Plant and Equipment		
Cost	29,211	28,456
Less accumulated depreciation and amortization	6,904	6,627
Net property, plant and equipment	22,307	21,829
Regulatory Assets and Deferred Debits	1,394	1,385
Total Assets	$34,040	$33,533

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY CORP
CONSOLIDATED BALANCE SHEETS
(In millions, except per-share amounts)

	December 31, 2014	2013
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$458	$440
Commercial paper	1,583	1,032
Taxes accrued	91	72
Interest accrued	181	201
Current maturities of long-term debt	327	1,197
Other	1,169	1,097
Total current liabilities	3,809	4,039
Long-term Debt	12,769	12,488
Deferred Credits and Other Liabilities		
Deferred income taxes	5,405	4,968
Regulatory and other	1,401	1,457
Total deferred credits and other liabilities	6,806	6,425
Commitments and Contingencies		
Preferred Stock of Subsidiaries	258	258
Equity		
Preferred stock, $0.001 par, 22 million shares authorized, no shares outstanding	—	—
Common stock, $0.001 par, 1 billion shares authorized, 671 million and 670 million shares outstanding at December 31, 2014 and 2013, respectively	1	1
Additional paid-in capital	4,956	4,869
Retained earnings	2,541	2,383
Accumulated other comprehensive income	662	1,241
Total controlling interests	8,160	8,494
Noncontrolling interests	2,238	1,829
Total equity	10,398	10,323
Total Liabilities and Equity	$34,040	$33,533

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY CORP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31, 2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$1,283	$1,159	$1,047
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	809	787	760
Deferred income tax expense	388	421	210
Equity in earnings of unconsolidated affiliates	(361)	(445)	(382)
Distributions received from unconsolidated affiliates	380	324	307
Decrease (increase) in			
Receivables	(9)	(94)	69
Inventory	(106)	17	80
Other current assets	(143)	(88)	1
Increase (decrease) in			
Accounts payable	25	(2)	(51)
Taxes accrued	28	(8)	14
Other current liabilities	3	101	43
Other, assets	(33)	(111)	(74)
Other, liabilities	(43)	(31)	(86)
Net cash provided by operating activities	2,221	2,030	1,938
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(2,028)	(1,947)	(2,025)
Investments in and loans to unconsolidated affiliates	(259)	(312)	(520)
Acquisitions, net of cash acquired	—	(1,254)	(30)
Purchases of held-to-maturity securities	(790)	(985)	(2,671)
Proceeds from sales and maturities of held-to-maturity securities	815	1,023	2,578
Purchases of available-for-sale securities	(13)	(5,878)	(644)
Proceeds from sales and maturities of available-for-sale securities	7	6,024	514
Distributions received from unconsolidated affiliates	266	87	17
Loan to unconsolidated affiliate	—	(71)	—
Repayment of loan to unconsolidated affiliate	—	71	—
Other changes in restricted funds	(1)	2	93
Other	—	4	14
Net cash used in investing activities	(2,003)	(3,236)	(2,674)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the issuance of long-term debt	1,028	4,372	1,301
Payments for the redemption of long-term debt	(1,184)	(2,139)	(525)
Net increase (decrease) in commercial paper	574	(206)	199
Distributions to noncontrolling interests	(175)	(144)	(120)
Contributions from noncontrolling interests	145	23	—
Proceeds from the issuance of Spectra Energy common stock	—	—	382
Proceeds from the issuance of Spectra Energy Partners, LP common units	327	214	145
Dividends paid on common stock	(925)	(821)	(753)
Other	11	17	25
Net cash provided by (used in) financing activities	(199)	1,316	654

Effect of exchange rate changes on cash	(5)	(3)	2
Net increase (decrease) in cash and cash equivalents	14	107	(80)
Cash and cash equivalents at beginning of period	201	94	174
Cash and cash equivalents at end of period	$215	$201	$94
Supplemental Disclosures			
Cash paid for interest, net of amount capitalized	$684	$625	$601
Net cash paid (refunds received) for income taxes	(8)	43	130
Property, plant and equipment non-cash accruals	125	112	147

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY CORP
CONSOLIDATED STATEMENTS OF EQUITY
(In millions)

	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income Foreign Currency Translation Adjustments	Accumulated Other Comprehensive Income Other	Noncontrolling Interests	Total
December 31, 2011	$ 1	$ 4,814	$ 1,977	$ 1,832	$ (559)	$ 831	$ 8,896
Net income	—	—	940	—	—	107	1,047
Other comprehensive income	—	—	—	212	24	3	239
Dividends on common stock	—	—	(752)	—	—	—	(752)
Stock-based compensation	—	24	—	—	—	—	24
Distributions to noncontrolling interests	—	—	—	—	—	(120)	(120)
Spectra Energy common stock issued	—	399	—	—	—	—	399
Spectra Energy Partners, LP common units issued	—	26	—	—	—	108	134
Transfer of interests in subsidiaries to Spectra Energy Partners, LP	—	34	—	—	—	(54)	(20)
Other, net	—	—	—	—	—	(4)	(4)
December 31, 2012	1	5,297	2,165	2,044	(535)	871	9,843
Net income	—	—	1,038	—	—	121	1,159
Other comprehensive income (loss)	—	—	—	(487)	219	(7)	(275)
Dividends on common stock	—	—	(820)	—	—	—	(820)
Stock-based compensation	—	19	—	—	—	—	19
Distributions to noncontrolling interests	—	—	—	—	—	(144)	(144)
Contributions from noncontrolling interests	—	—	—	—	—	23	23
Spectra Energy common stock issued	—	23	—	—	—	—	23
Spectra Energy Partners, LP common units issued	—	42	—	—	—	147	189
Transfer of interests in subsidiaries to Spectra Energy Partners, LP	—	(511)	—	—	—	817	306
Other, net	—	(1)	—	—	—	1	—
December 31, 2013	1	4,869	2,383	1,557	(316)	1,829	10,323
Net income	—	—	1,082	—	—	201	1,283
Other comprehensive loss	—	—	—	(541)	(38)	(7)	(586)
Dividends on common stock	—	—	(924)	—	—	—	(924)
Stock-based compensation	—	19	—	—	—	—	19
Distributions to noncontrolling interests	—	—	—	—	—	(175)	(175)

Contributions from noncontrolling interests	—	—	—	—	—	145	145
Spectra Energy common stock issued	—	11	—	—	—	—	11
Spectra Energy Partners, LP common units issued	—	49	—	—	—	248	297
Transfer of interests in subsidiaries to Spectra Energy Partners, LP	—	3	—	—	—	(1)	2
Other, net	—	5	—	—	—	(2)	3
December 31, 2014	$ 1	$ 4,956	$ 2,541	$ 1,016	$ (354)	$ 2,238	$ 10,398

See Notes to Consolidated Financial Statements.

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SPECTRA ENERGY CORP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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1. Summary of Operations and Significant Accounting Policies

The terms "we," "our," "us" and "Spectra Energy" as used in this report refer collectively to Spectra Energy Corp and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Spectra Energy. The term "Spectra Energy Partners" refers to our Spectra Energy Partners operating segment. The term "SEP" refers to Spectra Energy Partners, LP, our master limited partnership.

Nature of Operations. Spectra Energy Corp, through its subsidiaries and equity affiliates, owns and operates a large and diversified portfolio of complementary natural gas-related energy assets, and owns and operates a crude oil pipeline system that connects Canadian and U.S. producers to refineries in the U.S. Rocky Mountain and Midwest regions. We currently operate in three key areas of the natural gas industry: gathering and processing, transmission and storage, and distribution. We provide transmission and storage of natural gas to customers in various regions of the northeastern and southeastern United States, the Maritime Provinces in Canada, the Pacific Northwest in the United States and Canada, and in the province of Ontario, Canada. We also provide natural gas sales and distribution services to retail customers in Ontario, and natural gas gathering and processing services to customers in western Canada. We also own a 50% interest in DCP Midstream, LLC (DCP Midstream), based in Denver, Colorado, one of the leading natural gas gatherers in the United States based on wellhead volumes, and one of the largest U.S. producers and marketers of natural gas liquids (NGLs).

Basis of Presentation. The accompanying Consolidated Financial Statements include our accounts and the accounts of our majority-owned subsidiaries, after eliminating intercompany transactions and balances.

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Use of Estimates. To conform with generally accepted accounting principles (GAAP) in the United States, we make estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and Notes to Consolidated Financial Statements. Although these estimates are based on our best available knowledge at the time, actual results could differ.

Fair Value Measurements. We measure the fair value of financial assets and liabilities by maximizing the use of observable inputs and minimizing the use of unobservable inputs. Fair value is the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date.

Cost-Based Regulation. The economic effects of regulation can result in a regulated company recording assets for costs that have been or are expected to be approved for recovery from customers or recording liabilities for amounts that are expected to be returned to customers or for instances where the regulator provides current rates that are intended to recover costs that are expected to be incurred in the future. Accordingly, we record assets and liabilities that result from the regulated ratemaking process that may not be recorded under GAAP for non-regulated entities. We continually assess whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Based on this assessment, we believe our existing regulatory assets are probable of recovery. These regulatory assets and liabilities are mostly classified in the Consolidated Balance Sheets as Regulatory Assets and Deferred Debits, and Deferred Credits and Other Liabilities — Regulatory and Other. We evaluate our regulated assets, and consider factors such as regulatory changes and the effect of competition. If cost-based regulation ends or competition increases, we may have to reduce our asset balances to reflect a market basis less than cost and write-off the associated regulatory assets and liabilities. See Note 5 for further discussion.

Foreign Currency Translation. The Canadian dollar has been determined to be the functional currency of our Canadian operations based on an assessment of the economic circumstances of those operations. Assets and liabilities of our Canadian operations are translated into U.S. dollars at current exchange rates. Translation adjustments resulting from fluctuations in exchange rates are included as a separate component of Other Comprehensive Income on the Consolidated Statements of Comprehensive Income. Revenue and expense accounts of these operations are translated at average monthly exchange rates prevailing during the periods. Gains and losses arising from transactions denominated in currencies other than the functional currency are included in the results of operations of the period in which they occur. Foreign currency transaction gains (losses) totaled $3 million in 2014, $1 million in 2013 and $(3) million in 2012, and are included in Other Income and Expenses, Net on the Consolidated Statements of Operations. Deferred U.S. taxes related to translation gains and losses have not been provided on those Canadian operations that we expect the earnings to be indefinitely reinvested.

Revenue Recognition. Revenues from the transmission, storage, processing, distribution and sales of natural gas, from the sales of NGLs and from the transportation and storage of crude oil are generally recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month. These estimates are generally based on contract data, regulatory information, estimated distribution usage based on historical data adjusted for heating degree days, commodity prices and preliminary throughput and allocation measurements. Final bills for the current month are billed and collected in the following month. Differences between actual and estimated unbilled revenues are immaterial. There were no customers accounting for 10% or more of consolidated revenues during 2014, 2013 or 2012. We also have certain customer contracts with billed amounts that decline annually over the terms of the contracts. Differences between the amounts billed and recognized are deferred on the Consolidated Balance Sheets.

Stock-Based Compensation. For employee awards, equity-classified and liability-classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability-classified stock-based compensation cost is remeasured at each reporting period until settlement. Related compensation expense is recognized over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests, the date the employee becomes retirement-eligible or the date the market or performance condition of the award is met. Awards, including stock options, granted to employees that are retirement-eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted. See Note 24 for further discussion.

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Pension and Other Post-Retirement Benefits. We fully recognize the overfunded or underfunded status of our consolidating subsidiaries' pension and other post-retirement benefit plans as Investments and Other Assets - Other, Current Liabilities - Other or Deferred Credits and Other Liabilities - Regulatory and Other in the Consolidated Balance Sheets, as appropriate. A plan's funded status is the difference between the fair value of plan assets and the plan's projected benefit obligation. We record deferred plan costs and income (unrecognized losses and gains, and unrecognized prior service costs and credits) in Accumulated Other Comprehensive Income (AOCI) on the Consolidated Statements of Equity, until they are amortized and recognized as a component of benefit expense within Operating, Maintenance and Other in the Consolidated Statements of Operations. See Note 25 for further discussion.

Allowance for Funds Used During Construction (AFUDC). AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction of certain new regulated facilities, consists of two components, an equity component and an interest expense component. The equity component is a non-cash item. After construction is completed, we are permitted to recover these costs through inclusion in the rate base and in the depreciation provision. AFUDC is capitalized as a component of Property, Plant and Equipment - Cost in the Consolidated Balance Sheets, with offsetting credits to the Consolidated Statements of Operations through Other Income and Expenses, Net for the equity component and Interest Expense for the interest expense component. The total amount of AFUDC included in the Consolidated Statements of Operations was $72 million in 2014 (an equity component of $53 million and an interest expense component of $19 million), $155 million in 2013 (an equity component of $105 million and an interest expense component of $50 million) and $131 million in 2012 (an equity component of $85 million and an interest expense component of $46 million).

Income Taxes. Deferred income taxes are recognized for differences between the financial reporting and tax bases of assets and liabilities at enacted statutory tax rates in effect for the years in which the differences are expected to reverse. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Actual income taxes could vary from these estimates due to future changes in income tax law or results from the final review of tax returns by federal, state or foreign tax authorities.

Financial statement effects on tax positions are recognized in the period in which it is more likely than not that the position will be sustained upon examination, the position is effectively settled or when the statute of limitations to challenge the position has expired. Interest and penalties related to unrecognized tax benefits are recorded as interest expense and other expense, respectively.

Cash and Cash Equivalents. Highly liquid investments with original maturities of three months or less at the date of acquisition, except for the investments that were pledged as collateral against long-term debt as discussed in Note 16 and any investments that are considered restricted funds, are considered cash equivalents.

Inventory. Inventory consists of natural gas and NGLs held in storage for transmission and processing, and also includes materials and supplies. Natural gas inventories primarily relate to the Distribution segment in Canada and are valued at costs approved by the regulator, the Ontario Energy Board (OEB). The difference between the approved price and the actual cost of gas purchased is recorded in either accounts receivable or other current liabilities, as appropriate, for future disposition with customers, subject to approval by the OEB. The remaining inventory is recorded at the lower of cost or market, primarily using average cost.

Natural Gas Imbalances. The Consolidated Balance Sheets include in-kind balances as a result of differences in gas volumes received and delivered for customers. Since settlement of certain imbalances is in-kind, changes in their balances do not have an effect on our Consolidated Statements of Cash Flows. Receivables include $642 million and $606 million as of December 31, 2014 and December 31, 2013, respectively, and Other Current Liabilities include $634 million and $575 million as of December 31, 2014 and December 31, 2013, respectively, related to gas imbalances. Most natural gas volumes owed to or by us are valued at natural gas market index prices as of the balance sheet dates.

Risk Management and Hedging Activities and Financial Instruments. Currently, our use of derivative instruments is primarily limited to interest rate positions and commodity pricing. All derivative instruments that do not qualify for the normal purchases and normal sales exception are recorded on the Consolidated Balance Sheets at fair value. Cash inflows and outflows related to derivative instruments are a component of Cash Flows From Operating Activities in the accompanying Consolidated Statements of Cash Flows.

Cash Flow and Fair Value Hedges. Qualifying energy commodity and other derivatives may be designated as either a hedge of a forecasted transaction (cash flow hedge) or a hedge of a recognized asset, liability or firm commitment (fair value hedge). For all hedge contracts, we prepare documentation of the hedge in accordance with accounting standards and assess whether the hedge contract is highly effective using regression analysis, both at inception and on a quarterly basis, in offsetting changes in cash flows or fair values of hedged items. We document hedging activity by instrument type (futures or swaps) and risk management strategy (commodity price risk or interest rate risk).

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For derivatives designated as fair value hedges, we recognize the gain or loss on the derivative instrument, as well as the offsetting gain or loss on the hedged item in earnings, to the extent effective, in the current period. In the event the hedge is not effective, there is no offsetting gain or loss recognized in earnings for the hedged item. All derivatives designated and accounted for as hedges are classified in the same category as the item being hedged in the Consolidated Statements of Cash Flows. All components of each derivative gain or loss are included in the assessment of hedge effectiveness.

Investments. We may actively invest a portion of our available cash and restricted funds balances in various financial instruments, including taxable or tax-exempt debt securities. In addition, we invest in short-term money market securities, some of which are restricted due to debt collateral or insurance requirements. Investments in available-for-sale (AFS) securities are carried at fair value and investments in held-to-maturity (HTM) securities are carried at cost. Investments in money market securities are also accounted for at fair value. Realized gains and losses, and dividend and interest income related to these securities, including any amortization of discounts or premiums arising at acquisition, are included in earnings. The costs of securities sold are determined using the specific identification method. Purchases and sales of AFS and HTM securities are presented on a gross basis within Cash Flows From Investing Activities in the accompanying Consolidated Statements of Cash Flows.

Goodwill. We perform our goodwill impairment test annually and evaluate goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. No impairments of goodwill were recorded in 2014, 2013 or 2012. See Note 12 for further discussion.

We perform our annual review for goodwill impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete financial information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar. We determined that our reporting units are equivalent to our reportable segments, except for the reporting units of our Western Canada Transmission & Processing and Spectra Energy Partners reportable segments, which are one level below.

As permitted under accounting guidance on testing goodwill for impairment, we perform either a qualitative assessment or a quantitative assessment of each of our reporting units based on management’s judgment. With respect to our qualitative assessments, we consider events and circumstances specific to us, such as macroeconomic conditions, industry and market considerations, cost factors and overall financial performance, when evaluating whether it is more likely than not that the fair values of our reporting units are less than their respective carrying amounts.

In connection with our quantitative assessments, we primarily use a discounted cash flow analysis to determine the fair values of those reporting units. Key assumptions in the determination of fair value included the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in key markets served by our operations, regulatory stability, the ability to renew contracts, commodity prices (where appropriate) and foreign currency exchange rates, as well as other factors that affect our reporting units’ revenue, expense and capital expenditure projections. If the carrying amount of the reporting unit exceeds its fair value, a comparison of the fair value and carrying value of the goodwill of that reporting unit needs to be performed. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess. Additional impairment tests are performed between the annual reviews if events or changes in circumstances make it more likely than not that the fair value of a reporting unit is below its carrying amount.

Property, Plant and Equipment. Property, plant and equipment is stated at historical cost less accumulated depreciation. We capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Indirect costs include general engineering, taxes and the cost of funds used during construction. The costs of renewals and betterments that extend the useful life or increase the expected output of property, plant and equipment are also capitalized. The costs of repairs, replacements and major maintenance projects that do not extend the useful life or increase the expected output of property, plant and equipment are expensed as incurred. Depreciation is generally computed over the asset's estimated useful life using the straight-line method.

When we retire regulated property, plant and equipment, we charge the original cost plus the cost of retirement, less salvage value, to accumulated depreciation and amortization. When we sell entire regulated operating units or retire non-regulated properties, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body.

Preliminary Project Costs. Project development costs, including expenditures for preliminary surveys, plans, investigations, environmental studies, regulatory applications and other costs incurred for the purpose of determining the feasibility of capital expansion projects, are capitalized for rate-regulated enterprises when it is determined that recovery of

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such costs through regulated revenues of the completed project is probable. Any inception-to-date costs of the project that were initially expensed are reversed and capitalized as Property, Plant and Equipment.

Long-Lived Asset Impairments. We evaluate whether long-lived assets, excluding goodwill, have been impaired when circumstances indicate the carrying value of those assets may not be recoverable. For such long-lived assets, an impairment exists when its carrying value exceeds the sum of estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used in developing estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on these estimated future undiscounted cash flows, an impairment loss is measured as the excess of the asset's carrying value over its fair value, such that the asset's carrying value is adjusted to its estimated fair value.

We assess the fair value of long-lived assets using commonly accepted techniques and may use more than one source. Sources to determine fair value include, but are not limited to, recent third-party comparable sales, internally developed discounted cash flow analyses and analyses from outside advisors. Significant changes in market conditions resulting from events such as changes in natural gas available to our systems, the condition of an asset, a change in our intent to utilize the asset or a significant change in contracted revenues or regulatory recoveries would generally require us to reassess the cash flows related to the long-lived assets.

Asset Retirement Obligations. We recognize asset retirement obligations (AROs) for legal commitments associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within our control. The fair value of a liability for an ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made and is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset.

Unamortized Debt Premium, Discount and Expense. Premiums, discounts and expenses incurred with the issuance of outstanding long-term debt are amortized over the terms of the debt issues. Any call premiums or unamortized expenses associated with refinancing higher-cost debt obligations to finance regulated assets and operations are amortized consistent with regulatory treatment of those items, where appropriate.

Environmental Expenditures. We expense environmental expenditures related to conditions caused by past operations that do not generate current or future revenues. Environmental expenditures related to operations that generate current or future revenues are expensed or capitalized, as appropriate. Undiscounted liabilities are recorded when the necessity for environmental remediation becomes probable and the costs can be reasonably estimated, or when other potential environmental liabilities are reasonably estimable and probable.

Captive Insurance Reserves. We have captive insurance subsidiaries which provide insurance coverage to our consolidated subsidiaries as well as certain equity affiliates, on a limited basis, for various business risks and losses, such as workers compensation, property, business interruption and general liability. Liabilities include provisions for estimated losses incurred but not yet reported, as well as provisions for known claims which have been estimated on a claims-incurred basis. Incurred but not yet reported reserve estimates involve the use of assumptions and are based upon historical loss experience, industry data and other actuarial assumptions. Reserve estimates are adjusted in future periods as actual losses differ from historical experience.

Guarantees. Upon issuance or material modification of a guarantee made by us, we recognize a liability for the estimated fair value of the obligation we assume under that guarantee, if any. Fair value is estimated using a probability-weighted approach. We reduce the obligation over the term of the guarantee or related contract in a systematic and rational method as risk is reduced under the obligation.

Accounting For Sales of Stock by a Subsidiary. Sales of stock by a consolidated subsidiary are accounted for as equity transactions in those instances where a change in control does not take place.

Segment Reporting. Operating segments are components of an enterprise for which separate financial information is available and evaluated regularly by the chief operating decision maker in deciding how to allocate resources and evaluate performance. Two or more operating segments may be aggregated into a single reportable segment provided certain criteria are met. There is no such aggregation within our defined business segments. A description of our reportable segments, consistent with how business results are reported internally to management, and the disclosure of segment information is presented in Note 4.

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Consolidated Statements of Cash Flows. Cash flows from discontinued operations are combined with cash flows from continuing operations within operating, investing and financing cash flows. Cash received from insurance proceeds are classified depending on the activity that resulted in the insurance proceeds. For example, business interruption insurance proceeds are included as a component of operating activities while insurance proceeds from damaged property are included as a component of investing activities. With respect to cash overdrafts, book overdrafts are included within operating cash flows while bank overdrafts, if any, are included within financing cash flows. Cash flows from borrowings and repayments under revolving credit facilities that had documented original maturities of 90 days or less are reported on a net basis as Net Increase (Decrease) in Revolving Credit Facilities Borrowings within financing activities.

Distributions from Unconsolidated Affiliates. We consider distributions received from unconsolidated affiliates which do not exceed cumulative equity in earnings subsequent to the date of investment to be a return on investment and classify these amounts as Cash Flows From Operating Activities within the accompanying Consolidated Statements of Cash Flows. Cumulative distributions received in excess of cumulative equity in earnings subsequent to the date of investment are considered to be a return of investment and are classified as Cash Flows From Investing Activities.

New Accounting Pronouncements. The following new Accounting Standards Update (ASU) was adopted during 2014 and the effect of such adoption has been presented in the accompanying Consolidated Financial Statements:

ASU No. 2013-11. In July 2013, the Financial Accounting Standards Board (FASB) issued ASU No. 2013-11, "Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists (a Consensus of the FASB Emerging Issues Task Force)," which was issued to eliminate diversity in practice. This ASU requires entities to net unrecognized tax benefits against all same-jurisdiction net operating losses or tax credit carryforwards that would be used to settle the position with a tax authority. We adopted this standard on January 1, 2014. The adoption of this ASU did not have a material impact on our consolidated results of operations, financial position or cash flows.

Pending. The following new accounting pronouncements were issued but not adopted as of December 31, 2014:

ASU No. 2014-08. In April 2014, the FASB issued ASU No. 2014-08, "Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity." This ASU revises the definition of discontinued operations by limiting discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have or will have a major effect on an entity's operations and financial results, removing the lack of continuing involvement criteria and requiring discontinued operations reporting for the disposal of an equity method investment that meets the definition of discontinued operations. The update also requires expanded disclosures for discontinued operations, and disclosure of pretax profit or loss of certain individually significant components of an entity that do not qualify for discontinued operations reporting. This ASU was effective for us on January 1, 2015 and had no impact on our consolidated results of operations, financial position or cash flows.

ASU No. 2014-09. In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)" which supersedes the revenue recognition requirements of "Revenue Recognition (Topic 605)" and clarifies the principles of recognizing revenue. This ASU is effective for us January 1, 2017. We are currently evaluating this ASU and its potential impact on us.

2013. There were no significant accounting pronouncements issued during 2013 that had a material impact on our consolidated results of operations, financial position or cash flows.

2012. There were no significant accounting pronouncements issued during 2012 that had a material impact on our consolidated results of operations, financial position or cash flows.

2. Spectra Energy Partners, LP

SEP is our natural gas infrastructure and crude oil pipeline master limited partnership. As of December 31, 2014, Spectra Energy owned 82% of SEP, including a 2% general partner interest.

U.S. Assets Dropdown. In August 2013, Spectra Energy entered into a contribution agreement with SEP (the Contribution Agreement), pursuant to which Spectra Energy agreed to contribute to SEP substantially all of Spectra Energy's interests in its subsidiaries that own U.S. transmission and storage and liquids assets, including its remaining 60% interest in the U.S. portion of Express-Platte, and to assign to SEP its interests in certain related contracts (collectively, the U.S. Assets Dropdown).

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In November 2013, Spectra Energy completed the closing of substantially all of the U.S. Assets Dropdown. This first of three planned transactions consisted of all the contributed entities contemplated in the Contribution Agreement, excluding a 25.05% ownership interest in Southeast Supply Header, LLC (SESH) and a 1% ownership interest in Steckman Ridge, LP (Steckman Ridge). Consideration to Spectra Energy for the November 2013 closing included $2.3 billion in cash, assumption by SEP (indirectly by acquisition of the contributed entities) of approximately $2.4 billion of third-party indebtedness of the contributed entities, 167.6 million newly issued SEP limited partner units and 3.4 million newly issued general partner units. This transfer of assets between entities under common control resulted in a decrease to Additional Paid-in Capital of $733 million ($458 million net of tax) and an increase to Equity-Noncontrolling Interests of $733 million on the Consolidated Balance Sheet in 2013. The change in Equity-Noncontrolling Interests primarily represents the public unitholders' share of the increase in SEP's equity as a result of the issuance of additional units to Spectra Energy, less the effects of the resulting decrease in the public unitholders' ownership percentage of SEP. Spectra Energy's ownership in SEP increased as a result of the transaction.
On November 3, 2014, Spectra Energy completed the second of three planned transactions related to the U.S Assets Dropdown. This transaction consisted of contributing an additional 24.95% ownership interest in SESH and the remaining 1% interest in Steckman Ridge to SEP. Consideration to Spectra Energy was approximately 4.3 million newly issued SEP common units. Also, in connection with this transaction, SEP issued approximately 86,000 of newly issued general partner units to Spectra Energy in exchange for the same amount of common units in order to maintain Spectra Energy's 2% general partner interest in SEP. This transfer of assets between entities under common control resulted in a decrease to Additional Paid-in Capital of $29 million ($16 million net of tax) and an increase to Equity-Noncontrolling Interests of $29 million on the Consolidated Balance Sheet in 2014. The change in Equity-Noncontrolling Interests primarily represents the public unitholders' share of the increase in SEP's equity as a result of the issuance of additional units to Spectra Energy, less the effects of the resulting decrease in the public unitholders' ownership percentage of SEP. Spectra Energy's ownership in SEP increased as a result of the transaction.
The remaining, and final, transaction related to the U.S. Assets Dropdown is expected to occur in November 2015, and will consist of Spectra Energy's remaining 0.1% interest in SESH.
The contributed assets provide transportation and storage of natural gas, crude oil, and natural gas liquids for customers in various regions of the U.S. and in Alberta, Canada. The contributed assets included in the U.S. Assets Dropdown, once the third closing is completed, will have consisted of:

- a 100% ownership interest in Texas Eastern Transmission, LP (Texas Eastern)
- a 100% ownership interest in Algonquin Gas Transmission, LLC (Algonquin)
- Spectra Energy's remaining 60% ownership interest in the U.S. portion of Express-Platte
- Spectra Energy's remaining 38.77% ownership interest in Maritimes & Northeast Pipeline, L.L.C. (M&N U.S.)
- a 33.3% ownership interest in DCP Sand Hills Pipeline, LLC (Sand Hills)
- a 33.3% ownership interest in DCP Southern Hills Pipeline, LLC (Southern Hills)
- Spectra Energy's remaining 1% ownership interest in Gulfstream Natural Gas System, LLC (Gulfstream)
- a 50% ownership interest in SESH
- a 100% ownership interest in Bobcat Gas Storage (Bobcat)
- Spectra Energy's remaining 50% of Market Hub Partners Holding (Market Hub)
- a 50% ownership interest in Steckman Ridge
- Texas Eastern's and Express-Platte's storage facilities

Express-Platte. In August 2013, Spectra Energy contributed a 40% interest in the U.S. portion of Express-Platte and sold a 100% ownership interest in the Canadian portion to SEP. Aggregate consideration for the transactions consisted of $410 million in cash and 7.2 million of newly issued SEP partnership units. This transfer of assets between entities resulted in a decrease to Additional Paid-in Capital of $84 million ($53 million net of tax) and an increase to Equity-Noncontrolling Interest of $84 million. The change in Equity-Noncontrolling Interests primarily represents the public unitholders' share of the increase in SEP equity as a result of the issuance of additional units to Spectra Energy, less the effects of the resulting decrease in the public unitholders' ownership percentage.

M&N U.S. In 2012, Spectra Energy transferred a 38.76% interest in M&N U.S. to SEP for approximately $375 million, consisting of approximately $319 million in cash and $56 million in newly issued partnership units. The price received by Spectra Energy exceeded the book value of the M&N U.S. investment. Therefore, this transfer of assets between entities resulted in an increase to Additional Paid-in Capital of $54 million ($34 million net of tax) and a decrease to Equity-Noncontrolling Interests of $54 million, representing the portion of the excess that was associated with the public unitholders' of SEP.

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Sales of SEP Common Units. In November 2013, SEP entered into an equity distribution agreement under which it may sell and issue common units up to an aggregate amount of $400 million. This at-the-market program allows SEP to offer and sell its common units, representing limited partner interests, at prices it deems appropriate through a sales agent. Sales of common units, if any, will be made by means of ordinary brokers' transactions on the New York Stock Exchange, in block transactions, or as otherwise agreed to between SEP and the sales agent. SEP intends to use the net proceeds from sales under the program for general partnership purposes, which may include debt repayment, future acquisitions, capital expenditures and additions to working capital. SEP issued 6.4 million common units to the public in 2014 under this program, for total net proceeds of $327 million, and 0.6 million common units in 2013, for total net proceeds of $24 million.

In April 2013, SEP issued 5.2 million common units to the public, representing limited partner interests, and 0.1 million general partner units to Spectra Energy. Total net proceeds to SEP were $193 million (net proceeds to Spectra Energy were $190 million). Net proceeds to SEP were temporarily invested in restricted available-for-sale securities until the U.S. Assets Dropdown, at which time the funds were used to pay for a portion of the dropdown transaction. In connection with the sale of the units, a $61 million gain ($38 million net of tax) to Additional Paid-in Capital and a $128 million increase in Equity-Noncontrolling Interests were recorded in 2013.

In 2012, SEP issued 5.5 million common units to the public, representing limited partner interests, and 0.1 million general partner units to Spectra Energy. Total net proceeds to SEP were $148 million (net proceeds to Spectra Energy were $145 million) and were restricted for the purpose of funding SEP's capital expenditures and acquisitions. In connection with the sale of the units, a $42 million gain ($26 million net of tax) to Additional Paid-in Capital and a $108 million increase in Equity-Noncontrolling Interests were recorded in 2012.

3. Acquisitions and Dispositions

Acquisitions. We consolidate assets and liabilities from acquisitions as of the purchase date and include earnings from acquisitions in consolidated earnings after the purchase date. Assets acquired and liabilities assumed are recorded at estimated fair values on the date of acquisition. The purchase price less the estimated fair value of the acquired assets and liabilities meeting the definition of a "business" is recorded as goodwill. The allocation of the purchase price may be adjusted if additional information is received during the allocation period, which generally does not exceed one year from the consummation date.

Express-Platte. In March 2013, we acquired 100% of the ownership interests in the Express-Platte crude oil pipeline system for $1.5 billion, consisting of $1.25 billion in cash and $260 million of acquired debt, before working capital adjustments. The Express-Platte pipeline system, which begins in Hardisty, Alberta, and terminates in Wood River, Illinois, is comprised of both the Express and Platte crude oil pipelines. The Express pipeline carries crude oil to U.S. refining markets in the Rockies area, including Montana, Wyoming, Colorado and Utah. The Platte pipeline, which interconnects with Express pipeline in Casper, Wyoming, transports crude oil predominantly from the Bakken shale and western Canada to refineries in the Midwest. In 2013, subsidiaries of Spectra Energy contributed a 100% interest in the U.S. portion of Express-Platte and sold a 100% ownership interest in the Canadian portion to SEP. See Note 2 for further discussion.

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The following table summarizes the fair values of the assets and liabilities acquired as of the date of the acquisition.

	Purchase Price Allocation (in millions)
Cash purchase price	$ 1,250
Working capital and other purchase adjustments	71
Total	1,321
Cash	67
Receivables	25
Other current assets	9
Property, plant and equipment	1,251
Accounts payable	(18)
Other current liabilities	(17)
Deferred credits and other liabilities	(259)
Long-term debt, including current portion	(260)
Total assets acquired/liabilities assumed	798
Goodwill	$ 523

The purchase price is greater than the sum of fair values of the net assets acquired, resulting in goodwill as noted above. The goodwill reflects the value of the strategic location of the pipeline and the opportunity to grow the business. Goodwill related to the acquisition of Express-Platte is not deductible for income tax purposes.

The allocation of the fair values of assets and liabilities acquired related to the acquisition of Express-Platte was finalized in the first quarter of 2014, resulting in the following adjustments to amounts reported as of December 31, 2013: a $60 million decrease in Property, Plant and Equipment, a $1 million decrease in Other Current Assets and a $24 million decrease in Deferred Credits and Other Liabilities, resulting in a $37 million increase in Goodwill.

Sand Hills and Southern Hills. In 2012, Spectra Energy acquired direct one-third ownership interests in Sand Hills and Southern Hills NGL pipelines from DCP Midstream for an aggregate $459 million, both of which were placed in service during the second quarter of 2013. DCP Partners, DCP Midstream's master limited partnership, and Phillips 66 also each own direct one-third ownership interests in the two pipelines. The Sand Hills pipeline provides NGL transportation from the Permian and Eagle Ford basins to the premium NGL markets on the Gulf Coast. The Southern Hills pipeline provides NGL transportation from the Midcontinent to Mont Belvieu, Texas. In November 2013, subsidiaries of Spectra Energy contributed their 33% direct interests in Sand Hills and Southern Hills to SEP in connection with the U.S. Assets Dropdown. See Note 2 for further discussion. Our investments in Sand Hills and Southern Hills are included in Investments in and Loans to Unconsolidated Affiliates on our Consolidated Balance Sheets and Statements of Cash Flows.

Pro forma results of operations reflecting these acquisitions as if the acquisitions had occurred as of the beginning of the periods presented in this report do not materially differ from actual results reported in our Consolidated Statements of Operations.

4. Business Segments

We manage our business in four reportable segments: Spectra Energy Partners, Distribution, Western Canada Transmission & Processing and Field Services. The remainder of our business operations is presented as "Other," and consists of unallocated corporate costs and employee benefit plan assets and liabilities, 100%-owned captive insurance subsidiaries and other miscellaneous activities.

Our chief operating decision maker (CODM) regularly reviews financial information about each of these segments in deciding how to allocate resources and evaluate performance. There is no aggregation within our reportable business segments.

The presentation of our Spectra Energy Partners segment is reflective of the parent-level focus by our CODM, considering the resource allocation and governance provisions associated with SEP's master limited partnership structure. SEP maintains a capital and cash management structure that is separate from Spectra Energy's, is self-funding and maintains its own lines of bank credit and cash management accounts. It is in this context that our

CODM evaluates the Spectra Energy Partners segment as a whole, without regard to any of SEP’s individual businesses. These factors, coupled with a different cost of capital

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of our other businesses, serve to differentiate how our Spectra Energy Partners segment is managed as compared to how SEP is managed.

Spectra Energy Partners provides transmission, storage and gathering of natural gas, as well as the transportation of crude oil and NGLs through interstate pipeline systems for customers in various regions of the midwestern, northeastern and southeastern United States and Canada. The natural gas transmission and storage operations are primarily subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC). The crude oil transportation operations are primarily subject to regulation by the FERC in the U.S. and the National Energy Board (NEB) in Canada. Our Spectra Energy Partners segment is composed of the operations of SEP, less governance costs, which are included in “Other.”

Distribution provides retail natural gas distribution service in Ontario, Canada, as well as natural gas transmission and storage services to other utilities and energy market participants. These services are provided by Union Gas Limited (Union Gas), and are primarily subject to the rules and regulations of the OEB.

Western Canada Transmission & Processing provides transmission of natural gas, natural gas gathering and processing services, and NGL extraction, fractionation, transportation, storage and marketing to customers in western Canada, the northern tier of the United States and the Maritime Provinces in Canada. This segment conducts business mostly through BC Pipeline, BC Field Services, and the NGL marketing and Canadian Midstream businesses, and Maritimes & Northeast Pipeline Limited Partnership (M&N Canada). BC Pipeline and BC Field Services and M&N Canada operations are primarily subject to the rules and regulations of the NEB.

Field Services gathers, compresses, treats, processes, transports, stores and sells natural gas, produces, fractionates, transports, stores and sells NGLs, recovers and sells condensate, and trades and markets natural gas and NGLs. It conducts operations through DCP Midstream, which is owned 50% by us and 50% by Phillips 66. DCP Midstream gathers raw natural gas through gathering systems connecting to several interstate and intrastate natural gas NGL pipeline systems, one natural gas storage facility and one NGL storage facility. DCP Midstream operates in a diverse number of regions, including the Permian Basin, Eagle Ford, Niobrara/DJ Basin and the Midcontinent. DCP Midstream Partners, LP (DCP Partners) is a publicly traded master limited partnership, of which DCP Midstream acts as general partner. As of December 31, 2014, DCP Midstream had an approximate 22% ownership interest in DCP Partners, including DCP Midstream’s limited partner and general partner interests.

Our reportable segments offer different products and services and are managed separately as business units. Management evaluates segment performance based on earnings from continuing operations before interest, taxes, depreciation and amortization (EBITDA). Cash, cash equivalents and short-term investments are managed at the parent-company levels, so the associated gains and losses from foreign currency transactions and interest and dividend income are excluded from the segments’ EBITDA. Our segment EBITDA may not be comparable to similarly titled measures of other companies because other companies may not calculate EBITDA in the same manner. Transactions between reportable segments are accounted for on the same basis as transactions with unaffiliated third parties.

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Business Segment Data

	Unaffiliated Revenues	Intersegment Revenues	Total Operating Revenues (a)	Segment EBITDA/ Consolidated Earnings from Continuing Operations before Income Taxes (a)	Depreciation and Amortization (a)	Capital and Investment Expenditures (b,c)	Assets
	(in millions)						
2014							
Spectra Energy Partners	$2,269	$—	$ 2,269	$ 1,669	$ 290	$ 1,241	$17,865
Distribution	1,843	—	1,843	552	192	427	6,064
Western Canada Transmission & Processing	1,781	121	1,902	754	271	473	6,916
Field Services	—	—	—	217	—	—	1,345
Total reportable segments	5,893	121	6,014	3,192	753	2,141	32,190
Other	10	62	72	(58)	43	146	1,908
Eliminations	—	(183)	(183)	—	—	—	(58)
Depreciation and amortization	—	—	—	796	—	—	—
Interest expense	—	—	—	679	—	—	—
Interest income and other	—	—	—	6	—	—	—
Total consolidated	$5,903	$—	$ 5,903	$ 1,665	$ 796	$ 2,287	$34,040
2013							
Spectra Energy Partners	$1,964	$1	$ 1,965	$ 1,433	$ 263	$ 1,299	$16,800
Distribution	1,848	—	1,848	574	199	357	6,009
Western Canada Transmission & Processing	1,694	73	1,767	736	272	561	7,160
Field Services	—	—	—	343	—	—	1,365
Total reportable segments	5,506	74	5,580	3,086	734	2,217	31,334
Other	12	60	72	(86)	38	42	2,698
Eliminations	—	(134)	(134)	—	—	—	(499)
Depreciation and amortization	—	—	—	772	—	—	—
Interest expense	—	—	—	657	—	—	—
Interest income and other	—	—	—	7	—	—	—
Total consolidated	$5,518	$—	$ 5,518	$ 1,578	$ 772	$ 2,259	$33,533
2012							
Spectra Energy Partners	$1,754	$—	$ 1,754	$ 1,259	$ 232	$ 1,443	$13,856
Distribution	1,666	—	1,666	587	213	276	5,842
Western Canada Transmission & Processing	1,645	34	1,679	694	245	760	7,226
Field Services	—	—	—	279	—	—	1,235
Total reportable segments	5,065	34	5,099	2,819	690	2,479	28,159
Other	10	79	89	(36)	56	66	2,967
Eliminations	—	(113)	(113)	—	—	—	(539)
Depreciation and amortization	—	—	—	746	—	—	—
Interest expense	—	—	—	625	—	—	—
Interest income and other	—	—	—	3	—	—	—

Total consolidated	$5,075	$—	$ 5,075	$ 1,415	$ 746	$ 2,545	$30,587

(a) Excludes amounts associated with entities included in discontinued operations.

(b) Excludes the $1,254 million cash outlay for the acquisition of Express-Platte in March 2013 and $30 million paid in 2012 for amounts previously withheld from the purchase price consideration of the acquisition of Bobcat in 2010, all part of Spectra Energy Partners.

(c) Excludes a $71 million loan to an unconsolidated affiliate in 2013 at Spectra Energy Partners.

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Geographic Data

	U.S. (in millions)	Canada	Consolidated
2014			
Consolidated revenues	$2,212	$3,691	$5,903
Consolidated long-lived assets	15,859	12,732	28,591
2013			
Consolidated revenues	1,926	3,592	5,518
Consolidated long-lived assets	14,993	13,264	28,257
2012			
Consolidated revenues (a)	1,762	3,313	5,075
Consolidated long-lived assets	10,952	14,875	25,827

(a) Excludes revenues associated with businesses included in discontinued operations.

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5. Regulatory Matters
Regulatory Assets and Liabilities
We record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. See Note 1 for further discussion.

	December 31,		Recovery/
	2014	2013	Refund Period Ends
	(in millions)		
Regulatory Assets (a,b)			
Net regulatory asset related to income taxes (c,d)	$1,271	$1,224	(e)
Project development costs	10	14	2036
Vacation accrual	22	21	(f)
Deferred debt expense/premium (d)	31	32	(e)
Under-recovery of fuel costs (g,h)	44	28	2015
Gas purchase costs (h,i)	57	—	2015
Other	59	57	(j)
Total Regulatory Assets	$1,494	$1,376	
Regulatory Liabilities (b)			
Removal costs (d,k)	$326	$359	(l)
FT-RAM optimization (m)	—	31	2014
Gas purchase costs (i,m)	—	7	2014
Pipeline rate credit (k)	25	27	(e)
Over-recovery of fuel costs (i,m)	—	35	2014
Other (d)	79	51	(j)
Total Regulatory Liabilities	$430	$510	

(a) Included in Regulatory Assets and Deferred Debits unless otherwise noted.
(b) All regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(c) All amounts are expected to be included in future rate filings.
(d) All or a portion of the balance is included in rate base.
(e) Recovery/refund is over the life of the associated asset or liability.
(f) Recoverable in future periods.
(g) Amounts settled in cash annually through transportation rates in accordance with FERC gas tariffs.
(h) Included in Other Current Assets.
(i) Includes certain costs which are settled in cash annually through transportation rates in accordance with FERC and/or OEB gas tariffs.
(j) The majority of this balance has a recovery period of less than one year. The recovery/refund period for the remainder is currently unknown.
(k) Included in Deferred Credits and Other Liabilities — Regulatory and Other.
(l) Liability is extinguished as the associated assets are retired.
(m) Included in Other Current Liabilities.

Union Gas. Union Gas has regulatory assets of $303 million as of December 31, 2014 and $308 million as of December 31, 2013 related to deferred income tax liabilities. Under the current OEB-authorized rate structure, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since substantially all of these timing differences are related to property, plant and equipment costs, recovery of these regulatory assets is expected to occur over the life of those assets.

Union Gas has regulatory liabilities associated with plant removal costs of $322 million as of December 31, 2014 and $354 million as of December 31, 2013. These regulatory liabilities represent collections from customers under approved rates for future asset removal activities that are expected to occur associated with its regulated facilities.

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In addition, Union Gas has regulatory assets of $57 million as of December 31, 2014 and regulatory liabilities of $7 million as of December 31, 2013 representing gas cost collections from customers under approved rates that vary from actual cost of gas for the associated periods. Union Gas files an application quarterly with the OEB to ensure that customers' rates are updated to reflect published forward-market prices. The difference between the approved and the actual cost of gas is deferred for future repayment to or refund from customers.

BC Pipeline and BC Field Services. The BC Pipeline and BC Field Services businesses in western Canada have regulatory assets of $795 million as of December 31, 2014 and $774 million as of December 31, 2013 related to deferred income tax liabilities. Under the current NEB-authorized rate structure, income tax costs are recovered in tolls based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that transportation and field services tolls will be adjusted to recover these taxes. Since most of these timing differences are related to property, plant and equipment costs, this recovery is expected to occur over a 20 to 30 year period.

When evaluating the recoverability of the BC Pipelines' and BC Field Services' regulatory assets, we take into consideration the NEB regulatory environment, natural gas reserve estimates for reserves located or expected to be located near these assets, the ability to remain competitive in the markets served and projected demand growth estimates for the areas served by the BC Pipeline and BC Field Services businesses. Based on current evaluation of these factors, we believe that recovery of these tax costs is probable over the periods described above.

Rate Related Information

Union Gas. In 2012, the OEB determined that revenues derived from the optimization of Union Gas' upstream transportation contracts in 2011 would be treated as a reduction to gas costs rather than being treated as optimization revenues and included in utility earnings. Optimization revenues had been classified as utility earnings for 2008, 2009, 2010, and subsequently 2012, as described in the following paragraph. This decision was appealed to the Ontario Divisional Court on the basis of impermissible retroactive ratemaking. The appeal was dismissed in December 2013. In May 2014, Union Gas filed a notice of appeal to the Ontario Court of Appeal and a hearing was held in December 2014. A decision from the Ontario Court of Appeal is expected in 2015.

Union Gas filed an application with the OEB in May 2013 for the annual disposition of the 2012 deferral account balances. A decision on that application was issued by the OEB in March 2014. Among other things, the OEB determined that revenues derived from the optimization of Union Gas' upstream transportation contracts in 2012 will be treated as revenues and included in utility earnings rather than as a reduction to gas costs. The decision also denied a proposal to recover certain over-refunds to customers and reduced incentive amounts related to Union Gas' 2011 energy conservation program. As a result of this OEB decision, Union Gas recognized pre-tax income of $10 million in the first quarter of 2014, comprised of a $32 million increase in Transportation, Storage and Processing of Natural Gas revenues, a $15 million decrease in Distribution of Natural Gas revenues and a $7 million decrease in Other revenues on the Consolidated Statements of Operations. In addition, the decision approved the deferral of pension expense for recovery from customers, resulting in pre-tax income of $7 million, recorded as a reduction in Operating, Maintenance and Other expense in the second quarter of 2014.

In May 2014, Union Gas filed an application with the OEB for the annual disposition of its 2013 deferral account balances, excluding the energy conservation deferral accounts. The combined impact of the 2013 deferral account balances is a net payable to customers of approximately $19 million which is primarily reflected as Current Liabilities—Other on the Consolidated Balance Sheets at December 31, 2014 and 2013. In October 2014, the OEB approved the balances with no significant impact to the amounts filed. The net payable to customers is being refunded over a six month period that began January 1, 2015.

In December 2014, Union Gas filed an application with the OEB for the disposition of the 2013 energy conservation deferral and variance account balances. As a result of this application, Union Gas has a receivable from customers of approximately $9 million. A hearing and decision from the OEB is expected in 2015.

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6. Income Taxes

Income Tax Expense Components

	2014	2013	2012
	(in millions)		
Current income taxes			
Federal	$1	$(32)	$102
State	3	4	5
Foreign	(10)	26	52
Total current income taxes	(6)	(2)	159
Deferred income taxes			
Federal	335	353	174
State	(17)	69	33
Foreign	70	(1)	4
Total deferred income taxes	388	421	211
Income tax expense from continuing operations	382	419	370
Income tax expense from discontinued operations	—	—	2
Total income tax expense	$382	$419	$372

Earnings from Continuing Operations before Income Taxes

	2014	2013	2012
	(in millions)		
Domestic	$1,108	$1,059	$912
Foreign	557	519	503
Total earnings from continuing operations before income taxes	$1,665	$1,578	$1,415

Reconciliation of Income Tax Expense at the U.S. Federal Statutory Tax Rate to Actual Income Tax Expense from Continuing Operations

	2014	2013	2012
	(in millions)		
Income tax expense, computed at the statutory rate of 35%	$583	$552	$495
State income tax, net of federal income tax effect	25	20	19
Tax differential on foreign earnings	(125)	(147)	(110)
Noncontrolling interests	(70)	(42)	(37)
Valuation allowance	2	(3)	1
Revaluation of accumulated deferred state taxes	(25)	31	—
Other items, net	(8)	8	2
Total income tax expense from continuing operations	$382	$419	$370
Effective tax rate	22.9%	26.6%	26.1%

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Net Deferred Income Tax Liability Components

	December 31, 2014	2013
	(in millions)	
Deferred credits and other liabilities	$225	$242
Other	211	291
Total deferred income tax assets	436	533
Valuation allowance	(29)	(29)
Net deferred income tax assets	407	504
Investments and other assets	(1,531)	(1,004)
Accelerated depreciation rates	(3,875)	(4,092)
Regulatory assets and deferred debits	(426)	(383)
Total deferred income tax liabilities	(5,832)	(5,479)
Total net deferred income tax liabilities	$(5,425)	$(4,975)

The above deferred tax amounts have been classified in the Consolidated Balance Sheets as follows:

	December 31, 2014	2013
	(in millions)	
Other current assets	$—	$9
Other current liabilities	(20)	(16)
Deferred credits and other liabilities	(5,405)	(4,968)
Total net deferred income tax liabilities	$(5,425)	$(4,975)

At December 31, 2014, we had a federal net operating loss carryforward of $379 million that expires at various times beginning in 2021. The deferred tax asset attributable to the federal net operating loss is $133 million. At December 31, 2014 we also had a state net operating loss carryforward of approximately $299 million that expires at various times beginning in 2016. The deferred tax asset attributable to the state net operating loss carryovers is $15 million (net of federal impacts) at December 31, 2014. We had valuation allowances of $9 million at December 31, 2014 and $7 million at December 31, 2013 against the deferred tax asset related to the federal net operating loss carryforward.

At December 31, 2014, we had a foreign net operating loss carryforward of $40 million that expires at various times beginning in 2015. The deferred tax asset attributable to the foreign net operating loss is $10 million. At December 31, 2014, we also had a foreign capital loss carryforward of $151 million with an indefinite expiration period. The deferred tax asset attributable to the foreign capital loss carryforward is $20 million. We had valuation allowances of $20 million and $22 million at December 31, 2014 and 2013, respectively, against the deferred tax asset related to the foreign capital loss carryforward.

Reconciliation of Gross Unrecognized Income Tax Benefits

	2014	2013	2012
	(in millions)		
Balance at beginning of period	$76	$80	$76
Increases related to prior year tax positions	10	7	5
Decreases related to prior year tax positions	(6)	(17)	—
Increases related to current year tax positions	1	2	2
Settlements	—	(3)	(2)
Lapse of statute of limitations	(30)	9	(2)
Foreign currency translation	(1)	(2)	1
Balance at end of period	$50	$76	$80

Unrecognized tax benefits totaled $50 million at December 31, 2014. Of this, $33 million would reduce the annual effective tax rate if recognized on or after January 1, 2015. We recorded a net decrease of $26 million in gross unrecognized tax benefits during 2014. This was a result of $27 million attributable to deferred tax liabilities and foreign currency exchange rate fluctuations offset by a $1 million increase in income tax expense.

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We recognize potential accrued interest and penalties related to unrecognized tax benefits as interest expense and as other expense, respectively. We recognized interest income of $2 million in 2014 and $4 million in 2013 related to unrecognized tax benefits. Accrued interest and penalties totaled $19 million at December 31, 2014 and $21 million at December 31, 2013.

Although uncertain, we believe it is reasonably possible that the total amount of unrecognized tax benefits could decrease by $15 million to $20 million prior to December 31, 2015.

We remain subject to examination for Canada income tax return filings for years 2009 through 2013 and U.S. income tax return filings for 2007 through 2013.

We have foreign subsidiaries' undistributed earnings of approximately $1.8 billion at December 31, 2014 that are indefinitely invested outside the United States and, accordingly, no U.S. federal or state income taxes have been provided on those earnings. Upon distribution of those earnings, we may be subject to both foreign withholding taxes and U.S. income taxes, net of allowable foreign tax credits. The amount of such additional taxes would be dependent on several factors, including the size and timing of the distribution and the availability of foreign tax credits. As a result, the determination of the potential amount of unrecognized withholding and deferred income taxes is not practicable.

In September 2013, the U.S. Treasury and the Internal Revenue Service (IRS) issued final regulations regarding the deduction and capitalization of expenditures related to tangible property (tangible property regulations). The final IRS regulations apply to amounts paid to acquire, produce or improve tangible property as well as dispositions of such property and are for tax years beginning on or after January 1, 2014. The tangible property regulations impact the timing of the deductibility of these expenditures for tax purposes and therefore the impact resulted in an increase in our future tax liability with a corresponding increase in our net operating loss carryforward. Our earnings will not be impacted.

7. Discontinued Operations

Discontinued operations in 2012 were mostly comprised of the net effects of a settlement arrangement related to prior liquefied natural gas (LNG) contracts.

The following table summarizes results classified as Income From Discontinued Operations, Net of Tax in the accompanying Consolidated Statements of Operations:

	2012 (in millions)
Operating revenues	$99
Pre-tax earnings	4
Income tax expense	2
Income from discontinued operations, net of tax	2

Spectra Energy LNG Sales, Inc. (Spectra Energy LNG) reached a settlement agreement in 2007 related to an arbitration proceeding regarding Spectra Energy LNG's claims for the period prior to May 2002 under certain liquefied natural gas LNG transportation contracts with Sonatrach and Sonatrading Amsterdam B.V. (Sonatrach). Spectra Energy LNG was one of the entities contributed to us by Duke Energy in connection with our spin-off from Duke Energy and has been reflected as discontinued operations. In 2008, Sonatrach and Spectra Energy entered into a settlement agreement under which Spectra Energy LNG's claims for the period after May 2002 were to be satisfied pursuant to commercial transactions involving the purchase of propane by Spectra Energy Propane, LLC (a subsidiary) from Sonatrach. We subsequently entered into associated agreements with what are now affiliates of DCP Midstream for the sale of this propane. Net purchases and sales of propane under these arrangements are reflected as discontinued operations within the "Other" business segment. Purchases and sales of propane under these agreements ended in 2012.

8. Earnings per Common Share

Basic earnings per common share (EPS) is computed by dividing net income from controlling interests by the weighted-average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income from controlling interests by the diluted weighted-average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock, such as stock options, stock-based performance unit awards and phantom stock awards, were exercised, settled or converted into common stock.

Weighted-average shares used to calculate diluted EPS includes the effect of certain options and restricted stock awards. In 2014 and 2013, there were no options or stock awards that were not included in the calculation of diluted EPS. Certain other

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options and stock awards related to less than one million shares in 2012 were not included in the calculation of diluted EPS because either the option exercise prices were greater than the average market price of the shares or performance measures related to the awards had not yet been met.

The following table presents our basic and diluted EPS calculations:

	2014	2013	2012
	(in millions, except per-share amounts)		
Income from continuing operations, net of tax — controlling interests	$1,082	$1,038	$938
Income from discontinued operations, net of tax — controlling interests	—	—	2
Net income — controlling interests	$1,082	$1,038	$940
Weighted-average common shares outstanding			
Basic	671	669	653
Diluted	672	671	656
Basic earnings per common share	$1.61	$1.55	$1.44
Diluted earnings per common share	$1.61	$1.55	$1.43

Income from discontinued operations in 2012 had no effect on basic or diluted EPS.

9. Accumulated Other Comprehensive Income

The following table presents the net of tax changes in AOCI by component and amounts reclassified out of AOCI to Net Income, excluding amounts attributable to noncontrolling interests:

	Foreign Currency Translation Adjustments	Pension and Post-retirement Benefit Plan Obligations	Gas Purchase Contract Hedges	Other	Total Accumulated Other Comprehensive Income
			(in millions)		
December 31, 2012	$ 2,044	$ (507)	$(23)	$(5)	$ 1,509
Reclassified to net income	—	—	6	1	7
Other AOCI activity	(487)	203	6	3	(275)
December 31, 2013	1,557	(304)	(11)	(1)	1,241
Reclassified to net income	—	—	4	1	5
Other AOCI activity	(541)	(47)	4	—	(584)
December 31, 2014	$ 1,016	$ (351)	$(3)	$—	$ 662

Reclassifications to Net Income are primarily included in Other Income and Expenses, Net on our Consolidated Statements of Operations.

10. Inventory

The components of inventory are as follows:

	December 31, 2014	2013
	(in millions)	
Natural gas	$211	$155
NGLs	28	30
Materials and supplies	74	78
Total inventory	$313	$263

Non-cash charges totaling $19 million in 2014 ($14 million after tax) were recorded to Natural Gas and Petroleum Products Purchased on the Consolidated Statements of Operations to reduce propane inventory at our Empress operations at Western Canada Transmission & Processing to estimated net realizable value. There were no non-cash charges to inventory in 2013.

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11. Investments in and Loans to Unconsolidated Affiliates and Related Party Transactions
Investments in affiliates for which we are not the primary beneficiary, but over which we have significant influence, are accounted for using the equity method. As of December 31, 2014 and 2013, the carrying amounts of investments in affiliates approximated the amounts of underlying equity in net assets. We received distributions from our equity investments of $646 million in 2014, $411 million in 2013 and $324 million in 2012. Cumulative undistributed earnings of unconsolidated affiliates totaled $482 million at December 31, 2014 and $507 million at December 31, 2013.
Spectra Energy Partners. As of December 31, 2014, our Spectra Energy Partners segment investments were mostly comprised of a 41% effective interest in Gulfstream, a 41% effective interest in SESH, a 41% effective interest in Steckman Ridge and 27% effective interests in Sand Hills and Southern Hills. Our remaining 0.1% interest in SESH is currently held in “Other” and is expected to be contributed in November 2015. We also own additional 4% effective interests in Sand Hills and Southern Hills through our ownership interest in DCP Midstream, which is held in our Field Services segment.
We have a loan outstanding to Steckman Ridge in connection with the construction of its storage facilities. The loan carries market-based interest rates and is due the earlier of October 1, 2023 or coincident with the closing of any long-term financings by Steckman Ridge. The loan receivable from Steckman Ridge, including accrued interest, totaled $71 million at both December 31, 2014 and 2013. We recorded interest income on the Steckman Ridge loan of $1 million in each of 2014, 2013 and 2012. In conjunction with the U.S. Assets Dropdown in November 2013, Steckman Ridge repaid the loan to a subsidiary of Spectra Energy Corp and subsequently borrowed $71 million directly from SEP.
Field Services. Our most significant investment in unconsolidated affiliates is our 50% investment in DCP Midstream, which is accounted for under the equity method of accounting. DCP Partners, DCP Midstream’s master limited partnership, also has direct one-third equity investments in Sand Hills and Southern Hills. DCP Midstream is a limited liability company which is a pass-through entity for U.S. income tax purposes. DCP Midstream also owns an entity which files its own federal, foreign and state income tax returns. Income tax expense related to that entity is included in the income tax expense of DCP Midstream. Therefore, DCP Midstream’s net income attributable to members’ interests does not include income taxes for earnings which are passed through to the members based upon their ownership percentage. We recognize the tax effects of our share of DCP Midstream’s pass-through earnings in Income Tax Expense from Continuing Operations in the Consolidated Statements of Operations.
DCP Partners issues, from time to time, limited partner units to the public, which are recorded by DCP Midstream directly to its equity. Our proportionate 50% share of gains from those issuances, totaling $73 million in 2014, $98 million in 2013 and $36 million in 2012, are reflected in Equity in Earnings of Unconsolidated Affiliates in the Consolidated Statements of Operations.
Investments in and Loans to Unconsolidated Affiliates

	December 31, 2014			December 31, 2013		
	Domestic	International	Total	Domestic	International	Total
	(in millions)					
Spectra Energy Partners	$1,588	$ —	$1,588	$1,396	$ —	$1,396
Distribution	—	14	14	—	16	16
Western Canada Transmission & Processing	—	18	18	—	66	66
Field Services	1,345	—	1,345	1,365	—	1,365
Other	1	—	1	200	—	200
Total	$2,934	$ 32	$2,966	$2,961	$ 82	$3,043

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Equity in Earnings of Unconsolidated Affiliates

	2014			2013			2012		
	Domestic	International	Total	Domestic	International	Total	Domestic	International	Total
	(in millions)								
Spectra Energy Partners	$133	$—	$133	$90	$—	$90	$89	$—	$89
Distribution	—	1	1	—	1	1	—	—	—
Western Canada Transmission & Processing	—	1	1	—	(1)	(1)	—	1	1
Field Services	217	—	217	343	—	343	279	—	279
Other	9	—	9	12	—	12	13	—	13
Total	$359	$2	$361	$445	$—	$445	$381	$1	$382

Summarized Combined Financial Information of Unconsolidated Affiliates (Presented at 100%)

Statements of Operations

	2014			2013			2012		
	DCP Midstream	Other	Total	DCP Midstream	Other	Total	DCP Midstream	Other	Total
	(in millions)								
Operating revenues	$14,013	$744	$14,757	$12,038	$558	$12,596	$10,171	$511	$10,682
Operating expenses	13,262	319	13,581	11,230	261	11,491	9,427	217	9,644
Operating income	751	425	1,176	808	297	1,105	744	294	1,038
Net income	536	332	868	584	206	790	583	203	786
Net income attributable to members' interests	288	332	620	491	206	697	486	203	689

Balance Sheets

	December 31, 2014			December 31, 2013		
	DCP Midstream	Other	Total	DCP Midstream	Other	Total
	(in millions)					
Current assets	$1,380	$241	$1,621	$1,663	$248	$1,911
Non-current assets	12,299	5,358	17,657	11,058	5,448	16,506
Current liabilities	(2,938)	(632)	(3,570)	(3,114)	(143)	(3,257)
Non-current liabilities	(5,538)	(1,197)	(6,735)	(5,218)	(1,670)	(6,888)
Equity — total	5,203	3,770	8,973	4,389	3,883	8,272
Equity — noncontrolling interests	(2,578)	—	(2,578)	(1,725)	—	(1,725)
Equity — controlling interests	$2,625	$3,770	$6,395	$2,664	$3,883	$6,547

Related Party Transactions

DCP Midstream. DCP Midstream processes certain of our pipeline customers' gas to meet gas quality specifications in order to be transported on our Texas Eastern system. DCP Midstream processes the gas and sells the NGLs that are extracted from the gas. A portion of the proceeds from those sales are retained by DCP Midstream and the balance is remitted to us. We received proceeds of $79 million in 2014, $48 million in 2013 and $53 million in 2012 from DCP Midstream related to those sales, classified as Other Operating Revenues in our Consolidated Statements of Operations.

As discussed in Note 7, we entered into a propane sales agreement with an affiliate of DCP Midstream in 2008. We recorded revenues of $99 million in 2012 associated with this agreement classified within Income From Discontinued Operations, Net of Tax. Sales of propane under this agreement ended in 2012.

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In addition to the above, we recorded other revenues from DCP Midstream and its affiliates totaling $9 million in 2014 and 2013 and $12 million in 2012, primarily within Transportation, Storage and Processing of Natural Gas, and $7 million in 2014, $8 million in 2013 and $14 million in 2012 within Sales of Natural Gas Liquids.

We had accounts receivable from DCP Midstream and its affiliates of $1 million at December 31, 2014 and December 31, 2013. Total distributions received from DCP Midstream were $237 million in 2014, $215 million in 2013 and $203 million in 2012, classified as Cash Flows from Operating Activities — Distributions Received From Unconsolidated Affiliates.

In 2012, we acquired direct one-third ownership interests in Sand Hills and Southern Hills from DCP Midstream for $459 million. See Notes 2 and 3 for further discussion.

Other. We provide certain administrative and other services to certain other operating entities. We recorded recoveries of costs from these affiliates of $38 million in 2014, $68 million in 2013 and $70 million in 2012. Outstanding receivables from these affiliates totaled $1 million at December 31, 2014 and $23 million at December 31, 2013.

See also Notes 3, 17 and 19 for additional related party information.

12. Goodwill

The following table presents activity within goodwill based on the reporting unit determination:

	Spectra Energy Partners	Distribution	Western Canada Transmission & Processing	Total
	(in millions)			
December 31, 2012	$2,814	$878	$821	$4,513
Acquisition of Express-Platte	486	—	—	486
Foreign currency translation	(85)	(54)	(50)	(189)
December 31, 2013	3,215	824	771	4,810
Adjustment to acquisition of Express-Platte	37	—	—	37
Foreign currency translation	(8)	(65)	(60)	(133)
December 31, 2014	$3,244	$759	$711	$4,714

See Note 3 for discussion of the acquisition of Express-Platte and an adjustment to Goodwill recorded in the first quarter of 2014 related to the acquisition.

The following remaining goodwill amounts originating from the acquisition of Westcoast Energy, Inc. (Westcoast) in 2002 are included as segment assets within “Other” in the segment data presented in Note 4:

	December 31, 2014	2013
	(in millions)	
Distribution	$757	$821
Western Canada Transmission & Processing	677	736

Certain commodity prices, specifically NGLs, have fluctuated in 2013 and 2014. Within the Western Canada Transmission & Processing segment, our Empress NGL business is significantly affected by fluctuations in commodity prices. NGL prices have significantly declined in the fourth quarter of 2014 from levels earlier in 2014. Effective January 2014, we implemented a commodity hedging program at Empress to economically hedge a significant portion of their future NGL sales and related make-up gas purchases, which has mitigated the effects of short-term commodity price fluctuations. This hedging program is designed to reduce cash inflow volatility despite year to year earnings volatility. A sustained decline in NGL prices would reduce earnings and potentially serve as a triggering event to test goodwill for impairment at the Empress NGL reporting unit, which could result in an impairment.

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13. Marketable Securities and Restricted Funds

We routinely invest excess cash and various restricted balances in securities such as commercial paper, bankers acceptances, corporate debt securities, treasury bills and money market funds in the United States and Canada. We do not purchase marketable securities for speculative purposes, therefore we do not have any securities classified as trading securities. While we do not routinely sell marketable securities prior to their scheduled maturity dates, some of our investments may be held and restricted for insurance purposes, so these investments are classified as AFS marketable securities as they may occasionally be sold prior to their scheduled maturity dates due to the unexpected timing of cash needs. Initial investments in securities are classified as purchases of the respective type of securities (AFS marketable securities or HTM marketable securities). Maturities of securities are classified within proceeds from sales and maturities of securities in the Consolidated Statements of Cash Flows.

AFS Securities. AFS securities are as follows:

	Estimated Fair Value December 31,	
	2014	2013
	(in millions)	
Corporate debt securities	$23	$18
Money market funds	1	1
Total available-for-sale securities	$24	$19

Our AFS securities are classified on the Consolidated Balance Sheets as follows:

	Estimated Fair Value December 31,	
	2014	2013
	(in millions)	
Restricted funds		
Investments and other assets—other	$1	$1
Non-restricted funds		
Current assets—other	3	7
Investments and other assets—other	20	11
Total available-for-sale securities	$24	$19

During the second quarter of 2013, we invested the proceeds from SEP's issuance of common units in AFS marketable securities, which were restricted for the purpose of funding SEP's future capital expenditures and acquisitions. In September 2013, we invested the net proceeds from SEP's $1.9 billion issuance of long-term debt in AFS marketable securities, which were restricted for the purpose of paying a portion of the cash consideration for Spectra Energy's U.S. Assets Dropdown to SEP. These investments and SEP's other remaining restricted funds held for the purpose of funding capital expenditures and acquisitions were used to pay Spectra Energy for the U.S. Assets Dropdown on November 1, 2013.

At December 31, 2014, the weighted–average contractual maturity of outstanding AFS securities was less than two years.

There were no material gross unrealized holding gains or losses associated with investments in AFS securities at December 31, 2014 or 2013.

HTM Securities. All of our HTM securities are restricted funds and are as follows:

		Estimated Fair Value December 31,	
Description	Consolidated Balance Sheet Caption	2014	2013
		(in millions)	
Bankers acceptances	Current assets—other	$38	$35

Canadian government securities	Current assets—other	30	34
Money market funds	Current assets—other	3	3
Canadian government securities	Investments and other assets—other	101	131
Bankers acceptances	Investments and other assets—other	—	10
Total held-to-maturity securities		$172	$213

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All of our HTM securities are restricted funds pursuant to certain M&N Canada and Express-Platte debt agreements. The funds restricted for M&N Canada, plus future cash from operations that would otherwise be available for distribution to the partners of M&N Canada, are required to be placed in escrow until the balance in escrow is sufficient to fund all future debt service on the M&N Canada 6.90% senior secured notes. There are sufficient funds held in escrow to fund all future debt service on these M&N Canada notes as of December 31, 2014.

At December 31, 2014, the weighted–average contractual maturity of outstanding HTM securities was less than one year.

There were no material gross unrecognized holding gains or losses associated with investments in HTM securities at December 31, 2014 or 2013.

Other Restricted Funds. In addition to the portions of the AFS and HTM securities that were restricted funds as described above, we had other restricted funds totaling $13 million at December 31, 2014 and $19 million at December 31, 2013 classified as Current Assets—Other. These restricted funds are related to additional amounts for the M&N Canada debt service requirements and insurance. We also had other restricted funds totaling $6 million at December 31, 2014 classified as Investments and Other Assets—Other. These restricted funds are related to funds held and collected from customers for M&N Canada pipeline abandonment in accordance with the NEB's regulatory requirements.

Changes in restricted balances are presented within Cash Flows from Investing Activities on our Consolidated Statements of Cash Flows.

Interest income. Interest income totaled $4 million in 2014, and $6 million in both 2013 and 2012, and is included in Other Income and Expenses, Net on the Consolidated Statements of Operations.

14. Property, Plant and Equipment

	Estimated Useful Life (years)	December 31, 2014 (in millions)	2013
Plant			
Natural gas transmission	15–100	$15,001	$14,491
Natural gas distribution	25–60	2,971	3,076
Gathering and processing facilities	25–40	4,765	4,848
Natural gas storage	10–122	2,162	2,113
Crude oil transportation and storage	30–75	1,169	1,243
Land rights and rights of way	21–122	568	562
Other buildings and improvements	10–50	132	134
Equipment	3–40	343	341
Vehicles	5–20	114	115
Land	—	150	128
Construction in process	—	1,113	630
Software	4–10	387	438
Other	5–82	336	337
Total property, plant and equipment		29,211	28,456
Total accumulated depreciation		(6,543)	(6,258)
Total accumulated amortization		(361)	(369)
Total net property, plant and equipment		$22,307	$21,829

We had no material capital leases at December 31, 2014 or 2013.

Almost 85% of our property, plant and equipment is regulated with estimated useful lives based on rates approved by the applicable regulatory authorities in the United States and Canada: the FERC, the NEB and the OEB. Composite weighted-average depreciation rates were 2.82% for 2014, 2.96% for 2013 and 3.14% for 2012.

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Amortization expense of intangible assets totaled $74 million in 2014, $65 million in 2013 and $81 million in 2012. Estimated amortization expense for the next five years follows:

	Estimated Amortization Expense (in millions)
2015	$ 80
2016	68
2017	57
2018	44
2019	34

15. Asset Retirement Obligations

Our ARO's relate mostly to the retirement of certain gathering pipelines and processing facilities, obligations related to right-of-way agreements and contractual leases for land use. However, we have determined that a significant portion of our assets have an indeterminate life, and as such, the fair values of those associated retirement obligations are not reasonably estimable. These assets include onshore and some offshore pipelines, and certain processing plants and distribution facilities, whose retirement dates will depend mostly on the various natural gas supply sources that connect to our systems and the ongoing demand for natural gas usage in the markets we serve. We expect these supply sources and market demands to continue for the foreseeable future, therefore we are unable to estimate retirement dates that would result in asset retirement obligations.

ARO's are adjusted each period for liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. In 2014, Western Canada Transmission & Processing revised the estimated future cash flow assumptions for its ARO liabilities relating to asbestos abatement at its processing plants which resulted in an increase to ARO liabilities by $44 million. In 2013, Union Gas, which is a rate-regulated entity, reevaluated its estimated future cash flow assumptions for its ARO liabilities in connection with its 2013 rate filing with the OEB. This resulted in an increase in its estimates of expected future costs of abandoning distribution service pipelines by $172 million.

Reconciliation of Changes in Asset Retirement Obligation Liabilities

	2014	2013
	(in millions)	
Balance at beginning of year	$350	$188
Accretion expense	16	9
Revisions in estimated cash flows (a)	72	172
Foreign currency exchange impact	(28)	(12)
Liabilities settled	(10)	(7)
Balance at end of year (b)	$400	$350

(a) Reflects revised assumptions regarding ARO Liabilities relating to asbestos abatement at Western Canada Transmission & Processing in 2014 and expected future costs of abandonments at Union Gas in 2013.
(b) Amounts included in Deferred Credits and Other Liabilities in the Consolidated Balance Sheets.

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16. Debt and Credit Facilities

Summary of Debt and Related Terms	December 31,	
	2014	2013
Spectra Energy Capital, LLC	(in millions)	
5.50% senior unsecured notes due March 2014	$—	$149
5.67% senior unsecured notes due August 2014	—	408
6.20% senior unsecured notes due April 2018	500	500
6.75% senior unsecured notes due July 2018	150	150
Variable-rate senior unsecured term loan due November 2018	300	—
8.00% senior unsecured notes due October 2019	500	500
5.65% senior unsecured notes due March 2020	300	300
3.30% senior unsecured notes due March 2023	650	650
6.75% senior unsecured notes due February 2032	240	240
7.50% senior unsecured notes due September 2038	250	250
Total Spectra Energy Capital, LLC Debt	2,890	3,147
SEP		
SEP 2.95% senior unsecured notes due June 2016	250	250
SEP 2.95% senior unsecured notes due September 2018	500	500
SEP Variable-rate senior unsecured term loan due November 2018	400	400
SEP 4.60% senior unsecured notes due June 2021	250	250
SEP 4.75% senior unsecured notes due March 2024	1,000	1,000
SEP 5.95% senior unsecured notes due September 2043	400	400
Texas Eastern 6.00% senior unsecured notes due September 2017	400	400
Texas Eastern 4.13% senior unsecured notes due December 2020	300	300
Texas Eastern 2.80% senior unsecured notes due October 2022	500	500
Texas Eastern 7.00% senior unsecured notes due July 2032	450	450
Algonquin 3.51% senior notes due July 2024	350	350
East Tennessee Natural Gas, LLC 3.10% senior notes due December 2024	200	200
M&N U.S. 7.50% senior notes due May 2014	—	411
Express-Platte 6.09% senior secured notes due January 2020	110	110
Express-Platte 7.39% subordinated secured notes due 2014 to 2019	74	104
Total SEP Debt	5,184	5,625
Westcoast		
8.50% debentures due November 2015	108	118
3.28% medium-term notes due January 2016	215	235
8.50% debentures due September 2018	129	141
5.60% medium-term notes due January 2019	258	282
9.90% debentures due January 2020	86	94
4.57% medium-term notes due July 2020	215	235
3.88% medium-term notes due October 2021	129	142
3.12% medium-term notes due December 2022	215	235
3.43% medium-term notes due September 2024	301	—
8.85% debentures due July 2025	129	142
8.80% medium-term notes due November 2025	22	24
7.30% debentures due December 2026	108	118
6.75% medium-term notes due December 2027	129	141
7.15% medium-term notes due March 2031	172	188

4.79% medium-term notes due October 2041	129	141
M&N Canada 6.90% senior secured notes due 2014 to 2019	112	147
M&N Canada 4.34% senior secured notes due 2014 to 2019	83	120
Other	2	2
Total Westcoast Debt	$2,542	$2,505

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	December 31, 2014	2013
Union Gas	(in millions)	
7.90% debentures due February 2014	$—	$141
11.50% debentures due August 2015	129	141
4.64% medium-term notes due June 2016	172	188
9.70% debentures due November 2017	108	118
5.35% medium-term notes due April 2018	172	188
8.75% debentures due August 2018	108	118
8.65% senior debentures due October 2018	64	72
2.76% medium-term notes due June 2021	172	—
4.85% medium-term notes due April 2022	108	118
3.79% medium-term notes due July 2023	215	235
8.65% debentures due November 2025	108	118
5.46% medium-term notes due September 2036	142	155
6.05% medium-term notes due September 2038	258	282
5.20% medium-term notes due July 2040	215	235
4.88% medium-term notes due June 2041	258	282
4.20% medium-term notes due June 2044	215	—
Total Union Gas Debt	2,444	2,391
Total		
Long-term debt principal (including current maturities)	13,060	13,668
Change in fair value of debt hedged	17	17
Unamortized debt discount, net	(12)	(12)
Other unamortized items	7	12
Total other non-principal amounts	12	17
Commercial paper (a)	1,583	1,032
Capital Leases	24	—
Total debt (including capital lease obligations) (b)	14,679	14,717
Current maturities of long-term debt	(327)	(1,197)
Commercial paper (c)	(1,583)	(1,032)
Total long-term debt (including capital lease obligations)	$12,769	$12,488

(a) The weighted-average days to maturity was 14 days as of December 31, 2014 and 9 days as of December 31, 2013.

(b) As of December 31, 2014 and 2013, respectively, $5,264 million and $5,248 million of debt was denominated in Canadian dollars.

(c) Weighted-average rate on outstanding commercial paper was 0.6% at both December 31, 2014 and 2013.

Secured Debt. Secured debt, totaling $379 million as of December 31, 2014, includes project financings for M&N Canada and Express-Platte. Ownership interests in M&N Canada and certain of its accounts, revenues, business contracts and other assets are pledged as collateral. Express-Platte notes payable are secured by the assignment of the Express-Platte transportation receivables and by the Canadian portion of the Express-Platte pipeline system assets.

Floating Rate Debt. Debt included approximately $2,283 million of floating-rate debt as of December 31, 2014 and $1,432 million as of December 31, 2013. The weighted average interest rate of borrowings outstanding that contained floating rates was 0.8% at both December 31, 2014 and 2013.

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Annual Maturities	December 31, 2014
	(in millions)
2015	$327
2016	713
2017	563
2018	2,353
2019	787
Thereafter	8,353
Total long-term debt, including current maturities (a)	$13,096

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(a) Excludes commercial paper of $1,583 million. Includes capital leases of $24 million and other non-principal amounts of $12 million.

We have the ability under certain debt facilities to call and repay the obligations prior to scheduled maturities. Therefore, the actual timing of future cash repayments could be materially different than presented above.

Available Credit Facilities and Restrictive Debt Covenants

	Expiration Date	Total Credit Facilities Capacity	Commercial Paper Outstanding at December 31, 2014	Available Credit Facilities Capacity
		(in millions)		
Spectra Energy Capital, LLC (a)	2019	$1,000	$398	$602
SEP (b)	2019	2,000	907	1,093
Westcoast (c)	2019	344	46	298
Union Gas (d)	2019	430	232	198
Total		$3,774	$1,583	$2,191

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(a) Revolving credit facility contains a covenant requiring the Spectra Energy Corp consolidated debt-to-total capitalization ratio, as defined in the agreement, to not exceed 65%. Per the terms of the agreement, collateralized debt is excluded from the calculation of the ratio. This ratio was 58% at December 31, 2014.

(b) Revolving credit facility contains a covenant that requires SEP to maintain a ratio of total Consolidated Indebtedness-to-Consolidated EBITDA, as defined in the agreement, of 5.0 to 1 or less. As of December 31, 2014, this ratio was 3.7 to 1.

(c) U.S. dollar equivalent at December 31, 2014. The revolving credit facility is 400 million Canadian dollars and contains a covenant that requires the Westcoast non-consolidated debt-to-total capitalization ratio to not exceed 75%. The ratio was 35% at December 31, 2014.

(d) U.S. dollar equivalent at December 31, 2014. The revolving credit facility is 500 million Canadian dollars and contains a covenant that requires the Union Gas debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 68% at December 31, 2014.

On December 10, 2014, we amended the Westcoast and Union Gas revolving credit agreements. The Westcoast revolving credit facility was increased to 400 million Canadian dollars, and the Union Gas revolving credit facility was increased to 500 million Canadian dollars. Both facilities expire in December 2019.

On December 11, 2014, we amended the Spectra Energy Capital, LLC (Spectra Capital) and SEP revolving credit agreements. The expiration date of both credit facilities was extended one year, with both facilities expiring in December 2019.

The issuances of commercial paper, letters of credit and revolving borrowings reduce the amounts available under the credit facilities. As of December 31, 2014, there were no letters of credit issued or revolving borrowings outstanding under the credit facilities.

Our credit agreements contain various covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2014, we were in compliance with those covenants. In addition, our credit agreements allow for acceleration of payments or termination of the agreements due to nonpayment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. Our debt and credit agreements do not contain provisions that trigger an acceleration of indebtedness based solely on the occurrence of a material adverse change in our financial condition or results of operations.

As noted above, the terms of our Spectra Capital credit agreements require our consolidated debt-to-total capitalization ratio, as defined in the agreement, to be 65% or lower. Per the terms of the agreements, collateralized debt is excluded from the calculation of the ratio. This ratio was 58% at December 31, 2014. Approximately $7.8 billion of our equity (net assets) was considered restricted at December 31, 2014, representing the minimum amount of equity required to maintain the 65% consolidated debt-to-total capitalization ratio.

17. Preferred Stock of Subsidiaries

Westcoast and Union Gas have outstanding preferred shares that are generally not redeemable prior to specified redemption dates. On or after those dates, the shares may be redeemed, in whole or in part, for cash at the option of Westcoast and Union Gas, as applicable. The shares are not subject to any sinking fund or mandatory redemption and are not convertible into any other securities. As redemption of the shares is not solely within our control, we have classified the preferred stock of subsidiaries as temporary equity on our Consolidated Balance Sheets. Dividends are cumulative and payable quarterly, and are included in Net Income — Noncontrolling Interests in the Consolidated Statements of Operations. All outstanding preferred shares are redeemable at the option of Westcoast and Union Gas, as applicable.

18. Fair Value Measurements

The following presents, for each of the fair value hierarchy levels, assets and liabilities that are measured and recorded at fair value on a recurring basis:

Description	Consolidated Balance Sheet Caption	December 31, 2014			
		Total	Level 1	Level 2	Level 3
		(in millions)			
Corporate debt securities	Cash and cash equivalents	$85	$—	$85	$—
Corporate debt securities	Current assets — other	3	—	3	—
Commodity derivatives	Current assets — other	57	—	—	57
Interest rate swaps	Current assets — other	2	—	2	—
Commodity derivatives	Investments and other assets — other	21	—	—	21
Corporate debt securities	Investments and other assets — other	20	—	20	—
Interest rate swaps	Investments and other assets — other	22	—	22	—
Money market funds	Investments and other assets — other	1	1	—	—
Total Assets		$211	$1	$132	$78

Description	Consolidated Balance Sheet Caption	December 31, 2013			
		Total	Level 1	Level 2	Level 3
		(in millions)			
Corporate debt securities	Cash and cash equivalents	$49	$—	$49	$—
Corporate debt securities	Current assets — other	7	—	7	—
Interest rate swaps	Current assets — other	8	—	8	—
Corporate debt securities	Investments and other assets — other	11	—	11	—
Interest rate swaps	Investments and other assets — other	15	—	15	—
Money market funds	Investments and other assets — other	1	1	—	—
Total Assets		$91	$1	$90	$—
Natural gas purchase contracts	Deferred credits and other liabilities — regulatory and other	$3	$—	$—	$3
Interest rate swaps		6	—	6	—

Deferred credits and other liabilities — regulatory and other				
Total Liabilities	$9	$—	$6	$3

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The following presents changes in Level 3 assets and liabilities that are measured at fair value on a recurring basis using significant unobservable inputs:

	2014	2013
	(in millions)	
Derivative assets (liabilities)		
Fair value, beginning of period	$(3)	$(9)
Total gains (losses):		
Included in earnings	91	(3)
Included in other comprehensive income	5	8
Settlements	(15)	1
Fair value, end of period	$78	$(3)
Total gains (losses) for the period included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets and liabilities held at the end of the period	$56	$(2)

Level 1

Level 1 valuations represent quoted unadjusted prices for identical instruments in active markets.

Level 2 Valuation Techniques

Fair values of our financial instruments that are actively traded in the secondary market, including our long-term debt, are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency.

For interest rate swaps, we utilize data obtained from a third-party source for the determination of fair value. Both the future cash flows for the fixed-leg and floating-leg of our swaps are discounted to present value. In addition, credit default swap rates are used to develop the adjustment for credit risk embedded in our positions. We believe that since some of the inputs and assumptions for the calculations of fair value are derived from observable market data, a Level 2 classification is appropriate.

Level 3 Valuation Techniques

Level 3 valuation techniques include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation. The derivative financial instruments reported in Level 3 at December 31, 2014 primarily consist of NGL revenue swap contracts related to the Empress assets in Western Canada Transmission & Processing. As of December 31, 2014, we reported certain of our natural gas basis swaps at fair value using Level 3 inputs due to such derivatives not having observable market prices for substantially the full term of the derivative asset or liability. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract length extends into unobservable periods.

The fair value of these natural gas basis swaps is determined using a discounted cash flow valuation technique based on a forward commodity basis curve. For these derivatives, the primary input to the valuation model is the forward commodity basis curve, which is based on observable or public data sources and extrapolated when observable prices are not available.

The significant unobservable inputs used in the fair value measurements of our Level 3 derivatives are the forward natural gas basis curves, for which a significant portion of the derivative’s term is beyond available forward pricing. At December 31, 2014, a 10¢ per gallon movement in underlying forward NGL prices would affect the estimated fair value of our NGL derivatives by $16 million. This calculated amount does not take into account any other changes to the fair value measurement calculation.

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Financial Instruments

The fair values of financial instruments that are recorded and carried at book value are summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. These estimates are not necessarily indicative of the amounts we could have realized in current markets.

	December 31, 2014 Book Value	Approximate Fair Value	2013 Book Value	Approximate Fair Value
	(in millions)			
Note receivable, noncurrent (a)	$71	$71	$71	$71
Long-term debt, including current maturities (b)	13,060	14,446	13,668	14,701

(a) Included within Investments in and Loans to Unconsolidated Affiliates.
(b) Excludes capital leases, unamortized items and fair value hedge carrying value adjustments.

The fair value of our long-term debt is determined based on market-based prices as described in the Level 2 valuation technique described above and is classified as Level 2.

The fair values of cash and cash equivalents, restricted cash, short-term investments, accounts receivable, notes receivable-noncurrent, accounts payable and commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.

During the 2014 and 2013 periods, there were no material adjustments to assets and liabilities measured at fair value on a nonrecurring basis.

19. Risk Management and Hedging Activities

We are exposed to the impact of market fluctuations in the prices of NGLs and natural gas purchased as a result of our investment in DCP Midstream, and the ownership of the NGL marketing operations in western Canada and processing operations associated with our U.S. pipeline assets. Exposure to interest rate risk exists as a result of the issuance of variable and fixed-rate debt and commercial paper. We are exposed to foreign currency risk from our Canadian operations. We employ established policies and procedures to manage our risks associated with these market fluctuations, which may include the use of derivatives, mostly around interest rate and commodity exposures.

DCP Midstream manages their direct exposure to market prices separate from Spectra Energy, and utilizes various risk management strategies, including the use of commodity derivatives.

Derivative Portfolio Carrying Value as of December 31, 2014

	Maturities in 2015	Maturities in 2016	Maturities in 2017	Maturities in 2018 and Thereafter	Total Carrying Value
	(in millions)				
Derivatives designated as hedging instruments					
Interest rate swaps	$—	$—	$2	$20	$22
Total derivatives designated as hedging instruments	—	—	2	20	22
Derivatives not designated as hedging instruments					
Commodity derivatives	57	19	2	—	78
Interest rate swaps	2	—	—	—	2
Total derivatives not designated as hedging instruments	59	19	2	—	80
Total derivative instruments	$59	$19	$4	$20	$102

These amounts represent the combination of amounts presented as assets for non-cash gains on mark-to-market and hedging transactions on our Consolidated Balance Sheet and do not include any derivative positions of DCP Midstream. See Note 18 for information regarding the presentation of these derivative positions on our Consolidated Balance Sheets.

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Commodity Derivatives. Our NGL marketing operations are exposed to market fluctuations in the prices of natural gas and NGLs related to natural gas processing and marketing activities. We closely monitor the potential effects of commodity price changes and may choose to enter into contracts to protect margins for a portion of future sales and fuel expenses by using financial commodity instruments, such as swaps, forward contracts and options.
Effective January 2014, we implemented a commodity price risk management program at Western Canada Transmission & Processing's Empress NGL business and elected to not apply cash flow hedge accounting.

At December 31, 2014, we had commodity mark-to-market derivatives outstanding with a total notional amount of 163 million gallons. The longest dated commodity derivative contract we currently have expires in 2017.

Information about our commodity derivatives that had netting or rights of offset arrangements are as follows:

	December 31, 2014		
Description	Gross Amounts	Gross Amounts Offset	Net Amount Presented in the Condensed Consolidated Balance Sheets
	(in millions)		
Assets	$169	$91	$78
Liabilities	91	91	—

Substantially all of our commodity derivative agreements outstanding at December 31, 2014 have provisions that require collateral to be posted in the amount of the net liability position if one of our credit ratings falls below investment grade.
Information regarding the impacts of commodity derivatives on our Consolidated Statements of Operations is as follows:

Derivatives	Consolidated Statement of Operations Caption	2014	2013	2012
		(in millions)		
Commodity derivatives	Sales of natural gas liquids	$93	$—	$—

Interest Rate Swaps. Changes in interest rates expose us to risk as a result of our issuance of variable and fixed-rate debt and commercial paper. We manage our interest rate exposure by limiting our variable-rate exposures to percentages of total debt and by monitoring the effects of market changes in interest rates. We also enter into financial derivative instruments, including, but not limited to, interest rate swaps and rate lock agreements to manage and mitigate interest rate risk exposure.
For interest rate derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk is included in Interest Expense on the Consolidated Statements of Operations. There were no significant amounts of gains or losses, either effective or ineffective, recognized in net income or other comprehensive income in 2014, 2013 or 2012.
At December 31, 2014, we had "pay floating — receive fixed" interest rate swaps outstanding with a total notional amount of $1,208 million to hedge against changes in the fair value of our fixed-rate debt that arise as a result of changes in market interest rates. These swaps also allow us to transform a portion of the underlying interest payments related to our long-term fixed-rate debt securities into variable-rate interest payments in order to achieve our desired mix of fixed and variable-rate debt.

Information about our interest rate swaps that had netting or rights of offset arrangements are as follows:

	December 31, 2014			December 31, 2013		
	Gross Amounts Presented in	Amounts Not Offset in the	Net Amount	Gross Amounts Presented in	Amounts Not Offset in the	Net Amount

Description	the Consolidated Balance Sheets (in millions)	Consolidated Balance Sheets		the Consolidated Balance Sheets	Consolidated Balance Sheets	
Assets	$24	$ —	$24	$23	$ 3	$20
Liabilities	—	—	—	6	3	3

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Foreign Currency Risk. We are exposed to foreign currency risk from investments and operations in Canada. To mitigate risks associated with foreign currency fluctuations, contracts may be denominated in or indexed to the U.S. dollar and/or local inflation rates, or investments may be naturally hedged through debt denominated or issued in the foreign currency. To monitor our currency exchange rate risks, we use sensitivity analysis, which measures the effect of devaluation of the Canadian dollar.

Credit Risk. Our principal customers for natural gas transmission and crude oil transportation, storage and gathering and processing services are industrial end-users, marketers, exploration and production companies, local distribution companies and utilities located throughout the United States and Canada. We have concentrations of receivables from natural gas utilities and their affiliates, industrial customers and marketers throughout these regions, as well as retail distribution customers in Canada. These concentrations of customers may affect our overall credit risk in that risk factors can negatively affect the credit quality of the entire sector. Where exposed to credit risk, we analyze the customers' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. We also obtain parental guarantees, cash deposits or letters of credit from customers to provide credit support, where appropriate, based on our financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each contract.

20. Commitments and Contingencies

General Insurance

We carry, either directly or through our captive insurance companies, insurance coverages consistent with companies engaged in similar commercial operations with similar type properties. Our insurance program includes (1) commercial general and excess liability insurance for liabilities to third parties for bodily injury and property damage resulting from our operations; (2) workers' compensation liability coverage to required statutory limits; (3) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage; (4) insurance policies in support of the indemnification provisions of our by-laws; and (5) property insurance, including machinery breakdown, on an all-risk-replacement valued basis, onshore business interruption and extra expense. All coverages are subject to certain deductibles, terms and conditions common for companies with similar types of operations.

Environmental

We are subject to various U.S. federal, state and local laws and regulations, as well as Canadian federal and provincial laws, regarding air and water quality, hazardous and solid waste disposal and other environmental matters. These laws and regulations can change from time to time, imposing new obligations on us.

Like others in the energy industry, we and our affiliates are responsible for environmental remediation at various contaminated sites. These include some properties that are part of our ongoing operations, sites formerly owned or used by us, and sites owned by third parties. Remediation typically involves management of contaminated soils and may involve groundwater remediation. Managed in conjunction with relevant federal, state/provincial and local agencies, activities vary with site conditions and locations, remedial requirements, complexity and sharing of responsibility. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, we or our affiliates could potentially be held responsible for contamination caused by other parties. In some instances, we may share liability associated with contamination with other potentially responsible parties, and may also benefit from contractual indemnities that cover some or all cleanup costs. All of these sites generally are managed in the normal course of business or affiliated operations.

Included in Deferred Credits and Other Liabilities — Regulatory and Other on the Consolidated Balance Sheets are undiscounted liabilities related to extended environmental-related activities totaling $10 million as of December 31, 2014 and $11 million as of December 31, 2013. These liabilities represent provisions for costs associated with remediation activities at some of our current and former sites, as well as other environmental contingent liabilities.

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Litigation

Litigation and Legal Proceedings. We are involved in legal, tax and regulatory proceedings in various forums arising in the ordinary course of business, including matters regarding contract and payment claims, some of which involve substantial monetary amounts. We have insurance coverage for certain of these losses should they be incurred. We believe that the final disposition of these proceedings will not have a material effect on our consolidated results of operations, financial position or cash flows.

Legal costs related to the defense of loss contingencies are expensed as incurred. We had no material reserves for legal matters recorded as of December 31, 2014 or 2013 related to litigation.

Other Commitments and Contingencies

See Note 21 for a discussion of guarantees and indemnifications.

Operating Lease Commitments

We lease assets in various areas of our operations. Consolidated rental expense for operating leases classified in Income From Continuing Operations was $38 million in 2014, 2013 and 2012, which is included in Operating, Maintenance and Other on the Consolidated Statements of Operations. The following is a summary of future minimum lease payments under operating leases which at inception had noncancelable terms of more than one year. We had no material capital lease commitments at December 31, 2014.

	Long-term Operating Leases (in millions)
2015	$ 50
2016	44
2017	42
2018	36
2019	32
Thereafter	148
Total future minimum lease payments	$ 352

21. Guarantees and Indemnifications

We have various financial guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. We enter into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included on our Consolidated Balance Sheets. The possibility of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events.

We have issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-100%-owned entities. In connection with our spin-off from Duke Energy in 2007, certain guarantees that were previously issued by us were assigned to, or replaced by, Duke Energy as guarantor in 2006. For any remaining guarantees of other Duke Energy obligations, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements. The maximum potential amount of future payments we could have been required to make under these performance guarantees as of December 31, 2014 was approximately $406 million, which has been indemnified by Duke Energy as discussed above. One of these outstanding performance guarantees, which has a maximum potential amount of future payment of $201 million, expires in 2028. The remaining guarantees have no contractual expirations.

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We have also issued joint and several guarantees to some of the Duke/Fluor Daniel (D/FD) project owners, guaranteeing the performance of D/FD under its engineering, procurement and construction contracts and other contractual commitments in place at the time of our spin-off from Duke Energy. D/FD is one of the entities transferred to Duke Energy in connection with our spin-off. Substantially all of these guarantees have no contractual expiration and no stated maximum amount of future payments that we could be required to make. Fluor Enterprises Inc., as 50% owner in D/FD, issued similar joint and several guarantees to the same D/FD project owners.

Westcoast, a 100%-owned subsidiary, has issued performance guarantees to third parties guaranteeing the performance of unconsolidated entities, such as equity method investments, and of entities previously sold by Westcoast to third parties. Those guarantees require Westcoast to make payment to the guaranteed third party upon the failure of such unconsolidated or sold entity to make payment under some of its contractual obligations, such as debt agreements, purchase contracts and leases. Certain guarantees that were previously issued by Westcoast for obligations of entities that remained a part of Duke Energy are considered guarantees of third party performance; however, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements.

We have entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These agreements typically cover environmental, litigation and other matters, as well as breaches of representations, warranties and covenants. Typically, claims may be made by third parties for various periods of time depending on the nature of the claim. Our potential exposure under these indemnification agreements can range from a specified amount, such as the purchase price, to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. We are unable to estimate the total potential amount of future payments under these indemnification agreements due to several factors, such as the unlimited exposure under certain guarantees.

As of December 31, 2014, the amounts recorded for the guarantees and indemnifications described above are not material, both individually and in the aggregate.

22. Common Stock Issuance

In 2012, we issued 14.7 million shares of our common stock and received net proceeds of $382 million to fund acquisitions and capital expenditures and for other general corporate purposes.

23. Effects of Changes in Noncontrolling Interests Ownership

The following table presents the effects of changes in our ownership interests in non-100%-owned consolidated subsidiaries:

	2014	2013	2012
	(in millions)		
Net income — controlling interests	$1,082	$1,038	$940
Increase in additional paid-in capital resulting from issuances of SEP units (a)	49	42	26
Total net income — controlling interests and changes in equity — controlling interests	$1,131	$1,080	$966

(a) See Note 2 for further discussion.

24. Stock-Based Compensation

The Spectra Energy Corp 2007 Long-Term Incentive Plan (the 2007 LTIP), as amended and restated, provides for the granting of stock options, restricted and unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for us. A maximum of 40 million shares of common stock may be awarded under the 2007 LTIP.

Restricted, performance and phantom awards granted under the 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. Equity-classified and liability-classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability-classified stock-based compensation cost is re-measured at each reporting period until settlement. Related compensation expense is recognized over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award becomes vested, the date the employee becomes retirement-eligible, or the date the market or performance condition is met.

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Options granted under the 2007 LTIP are issued with exercise prices equal to the fair market value of our common stock on the grant date, have ten-year terms and generally vest over a three-year term. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible. We issue new shares upon exercising or vesting of share-based awards. The Black-Scholes option-pricing model is used to estimate the fair value of options at grant date. All outstanding stock options are fully vested, and as a result, we do not expect to recognize future compensation costs related to stock options.

We recorded pre-tax stock-based compensation expense in continuing operations as follows, the components of which are described further below:

	2014	2013	2012
	(in millions)		
Phantom awards	$14	$13	$12
Performance awards	13	33	17
Total	$27	$46	$29

The tax benefit in Income From Continuing Operations associated with the recorded stock-based compensation expense was $7 million in 2014 and $8 million in both 2013 and 2012. We recognized tax benefits from stock-based compensation cost of approximately $3 million in 2014, $5 million in 2013 and $16 million in 2012 in Additional Paid-in Capital.

Stock Awards Activity

	Performance Awards		Phantom Stock Awards	
	Units	Weighted Average Grant Date Fair Value	Units	Weighted Average Grant Date Fair Value
	(thousands)		(thousands)	
Outstanding at December 31, 2013	1,936	$38	1,302	$29
Granted	557	46	454	38
Vested	(601)	33	(431)	26
Forfeited	(117)	38	(44)	33
Outstanding at December 31, 2014	1,775	35	1,281	33
Awards expected to vest	1,709	35	1,229	33

Performance Awards

Under the 2007 LTIP, we can also grant stock-based performance awards. The performance awards generally vest over three years at the earliest, if performance metrics are met. The liability-classified awards will be settled in cash at vesting. We granted 557,100 equity-classified awards during 2014, 356,600 during 2013 and 306,800 during 2012, with fair values of $26 million in 2014 and $13 million in both 2013 and 2012. We did not grant liability-classified awards during 2014; however, we granted 343,700 during 2013 and 306,800 during 2012, with fair values of $13 million in 2013 and $5 million in 2012. Of the unvested and outstanding performance awards granted, 1,761,967 awards contain market conditions based on the total shareholder return of Spectra Energy common stock relative to a pre-defined peer group, and 12,900 awards contain performance conditions based on EBITDA performance of one subsidiary company. The equity-classified and liability-classified awards with market conditions are valued using the Monte Carlo valuation method. The liability-classified awards are remeasured at each reporting period until settlement.

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Weighted-Average Assumptions for Stock-Based Performance Awards

	2014	2013	2012
Risk-free rate of return	0.7%	0.4%	0.4%
Expected life	3 years	3 years	3 years
Expected volatility—Spectra Energy	20%	21%	25%
Expected volatility—peer group	14%–32%	13%–33%	16%–42%
Market index (a)	N/A	16%	20%

(a) Beginning in 2014, the valuation model was refined to use an alternate analytical approach to project future stock prices in order to improve consistency and efficiency. The improved approach does not require the use of a market index assumption to determine the future stock price used in the valuation model. As such, the volatility of the market index assumption will not be presented going forward. Based on our assessment, it was determined that this refinement did not have a significant impact on the fair value of the shares for all periods presented.

The risk-free rate of return was determined based on a yield of three-year U.S. Treasury bonds on the grant date. The expected volatility was established based on historical volatility over three years using daily stock price observations. A shorter period was used if three years of data was not available. Because the award payout includes dividend equivalents, no dividend yield assumption is required.

The total fair value of the shares vested was $20 million in 2014, $19 million in 2013 and $12 million in 2012. As of December 31, 2014, we expect to recognize $26 million of future compensation cost related to outstanding performance awards over a weighted-average period of less than one year.

Phantom Awards

Under the 2007 LTIP, we can also grant stock-based phantom awards. The phantom awards generally vest over three years. The liability-classified awards will be settled in cash at vesting. We awarded 101,500 equity-classified awards to our employees in 2014, 474,500 in 2013 and 440,200 in 2012, with fair values of $4 million in 2014, $14 million in both 2013 and 2012. We awarded 353,000 liability-classified awards to our employees in 2014, with a fair value of $13 million. The liability-classified awards are remeasured at each reporting period until settlement.

The total fair value of the shares vested was $11 million in 2014, $14 million in 2013 and $11 million in 2012. As of December 31, 2014, we expect to recognize $18 million of future compensation cost related to phantom stock awards over a weighted-average period of less than two years.

Stock Option Activity

	Options (in thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Life (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2013	1,532	$25	2.9	$16
Exercised	(430)	25		
Forfeited or expired	—	—		
Outstanding at December 31, 2014	1,102	25	2.0	12
Exercisable at December 31, 2014	1,102	25	2.0	12

We did not award any non-qualified stock options to employees during 2014, 2013 or 2012.

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The total intrinsic value of options exercised was $6 million in 2014, $21 million in 2013 and $11 million in 2012. Cash received by us from options exercised was $11 million in 2014, $43 million in 2013 and $17 million in 2012. All stock options were fully vested as of December 31, 2011, and as a result, we do not expect to recognize future compensation costs related to stock options.

25. Employee Benefit Plans

Retirement Plans. We have a qualified non-contributory defined benefit (DB) retirement plan for U.S. employees (U.S. Qualified Pension Plan). This plan covers U.S. employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits that are based upon a percentage (which may vary with age and years of service) of current eligible earnings and current interest credits.

We also maintain non-qualified, non-contributory, unfunded defined benefit plans (U.S. Non-Qualified Pension Plans) which cover certain current and former U.S. executives. The U.S. Non-Qualified Pension Plans have no plan assets. There are other non-qualified plans such as savings and deferred compensation plans which cover certain current and former U.S. executives. Pursuant to trust agreements, Spectra Energy has set aside funds for certain of the above non-qualified plans in several trusts. Although these funds are restrictive in nature, they remain a component of our general assets and are subject to the claims of creditors. These trust funds totaling $17 million as of December 31, 2014 and $18 million as of December 31, 2013, invested in money market funds and valued using a Level 1 hierarchy level, are considered AFS securities and are classified as Investments and Other Assets-Other on the Consolidated Balance Sheets.

In addition, our Westcoast subsidiary maintains qualified and non-qualified, contributory and non-contributory (Canadian Qualified Pension Plan) and (Canadian Non-Qualified Pension Plan) DB and defined contribution (Canadian DC) retirement plans covering substantially all employees of our Canadian operations. The DB plans provide retirement benefits based on each plan participant’s years of service and final average earnings. Under the Canadian DC plan, company contributions are determined according to the terms of the plan and based on each plan participant’s age, years of service and current eligible earnings. We also provide non-qualified DB supplemental pensions to all employees who retire under a DB qualified pension plan and whose pension is limited by the maximum pension limits under the Income Tax Act (Canada). We report our Canadian benefit plans separate from the U.S. plans due to differences in actuarial assumptions.

Our policy is to fund our retirement plans, where applicable, on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants or as required by legislation or plan terms. We made contributions of $21 million to our U.S. Qualified and Non-Qualified Pension Plans in 2014, $22 million in 2013 and $26 million in 2012. We made total contributions to our Canadian Qualified and Non-Qualified Pension Plans of $36 million in 2014, $80 million in 2013 and $87 million in 2012. Contributions of $9 million in 2014, 2013 and 2012 were made to our Canadian DC plan. We anticipate that in 2015 we will make total contributions of approximately $22 million to the U.S. Qualified and Non-Qualified Pension Plans, approximately $30 million to the Canadian Qualified and Non-Qualified Pension Plans and approximately $10 million to the Canadian DC Plan.

Actuarial gains and losses are amortized over the average remaining service period of active employees. The average remaining service period of active employees covered by the U.S. Qualified and Non-Qualified Pension Plans is 10 years. The average remaining service periods of active employees covered by the Canadian Qualified and Non-Qualified Pension Plans is 10 years. We determine the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets over five years for the U.S. plans and over three years for the Canadian plans.

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Qualified and Non-Qualified Pension Plans

Change in Projected Benefit Obligation and Change in Fair Value of Plan Assets

	U.S.		Canada	
	2014	2013	2014	2013
	(in millions)			
Change in Projected Benefit Obligation				
Projected benefit obligation, beginning of period	$575	$610	$1,131	$1,262
Transfers in	—	—	—	6
Service cost	19	19	25	33
Interest cost	24	21	52	50
Actuarial loss (gain)	13	(36)	143	(92)
Participant contributions	—	—	5	5
Benefits paid	(45)	(39)	(49)	(51)
Foreign currency translation effect	—	—	(105)	(82)
Projected benefit obligation, end of period	586	575	1,202	1,131
Change in Fair Value of Plan Assets				
Plan assets, beginning of period	531	483	1,040	961
Transfers in	—	—	—	3
Actual return on plan assets	44	65	115	110
Benefits paid	(45)	(39)	(49)	(51)
Employer contributions	21	22	36	80
Plan participants’ contributions	—	—	5	5
Expected non-investment expenses	—	—	(3)	—
Foreign currency translation effect	—	—	(94)	(68)
Plan assets, end of period	551	531	1,050	1,040
Net amount recognized	$(35)	$(44)	$(152)	$(91)
Accumulated Benefit Obligation	$567	$547	$1,123	$1,059

	U.S.		Canada	
	2014	2013	2014	2013
	(in millions)			
Net amount recognized				
Current Liabilities - Other	$(2)	$(2)	$(6)	$(6)
Deferred Credits and Other Liabilities - Regulatory and Other	(33)	(42)	(165)	(130)
Other Assets - Other	—	—	19	45
Total net amount recognized	$(35)	$(44)	$(152)	$(91)

The tables above include certain nonqualified pension plans that are unfunded. Those U.S. plans had projected benefit obligations of $22 million at both December 31, 2014 and 2013. Those Canadian plans had projected benefit obligations of $117 million at both December 31, 2014 and 2013.

At December 31, 2014, all U.S. plans had accumulated benefit obligations in excess of plan assets. Canadian plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations of $388 million, accumulated benefit obligations of $360 million and plan assets with a fair value of $239 million.

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Amounts Recognized in Accumulated Other Comprehensive Income

	U.S.		Canada	
	December 31,		December 31,	
	2014	2013	2014	2013
	(in millions)			
Net actuarial loss	$141	$145	$345	$275
Prior service cost	—	1	6	7
Total amount recognized in AOCI	$141	$146	$351	$282

Components of Net Periodic Pension Costs

	U.S.			Canada		
	2014	2013	2012	2014	2013	2012
	(in millions)					
Net Periodic Pension Cost						
Service cost benefit earned	$19	$19	$17	$29	$33	$30
Interest cost on projected benefit obligation	24	21	23	52	50	50
Expected return on plan assets	(39)	(33)	(33)	(69)	(66)	(61)
Amortization of prior service cost	—	—	—	2	2	2
Amortization of loss	13	20	15	22	35	36
Net periodic pension cost	17	27	22	36	54	57
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income						
Current year actuarial loss (gain)	8	(69)	33	93	(133)	44
Amortization of actuarial loss	(13)	(20)	(15)	(22)	(35)	(36)
Amortization of prior service credit	—	—	—	(2)	(2)	(2)
Total recognized in other comprehensive income	(5)	(89)	18	69	(170)	6
Total Recognized in Net Periodic Pension Cost and Other Comprehensive Income	$12	$(62)	$40	$105	$(116)	$63

In 2015, approximately $10 million of actuarial losses for the U.S. plans and $27 million for the Canadian plans will be amortized from AOCI on the Consolidated Balance Sheets into net periodic pension cost, and approximately $1 million of prior service credits will be amortized from AOCI into net periodic pension costs for the Canadian plans.

Assumptions Used for Pension Benefits Accounting

	U.S.			Canada		
	2014	2013	2012	2014	2013	2012
Benefit Obligations						
Discount rate	4.10 %	4.31 %	3.55 %	4.00 %	4.81 %	4.15 %
Salary increase	4.00	4.61	4.61	3.25	3.25	3.25
Net Periodic Benefit Cost						
Discount rate	4.31	3.55	4.17	4.81	4.15	4.30
Salary increase	4.61	4.61	4.61	3.25	3.25	3.25
Expected long-term rate of return on plan assets	8.00	7.40	7.40	7.40	7.10	7.10

The discount rates used to determine the benefit obligations are the rates at which the benefit obligations could be effectively settled. The discount rates for our U.S. and Canadian plans are developed from yields on available high-quality bonds in each country and reflect each plan’s expected cash flows.

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The long-term rates of return for the U.S. and Canadian plan assets as of December 31, 2014 were developed using weighted-average calculations of expected returns based primarily on future expected returns across classes considering the use of active asset managers applied against the U.S. and Canadian plans' respective targeted asset mix.

Qualified Pension Plan Assets

Asset Category	U.S. Target Allocation		December 31, 2014		2013		Canada Target Allocation		December 31, 2014		2013	
U.S. equity securities	30	%	31	%	31	%	17	%	17	%	18	%
Canadian equity securities	—		—		—		25		25		26	
Other equity securities	14		11		14		13		13		13	
Fixed income securities	46		48		45		45		45		43	
Other investments	10		10		10		—		—		—	
Total	100	%	100	%	100	%	100	%	100	%	100	%

Pension plan assets are maintained in master trusts in both the U.S. and Canada. The investment objective of the master trusts is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trusts. Equities are held for their high expected return. Other equity and fixed income securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the effects of individual managers or investments. We regularly review our actual asset allocation and periodically rebalance our investments to the targeted allocation when considered appropriate.

The following table summarizes the fair values of pension plan assets recorded at each fair value hierarchy level, as determined in accordance with the valuation techniques described in Note 18:

	U.S. Total (in millions)	Level 1	Level 2	Level 3	Canada Total	Level 1	Level 2	Level 3
December 31, 2014								
Cash and cash equivalents	$3	$3	$—	$—	$3	$3	$—	$—
Fixed income securities	262	262	—	—	471	471	—	—
Equity securities	233	233	—	—	576	342	234	—
Other	53	—	—	53	—	—	—	—
Total	$551	$498	$—	$53	$1,050	$816	$234	$—
December 31, 2013								
Cash and cash equivalents	$2	$2	$—	$—	$8	$8	$—	$—
Fixed income securities	240	240	—	—	442	442	—	—
Equity securities	240	240	—	—	590	428	162	—
Other	49	—	—	49	—	—	—	—
Total	$531	$482	$—	$49	$1,040	$878	$162	$—

The following presents changes in Level 3 assets that are measured at fair value on a recurring basis using significant unobservable inputs:

	U.S. 2014 (in millions)	2013		Canada 2014	2013
Fair value, beginning of period	$49	$69		$—	$1
Sales	—	(25	)	—	—
Settlements	—	1		—	—

Gain (loss) included in other comprehensive income	4	4	—	(1)
Fair value, end of period	$53	$49	$—	$—

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Expected Benefit Payments

	U.S.	Canada
	(in millions)	
2015	$42	$51
2016	47	54
2017	50	57
2018	49	60
2019	53	63
2020 – 2024	235	346

Other Post-Retirement Benefit Plans

U.S. Other Post-Retirement Benefits. We provide certain health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans.

These benefit costs are accrued over an employee's active service period to the date of full benefits eligibility. Actuarial gains and losses are amortized over the average remaining service period of the active employees of 12 years. We determine the market-related value of the plan assets using a calculated value that recognizes changes in fair value of the plan assets over five years for the U.S. plans.

Canadian Other Post-Retirement Benefits. We provide health care and life insurance benefits for retired employees on a non-contributory basis for our Canadian operations predominantly under defined contribution plans. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. The Canadian plans are not funded.

Other Post-Retirement Benefit Plans — Change in Projected Benefit Obligation and Fair Value of Plan Assets

	U.S.		Canada	
	2014	2013	2014	2013
	(in millions)			
Change in Benefit Obligation				
Accumulated post-retirement benefit obligation, beginning of period	$184	$202	$133	$149
Transfers in	—	—	—	1
Service cost	1	1	4	5
Interest cost	8	7	6	6
Plan participants' contributions	2	3	—	—
Actuarial loss (gain)	(7)	(13)	7	(13)
Medicare subsidy receivable	2	2	—	—
Benefits paid	(18)	(18)	(4)	(5)
Foreign currency translation effect	—	—	(13)	(10)
Accumulated post-retirement benefit obligation, end of period	172	184	133	133
Change in Fair Value of Plan Assets				
Plan assets, beginning of period	87	79	—	—
Actual return on plan assets	7	10	—	—
Benefits paid	(18)	(18)	(4)	(5)
Employer contributions	14	13	4	5
Plan participants' contributions	2	3	—	—
Plan assets, end of period	92	87	—	—
Net amount recognized (a)	$(80)	$(97)	$(133)	$(133)

(a) Recognized primarily in Deferred Credits and Other Liabilities—Regulatory and Other in the Consolidated Balance Sheets.

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Other Post-Retirement Benefit Plans — Amounts Recognized in Accumulated Other Comprehensive Income

	U.S.		Canada	
	December 31,		December 31,	
	2014	2013	2014	2013
	(in millions)			
Prior service credit	$—	$—	$(4)	$(5)
Net actuarial loss (gain)	(4)	6	12	6
Total amount recognized in AOCI	$(4)	$6	$8	$1

In 2015, approximately $1 million of prior service costs will be amortized from AOCI into net periodic pension costs for the Canadian plans.

	U.S.			Canada		
	2014	2013	2012	2014	2013	2012
	(in millions)					
Other Post-Retirement Benefit Plans — Components of Net Periodic Benefit Cost						
Service cost benefit earned	$1	$1	$1	$4	$5	$7
Interest cost on accumulated post-retirement benefit obligation	8	7	8	6	6	7
Expected return on plan assets	(5)	(4)	(5)	—	—	—
Amortization of prior service credit	—	—	—	(1)	(1)	(1)
Amortization of loss	1	2	2	—	—	2
Net periodic other post-retirement benefit cost	5	6	6	9	10	15
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income						
Current year actuarial loss (gain)	(9)	(18)	6	6	(13)	(26)
Amortization of actuarial loss	(1)	(2)	(2)	—	—	(2)
Amortization of prior service credit	—	—	—	1	1	1
Total recognized in other comprehensive income	(10)	(20)	4	7	(12)	(27)
Total recognized in net periodic benefit cost and other comprehensive income	$(5)	$(14)	$10	$16	$(2)	$(12)

Other Post-Retirement Benefits Plans — Assumptions Used for Benefits Accounting

	U.S.			Canada		
	2014	2013	2012	2014	2013	2012
Benefit Obligations						
Discount rate	4.08%	4.46%	3.70%	4.00%	4.83%	4.20%
Salary increase	4.00	4.61	4.61	3.25	3.25	3.25
Net Periodic Benefit Cost						
Discount rate	4.46	3.70	4.31	4.83	4.20	4.33
Salary increase	4.61	4.61	4.61	3.25	3.25	3.25
Expected return on plan assets	6.98	6.51	6.54	N/A	N/A	N/A

The discount rates used to determine the post-retirement obligations are the rates at which the benefit obligations could be effectively settled. The discount rates for our U.S. and Canadian plans are developed from yields on available high-quality bonds in each country and reflect each plan's expected cash flows.

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Assumed Health Care Cost Trend Rates

	U.S.		Canada	
	2014	2013	2014	2013
Health care cost trend rate assumed for next year	7.00%	7.00%	6.00%	6.50%
Rate to which the cost trend is assumed to decline	5.00%	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2019	2019	2017	2017

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

	U.S.		Canada	
	1% Point Increase	1% Point Decrease	1% Point Increase	1% Point Decrease
	(in millions)			
Effect on total service and interest costs	$—	$—	$1	$(1)
Effect on post-retirement benefit obligations	7	(6)	9	(7)

Other Post-Retirement Plan Assets

Asset Category	U.S. December 31, 2014	2013
Equity securities	48%	49%
Fixed income securities	47	46
Other assets	5	5
Total	100%	100%

A portion of our other post-retirement plan assets is maintained within the U.S. master trust discussed under the pension plans above. We invest other post-retirement plan assets in the Spectra Energy Corp Employee Benefits Trust (VEBA I) and the Spectra Energy Corp Post-Retirement Medical Benefits Trust (VEBA II). The investment objective of the VEBAs is to achieve sufficient returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of promoting the security of plan benefits for participants. The VEBA trusts are passively managed.

The asset allocation table above includes the other post-retirement benefit assets held in the master trusts, VEBA I and VEBA II.

The following table summarizes the fair values of the other post-retirement plan assets recorded at each fair value hierarchy level as determined in accordance with the valuation techniques described in Note 18:

	U.S. VEBA I and VEBA II Trusts				Master Trust			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
	(in millions)							
December 31, 2014								
Fixed income securities	$21	$—	$21	$—	$22	$22	$—	$—
Equity securities	25	—	25	—	20	20	—	—
Other investments	—	—	—	—	4	—	—	4
Total	$46	$—	$46	$—	$46	$42	$—	$4
December 31, 2013								
Fixed income securities	$20	$—	$20	$—	$20	$20	$—	$—
Equity securities	23	—	23	—	20	20	—	—
Other investments	—	—	—	—	4	—	—	4
Total	$43	$—	$43	$—	$44	$40	$—	$4

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The following presents changes in Level 3 assets that are measured at fair value on a recurring basis using significant unobservable inputs:

	U.S.	
	2014	2013
	(in millions)	
Fair value, beginning of period	$4	$5
Sales	—	(2)
Unrealized gain included in other comprehensive income	—	1
Fair value, end of period	$4	$4

Other Post-Retirement Benefit Plans-Payments and Receipts

We expect to make future benefit payments, which reflect expected future service, as appropriate. As our plans provide benefits that are actuarially equivalent to the benefits received by Medicare recipients, we expect to receive future subsidies under Medicare Part D. The following benefit payments and subsidies are expected to be paid (or received) over each of the next five years and thereafter.

	Benefit Payments		Medicare Part D Subsidy Receipts
	U.S.	Canada	U.S.
	(in millions)		
2015	$16	$5	$ (2)
2016	15	5	(2)
2017	15	5	(1)
2018	14	6	(1)
2019	14	6	(1)
2020 – 2024	60	33	(6)

We anticipate making contributions in 2015 of $10 million to the U.S. plans and $5 million to the Canadian plans.

Retirement/Savings Plan

In addition to the retirement plans discussed above, we also have defined contribution employee savings plans available to both U.S. and Canadian employees. Employees may participate in a matching contribution where we match a certain percentage of before-tax employee contributions of up to 6% of eligible pay per pay period for U.S. employees and up to 5% of eligible pay per pay period for Canadian employees. We expensed pre-tax employer matching contributions of $15 million in 2014, $14 million in 2013 and $12 million in 2012 for U.S employees, and $13 million in both 2014 and 2013 and $12 million in 2012 for Canadian employees.

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26. Condensed Consolidating Financial Information

Spectra Energy Corp has agreed to fully and unconditionally guarantee the payment of principal and interest under all series of notes outstanding under the Senior Indenture of Spectra Capital, a 100%-owned, consolidated subsidiary. In accordance with the Securities and Exchange Commission (SEC) rules, the following condensed consolidating financial information is presented. The information shown for Spectra Energy Corp and Spectra Capital is presented utilizing the equity method of accounting for investments in subsidiaries, as required. The non-guarantor subsidiaries column represents all consolidated subsidiaries of Spectra Capital. This information should be read in conjunction with our accompanying Consolidated Financial Statements and notes thereto.

Spectra Energy Corp
Condensed Consolidating Statement of Operations
Year Ended December 31, 2014
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$—	$—	$ 5,906	$ (3)	$ 5,903
Total operating expenses	6	1	3,975	(3)	3,979
Operating income (loss)	(6)	(1)	1,931	—	1,924
Equity in earnings of unconsolidated affiliates	—	—	361	—	361
Equity in earnings of consolidated subsidiaries	1,054	1,651	—	(2,705)	—
Other income and expenses, net	(2)	9	52	—	59
Interest expense	—	253	426	—	679
Earnings before income taxes	1,046	1,406	1,918	(2,705)	1,665
Income tax expense (benefit)	(36)	352	66	—	382
Net income	1,082	1,054	1,852	(2,705)	1,283
Net income — noncontrolling interests	—	—	201	—	201
Net income — controlling interests	$ 1,082	$ 1,054	$ 1,651	$ (2,705)	$ 1,082

Spectra Energy Corp
Condensed Consolidating Statement of Operations
Year Ended December 31, 2013
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$—	$—	$ 5,521	$ (3)	$ 5,518
Total operating expenses	8	3	3,844	(3)	3,852
Operating income (loss)	(8)	(3)	1,677	—	1,666
Equity in earnings of unconsolidated affiliates	—	—	445	—	445
Equity in earnings of consolidated subsidiaries	1,015	1,649	—	(2,664)	—
Other income and expenses, net	1	15	108	—	124
Interest expense	—	216	441	—	657
Earnings before income taxes	1,008	1,445	1,789	(2,664)	1,578
Income tax expense (benefit)	(30)	430	19	—	419
Net income	1,038	1,015	1,770	(2,664)	1,159
Net income — noncontrolling interests	—	—	121	—	121
Net income — controlling interests	$ 1,038	$ 1,015	$ 1,649	$ (2,664)	$ 1,038

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Spectra Energy Corp
Condensed Consolidating Statement of Operations
Year Ended December 31, 2012
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$—	$—	$ 5,077	$ (2)	$ 5,075
Total operating expenses	5	5	3,492	(2)	3,500
Operating income (loss)	(5)	(5)	1,585	—	1,575
Equity in earnings of unconsolidated affiliates	—	—	382	—	382
Equity in earnings of consolidated subsidiaries	917	1,377	—	(2,294)	—
Other income and expenses, net	(2)	3	82	—	83
Interest expense	—	190	435	—	625
Earnings from continuing operations before income taxes	910	1,185	1,614	(2,294)	1,415
Income tax expense (benefit) from continuing operations	(31)	268	133	—	370
Income from continuing operations	941	917	1,481	(2,294)	1,045
Income (loss) from discontinued operations, net of tax	(1)	—	3	—	2
Net income	940	917	1,484	(2,294)	1,047
Net income — noncontrolling interests	—	—	107	—	107
Net income — controlling interests	$940	$917	$ 1,377	$ (2,294)	$ 940

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Spectra Energy Corp
Condensed Consolidating Statements of Comprehensive Income
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Year Ended December 31, 2014					
Net income	$1,082	$1,054	$ 1,852	$ (2,705)	$ 1,283
Other comprehensive income (loss)	9	1	(596)	—	(586)
Total comprehensive income, net of tax	1,091	1,055	1,256	(2,705)	697
Less: comprehensive income — noncontrolling interests	—	—	194	—	194
Comprehensive income — controlling interests	$1,091	$1,055	$ 1,062	$ (2,705)	$ 503
Year Ended December 31, 2013					
Net income	$1,038	$1,015	$ 1,770	$ (2,664)	$ 1,159
Other comprehensive income (loss)	69	2	(346)	—	(275)
Total comprehensive income, net of tax	1,107	1,017	1,424	(2,664)	884
Less: comprehensive income — noncontrolling interests	—	—	114	—	114
Comprehensive income — controlling interests	$1,107	$1,017	$ 1,310	$ (2,664)	$ 770
Year Ended December 31, 2012					
Net income	$940	$917	$ 1,484	$ (2,294)	$ 1,047
Other comprehensive income (loss)	(12)	3	248	—	239
Total comprehensive income, net of tax	928	920	1,732	(2,294)	1,286
Less: comprehensive income — noncontrolling interests	—	—	110	—	110
Comprehensive income — controlling interests	$928	$920	$ 1,622	$ (2,294)	$ 1,176

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Spectra Energy Corp
Condensed Consolidating Balance Sheet
December 31, 2014
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$—	$1	$ 214	$ —	$ 215
Receivables — consolidated subsidiaries	18	—	11	(29)	—
Receivables — other	2	—	1,334	—	1,336
Other current assets	71	2	708	—	781
Total current assets	91	3	2,267	(29)	2,332
Investments in and loans to unconsolidated affiliates	—	—	2,966	—	2,966
Investments in consolidated subsidiaries	14,531	20,562	—	(35,093)	—
Advances receivable — consolidated subsidiaries	—	4,683	898	(5,581)	—
Notes receivable — consolidated subsidiaries	—	—	3,198	(3,198)	—
Goodwill	—	—	4,714	—	4,714
Other assets	38	22	267	—	327
Net property, plant and equipment	—	—	22,307	—	22,307
Regulatory assets and deferred debits	4	15	1,375	—	1,394
Total Assets	$14,664	$25,285	$ 37,992	$ (43,901)	$ 34,040
Accounts payable	$3	$—	$ 455	$ —	$ 458
Accounts payable — consolidated subsidiaries	—	17	12	(29)	—
Commercial paper	—	398	1,185	—	1,583
Short-term borrowings — consolidated subsidiaries	—	398	—	(398)	—
Taxes accrued	5	—	86	—	91
Current maturities of long-term debt	—	—	327	—	327
Other current liabilities	96	54	1,200	—	1,350
Total current liabilities	104	867	3,265	(427)	3,809
Long-term debt	—	2,900	9,869	—	12,769
Advances payable — consolidated subsidiaries	5,581	—	—	(5,581)	—
Notes payable — consolidated subsidiaries	—	2,800	—	(2,800)	—
Deferred credits and other liabilities	819	4,187	1,800	—	6,806
Preferred stock of subsidiaries	—	—	258	—	258
Equity					
Controlling interests	8,160	14,531	20,562	(35,093)	8,160
Noncontrolling interests	—	—	2,238	—	2,238
Total equity	8,160	14,531	22,800	(35,093)	10,398
Total Liabilities and Equity	$14,664	$25,285	$ 37,992	$ (43,901)	$ 34,040

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Spectra Energy Corp
Condensed Consolidating Balance Sheet
December 31, 2013
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$—	$12	$189	$—	$201
Receivables — consolidated subsidiaries	176	394	—	(570)	—
Receivables — other	1	—	1,335	—	1,336
Other current assets	40	15	489	—	544
Total current assets	217	421	2,013	(570)	2,081
Investments in and loans to unconsolidated affiliates	—	—	3,043	—	3,043
Investments in consolidated subsidiaries	13,244	19,403	—	(32,647)	—
Advances receivable — consolidated subsidiaries	—	4,038	677	(4,715)	—
Notes receivable — consolidated subsidiaries	—	—	3,215	(3,215)	—
Goodwill	—	—	4,810	—	4,810
Other assets	39	30	316	—	385
Net property, plant and equipment	—	—	21,829	—	21,829
Regulatory assets and deferred debits	3	17	1,365	—	1,385
Total Assets	$13,503	$23,909	$37,268	$(41,147)	$33,533
Accounts payable	$4	$—	$436	$—	$440
Accounts payable — consolidated subsidiaries	89	—	481	(570)	—
Commercial paper	—	344	688	—	1,032
Short-term borrowings — consolidated subsidiaries	—	415	—	(415)	—
Taxes accrued	4	—	68	—	72
Current maturities of long-term debt	—	557	640	—	1,197
Other current liabilities	81	75	1,142	—	1,298
Total current liabilities	178	1,391	3,455	(985)	4,039
Long-term debt	—	2,605	9,883	—	12,488
Advances payable — consolidated subsidiaries	4,715	—	—	(4,715)	—
Notes payable — consolidated subsidiaries	—	2,800	—	(2,800)	—
Deferred credits and other liabilities	116	3,869	2,440	—	6,425
Preferred stock of subsidiaries	—	—	258	—	258
Equity					
Controlling interests	8,494	13,244	19,403	(32,647)	8,494
Noncontrolling interests	—	—	1,829	—	1,829
Total equity	8,494	13,244	21,232	(32,647)	10,323
Total Liabilities and Equity	$13,503	$23,909	$37,268	$(41,147)	$33,533

Spectra Energy Corp
Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2014
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$1,082	$1,054	$ 1,852	$ (2,705)	$ 1,283
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Depreciation and amortization	—	—	809	—	809
Equity in earnings of unconsolidated affiliates	—	—	(361)	—	(361)
Equity in earnings of consolidated subsidiaries	(1,054)	(1,651)	—	2,705	—
Distributions received from unconsolidated affiliates	—	—	380	—	380
Other	14	304	(208)	—	110
Net cash provided by (used in) operating activities	42	(293)	2,472	—	2,221
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures	—	—	(2,028)	—	(2,028)
Investments in and loans to unconsolidated affiliates	—	—	(259)	—	(259)
Purchases of held-to-maturity securities	—	—	(790)	—	(790)
Proceeds from sales and maturities of held-to-maturity securities	—	—	815	—	815
Purchases of available-for-sale securities	—	—	(13)	—	(13)
Proceeds from sales and maturities of available-for-sale securities	—	—	7	—	7
Distributions received from unconsolidated affiliates	—	—	266	—	266
Advances from affiliates	92	495	—	(587)	—
Other changes in restricted funds	—	—	(1)	—	(1)
Net cash provided by (used in) investing activities	92	495	(2,003)	(587)	(2,003)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt	—	300	728	—	1,028
Payments for the redemption of long-term debt	—	(557)	(627)	—	(1,184)
Net increase in commercial paper	—	54	520	—	574
Distributions to noncontrolling interests	—	—	(175)	—	(175)
Contributions from noncontrolling interests	—	—	145	—	145
Proceeds from the issuance of SEP common units	—	—	327	—	327
Dividends paid on common stock	(925)	—	—	—	(925)
Distributions and advances from (to) affiliates	777	(10)	(1,354)	587	—
Other	14	—	(3)	—	11
Net cash used in financing activities	(134)	(213)	(439)	587	(199)
Effect of exchange rate changes on cash	—	—	(5)	—	(5)
Net increase (decrease) in cash and cash equivalents	—	(11)	25	—	14
Cash and cash equivalents at beginning of period	—	12	189	—	201
Cash and cash equivalents at end of period	$—	$1	$ 214	$ —	$ 215

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Spectra Energy Corp
Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2013
(In millions)

	Spectra Energy Corp	Spectra Capital (a)	Non-Guarantor Subsidiaries (a)	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 1,038	$ 1,015	$ 1,770	$ (2,664)	$ 1,159
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Depreciation and amortization	—	—	787	—	787
Equity in earnings of unconsolidated affiliates	—	—	(445)	—	(445)
Equity in earnings of consolidated subsidiaries	(1,015)	(1,649)	—	2,664	—
Distributions received from unconsolidated affiliates	—	—	324	—	324
Other	(2)	478	(271)	—	205
Net cash provided by (used in) operating activities	21	(156)	2,165	—	2,030
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures	—	—	(1,947)	—	(1,947)
Investments in and loans to unconsolidated affiliates	—	—	(312)	—	(312)
Acquisitions, net of cash acquired	—	—	(1,254)	—	(1,254)
Purchases of held-to-maturity securities	—	—	(985)	—	(985)
Proceeds from sales and maturities of held-to-maturity securities	—	—	1,023	—	1,023
Purchases of available-for-sale securities	—	—	(5,878)	—	(5,878)
Proceeds from sales and maturities of available-for-sale securities	—	—	6,024	—	6,024
Distributions received from unconsolidated affiliates	—	—	87	—	87
Advances to affiliates	(75)	(1,856)	—	1,931	—
Loan to unconsolidated affiliate	—	—	(71)	—	(71)
Repayment of loan to unconsolidated affiliate	—	71	—	—	71
Other changes in restricted funds	—	—	2	—	2
Other	—	—	4	—	4
Net cash used in investing activities	(75)	(1,785)	(3,307)	1,931	(3,236)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt	—	1,848	2,524	—	4,372
Payments for the redemption of long-term debt	—	(1,944)	(195)	—	(2,139)
Net decrease in commercial paper	—	(170)	(36)	—	(206)
Net increase in short-term borrowings – consolidated subsidiaries	—	(497)	—	497	—
Distributions to noncontrolling interests	—	—	(144)	—	(144)
Contributions from noncontrolling interests	—	—	23	—	23
Proceeds from the issuance of SEP common units	—	—	214	—	214
Dividends paid on common stock	(821)	—	—	—	(821)
Distributions and advances from (to) affiliates	847	2,718	(1,137)	(2,428)	—
Other	28	(5)	(6)	—	17
Net cash provided by financing activities	54	1,950	1,243	(1,931)	1,316
Effect of exchange rate changes on cash	—	—	(3)	—	(3)
Net increase in cash and cash equivalents	—	9	98	—	107

Cash and cash equivalents at beginning of period	—	3	91	—	94
Cash and cash equivalents at end of period	$—	$12	$ 189	$—	$ 201

(a) Excludes the effects of $3,869 million of non-cash equitizations of advances receivable owed to Spectra Capital.

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Spectra Energy Corp
Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2012
(In millions)

	Spectra Energy Corp	Spectra Capital (a)	Non-Guarantor Subsidiaries (a)	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$940	$917	$ 1,484	$ (2,294)	$ 1,047
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Depreciation and amortization	—	—	760	—	760
Equity in earnings of unconsolidated affiliates	—	—	(382)	—	(382)
Equity in earnings of consolidated subsidiaries	(917)	(1,377)	—	2,294	—
Distributions received from unconsolidated affiliates	—	—	307	—	307
Other	(86)	246	46	—	206
Net cash provided by (used in) operating activities	(63)	(214)	2,215	—	1,938
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures	—	—	(2,025)	—	(2,025)
Investments in and loans to unconsolidated affiliates	—	—	(520)	—	(520)
Acquisitions, net of cash acquired	—	—	(30)	—	(30)
Purchases of held-to-maturity securities	—	—	(2,671)	—	(2,671)
Proceeds from sales and maturities of held-to-maturity securities	—	—	2,578	—	2,578
Purchases of available-for-sale securities	—	—	(644)	—	(644)
Proceeds from sales and maturities of available-for-sale securities	—	—	514	—	514
Distributions received from unconsolidated affiliates	—	—	17	—	17
Advances from (to) affiliates	(163)	(335)	888	(390)	—
Other changes in restricted funds	—	—	93	—	93
Other	—	—	14	—	14
Net cash used in investing activities	(163)	(335)	(1,786)	(390)	(2,674)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt	—	—	1,301	—	1,301
Payments for the redemption of long-term debt	—	—	(525)	—	(525)
Net increase (decrease) in commercial paper	—	(238)	437	—	199
Net increase in short-term borrowings - consolidated subsidiaries	—	322	—	(322)	—
Distributions to noncontrolling interests	—	—	(120)	—	(120)
Proceeds from the issuance of Spectra Energy common stock	382	—	—	—	382
Proceeds from the issuance of SEP common units	—	—	145	—	145
Dividends paid on common stock	(753)	—	—	—	(753)
Distributions and advances from (to) affiliates	564	466	(1,742)	712	—
Other	33	—	(8)	—	25
Net cash provided by (used in) financing activities	226	550	(512)	390	654
Effect of exchange rate changes on cash	—	—	2	—	2
Net increase (decrease) in cash and cash equivalents	—	1	(81)	—	(80)
Cash and cash equivalents at beginning of period	—	2	172	—	174

Cash and cash equivalents at end of period	$—	$3	$ 91	$—	$ 94

(a) Excludes the effects of $1,207 million of non-cash equitizations of advances receivable owed to Spectra Capital.

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27. Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(in millions, except per share amounts)				
2014					
Operating revenues	$1,843	$1,253	$1,207	$1,600	$5,903
Operating income	639	338	382	565	1,924
Net income	467	188	254	374	1,283
Net income — controlling interests	419	146	201	316	1,082
Earnings per share (a)					
Basic	0.63	0.22	0.30	0.47	1.61
Diluted	0.62	0.22	0.30	0.47	1.61
2013					
Operating revenues	$1,589	$1,220	$1,144	$1,565	$5,518
Operating income	506	354	333	473	1,666
Net income	370	226	292	271	1,159
Net income — controlling interests	340	199	263	236	1,038
Earnings per share (a)					
Basic	0.51	0.30	0.39	0.35	1.55
Diluted	0.51	0.30	0.39	0.35	1.55

(a) Quarterly earnings-per-share amounts are stand-alone calculations and may not be additive to full-year amounts due to rounding.

Unusual or Infrequent Items

During the third and fourth quarters of 2013, we recorded transaction costs related to the U.S. Assets Dropdown and additional merger and acquisitions costs. These costs impacted operating income by $23 million, net income by $22 million and net income-controlling interests by $20 million in the third quarter of 2013, and operating income, net income and net income-controlling interests by $11 million the fourth quarter 2013.

During the fourth quarter of 2013, we recorded income tax expense resulting from a change in state tax rate related to the U.S. Assets Dropdown, which impacted net income and net income-controlling by $31 million for the year ended .

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SPECTRA ENERGY CORP
SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

	Balance at Beginning of Period	Additions: Charged to Expense	Charged to Other Accounts	Deductions (a)	Balance at End of Period
	(in millions)				
December 31, 2014					
Allowance for doubtful accounts	$10	$6	$—	$ 5	$11
Other (b)	164	29	—	80	113
	$174	$35	$—	$ 85	$124
December 31, 2013					
Allowance for doubtful accounts	$13	$7	$—	$ 10	$10
Other (b)	181	21	—	38	164
	$194	$28	$—	$ 48	$174
December 31, 2012					
Allowance for doubtful accounts	$14	$10	$1	$ 12	$13
Other (b)	171	64	—	54	181
	$185	$74	$1	$ 66	$194

(a) Principally cash payments and reserve reversals.
(b) Principally income tax, insurance-related, litigation and other reserves, included primarily in Deferred Credits and Other Liabilities—Regulatory and Other on the Consolidated Balance Sheets.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2014, and, based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated changes in internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended December 31, 2014 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

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Management’s Annual Report on Internal Control over Financial Reporting

The report of management required under this Item 9A is contained in Item 8. Financial Statements and Supplementary Data, Management’s Annual Report on Internal Control over Financial Reporting.

Attestation Report of Independent Registered Public Accounting Firm

The attestation report required under this Item 9A is contained in Item 8. Financial Statements and Supplementary Data, Report of Independent Registered Public Accounting Firm.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Reference to “Executive Officers” is included in “Part I. Item 1. Business” of this report. Other information in response to this item is incorporated by reference from our Proxy Statement relating to our 2015 annual meeting of shareholders.

Item 11. Executive Compensation.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2015 annual meeting of shareholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2015 annual meeting of shareholders.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2015 annual meeting of shareholders.

Item 14. Principal Accounting Fees and Services.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2015 annual meeting of shareholders.

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PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Spectra Energy Corp:

Report of Independent Registered Accounting Firm
Consolidated Statements of Operations
Consolidated Statements of Comprehensive Income
Consolidated Balance Sheets
Consolidated Statements of Cash Flows
Consolidated Statements of Equity
Notes to Consolidated Financial Statements
Consolidated Financial Statement Schedule II—Valuation and Qualifying Accounts and Reserves

Separate Financial Statements of Subsidiaries not Consolidated Pursuant to Rule 3-09 of Regulation S-X:

DCP Midstream, LLC:

Independent Auditors' Report
Consolidated Balance Sheets
Consolidated Statements of Operations
Consolidated Statements of Comprehensive Income
Consolidated Statements of Cash Flows
Consolidated Statements of Changes in Equity
Notes to Consolidated Financial Statements

All other schedules are omitted because they are not required or because the required information is included in the Consolidated Financial Statements or Notes.

(c) Exhibits—See Exhibit Index immediately following the signature page.

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SIGNATURES

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.

Date: February 27, 2015

SPECTRA ENERGY CORP

By: /s/ Gregory L. Ebel
Gregory L. Ebel
Chairman, President and Chief Executive Officer

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 and on the date indicated.

Gregory L. Ebel*
Chairman of the Board of Directors, President and Chief Executive Officer (Principal Executive Officer and Director)
J. Patrick Reddy*
Chief Financial Officer (Principal Financial Officer)
Allen C. Capps*
Vice President and Controller (Principal Accounting Officer)
Austin A. Adams*
Director
Joseph Alvarado*
Director
Pamela L. Carter*
Director
Clarence P. Cazalot, Jr*
Director
F. Anthony Comper*
Lead Director
Peter B. Hamilton*
Director
Michael McShane*
Director
Michael G. Morris*
Director
Michael E.J. Phelps *
Director

Date: February 27, 2015

J. Patrick Reddy, by signing his name hereto, does hereby sign this document on behalf of the registrant and on behalf of each of the above-named persons previously indicated by asterisk pursuant to a power of attorney duly executed by the registrant and such persons, filed with the Securities and Exchange Commission as an exhibit hereto.

By: /s/ J. Patrick Reddy
J. Patrick Reddy
Attorney-In-Fact

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DCP MIDSTREAM, LLC
CONSOLIDATED FINANCIAL STATEMENTS

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INDEPENDENT AUDITORS' REPORT
To the Board of Directors and Members of
DCP Midstream, LLC
Denver, Colorado

We have audited the accompanying consolidated financial statements of DCP Midstream, LLC and its subsidiaries (the "Company"), which comprise the consolidated balance sheets as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2014, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor’s judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of DCP Midstream, LLC and its subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

February 26, 2015

F-2 Member of
Deloitte Touche Tohmatsu

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DCP MIDSTREAM, LLC
CONSOLIDATED BALANCE SHEETS
(millions)

	December 31, 2014	2013
ASSETS		
Current assets:		
Cash and cash equivalents	$27	$31
Accounts receivable:		
Customers, net of allowance for doubtful accounts of $3 million and $4 million, respectively	813	1,139
Affiliates	180	265
Other	39	28
Inventories	76	96
Unrealized gains on derivative instruments	165	59
Other	80	45
Total current assets	1,380	1,663
Property, plant and equipment, net	9,537	8,420
Investments in unconsolidated affiliates	1,463	1,378
Intangible assets, net	290	311
Goodwill	704	722
Unrealized gains on derivative instruments	23	10
Other long-term assets	282	217
Total assets	$13,679	$12,721
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$904	$1,296
Affiliates	35	59
Other	58	58
Short-term borrowings	1,012	1,300
Current maturities of long-term debt	450	—
Unrealized losses on derivative instruments	124	64
Accrued taxes	34	37
Other	321	300
Total current liabilities	2,938	3,114
Deferred income taxes	105	96
Long-term debt	5,233	4,962
Unrealized losses on derivative instruments	15	2
Other long-term liabilities	185	158
Total liabilities	8,476	8,332
Commitments and contingent liabilities		
Equity:		
Members' interest	2,630	2,670
Accumulated other comprehensive loss	(5)	(6)
Total members' equity	2,625	2,664
Noncontrolling interest	2,578	1,725
Total equity	5,203	4,389

Total liabilities and equity	$13,679	$12,721

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
(millions)

	Year Ended December 31,		
	2014	2013	2012
Operating revenues:			
Sales of natural gas and NGL products	$11,378	$9,807	$7,826
Sales of natural gas and NGL products to affiliates	2,030	1,732	1,886
Transportation, storage and processing	517	463	373
Trading and marketing gains, net	88	36	86
Total operating revenues	14,013	12,038	10,171
Operating costs and expenses:			
Purchases of natural gas and NGL products	11,361	9,679	7,662
Purchases of natural gas and NGL products from affiliates	467	288	510
Operating and maintenance	780	691	667
Depreciation and amortization	348	314	291
General and administrative	281	280	297
Loss (gain) on sale of assets and goodwill impairment	25	(22)	—
Total operating costs and expenses	13,262	11,230	9,427
Operating income	751	808	744
Earnings from unconsolidated affiliates	83	35	34
Interest expense, net	(287)	(249)	(193)
Income before income taxes	547	594	585
Income tax expense	(11)	(10)	(2)
Net income	536	584	583
Net income attributable to noncontrolling interests	(248)	(93)	(97)
Net income attributable to members’ interests	$288	$491	$486

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(millions)

	Year Ended December 31,		
	2014	2013	2012
Net income	$536	$584	$583
Other comprehensive income:			
Net unrealized gains on cash flow hedges	—	—	1
Reclassification of cash flow hedge losses into earnings	2	3	11
Total other comprehensive income	2	3	12
Total comprehensive income	538	587	595
Total comprehensive income attributable to noncontrolling interests	(249)	(93)	(106)
Total comprehensive income attributable to members' interests	$289	$494	$489

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
(millions)

	Year Ended December 31,		
	2014	2013	2012
Cash flows from operating activities:			
Net income	$536	$584	$583
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	348	314	291
Earnings from unconsolidated affiliates	(83)	(35)	(34)
Distributions from unconsolidated affiliates	141	52	36
Deferred income tax expense (benefit)	9	4	(1)
Net unrealized gains on derivative instruments	(43)	(5)	—
Loss (gain) on sale of assets and goodwill impairment	25	(22)	—
Other, net	27	20	6
Changes in operating assets and liabilities which provided (used) cash:			
Accounts receivable	397	(333)	241
Inventories	16	9	(9)
Accounts payable	(452)	300	(630)
Other	(104)	(50)	(139)
Net cash provided by operating activities	817	838	344
Cash flows from investing activities:			
Capital expenditures	(1,384)	(1,420)	(2,285)
Acquisitions, net of cash acquired	—	—	(123)
Proceeds from sales of two-thirds interest in Sand Hills and Southern Hills	—	—	919
Investments in unconsolidated affiliates	(161)	(523)	(240)
Proceeds from sale of assets and equity method investments	30	46	1
Net cash used in investing activities	(1,515)	(1,897)	(1,728)
Cash flows from financing activities:			
Payment of dividends and distributions to members	(474)	(430)	(405)
Proceeds from long-term debt	719	2,507	2,915
Payment of long-term debt	—	(2,238)	(2,042)
Proceeds from issuance of common units by DCP Partners, net of offering costs	1,001	1,083	455
(Repayment) borrowings of commercial paper, net	(288)	342	588
Distributions paid to noncontrolling interests	(252)	(167)	(112)
Payment of deferred financing costs	(12)	(11)	(20)
Net cash provided by financing activities	694	1,086	1,379
Net change in cash and cash equivalents	(4)	27	(5)
Cash and cash equivalents, beginning of period	31	4	9
Cash and cash equivalents, end of period	$27	$31	$4

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(millions)

	Members' Equity			
	Members' Interest	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interest	Total Equity
Balance, January 1, 2012	$2,164	$(12)	$537	$2,689
Net income	486	—	97	583
Other comprehensive income	—	3	9	12
Dividends and distributions	(310)	—	(112)	(422)
Issuance of common units by DCP Partners, net of offering costs	73	—	382	455
Balance, December 31, 2012	2,413	(9)	913	3,317
Net income	491	—	93	584
Other comprehensive income	—	3	—	3
Dividends and distributions	(430)	—	(167)	(597)
Issuance of common units by DCP Partners, net of offering costs	196	—	886	1,082
Balance, December 31, 2013	2,670	(6)	1,725	4,389
Net income	288	—	248	536
Other comprehensive income	—	1	1	2
Dividends and distributions	(474)	—	(252)	(726)
Issuance of common units by DCP Partners, net of offering costs	146	—	856	1,002
Balance, December 31, 2014	$2,630	$(5)	$2,578	$5,203

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC
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1. Description of Business and Basis of Presentation

DCP Midstream, LLC, with its consolidated subsidiaries, or us, we, our, or the Company, is a joint venture owned 50% by Phillips 66 and its affiliates, or Phillips 66, and 50% by Spectra Energy Corp and its affiliates, or Spectra Energy. We operate in the midstream natural gas industry and are engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas and producing, fractionating, transporting, storing and selling natural gas liquids, or NGLs, and recovering and selling condensate. Additionally, we generate revenues by trading and marketing natural gas and NGLs.

DCP Midstream Partners, LP, or DCP Partners, is a master limited partnership, of which we act as general partner. As of December 31, 2014 and 2013, we owned an approximate 22% and 23% interest in DCP Partners, respectively, including our limited partner and general partner interests. We also own incentive distribution rights that entitle us to receive an increasing share of available cash as pre-defined distribution targets are achieved. As the general partner of DCP Partners, we have responsibility for its operations.

We are governed by a five member board of directors, consisting of two voting members from each of Phillips 66 and Spectra Energy and our Chairman of the Board, President and Chief Executive Officer, a non-voting member. All decisions requiring the approval of our board of directors are made by simple majority vote of the board, but must include at least one vote from both a Phillips 66 and Spectra Energy board member. In the event the board cannot reach a majority decision, the decision is appealed to the Chief Executive Officers of both Phillips 66 and Spectra Energy.

The consolidated financial statements include the accounts of the Company and all majority-owned subsidiaries where we have the ability to exercise control and undivided interests in jointly owned assets. We also consolidate DCP Partners, which we control through our ownership and general partner interest, and where the limited partners do not have substantive kick-out or participating rights. Investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence, are accounted for using the equity method. Intercompany balances and transactions have been eliminated.

2. Summary of Significant Accounting Policies

Use of Estimates - Conformity with accounting principles generally accepted in the United States of America, or GAAP, requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and notes. Although these estimates are based on management's best available knowledge of current and expected future events, actual results could differ from those estimates.

Cash and Cash Equivalents - Cash and cash equivalents include all cash balances and investments in highly liquid financial instruments purchased with an original stated maturity of 90 days or less and temporary investments of cash in short-term money market securities.

Allowance for Doubtful Accounts - Management estimates the amount of required allowances for the potential non-collectability of accounts receivable generally based upon the number of days past due, past collection experience and consideration of other relevant factors. However, past experience may not be indicative of future collections and therefore additional charges could be incurred in the future to reflect differences between estimated and actual collections.

Inventories - Inventories, which consist primarily of natural gas and NGLs held in storage for transportation, processing and sales commitments, are recorded at the lower of weighted-average cost or market value. Transportation costs are included in inventory.

Accounting for Risk Management and Derivative Activities and Financial Instruments - We designate each energy commodity derivative as either trading or non-trading. Certain non-trading derivatives are further designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales contract. The remaining other non-trading derivatives, which are related to asset based activities for which hedge accounting or the normal purchase or normal sale exception is not elected, are recorded at fair value in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments, with changes in

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DCP MIDSTREAM, LLC
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Years Ended December 31, 2014, 2013 and 2012

the fair value recognized in the consolidated statements of operations. For each derivative, the accounting method and presentation of gains and losses or revenue and expense in the consolidated statements of operations are as follows:

Classification of Contract	Accounting Method	Presentation of Gains & Losses or Revenue & Expense
Trading Derivatives	Mark-to-market method (a)	Net basis in trading and marketing gains and losses
Non-Trading Derivatives:		
Cash Flow Hedge	Hedge method (b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Fair Value Hedge	Hedge method (b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Normal Purchases or Normal Sales	Accrual method (c)	Gross basis upon settlement in the corresponding consolidated statements of operations category based on purchase or sale
Other Non-Trading Derivatives	Mark-to-market method (a)	Net basis in trading and marketing gains and losses

(a) Mark-to-market method - An accounting method whereby the change in the fair value of the asset or liability is recognized in the consolidated statements of operations in trading and marketing gains and losses during the current period.
(b) Hedge method - An accounting method whereby the change in the fair value of the asset or liability is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. For cash flow hedges, there is no recognition in the consolidated statements of operations for the effective portion until the service is provided or the associated delivery impacts earnings. For fair value hedges, the changes in the fair value of the asset or liability, as well as the offsetting changes in value of the hedged item, are recognized in the consolidated statements of operations in the same category as the related hedged item.
(c) Accrual method - An accounting method whereby there is no recognition in the consolidated balance sheets or consolidated statements of operations for changes in fair value of a contract until the service is provided or the associated delivery impacts earnings.

Cash Flow and Fair Value Hedges - For derivatives designated as a cash flow hedge or a fair value hedge, we maintain formal documentation of the hedge. In addition, we formally assess both at the inception of the hedging relationship and on an ongoing basis, whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. All components of each derivative gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

The fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. The change in fair value of the effective portion of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as accumulated other comprehensive income, or AOCI, and the ineffective portion is recorded in the consolidated statements of operations. During the period in which the hedged transaction impacts earnings, amounts in AOCI associated with the hedged transaction are reclassified to the consolidated statements of operations in the same line item as the item being hedged. Hedge accounting is discontinued prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is probable that the hedged transaction will not occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the consolidated balance sheets at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction impacts earnings, unless it is probable that the hedged transaction will not occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

The fair value of a derivative designated as a fair value hedge is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. We recognize the gain or loss on the derivative instrument, as well as the offsetting loss or gain on the hedged item in earnings in the current period. The change in fair value of all derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in the consolidated results of operations.

Valuation - When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on internally developed pricing models developed primarily from historical relationships with quoted market prices and the expected relationship with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Property, Plant and Equipment - Property, plant and equipment are recorded at historical cost. The cost of maintenance and repairs, which are not significant improvements, are expensed when incurred. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

Capitalized Interest - We capitalize interest during construction of major projects. Interest is calculated on the monthly outstanding capital balance and ceases in the month that the asset is placed into service. We also capitalize interest on our equity method investments which are devoting substantially all efforts to establishing a new business and have not yet begun planned principal operations. Capitalization ceases when the investee commences planned principal operations. The rates used to calculate capitalized interest are the weighted-average cost of debt, including the impact of interest rate swaps.

Asset Retirement Obligations - Asset retirement obligations associated with tangible long-lived assets are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability is determined using a credit-adjusted risk free interest rate and accretes due to the passage of time based on the time value of money until the obligation is settled.

Our asset retirement obligations relate primarily to the retirement of various gathering pipelines and processing facilities, obligations related to right-of-way easement agreements, and contractual leases for land use. We adjust our asset retirement obligation each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Goodwill and Intangible Assets - Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business. We perform an annual impairment test of goodwill in the third quarter, and update the test during interim periods when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value of a reporting unit. We primarily use a discounted cash flow analysis, supplemented by a market approach analysis, to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future goodwill and intangible assets impairment charges for other reporting units due to the potential impact on our operations and cash flows.

Intangible assets consist primarily of customer contracts, including commodity purchase, transportation and processing contracts and related relationships. These intangible assets are amortized on a straight-line basis over the period of expected future benefit. Intangible assets are removed from the gross carrying amount and the total of accumulated amortization in the period in which they become fully amortized.

Investments in Unconsolidated Affiliates - We use the equity method to account for investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence.

We evaluate our investments in unconsolidated affiliates for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced a decline in value. When there is evidence of loss in value that is other than temporary, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred. We assess the fair value of our investments in unconsolidated affiliates using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. If the estimated fair value is less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

Long-Lived Assets - We evaluate whether the carrying value of long-lived assets, including intangible assets, has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. We consider various factors when determining if these assets should be evaluated for impairment, including but not limited to:

- a significant adverse change in legal factors or business climate;
- a current period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- a significant adverse change in the market value of an asset; or
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value. We determine the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management's intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future impairment due to the potential impact on our operations and cash flow.

Unamortized Debt Premium, Discount and Expense - Premiums, discounts and expenses incurred with the issuance of long-term debt are amortized over the term of the debt using the effective interest method. The premiums and discounts are recorded on the consolidated balance sheets within the carrying amount of long-term debt. The unamortized expenses are recorded on the consolidated balance sheets as other long-term assets.

Noncontrolling Interest - Noncontrolling interest represents the ownership interests of third-party entities in the net assets of consolidated affiliates, including the ownership interest of DCP Partners' public unitholders, through DCP Partners' publicly traded common units, in net assets of DCP Partners and the noncontrolling interest which is recorded in DCP Partners' consolidated balance sheets. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party interest in our consolidated balance sheet amounts shown as noncontrolling interest in equity. Distributions to and contributions from noncontrolling interests represent cash payments to and cash contributions from, respectively, such third-party investors.

Dividends and Distributions - Under the terms of the Second Amended and Restated LLC Agreement dated July 5, 2005, as amended, or the LLC Agreement, we are required to make quarterly distributions to Phillips 66 and Spectra Energy based on allocated taxable income. The LLC Agreement provides for taxable income to be allocated in accordance with Internal Revenue Code Section 704(c). This Code Section accounts for the variation between the adjusted tax basis and the fair market value of assets contributed to the joint venture. The distribution is based on the highest taxable income allocated to either member, with the other member receiving a proportionate amount to maintain the ownership capital accounts at 50% for both Phillips 66 and Spectra Energy. Tax distributions to the members are calculated based on estimated annual taxable income allocated to the members according to their respective ownership percentages at the date the distributions became due. Our board of directors determines the amount of the periodic dividends to be paid by considering net income attributable to members' interests, cash flow or any other criteria deemed appropriate. The LLC Agreement restricts payment of dividends except with the approval of both members. Dividends are allocated to the members in accordance with their respective ownership percentages.

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DCP Partners considers the payment of a quarterly distribution to the holders of its common units, to the extent DCP Partners has sufficient cash from its operations after establishment of cash reserves and payment of fees and expenses, including payments to its general partner, a 100% owned subsidiary of ours. There is no guarantee, however, that DCP Partners will pay the minimum quarterly distribution on the units in any quarter. DCP Partners will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under its credit agreement.

Revenue Recognition - We generate the majority of our revenues from gathering, processing, compressing, treating, transporting, storing and selling natural gas and producing, fractionating, transporting, storing and selling NGLs and recovering and selling condensate, as well as trading and marketing of natural gas and NGLs. We realize revenues either by selling the residue natural gas, NGLs and condensate, or by receiving fees.

We obtain access to commodities and provide our midstream services principally under contracts that contain a combination of one or more of the following arrangements:

- Percent-of-proceeds/index arrangements - Under percent-of-proceeds/index arrangements, we generally purchase natural gas from producers at the wellhead or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas, NGLs and condensate based on published index prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas, NGLs and condensate, or an agreed-upon percentage of the proceeds based on index related prices or contractual recoveries for the natural gas, NGLs and condensate, regardless of the actual amount of the sales proceeds we receive. We keep the difference between the proceeds received and the amount remitted back to the producer. Under percent-of-liquid arrangements, we do not keep any amounts related to the residue natural gas proceeds and only keep amounts related to the difference between the proceeds received and the amount remitted back to the producer related to NGLs and condensate. Certain of these arrangements may also result in the producer retaining title to all or a portion of the residue natural gas and/or the NGLs, in lieu of us returning sales proceeds to the producer. Additionally, these arrangements may include fee-based components. Our revenues under percent-of-proceeds/index arrangements relate directly with the price of natural gas, NGLs and condensate. Our revenues under percent-of-liquids arrangements relate directly to the price of NGLs and condensate.

- Fee-based arrangements - Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing, transporting or storing natural gas and fractionating, storing and transporting NGLs. Our fee-based arrangements include natural gas arrangements pursuant to which we obtain natural gas at the wellhead, or other receipt points, at an index related price at the delivery point less a specified amount, generally the same as the transportation fees we would otherwise charge for transportation of natural gas from the wellhead location to the delivery point. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are not directly dependent on commodity prices. However, to the extent a sustained decline in commodity prices results in a decline in volumes our revenues from these arrangements would be reduced.

- Keep-whole and wellhead purchase arrangements - Under the terms of a keep-whole processing contract, natural gas is gathered from the producer for processing, the NGLs and condensate are sold and the residue natural gas is returned to the producer with a British thermal unit, or Btu, content equivalent to the Btu content of the natural gas gathered. This arrangement keeps the producer whole to the thermal value of the natural gas received. Under the terms of a wellhead purchase contract, we purchase natural gas from the producer at the wellhead or defined receipt point for processing and then market the resulting NGLs and residue gas at market prices. Under these types of contracts, we are exposed to the difference between the value of the NGLs extracted from processing and the value of the Btu equivalent of residue natural gas, or frac spread. We benefit in periods when NGL prices are higher relative to natural gas prices when that frac spread exceeds our operating costs.

Our trading and marketing of natural gas and NGL products consists of physical purchases and sales, as well as derivative instruments.

We recognize revenues for sales and services under the four revenue recognition criteria, as follows:

- Persuasive evidence of an arrangement exists - Our customary practice is to enter into a written contract.

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- Delivery - Delivery is deemed to have occurred at the time custody is transferred, or in the case of fee-based arrangements, when the services are rendered. To the extent we retain product as inventory, delivery occurs when the inventory is subsequently sold and custody is transferred to the third party purchaser.

- The fee is fixed or determinable - We negotiate the fee for our services at the outset of our fee-based arrangements. In these arrangements, the fees are nonrefundable. For other arrangements, the amount of revenue, based on contractual terms, is determinable when the sale of the applicable product has been completed upon delivery and transfer of custody.

- Collectability is reasonably assured - Collectability is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates the customers' financial position (for example, credit metrics, liquidity and credit rating) and their ability to pay. If collectability is not considered probable at the outset of an arrangement in accordance with our credit review process, revenue is not recognized until the cash is collected.

We generally report revenues gross in the consolidated statements of operations, as we typically act as the principal in these transactions, take custody of the product, and incur the risks and rewards of ownership. New or amended contracts for certain sales and purchases of inventory with the same counterparty, when entered into in contemplation of one another, are reported net as one transaction. We recognize revenues for our NGL and residue gas derivative trading activities net in the consolidated statements of operations as trading and marketing gains and losses. These activities include mark-to-market gains and losses on energy trading contracts, and the settlement of financial and physical energy trading contracts.

Revenue for goods and services provided but not invoiced is estimated each month and recorded along with related purchases of goods and services used but not invoiced. These estimates are generally based on estimated commodity prices, preliminary throughput measurements and allocations and contract data. There are no material differences between the actual amounts and the estimated amounts of revenues and purchases recorded at December 31, 2014, 2013 and 2012.

Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as accounts receivable or accounts payable using current market prices or the weighted-average prices of natural gas or NGLs at the plant or system. These balances are settled with deliveries of natural gas or NGLs, or with cash. Included in the consolidated balance sheets as accounts receivable - other, as of December 31, 2014 and 2013, were imbalances totaling $38 million and $28 million, respectively. Included in the consolidated balance sheets as accounts payable - other, as of both December 31, 2014 and 2013, were imbalances totaling $58 million.

Significant Customers - There were no third party customers that accounted for more than 10% of total operating revenues for the years ended December 31, 2014, 2013 or 2012. We had significant transactions with affiliates. See Note 5, Agreements and Transactions with Related Parties and Affiliates.

Environmental Expenditures - Environmental expenditures are expensed or capitalized as appropriate, depending upon the future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not generate current or future revenue, are expensed. Liabilities for these expenditures are recorded on an undiscounted basis when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated.

Equity-Based Compensation - Liability classified share-based compensation cost is remeasured at each reporting date at fair value, based on the closing security price, and is recognized as expense over the requisite service period. Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award.

Accounting for Sales of Units by a Subsidiary - We account for sales of units by a subsidiary by recording an increase or decrease in members' interest within equity equal to the amount of net proceeds received in excess or deficit of the carrying value of the units sold. The remaining net proceeds are recorded as an increase to noncontrolling interest.

Income Taxes - We are structured as a limited liability company, which is a pass-through entity for federal income tax purposes. We own a corporation that files its own federal, foreign and state corporate income tax returns. The income tax expense related to this corporation is included in our income tax expense, along with state, local, franchise and margin taxes of the limited liability company and other subsidiaries.

We follow the asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the tax consequences of temporary differences between the financial statement carrying amounts and the tax basis of the assets and liabilities. Our taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statements of operations, is included in the federal returns of each partner.

3. Recent Accounting Pronouncements

Financial Accounting Standards Board, or FASB, Accounting Standards Update, or ASU, 2014-09 "Revenue from Contracts with Customers (Topic 606)," or ASU 2014-09 - In May 2014, the FASB issued ASU 2014-09, which supersedes the revenue recognition requirements of Accounting Standards Codification, or ASC, Topic 605 "Revenue Recognition." We intend to adopt this ASU when it is effective for public entities, which is for annual reporting periods beginning after December 15, 2016 and we are currently assessing the impact of adoption on our consolidated results of operations, cash flows and financial position.

ASU 2014-12 "Compensation - Stock Compensation (Topic 718): Accounting for Share-Based payments When the Terms of an Award Provide That a Performance Target Could be Achieved after the Requisite Service Period," or ASU 2014-12 - In May 2014, the FASB issued ASU 2014-12, which provides more explicit guidance for treating share-based payment awards that require a specific performance target that affects vesting and that could be achieved after the requisite service period as a performance condition. This ASU is effective for interim and annual reporting periods beginning after December 15, 2015 and is not expected to have a material impact on our consolidated results of operations, cash flows and financial position.

4. Dispositions

In August 2014, we entered into a purchase and sale agreement with American Midstream, LLC to divest our two-thirds ownership interest in Main Pass Oil Gathering Company, or Main Pass, for total proceeds of approximately $14 million and selling costs of approximately $3 million. This transaction closed on August 11, 2014, and we recognized a $6 million loss on sale in the consolidated statements of operations for the year ended December 31, 2014.

5. Agreements and Transactions with Related Parties and Affiliates

Dividends and Distributions

During the years ended December 31, 2014, 2013 and 2012, we paid tax distributions to the members of $159 million, $18 million and $244 million, respectively, based on estimated annual taxable income allocated to Phillips 66 and Spectra Energy according to their respective ownership percentages at the date the distributions became due. During the years ended December 31, 2014, 2013 and 2012, we declared and paid dividends of $315 million, $412 million and $161 million, respectively, to Phillips 66 and Spectra Energy, allocated in accordance with their respective ownership percentages. During the years ended December 31, 2014, 2013 and 2012, DCP Partners paid distributions of $247 million, $161 million and $106 million, respectively, to its public unitholders.

Phillips 66, CPChem and ConocoPhillips

Long-Term NGL Purchases Contract and Transactions - We sell a portion of our NGLs to Phillips 66 and Chevron Phillips Chemical LLC, or CPChem. In addition, we purchase NGLs from CPChem. CPChem is owned 50% by

Phillips 66, and is considered a related party. Prior to December 31, 2014, approximately 35% of our NGL production was committed to Phillips 66 and CPChem, under 15-year contracts, the primary production commitment of which began a wind down period in December 2014 and expires in January 2019. We anticipate continuing to purchase and sell commodities with Phillips 66 and CPChem in the ordinary course of business.

Spectra Energy

Commodity Transactions - We sell a portion of our residue gas and NGLs to, purchase natural gas and other NGL products from, and provide gathering, transportation and other services to Spectra Energy. Management anticipates continuing to purchase and sell commodities and provide services to Spectra Energy in the ordinary course of business.

DCP Partners

We have entered into a services agreement, as amended, or the Services Agreement, with DCP Partners. Under the Services Agreement, DCP Partners is required to reimburse us for salaries of operating personnel and employee benefits, as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by us on behalf of DCP Partners. DCP Partners also pays us an annual fee under the Services Agreement for centralized corporate functions performed by us on behalf of DCP Partners. Except with respect to the annual fee, there is no limit on the reimbursements DCP Partners makes to us under the Services Agreement for other expenses and expenditures incurred or payments made by us on behalf of DCP Partners. Reimbursements received from DCP Partners have been eliminated in consolidation. In the event DCP Partners acquires assets or its business otherwise expands, the annual fee under the Services Agreement is subject to adjustment based on the nature and extent of general and administrative services performed by us on DCP Partners' behalf, as well as an annual adjustment based on the changes to the Consumer Price Index.

On March 31, 2014, the annual fee payable under the Services Agreement was increased by approximately $15 million, prorated for the remainder of the calendar year, to $44 million. The increase was predominately attributable to additional general and administrative expenses previously incurred directly by DCP SC Texas GP, or the Eagle Ford system, being reallocated to the Services Agreement in connection with the contribution of the remaining 20% interest in the Eagle Ford system to DCP Partners, bringing DCP Partners' ownership to 100%.

On February 23, 2015, the annual fee payable under the Services Agreement was increased by approximately $25 million to $71 million, following approval of the increase by the special committee of DCP Partners' Board of Directors. DCP Partners' growth, both from organic growth and acquisitions, has resulted in DCP Partners becoming a much larger portion of our business over the past few years. Additionally, DCP Partners' expansion into downstream logistics has required us to expand our capabilities and provide DCP Partners with a broader range of services than what was previously provided. As a result, we initiated a comprehensive review of our costs and the methodology for allocating general and administrative services. The result of this review reflects the level and cost of general and administrative services we provide to DCP Partners as the operator of its assets.

In March 2014, we contributed: (i) our 33.33% membership interest in DCP Sand Hills Pipeline, LLC, or Sand Hills, which owns the Sand Hills pipeline, and our 33.33% interest in DCP Southern Hills Pipeline, LLC, or Southern Hills, which owns the Southern Hills pipeline; (ii) the remaining 20% interest in the Eagle Ford system; (iii) a 35 million cubic feet per day, or MMcf/d, cryogenic natural gas processing plant located in Weld County, Colorado, or the Lucerne 1 plant; and (iv) a 200 MMcf/d cryogenic natural gas processing plant also in Weld County, Colorado, which is currently under construction, or the Lucerne 2 plant, to DCP Partners, collectively referred to as the March 2014 Transactions. Total consideration for the March 2014 Transactions at closing was $1,220 million, less customary working capital and other adjustments. We will continue to account for Sand Hills and Southern Hills as equity method investments through our consolidation of DCP Partners.

Unconsolidated Affiliates

We, along with other third party shippers, have entered into 15-year transportation agreements with Sand Hills, Southern Hills, Front Range Pipeline LLC, or Front Range, and Texas Express Pipeline LLC, or Texas Express. Under the terms of these 15-year agreements, which commenced at each of the pipelines' respective in-service dates, we have committed to transport minimum throughput volumes at rates defined in each of the pipelines' respective tariffs.

Under the terms of the Sand Hills LLC Agreement and the Southern Hills LLC Agreement, or the Sand Hills and Southern Hills LLC Agreements, Sand Hills and Southern Hills are required to reimburse us for any direct costs or expenses (other than general and administration services) which we incur on behalf of Sand Hills and Southern Hills. Additionally, Sand Hills and Southern Hills pay us an annual service fee totaling $10 million, for centralized corporate functions provided by us as operator of Sand Hills and Southern Hills, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering. Except with respect to the annual service fee, there is no limit on the reimbursements Sand Hills and Southern Hills make to us under the Sand Hills and Southern Hills LLC Agreements for other expenses and expenditures which we incur on behalf of Sand Hills or Southern Hills.

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Competition

Our related parties or affiliates, including DCP Partners, Phillips 66 and Spectra Energy, are not restricted, under either the LLC Agreement or the Services Agreement, from competing with us. Our related parties or affiliates, including DCP Partners, Phillips 66 and Spectra Energy, may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Transactions with other unconsolidated affiliates

We sell a portion of our residue gas and NGLs to, purchase natural gas and other NGL products from, and provide gathering and transportation services to unconsolidated affiliates. We anticipate continuing to purchase and sell commodities and provide services to unconsolidated affiliates in the ordinary course of business.

The following table summarizes our transactions with related parties and affiliates:

	Year Ended December 31,		
	2014	2013	2012
	(millions)		
Phillips 66 (including CPChem) (a):			
Sales of natural gas and NGL products to affiliates	$1,960	$1,665	$1,028
Transportation, storage and processing	$—	$1	$—
Purchases of natural gas and NGL products from affiliates	$11	$14	$21
Operating and general and administrative expenses (b)	$3	$(11)	$3
ConocoPhillips (a):			
Sales of natural gas and NGL products to affiliates	$—	$—	$800
Transportation, storage and processing	$—	$—	$5
Purchases of natural gas and NGL products from affiliates	$—	$—	$192
Operating and general and administrative expenses (c)	$—	$—	$(1)
Spectra Energy:			
Transportation, storage and processing	$14	$—	$—
Purchases of natural gas and NGL products from affiliates	$88	$74	$181
Operating and general and administrative expenses	$10	$10	$12
Unconsolidated affiliates:			
Sales of natural gas and NGL products to affiliates	$70	$67	$58
Transportation, storage and processing	$12	$10	$16
Purchases of natural gas and NGL products from affiliates	$368	$200	$116

(a) On May 1, 2012, ConocoPhillips created two independent publicly traded companies by separating its downstream businesses, including its 50% ownership in us, to a newly formed company, Phillips 66. As a result of this transaction, ConocoPhillips is not considered a related party for periods after May 1, 2012.
(b) The year ended December 31, 2013 includes a gain on the sale of sections of our existing Seaway pipeline to Phillips 66, which was treated as a reduction to operating expense in the consolidated statements of operations.
(c) The year ended December 31, 2012 includes hurricane insurance recovery receivables, which were treated as a reduction to operating expense in the consolidated statements of operations.

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We had balances with related parties and affiliates as follows:

	December 31, 2014	2013
	(millions)	
Phillips 66 (including CPChem):		
Accounts receivable	$161	$236
Accounts payable	$(4)	$(17)
Other assets	$1	$2
Spectra Energy:		
Accounts receivable	$1	$1
Accounts payable	$(4)	$(6)
Other assets	$1	$1
Unconsolidated affiliates:		
Accounts receivable	$18	$28
Accounts payable	$(27)	$(36)
Other assets	$30	$18

6. Inventories

Inventories were as follows:

	December 31, 2014	2013
	(millions)	
Natural gas	$36	$39
NGLs	40	57
Total inventories	$76	$96

We recognize lower of cost or market adjustments when the carrying value of our inventories exceeds their estimated market value. These non-cash charges are a component of purchases of natural gas, propane and NGLs in the consolidated statements of operations. We recognized $24 million, $4 million and $19 million in lower of cost or market adjustments during the years ended December 31, 2014, 2013 and 2012, respectively.

7. Property, Plant and Equipment

Property, plant and equipment by classification were as follows:

	Depreciable Life	December 31, 2014	2013
		(millions)	
Gathering and transmission systems	20 - 50 years	$8,434	$7,986
Processing, storage and terminal facilities	35 - 60 years	4,522	3,908
Other	3 - 30 years	415	366
Construction work in progress		1,159	831
Property, plant and equipment		14,530	13,091
Accumulated depreciation		(4,993)	(4,671)
Property, plant and equipment, net		$9,537	$8,420

Interest capitalized on construction projects for the years ended December 31, 2014, 2013 and 2012 was $34 million, $40 million and $79 million, respectively.

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Depreciation expense for the years ended December 31, 2014, 2013 and 2012 was $327 million, $289 million and $265 million, respectively.

Asset Retirement Obligations - As of December 31, 2014 and 2013, we had $117 million and $93 million, respectively, of asset retirement obligations, or AROs, in other long-term liabilities in the consolidated balance sheets. Accretion expense is recorded within operating and maintenance expense in our consolidated statements of operations.

We identified various assets as having an indeterminate life, for which there is no requirement to establish a fair value for future retirement obligations associated with such assets. These assets include certain pipelines, gathering systems and processing facilities. A liability for these asset retirement obligations will be recorded only if and when a future retirement obligation with a determinable life is identified. These assets have an indeterminate life because they will operate for an indeterminate future period when properly maintained. Additionally, if the portion of an owned plant containing asbestos were to be modified or dismantled, we would be legally required to remove the asbestos. We currently have no plans to take actions that would require the removal of asbestos in these assets. Accordingly, the fair value of the asset retirement obligation related to this asbestos cannot be estimated and no obligation has been recorded.

The following table summarizes changes in the asset retirement obligations included in our balance sheets:

	December 31,	
	2014	2013
	(millions)	
Balance, beginning of period	$93	$91
Accretion expense (benefit)	6	(1)
Revisions in estimated cash flows	18	3
Balance, end of period	$117	$93

8. Goodwill and Intangible Assets

The change in the carrying amount of goodwill is as follows:

	December 31,	
	2014	2013
	(millions)	
Balance, beginning of period	$722	$723
Impairment	(18)	—
Dispositions	—	(1)
Balance, end of period	$704	$722

We performed our annual goodwill assessment at the reporting unit level. We primarily used a discounted cash flow analysis, supplemented by a market approach analysis, to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to goodwill impairment charges, which would be recognized in the period in which the carrying value exceeds fair value. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future goodwill impairment charges for other reporting units due to the potential impact on our operations and cash flows.

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The disposition of Main Pass was considered a triggering event for a goodwill impairment analysis for the related reporting unit. We determined that the estimated fair value of the related reporting unit was less than its carrying amount, primarily due to current economic factors and changes in assumptions related to potential future revenues of this reporting unit. An assessment of these factors in step one of the goodwill impairment test led to a conclusion that the estimated fair value of the reporting unit was less than its carrying amount. The fair value was assessed utilizing a probability weighted approach which included discounted cash flow and market-based valuation techniques. We then applied the second step of the goodwill impairment test, allocating the estimated fair value of the reporting unit among all of the assets and liabilities of the reporting unit in a hypothetical purchase price allocation. As a result of this analysis, we recorded a full impairment of the goodwill associated with this reporting unit totaling $18 million during the third quarter of 2014, which is included in loss on sale of assets and goodwill impairment in the consolidated statements of operations. We concluded that the fair value of goodwill of our remaining reporting units exceeded its carrying value, and the entire amount of goodwill disclosed on the consolidated balance sheet associated with these remaining reporting units is recoverable, therefore, no other goodwill impairments were identified or recorded for the remaining reporting units as a result of our annual goodwill assessment.

Intangible assets consist of customer contracts, including commodity purchase, transportation and processing contracts and related relationships. The gross carrying amount and accumulated amortization of these intangible assets are included in the accompanying consolidated balance sheets as intangible assets, net, and are as follows:

	December 31,	
	2014	2013
	(millions)	
Gross carrying amount	$524	$524
Accumulated amortization	(234)	(213)
Intangible assets, net	$290	$311

For the years ended December 31, 2014, 2013 and 2012, we recorded amortization expense of $21 million, $25 million and $26 million, respectively. As of December 31, 2014, the remaining amortization periods ranged from approximately 4 years to approximately 21 years, with a weighted-average remaining period of approximately 17 years.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization
	(millions)
2015	$19
2016	19
2017	19
2018	18
2019	18
Thereafter	197
Total	$290

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9. Investments in Unconsolidated Affiliates

We had investments in the following unconsolidated affiliates accounted for using the equity method:

	Percentage Ownership	December 31, 2014	2013
		(millions)	
DCP Sand Hills Pipeline, LLC	33.33%	$413	$402
Discovery Producer Services, LLC	40.00%	407	347
DCP Southern Hills Pipeline, LLC	33.33%	329	325
Front Range Pipeline LLC	33.33%	169	134
Texas Express Pipeline LLC	10.00%	98	96
Mont Belvieu Enterprise Fractionator	12.50%	23	25
Main Pass Oil Gathering Company (a)	66.67%	—	23
Mont Belvieu I Fractionation Facility	20.00%	14	16
Other unconsolidated affiliates	Various	10	10
Total investments in unconsolidated affiliates		$1,463	$1,378

(a) In August 2014, we sold our two-thirds ownership interest in Main Pass. See Note 4, Dispositions.

There was an excess of the carrying amount of the investment over the underlying equity of Sand Hills of $10 million at both December 31, 2014 and 2013, which is associated with interest capitalized during the construction of the Sand Hills pipeline. The Sand Hills pipeline was placed into service in the second quarter of 2013, and the excess carrying amount is being amortized over the life of the underlying long-lived assets of Sand Hills.

There was a deficit between the carrying amount of the investment and the underlying equity of Discovery Producer Services, LLC, or Discovery, of $25 million and $28 million as of December 31, 2014 and 2013, respectively, which is associated with, and is being amortized over the life of, the underlying long-lived assets of Discovery.

There was an excess of the carrying amount of the investment over the underlying equity of Southern Hills of $7 million and $8 million as of December 31, 2014 and 2013, respectively, which is associated with interest capitalized during the construction of the Southern Hills pipeline. The Southern Hills pipeline was placed into service in the second quarter of 2013, and the excess carrying amount is being amortized over the life of the underlying long-lived assets of Southern Hills.

There was an excess of the carrying amount of the investment over the underlying equity of Front Range of $5 million and $4 million as of December 31, 2014 and 2013, respectively, which is associated with interest capitalized during the construction of the Front Range pipeline. The Front Range pipeline was placed into service in the first quarter of 2014, and the excess carrying amount is being amortized over the life of the underlying long-lived assets of Front Range.

There was an excess of the carrying amount of the investment over the underlying equity of Texas Express of $3 million at both December 31, 2014 and 2013, which is associated with interest capitalized during the construction of the Texas Express pipeline. The Texas Express pipeline was placed into service in the fourth quarter of 2013, and the excess carrying amount is being amortized over the life of the underlying long-lived assets of Texas Express.

There was an excess of the carrying amount of the investment over the underlying equity of Main Pass of approximately $7 million as of December 31, 2013. In August 2014, we sold our two-thirds ownership interest in Main Pass. See Note 4, Dispositions.

There was a deficit between the carrying amount of the investment and the underlying equity of Mont Belvieu I Fractionation Facility, or Mont Belvieu I, of $4 million and $5 million as of December 31, 2014 and 2013, which is associated with, and is being amortized over the life of, the underlying long-lived assets of Mont Belvieu I.

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Earnings (loss) from unconsolidated affiliates amounted to the following:

	Year Ended December 31,		
	2014	2013	2012
	(millions)		
DCP Sand Hills Pipeline, LLC	$27	$5	$—
Discovery Producer Services, LLC	7	1	13
DCP Southern Hills Pipeline, LLC	15	(2)	—
Front Range Pipeline LLC	2	—	—
Texas Express Pipeline LLC	3	(1)	—
Mont Belvieu Enterprise Fractionator	17	13	12
Main Pass Oil Gathering Company (a)	—	1	—
Mont Belvieu I Fractionation Facility	12	19	9
Other unconsolidated affiliates	—	(1)	—
Total earnings from unconsolidated affiliates	$83	$35	$34

(a) In August 2014, we sold our two-thirds ownership interest in Main Pass. See Note 4, Dispositions.

The following tables summarize the combined financial information of unconsolidated affiliates:

	Year Ended December 31,		
	2014	2013	2012
	(millions)		
Income statement:			
Operating revenues	$859	$556	$431
Operating expenses	$503	$359	$254
Net income	$354	$194	$175

	December 31,	
	2014	2013
	(millions)	
Balance sheet:		
Current assets	$270	$314
Long-term assets	5,125	4,776
Current liabilities	(192)	(322)
Long-term liabilities	(165)	(69)
Net assets	$5,038	$4,699

10. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities which are measured at fair value. Fair values are generally based upon quoted market prices or prices obtained through external sources, where available. If listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an “exit price” methodology, in line with how we believe a marketplace participant would value that asset or liability. Fair values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, the time value of money and/or the liquidity of the market.

- Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us as well as any letters of credit that they have provided.

- Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability positions with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.

- Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in less active markets for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

We manage our derivative instruments on a portfolio basis and the valuation adjustments described above are calculated on this basis. We believe that the portfolio level approach represents the highest and best use for these assets as there are benefits inherent in naturally offsetting positions within the portfolio at any given time, and this approach is consistent with how a market participant would view and value the assets and liabilities. Although we take a portfolio approach to managing these assets/liabilities, in order to reflect the fair value of any one individual contract within the portfolio, we allocate all valuation adjustments down to the contract level, to the extent deemed necessary, based upon either the notional contract volume, or the contract value, whichever is more applicable.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other market participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 12, Risk Management and Hedging Activities, Credit Risk and Financial Instruments.

Valuation Hierarchy

Our fair value measurements are grouped into a three-level valuation hierarchy. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows:

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- Level 1 - inputs are unadjusted quoted prices for identical assets or liabilities in active markets.
- Level 2 - inputs include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 - inputs are unobservable and considered significant to the fair value measurement.

A financial instrument's categorization within the hierarchy is based upon level of judgment involved in the most significant input in the determination of the instrument's fair value. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

We enter into a variety of derivative financial instruments, which may include exchange traded instruments (such as New York Mercantile Exchange, or NYMEX, crude oil or natural gas futures) or over-the-counter, or OTC, instruments (such as natural gas contracts, costless commodity collars, crude oil or NGL swaps). The exchange traded instruments are generally executed on the NYMEX exchange with a highly rated broker dealer serving as the clearinghouse for individual transactions.

Our activities expose us to varying degrees of commodity price risk. To mitigate a portion of this risk and to manage commodity price risk related primarily to owned natural gas storage and pipeline assets, we engage in natural gas asset based trading and marketing, and we may enter into natural gas and crude oil derivatives to lock in a specific margin when market conditions are favorable. A portion of this may be accomplished through the use of exchange traded derivative contracts. Such instruments are generally classified as Level 1 since the value is equal to the quoted market price of the exchange traded instrument as of our balance sheet date, and no adjustments are required. Depending upon market conditions and our strategy we may enter into exchange traded derivative positions with a significant time horizon to maturity. Although such instruments are exchange traded, market prices may only be readily observable for a portion of the duration of the instrument. In order to calculate the fair value of these instruments, readily observable market information is utilized to the extent it is available; however, in the event that readily observable market data is not available, we may interpolate or extrapolate based upon observable data. In instances where we utilize an interpolated or extrapolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

We also engage in the business of trading energy related products and services, which exposes us to market variables and commodity price risk. We may enter into physical contracts or financial instruments with the objective of realizing a positive margin from the purchase and sale of these commodity-based instruments. We may enter into derivative instruments for NGLs or other energy related products, primarily using the OTC derivative instrument markets, which are not as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and an active market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, data obtained from third-party pricing services, historical and future expected relationship of NGL prices to crude oil prices, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for

NGLs.

Each instrument is assigned to a level within the hierarchy at the end of each financial quarter depending upon the extent to which the valuation inputs are observable. Generally, an instrument will move toward a level within the hierarchy that requires a lower degree of judgment as the time to maturity approaches, and as the markets in which the asset trades will likely become more liquid and prices more readily available in the market, thus reducing the need to rely upon our internally developed assumptions. However, the level of a given instrument may change, in either direction, depending upon market conditions and the availability of market observable data.

Interest Rate Derivative Assets and Liabilities

We periodically use interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our fixed-rate debt for floating rate debt or floating rate debt for fixed-rate debt. The swaps are generally

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priced based upon a London Interbank Offered Rate, or LIBOR, instrument with similar duration, adjusted by the credit spread between our company and the LIBOR instrument. Given that a portion of the swap value is derived from the credit spread, which may be observed by comparing similar assets in the market, these instruments are classified within Level 2. Default risk on either side of the swap transaction is also considered in the valuation. We record counterparty credit and entity valuation adjustments in the valuation of interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

Benefits

We offer certain eligible executives the opportunity to participate in DCP Midstream LP's Non-Qualified Executive Deferred Compensation Plan, or the EDC Plan. All amounts contributed to and earned by the EDC Plan's investments are held in a trust account, which is managed by a third-party service provider. The trust account is invested in short-term money market securities and mutual funds. These investments are recorded at fair value, with any changes in fair value being recorded as a gain or loss in the consolidated statements of operations. Given that the value of the short-term money market securities and mutual funds are publicly traded and for which market prices are readily available, these investments are classified within Level 1.

Nonfinancial Assets and Liabilities

We utilize fair value to perform impairment tests as required on our property, plant and equipment; goodwill; and long-lived intangible assets. Assets and liabilities acquired in third party business combinations are recorded at their fair value as of the date of acquisition. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and would generally be classified within Level 3 in the event that we were required to measure and record such assets at fair value within our consolidated financial statements. Additionally, we use fair value to determine the inception value of our asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified within Level 3.

The following table presents the financial instruments carried at fair value on a recurring basis, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	December 31, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
	(millions)							
Current assets:								
Commodity derivatives (a)	$33	$108	$23	$164	$9	$29	$21	$59
Interest rate derivatives (a)	$—	$1	$—	$1	$—	$—	$—	$—
Short-term investments (b)	$25	$—	$—	$25	$28	$—	$—	$28
Long-term assets:								
Commodity derivatives (c)	$1	$19	$3	$23	$—	$8	$2	$10
Mutual funds (d)	$14	$—	$—	$14	$4	$—	$—	$4
Current liabilities (e):								
Commodity derivatives	$(22)	$(57)	$(45)	$(124)	$(9)	$(43)	$(10)	$(62)
Interest rate derivatives	$—	$—	$—	$—	$—	$(2)	$—	$(2)

Long-term liabilities (f):								
Commodity derivatives	$(2)	$(1)	$(12)	$(15)	$—	$(1)	$(1)	$(2)
Interest rate derivatives	$—	$—	$—	$—	$—	$—	$—	$—

(a) Included in current unrealized gains on derivative instruments in our consolidated balance sheets.
(b) Includes short-term money market securities included in cash and cash equivalents in our consolidated balance sheets.
(c) Included in long-term unrealized gains on derivative instruments in our consolidated balance sheets.
(d) Included in other long-term assets in our consolidated balance sheets.
(e) Included in current unrealized losses on derivative instruments in our consolidated balance sheets.
(f) Included in long-term unrealized losses on derivative instruments in our consolidated balance sheets.

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Changes in Levels 1 and 2 Fair Value Measurements

The determination to classify a financial instrument within Level 1 or Level 2 is based upon the availability of quoted prices for identical or similar assets and liabilities in active markets. Depending upon the information readily observable in the market, and/or the use of identical or similar quoted prices, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. To qualify as a transfer, the asset or liability must have existed in the previous reporting period and moved into a different level during the current period. Amounts transferred in and out of Level 1 and Level 2 are reflected at fair value as of the end of the period. During the years ended December 31, 2014 and 2013, there were no transfers from Level 1 to Level 2 of the fair value hierarchy. During the years ended December 31, 2014 and 2013, we had the following transfers from Level 2 to Level 1 of the fair value hierarchy:

	Year Ended December 31,	
	2014 (a)	2013
	(millions)	
Current assets	$3	$—
Long-term assets	$1	$—
Current liabilities	$(4)	$—
Long-term liabilities	$(2)	$—

(a) Financial instruments have moved from Level 2 to Level 1 due to the passage of time.

Changes in Level 3 Fair Value Measurements

The tables below illustrate a rollforward of the amounts included in our consolidated balance sheets for derivative financial instruments that we have classified within Level 3. Since financial instruments classified as Level 3 typically include a combination of observable components (that is, components that are actively quoted and can be validated to external sources) and unobservable components, the gains and losses in the table below may include changes in fair value due in part to observable market factors, or changes to our assumptions on the unobservable components. Depending upon the information readily observable in the market, and/or the use of unobservable inputs, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. The significant unobservable inputs used in determining fair value include adjustments by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. In the event that there is a movement to/from the classification of an instrument as Level 3, we have reflected such items in the table below within the “Transfers into Level 3” and “Transfers out of Level 3” captions.

We manage our overall risk at the portfolio level and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. Since Level 1 and Level 2 risk management instruments are not included in the rollforwards below, the gains or losses in the tables do not reflect the effect of our total risk management activities.

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Years Ended December 31, 2014, 2013 and 2012

	Commodity Derivative Instruments			
	Current Assets (millions)	Long-Term Assets	Current Liabilities	Long-Term Liabilities
Year Ended December 31, 2014 (a):				
Beginning balance	$21	$2	$(10)	$(1)
Net realized and unrealized gains (losses) included in earnings (b)	23	1	(41)	(11)
Transfers out of Level 3 (c)	—	—	—	—
Settlements	(21)	—	6	—
Ending balance	$23	$3	$(45)	$(12)
Net unrealized gains (losses) still held included in earnings (b)	$23	$—	$(45)	$(11)
Year Ended December 31, 2013 (a):				
Beginning balance	$16	$3	$(14)	$—
Net realized and unrealized gains (losses) included in earnings (b)	20	(1)	(5)	(1)
Transfers out of Level 3 (c)	—	—	1	—
Settlements	(15)	—	8	—
Ending balance	$21	$2	$(10)	$(1)
Net unrealized gains (losses) still held included in earnings (b)	$21	$—	$(10)	$(1)

(a) There were no purchases, issuances, sales of derivatives or transfers into Level 3 for the years ended December 31, 2014 and 2013.
(b) Represents the amount of total gains or losses for the period, included in trading and marketing gains, net, in the consolidated statements of operations attributable to changes in unrealized gains or losses relating to assets and liabilities classified as Level 3.

(c) Amounts transferred in and amounts transferred out of Level 3 are reflected at fair value as of the end of the period.

Quantitative Information and Fair Value Sensitivities Related to Level 3 Unobservable Inputs

We utilize the market approach to measure the fair value of our commodity contracts. The significant unobservable inputs used in this approach are longer dated price quotes. Our sensitivity to these longer dated forward curve prices are presented in the table below. Significant changes in any of those inputs in isolation would result in significantly different fair value measurements, depending on our short or long position in these contracts.

Product Group	Fair Value (millions)	Forward Curve Range	
Assets:			
NGLs	$26	$0.17 - $1.05	Per gallon
Liabilities:			
NGLs	$(57)	$0.15 - $1.12	Per gallon

Estimated Fair Value of Financial Instruments

Valuation of a contract's fair value is validated by an internal group independent of the marketing group. While common industry practices are used to develop valuation techniques, changes in pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition. When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected relationship with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

The fair value of our interest rate swaps, if applicable, and commodity non-trading derivatives are based on prices supported by quoted market prices and other external sources and prices based on models and other valuation methods. The “prices supported by quoted market prices and other external sources” category includes our interest rate swaps, if applicable, our NGL and crude oil swaps and our NYMEX positions in natural gas. In addition, this category includes our forward positions in natural gas for which our forward price curves are obtained from a third-party pricing service and then validated through an internal process which includes the use of independent broker quotes. This category also includes our forward positions in NGLs at points for which over-the-counter, or OTC, broker quotes for similar assets or liabilities are available for the full term of the instrument. This category also includes “strip” transactions whose pricing inputs are directly or indirectly observable from external sources and then modeled to daily or monthly prices as appropriate. The “prices based on models and other valuation methods” category includes the value of transactions for which inputs to the fair value of the instrument are unobservable in the marketplace and are considered significant to the overall fair value of the instrument. The fair value of these instruments may be based upon an internally developed price curve, which was constructed as a result of the long dated nature of the transaction or the illiquidity of the specific market point.

We have determined fair value amounts using available market information and appropriate valuation methodologies. However, considerable judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts.

The fair value of accounts receivable, accounts payable and short-term borrowings are not materially different from their carrying amounts because of the short-term nature of these instruments or the stated rates approximating market rates. Derivative instruments are carried at fair value. We determine the fair value of our variable rate debt based upon the discounted present value of expected future cash flows, taking into account the difference between the contractual borrowing spread and the spread for similar credit facilities available in the marketplace. We determine the fair value of our fixed-rate debt based on quotes obtained from bond dealers. We classify the fair value of our outstanding debt balances within Level 2 of the fair value hierarchy. As of December 31, 2014, the carrying and fair value of our long-term debt, including current maturities of long-term debt, was $5,683 million and $5,951 million, respectively. As of December 31, 2013, the carrying and fair value of our long-term debt was $4,962 million and $5,169 million, respectively.

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DCP MIDSTREAM, LLC
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11. Financing

	December 31, 2014 (millions)	2013
Commercial paper:		
DCP Midstream’s short-term borrowings, weighted-average interest rate of 0.89% and 0.91%, respectively	$1,012	$965
DCP Partners’ short-term borrowings, weighted-average interest rate of 1.14% as of December 31, 2013	—	335
DCP Midstream’s debt securities:		
Senior notes:		
Issued October 2005, interest at 5.375% payable semiannually, due October 2015	200	200
Issued February 2009, interest at 9.750% payable semiannually, due March 2019 (a)	450	450
Issued March 2010, interest at 5.350% payable semiannually, due March 2020 (a)	600	600
Issued September 2011, interest at 4.750% payable semiannually, due September 2021	500	500
Issued August 2000, interest at 8.125% payable semiannually, due August 2030 (b)	300	300
Issued October 2006, interest at 6.450% payable semiannually, due November 2036	300	300
Issued September 2007, interest at 6.750% payable semiannually, due September 2037	450	450
Junior subordinated notes:		
Issued May 2013, interest at 5.850% payable semiannually, due May 2043	550	550
DCP Partners’ debt securities:		
Issued September 2010, interest at 3.25% payable semiannually, due October 2015	250	250
Issued November 2012, interest at 2.50% payable semiannually, due December 2017	500	500
Issued March 2014, interest at 2.70% payable semiannually, due April 2019	325	—
Issued March 2012, interest at 4.95% payable semiannually, due April 2022	350	350
Issued March 2013, interest at 3.875% payable semiannually, due March 2023	500	500
Issued March 2014, interest at 5.60% payable semiannually, due April 2044	400	—
Fair value adjustments related to interest rate swap fair value hedges (a) (b)	29	30
Unamortized discount	(21)	(18)
Total debt	6,695	6,262
Current maturities of long-term debt	(450)	—
DCP Midstream short-term borrowings	(1,012)	(965)
DCP Partners short-term borrowings	—	(335)
Total long-term debt	$5,233	$4,962

(a) Prior to December 31, 2014, $50 million of debt associated with each of these note issuances was swapped to a floating rate obligation. These interest rate swap agreements were terminated in January 2015, and the remaining long-term fair value of approximately $1 million related to these swaps will be amortized as a reduction of interest expense through March 2019 and March 2020, respectively, the original maturity date of the debt.
(b) In December 2008, the swaps associated with this debt were terminated. The remaining long-term fair value of approximately $28 million related to the swaps is being amortized as a reduction to interest expense through August 2030, the original maturity date of the debt.

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Approximate future maturities of long-term debt in the year indicated are as follows at December 31, 2014:

	Debt Maturities (millions)
2015	$450
2016	—
2017	500
2018	—
2019	775
Thereafter	3,950
	5,675
Fair value adjustments related to interest rate swap fair value hedges	29
Unamortized discount	(21)
Current maturities of long-term debt	(450)
Long-term debt	$5,233

DCP Midstream's Debt Securities - In May 2013, we issued $550 million principal amount of 5.85% Fixed-to-Floating Rate Junior Subordinated Notes, due May 2043, for proceeds of approximately $544 million, net of unamortized offering costs and expenses of $6 million. The net proceeds were used to repay short-term borrowings.

The DCP Midstream senior debt securities mature and become payable on the respective due dates, and are not subject to any sinking fund provisions. The DCP Midstream senior debt securities are senior unsecured obligations, and are redeemable at a premium at our option. The underwriters' fees and related expenses are deferred in other long-term assets in the consolidated balance sheets and will be amortized over the term of the notes.

DCP Midstream's Commercial Paper Program - We have a commercial paper program, or the DCP Midstream Commercial Paper Program, under which we may issue unsecured commercial paper notes, or the Notes. The Notes may be borrowed, repaid and re-borrowed from time to time with the maximum aggregate principal amount of the Notes outstanding, combined with the amount outstanding under our $2 billion amended and restated revolving credit agreement, or the DCP Midstream Amended and Restated Revolving Credit Agreement, not to exceed $2 billion in the aggregate. As of December 31, 2014 and 2013, we had $1,012 million and $965 million, respectively, of commercial paper outstanding, which are included in short-term borrowings in the consolidated balance sheets. Subsequent to December 31, 2014, our credit rating has been lowered below investment grade. As a result of this ratings action, we no longer have access to the DCP Midstream Commercial Paper Program. Our available liquidity under the DCP Midstream Commercial Paper Program will be replaced with borrowings under the DCP Midstream Amended and Restated Revolving Credit Agreement. As of February 24, 2015, we have no commercial paper outstanding.

DCP Midstream's Credit Facilities with Financial Institutions - In May 2014, we entered into the DCP Midstream Amended and Restated Revolving Credit Agreement, which matures in May 2019. The DCP Midstream Amended and Restated Revolving Credit Agreement replaced our previous credit agreement dated as of March 2, 2012, or the DCP Midstream Credit Facility, which had a total borrowing capacity of $2 billion and would have matured in March 2017. The DCP Midstream Amended and Restated Revolving Credit Agreement may be used to support our capital expansion program, for working capital requirements and other general corporate purposes, including acquisitions, as well as for letters of credit. There were no borrowings outstanding under the DCP Midstream Amended and Restated Revolving Credit Facility as of December 31, 2014.

As of December 31, 2014 and 2013, we had $6 million and $8 million in letters of credit outstanding, respectively. As of December 31, 2014, the available capacity under the DCP Midstream Amended and Restated Revolving Credit Agreement was $982 million, net of letters of credit, of which approximately $865 million was available for general working capital purposes. Our borrowing capacity may be limited by the DCP Midstream Amended and Restated Revolving Credit Agreement's financial covenant requirements. Except in the case of default, amounts borrowed under the DCP Midstream Amended and Restated Revolving Credit Agreement will not become due prior to the May 2019 maturity date.

Indebtedness under the DCP Midstream Amended and Restated Revolving Credit Agreement bears interest at either: (1) LIBOR, plus an applicable margin of 1.075% based on our credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A.'s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1% plus (b) an applicable margin of 0.075% based on our credit rating. The DCP Midstream Amended and Restated Revolving Credit Agreement incurs an annual facility fee of 0.175% based on our credit rating. This fee is paid on drawn and undrawn portions of the DCP Midstream Amended and Restated Revolving Credit Agreement. Subsequent to December 31, 2014, our credit rating has been lowered below investment grade. As a result of this ratings action, interest rates and fees under the DCP Midstream Amended and Restated Revolving Credit Agreement have increased.

The DCP Midstream Amended and Restated Revolving Credit Agreement requires us to maintain a consolidated leverage ratio (the ratio of consolidated indebtedness to consolidated EBITDA as defined) of not more than 5.0 to 1.0, and following the consummation of qualifying acquisitions (as defined), not more than 5.5 to 1.0, on a temporary basis for three consecutive quarters, including the quarter in which such acquisition is consummated. As a result of the current commodity price environment, we expect to exceed our consolidated leverage ratio as of March 31, 2015. As of February 24, 2015 we have $948 million outstanding under the DCP Midstream Amended and Restated Revolving Credit Agreement. Subsequent to December 31, 2014, we and our owners have initiated a process to modify certain terms of the DCP Midstream Amended and Restated Revolving Credit Agreement. If successfully completed, the outcome of these discussions may impact the availability, capacity and the cost of the borrowings under the DCP Midstream Amended and Restated Revolving Credit Agreement. Should a modification not be obtained, the amount outstanding would become due. However, we have multiple alternatives in the event an amendment is not obtained including, but not limited to, drop down transactions with DCP Partners, the sale of certain investments held by us or the sale of assets. We believe one, or a combination, of these alternatives would be sufficient to address our ongoing liquidity needs.

DCP Partners' Commercial Paper Program - DCP Partners has a commercial paper program, or the DCP Partners Commercial Paper Program, under which DCP Partners may issue unsecured commercial paper notes, or the DCP Partners' Notes. The DCP Partners' Notes outstanding may be borrowed, repaid, and re-borrowed from time to time with the maximum aggregate principal amount of the notes outstanding, combined with the amount outstanding under DCP Partners' $1.25 billion amended senior unsecured revolving credit agreement, or the DCP Partners Amended and Restated Credit Agreement, not to exceed $1.25 billion in the aggregate. As of December 31, 2014, DCP Partners had no commercial paper outstanding. As of December 31, 2013, DCP Partners had $335 million of commercial paper outstanding which was included in short-term borrowings in the consolidated balance sheets. Subsequent to December 31, 2014, DCP Partners' credit rating has been lowered below investment grade. As a result of this ratings action, DCP Partners no longer has access to the DCP Partners Commercial Paper Program. Available liquidity under the DCP Partners Commercial Paper Program will be replaced with borrowings under the DCP Partners Amended and Restated Credit Agreement, which had $89 million outstanding as of February 24, 2015.

DCP Partners' Credit Facilities with Financial Institutions - In May 2014, DCP Partners entered into the DCP Partners Amended and Restated Credit Agreement. The DCP Partners Amended and Restated Credit Agreement replaced DCP Partners' previous credit agreement dated as of November 10, 2011, or the DCP Partners Credit Agreement, which had a total borrowing capacity of $1 billion and would have matured in November 2016. The DCP Partners Amended and Restated Credit Agreement will be used for working capital requirements and other general partnership purposes including acquisitions. As of December 31, 2014 and 2013, DCP Partners had $1 million of letters of credit issued and outstanding under the DCP Partners Amended and Restated Credit Agreement and the DCP Partners Credit Agreement, respectively. As of December 31, 2014, the unused capacity under the DCP Partners Amended and Restated Credit Agreement was $1,249 million, which is net of letters of credit. DCP Partners' borrowing capacity may be limited by the DCP Partners Amended and Restated Credit Agreement's financial covenant requirements. Except in the case of default, amounts borrowed under the DCP Partners Amended and Restated Credit Agreement will not become due prior to the May 2019 maturity date.

Indebtedness under the DCP Partners Amended and Restated Credit Agreement bears interest at either: (1) LIBOR, plus an applicable margin of 1.275% based on DCP Partners' current credit rating; or (2) (a) the base rate which shall be the higher of Wells Fargo Bank N.A.'s prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1%, plus (b) an applicable margin of 0.275% based on DCP Partners' current credit rating. The DCP Partners Amended and Restated Credit Agreement incurs an annual facility fee of 0.225% based on DCP Partners' current credit rating. This fee is paid on drawn and undrawn portions of the DCP Partners Amended and Restated Credit Agreement.

The DCP Partners Amended and Restated Credit Agreement requires DCP Partners to maintain a leverage ratio (the ratio of DCP Partners' consolidated indebtedness to its consolidated EBITDA, in each case as defined) of not more than 5.0 to 1.0, and following consummation of qualifying acquisitions, not more than 5.5 to 1.0, on a temporary basis for three consecutive quarters, including the quarter in which such acquisition is consummated. Further, DCP Partners' cost of borrowing under the DCP Partners Amended and Restated Credit Agreement is determined by a ratings based pricing grid. Subsequent to December 31, 2014, DCP Partners' credit rating has been lowered below investment grade. As a result of this ratings action, interest rates and fees under the DCP Partners Amended and Restated Credit Agreement have increased.

DCP Partners' Debt Securities - In March 2014, DCP Partners issued $325 million of 2.70% five-year Senior Notes due April 2019 and $400 million of 5.60% 30-year Senior Notes, due April 2044. DCP Partners received proceeds of $320 million and $392 million, respectively, net of underwriters' fees, related expenses and unamortized discounts, which were used to pay a portion of the consideration for the March 2014 Transactions. Interest on the notes is paid semiannually on April 1 and October 1 of each year, commencing on October 1, 2014. The notes will mature in April 2019 and April 2044, respectively, unless redeemed prior to maturity.

In March 2013, DCP Partners issued $500 million of 3.875% 10-year Senior Notes, due March 2023. DCP Partners received proceeds of $490 million, net of underwriters' fees, related expenses and unamortized discounts, which were used to fund a portion of the acquisition of an additional 46.67% interest in the Eagle Ford system. Interest on the notes is paid semiannually on March 15 and September 15 of each year, and the first payment occurred on September 15, 2013. The notes will mature in March 2023, unless redeemed prior to maturity.

DCP Partners' debt securities are senior unsecured obligations, ranking equally in right of payment with other unsecured indebtedness, including indebtedness under the DCP Partners Amended and Restated Credit Agreement. DCP Partners is not required to make mandatory redemption or sinking fund payments with respect to any of these notes, and they are redeemable at a premium at DCP Partners' option. The underwriters' fees and related expenses are deferred in other long-term assets in our consolidated balance sheets and will be amortized over the term of the notes.

Other Financing - In June 2014, DCP Partners filed a shelf registration statement on Form S-3 with the U.S. Securities and Exchange Commission, or SEC, with a maximum offering price of $500 million, which became effective on July 11, 2014. The shelf registration statement allows DCP Partners to issue additional common units. In September 2014, DCP Partners entered into an equity distribution agreement, or the 2014 equity distribution agreement, with a group of financial institutions as sales agents. The 2014 equity distribution agreement provides for the offer and sale from time to time, through DCP Partners' sales agents, of common units having an aggregate offering amount of up to $500 million. During the year ended December 31, 2014, DCP Partners issued 2,256,066 of its common units pursuant to the 2014 equity distribution agreement and received proceeds of $119 million, net of commissions and accrued offering costs of $1 million, which were used to finance growth opportunities and for general partnership purposes. As of December 31, 2014, approximately $380 million remained available for sale pursuant to the 2014 equity distribution agreement.

In March 2014, DCP Partners issued 14,375,000 of its common units to the public at $48.90 per unit. DCP Partners received proceeds of $677 million, net of offering costs.

In August 2013, DCP Partners issued 9,000,000 of its common units to the public at $50.04 per unit. DCP Partners received proceeds of $434 million, net of offering costs.

In June 2013, DCP Partners filed a shelf registration statement on Form S-3, or the June 2013 shelf registration statement, with the SEC with a maximum offering price of $300 million, which became effective on June 27, 2013.

The June 2013 shelf registration statement allowed DCP Partners to issue additional common units. In November 2013, DCP Partners entered into an equity distribution agreement, or the 2013 equity distribution agreement, related to the June 2013 shelf registration statement, with a group of financial institutions as sales agents. The 2013 equity distribution agreement provided for the offer and sale from time to time, through DCP Partners' sales agents, of common units having an aggregate offering amount of up to $300 million. During the year ended December 31, 2014, DCP Partners issued 3,769,635 of its common units pursuant to the 2013 equity distribution agreement and received proceeds of $206 million, which is net of commissions and offering costs of $2 million. During the year ended December 31, 2013, DCP Partners issued 1,839,430 of its common units pursuant to the 2013 equity distribution agreement and received proceeds of $87 million, net of commissions and offering costs of $1 million. The proceeds were used to finance growth opportunities and for general partnership purposes. In connection with DCP Partners' entry into the 2014 equity distribution agreement, DCP Partners terminated the 2013 equity distribution agreement in September 2014. In October 2014, DCP Partners de-registered the common units that remained unsold under the 2013 equity distribution agreement at the time of its termination.

In March 2013, DCP Partners issued 12,650,000 of its common units to the public at $40.63 per unit. DCP Partners received proceeds of $494 million, net of offering costs.

In July 2012, DCP Partners closed a private placement of equity with a group of institutional investors in which DCP Partners sold 4,989,802 of its common units at a price of $35.55 per unit and received proceeds of $174 million, net of offering costs.

In March 2012, DCP Partners issued 5,148,500 of its common units at $47.42 per unit. DCP Partners received proceeds of $234 million, net of offering costs.

During the year ended December 31, 2013, DCP Partners issued 1,408,547 of its common units pursuant to the equity distribution agreement entered into in August 2011, or the 2011 equity distribution agreement. DCP Partners received proceeds of $67 million, net of commissions and offering costs of $2 million, which were used to finance growth opportunities and for general partnership purposes. During the year ended December 31, 2012, DCP Partners issued 1,147,654 of its common units under the 2011 equity distribution agreement, and received proceeds of $47 million, net of commissions and offering costs of $2 million. The 2011 equity distribution agreement provided for the offer and sale of common units having an aggregate offering amount of up to $150 million. In September 2013, DCP Partners de-registered the common units that remained unsold under this equity distribution agreement.

12. Risk Management and Hedging Activities, Credit Risk and Financial Instruments

Our day-to-day operations expose us to a variety of risks including but not limited to changes in the prices of commodities that we buy or sell, changes in interest rates, and the creditworthiness of each of our counterparties. We manage certain of these exposures with either physical or financial transactions. We have established a comprehensive risk management policy, or Risk Management Policy, and a risk management committee, or the Risk Management Committee, to monitor and manage market risks associated with commodity prices and counterparty credit. Our Risk Management Committee is composed of senior executives who receive regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities. The Risk Management Committee is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. The following describes each of the risks that we manage.

Commodity Price Risk

Our portfolio of commodity derivative activity is primarily accounted for using the mark-to-market method of accounting; however, depending upon our risk profile and objectives, in certain limited cases, we may execute transactions that qualify for the hedge method of accounting. The risks, strategies and instruments used to mitigate such risks, as well as the method of accounting are discussed and summarized below.

Natural Gas Asset Based Trading and Marketing

Our natural gas storage and pipeline assets are exposed to certain risks including changes in commodity prices. We manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads.

A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statements of operations. While gas held in our storage locations is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in our consolidated statements of operations. Even though we may have economically hedged our exposure and locked in a future margin, the use of lower-of-cost-or-market accounting for our

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physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.

DCP Partners Commodity Cash Flow Hedges

In order for our storage facilities to remain operational, a minimum level of base gas must be maintained in each storage cavern, which is capitalized on our consolidated balance sheets as a component of property, plant and equipment, net. During construction or expansion of DCP Partners' storage caverns, DCP Partners may execute a series of derivative financial instruments to mitigate a portion of the risk associated with the forecasted purchase of natural gas when DCP Partners brings the storage caverns to operation. These derivative financial instruments may be designated as cash flow hedges. While the cash paid upon settlement of these hedges economically fixes the cash required to purchase base gas, the deferred losses or gains would remain in accumulated other comprehensive income, or AOCI, until the cavern is emptied and the base gas is sold. The balance in AOCI of DCP Partners' previously settled base gas cash flow hedges was in a loss position of $6 million as of December 31, 2014.

NGL Proprietary Trading

Our NGL proprietary trading activity includes trading energy related products and services. We undertake these activities through the use of fixed forward sales and purchases, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and these operations may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. These physical and financial instruments are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statements of operations.

We employ established risk limits, policies and procedures to manage risks associated with our natural gas asset based trading and marketing and NGL proprietary trading.

Commodity Cash Flow Protection Activities at DCP Partners

DCP Partners is exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of its gathering, processing, sales and storage activities. For gathering, processing and storage services, DCP Partners may receive cash or commodities as payment for these services, depending on the contract type. DCP Partners enters into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with its gathering, processing and sales activities, thereby stabilizing its cash flows. DCP Partners has mitigated a portion of its expected commodity cash flow risk associated with its gathering, processing and sales activities through 2017 with commodity derivative instruments. DCP Partners' commodity derivative instruments used for its hedging program are a combination of direct NGL product, crude oil and natural gas hedges. Due to the limited liquidity and tenor of the NGL derivative market, DCP Partners has used crude oil swaps and costless commodity collars to mitigate a portion of its commodity price risk exposure for NGLs. Historically, prices of NGLs have generally been related to crude oil prices; however, there are periods of time when NGL pricing may be at a greater discount to crude oil, resulting in additional exposure to NGL commodity prices. The relationship of NGLs to crude oil continues to be lower than historical relationships; however, a significant amount of DCP Partners' NGL hedges from 2014 through 2016 are direct product hedges with us. When its crude oil swaps become short-term in nature, DCP Partners has periodically converted certain crude oil derivatives to NGL derivatives by entering into offsetting crude oil swaps while adding NGL swaps. DCP Partners' crude oil and NGL transactions are primarily accomplished through the use of forward contracts that effectively exchange DCP Partners' floating price risk for a fixed price. DCP Partners also utilizes crude oil costless commodity collars that minimize its floating price risk by establishing a fixed price floor and a fixed price ceiling. However, the type of instrument that DCP Partners uses to mitigate a portion of its risk may vary depending on DCP Partners' risk management objective. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected in the current period within our consolidated statements of operations as trading and marketing gains, net.

Interest Rate Risk

We enter into debt arrangements that have either fixed or floating rates, therefore we are exposed to market risks related to changes in interest rates. We periodically use interest rate swaps to convert our floating rate debt to fixed-rate debt or to convert our fixed-rate debt to floating rate debt. Our primary goals include: (1) maintaining an appropriate ratio of fixed-rate debt to floating-rate debt; (2) reducing volatility of earnings resulting from interest rate fluctuations; and (3) locking in attractive interest rates.

Prior to June 30, 2014, DCP Partners had interest rate swap agreements with notional values totaling $150 million, which were accounted for under the mark-to-market method of accounting and repriced prospectively approximately every 30 days. Under the terms of the interest rate swap agreements, DCP Partners paid fixed rates ranging from 2.94% to 2.99%, and received interest payments based on the one-month LIBOR. These interest rate swap agreements settled in June 2014. Prior to August 2013, these interest rate swaps were designated as cash flow hedges whereby the effective portions of changes in fair value were recognized in AOCI in the consolidated balance sheets. In March 2014, DCP Partners paid down a portion of the balance outstanding under the DCP Partners Commercial Paper Program and reclassified the remaining loss of $1 million in AOCI into earnings as interest expense, net.

In conjunction with the issuance of DCP Partners' 4.95% Senior Notes in March 2012, DCP Partners entered into forward-starting interest rate swap agreements to reduce its exposure to market rate fluctuations prior to issuance. These derivative financial instruments were designated as cash flow hedges. While the cash paid upon settlement of these hedges economically fixed the rate DCP Partners would pay on a portion of its 4.95% Senior Notes, the deferred loss in AOCI will be amortized into interest expense through the maturity of the notes in 2022. The balance in AOCI of these cash flow hedges was in a loss position of $4 million as of December 31, 2014.

In July 2014, we entered into an interest rate swap agreement to convert $50 million of fixed-rate debt securities issued in February 2009 to floating rate debt. Additionally, in July 2014, we entered into an interest rate swap agreement to convert $50 million of fixed-rate debt securities issued in March 2010, to floating rate debt. The interest rate fair value hedges associated with each of these interest rate swap agreements are at a floating rate based on one month LIBOR, which resets monthly and are paid semi-annually through the expiration of the securities in March 2019 and March 2020, respectively. These swap agreements meet conditions that permit the assumption of no ineffectiveness. As such, for the life of the swap agreements no ineffectiveness will be recognized. These interest rate swap agreements were terminated in January 2015, and the remaining long-term fair value relative to these interest rate swap agreements will be reclassified to interest expense, net through March 2019 and March 2020, respectively, the original maturity date of the debt, as the underlying transactions impact earnings.

We previously had interest rate cash flow hedges and fair value hedges in place that were terminated in 2000 and 2008, respectively. As a result, the remaining net loss deferred in AOCI relative to these cash flow hedges and the remaining net loss included in long-term debt relative to these fair value hedges will be reclassified to interest expense, net through August 2030, the original maturity date of the debt, as the underlying transactions impact earnings.

Credit Risk

Our principal customers range from large, natural gas marketers to industrial end-users for our natural gas products and services, as well as large multi-national petrochemical and refining companies, to small regional propane distributors for our NGL products and services. Substantially all of our natural gas and NGL sales are made at market-based prices. Prior to December 31, 2014, approximately 35% of our NGL production was committed to Phillips 66 and CPChem, under 15-year contracts, the primary production commitment of which expired in December 2014 and began a wind down period and expires in January 2019. This concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of these limits on an ongoing basis. We may use various master agreements that include language giving us the right to request collateral to mitigate credit exposure. The collateral language provides for a counterparty to post cash or letters of credit for exposure in excess of the established threshold. The threshold amount represents an open credit limit, determined in accordance with our credit policy. The collateral language also provides that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, our master agreements and our standard gas and NGL sales contracts contain adequate assurance provisions, which allow us to suspend deliveries and cancel agreements, or continue deliveries to the buyer after the buyer provides security for payment in a satisfactory form.

Contingent Credit Features

Each of the above risks is managed through the execution of individual contracts with a variety of counterparties. Certain of our derivative contracts may contain credit-risk related contingent provisions that may require us to take certain actions in certain circumstances.

We have International Swaps and Derivatives Association, or ISDA, contracts which are standardized master legal arrangements that establish key terms and conditions which govern certain derivative transactions. These ISDA contracts contain standard credit-risk related contingent provisions. Some of the provisions we are subject to are outlined below.

- In the event that we or DCP Partners were to be downgraded below investment grade by at least one of the major credit rating agencies, certain of our ISDA counterparties would have the right to reduce our collateral threshold to zero, potentially requiring us to fully collateralize any commodity contracts in a net liability position.

- In some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. For example, if we were to fail to make a required interest or principal payment on a debt instrument, above a predefined threshold level, and after giving effect to any applicable notice or grace period as defined in the ISDA contracts, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative positions.

Depending upon the movement of commodity prices and interest rates, each of our individual contracts with counterparties to our commodity derivative instruments or interest rate swap instruments are in either a net asset or net liability position. Our commodity derivative contracts that are not governed by ISDA contracts do not have any credit-risk related contingent features. As of December 31, 2014, we had less than $1 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability position and have not posted any cash collateral relative to such positions. If a credit-risk related event were to occur and we were required to net settle our position with an individual counterparty, our ISDA contracts permit us to net all outstanding contracts with that counterparty, whether in a net asset or net liability position, as well as any cash collateral already posted. As of December 31, 2014, if a credit-risk related event were to occur, we may be required to post additional collateral. Although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of December 31, 2014, if a credit-risk related event were to occur, the net liability position would be partially offset by contracts in a net asset position.

Collateral

As of December 31, 2014, we had cash deposits with counterparties of $35 million, included in other current assets in the consolidated balance sheets, to secure our obligations to provide future services or to perform under financial contracts. Additionally, as of December 31, 2014, we held cash of $9 million, included in other current liabilities in the consolidated balance sheet, related to cash postings by third parties and letters of credit of $79 million from counterparties to secure their future performance under financial or physical contracts. Collateral amounts held or posted may be fixed or may vary, depending on the value of the underlying contracts, and could cover normal purchases and sales, trading and hedging contracts. In many cases, we and our counterparties have publicly disclosed credit ratings, which may impact the amounts of collateral requirements.

Physical forward contracts and financial derivatives are generally cash settled at the expiration of the contract term. These transactions are generally subject to specific credit provisions within the contracts that would allow the seller, at its discretion, to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment satisfactory to the seller.

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Offsetting

Certain of our derivative instruments are subject to a master netting or similar arrangement, whereby we may elect to settle multiple positions with an individual counterparty through a single net payment. Each of our individual derivative instruments are presented on a gross basis on the consolidated balance sheets, regardless of our ability to net settle our positions. Instruments that are governed by agreements that include net settle provisions allow final settlement, when presented with a termination event, of outstanding amounts by extinguishing the mutual debts owed between the parties in exchange for a net amount due. We have trade receivables and payables associated with derivative instruments, subject to master netting or similar agreements, which are not included in the table below. The following summarizes the gross and net amounts of our derivative instruments:

	December 31, 2014				December 31, 2013		
	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet		Net Amount	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet - Financial Instruments (b)	Net Amount
		Financial Instruments	Cash Collateral Pledged/ (Received) (a)				
	(millions)						
Assets:							
Commodity derivative instruments	$187	$—	$(9)	$178	$69	$(2)	$67
Interest rate derivative instruments	$1	$—	$—	$1	$—	$—	$—
Liabilities:							
Commodity derivative instruments	$(139)	$—	$—	$(139)	$(64)	$2	$(62)
Interest rate derivative instruments	$—	$—	$—	$—	$(2)	$—	$(2)

(a) Included in other current liabilities in the consolidated balance sheets.
(b) There is no cash collateral pledged or received against these positions.

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Summarized Derivative Information

The fair value of our derivative instruments that are designated as hedging instruments, those that are marked to market each period, and the location of each within our consolidated balance sheets, by major category, is summarized below:

Balance Sheet Line Item	December 31, 2014	December 31, 2013	Balance Sheet Line Item	December 31, 2014	December 31, 2013
	(millions)			(millions)	
Derivative Assets Designated as Hedging Instruments:			Derivative Liabilities Designated as Hedging Instruments:		
Interest rate derivatives:			Interest rate derivatives:		
Unrealized gains on derivative instruments - current	$1	$—	Unrealized losses on derivative instruments - current	$—	$—
Unrealized gains on derivative instruments - long-term	—	—	Unrealized losses on derivative instruments - long-term	—	—
	$1	$—		$—	$—
Derivative Assets Not Designated as Hedging Instruments:			Derivative Liabilities Not Designated as Hedging Instruments:		
Interest rate derivatives:			Interest rate derivatives:		
Unrealized gains on derivative instruments - current	$—	$—	Unrealized losses on derivative instruments - current	$—	$(2)
Unrealized gains on derivative instruments - long-term	—	—	Unrealized losses on derivative instruments - long-term	—	—
	$—	$—		$—	$(2)
Commodity derivatives:			Commodity derivatives:		
Unrealized gains on derivative instruments - current	$164	$59	Unrealized losses on derivative instruments - current	$(124)	$(62)
Unrealized gains on derivative instruments - long-term	23	10	Unrealized losses on derivative instruments - long-term	(15)	(2)
	$187	$69		$(139)	$(64)

The following table summarizes the balance and activity within AOCI relative to our interest rate and commodity derivatives, net of noncontrolling interest, for the year ended December 31, 2014:

	Interest Rate Derivatives	Commodity Derivatives	Total
	(millions)		
Net deferred losses in AOCI, beginning balance	$(3)	$(3)	$(6)
Gains recognized in AOCI on derivatives - effective portion	—	—	—
Losses reclassified from AOCI - effective portion	1 (a)	—	1
Net deferred losses in AOCI, ending balance	$(2)	$(3)	$(5)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$—	$—	$—

(a) Included in interest expense, net in our consolidated statements of operations.

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For the year ended December 31, 2014, no derivative gains or losses were recognized in trading and marketing gains, net and interest expense, net in our consolidated statements of operations attributable to the ineffective portion of our derivative instruments, as a result of exclusion from effectiveness testing or as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

The following table summarizes the balance and activity within AOCI relative to our interest rate and commodity derivatives, net of noncontrolling interest, for the year ended December 31, 2013:

	Interest Rate Derivatives	Commodity Derivatives	Total
	(millions)		
Net deferred losses in AOCI, beginning balance	$(4)	$(5)	$(9)
Gains recognized in AOCI on derivatives - effective portion	—	—	—
Losses reclassified from AOCI - effective portion	1 (a)	2 (b)	3
Net deferred losses in AOCI, ending balance	$(3)	$(3)	$(6)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$(1)	$—	$(1)

(a) Included in interest expense, net in our consolidated statements of operations.
(b) Included in noncontrolling interest in our consolidated balance sheets, as a result of changes in our ownership interest in DCP Partners.

For the year ended December 31, 2013, no derivative gains or losses were recognized in trading and marketing gains, net and interest expense, net in our consolidated statements of operations attributable to the ineffective portion of our derivative instruments, as a result of exclusion from effectiveness testing or as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

Changes in value of derivative instruments, for which the hedge method of accounting has not been elected from one period to the next, are recorded in the consolidated statements of operations. The following summarizes these amounts and the location within the consolidated statements of operations that such amounts are reflected:

	Year Ended December 31,		
Commodity Derivatives: Statement of Operations Line Item	2014	2013	2012
	(millions)		
Realized gains	$45	$31	$86
Unrealized gains	43	5	—
Trading and marketing gains, net	$88	$36	$86

We do not have any derivative financial instruments that qualify as a hedge of a net investment.

The following tables represent, by commodity type, our net long or short derivative positions, as well as the number of outstanding contracts that are expected to partially or entirely settle in each respective year. To the extent that we have long dated derivative positions that span multiple calendar years, the contract will appear in more than one line item in the table below. Additionally, relative to the hedging of certain of our storage and/or transportation assets, we may execute basis transactions for natural gas, which may result in a net long/short position of zero. This table also presents our net long or short natural gas basis swap positions separately from our net long or short natural gas positions.

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December 31, 2014

	Crude Oil		Natural Gas		Natural Gas Liquids			Natural Gas Basis Swaps	
Year of Expiration	Net Short Position (Bbls) (a)	Number of Contracts	Net Short Position (MMBtu) (b)	Number of Contracts	Net Short Position (Bbls)	Number of Contracts		Net Long (Short) Position (MMBtu)	Number of Contracts
2015	(1,091,000)	115	(18,882,800)	238	(21,236,472)	336	(c)	9,200,000	66
2016	(544,000)	19	(3,830,000)	2	(4,946,778)	23	(d)	(1,830,000)	10
2017	—	—	(6,387,500)	4	(2,700,000)	1	(e)	—	—

(a) Bbls represents barrels.
(b) MMBtu represents one million British thermal units.
(c) Includes 41 physical index based derivative contracts totaling (20,649,707) Bbls.
(d) Includes 2 physical index based derivative contracts totaling (5,400,000) Bbls.
(e) Includes 1 physical index based derivative contracts totaling (2,700,000) Bbls.

December 31, 2013

	Crude Oil		Natural Gas		Natural Gas Liquids			Natural Gas Basis Swaps	
Year of Expiration	Net Short Position (Bbls)	Number of Contracts	Net (Short) Long Position (MMBtu)	Number of Contracts	Net (Short) Long Position (Bbls)	Number of Contracts		Net Long Position (MMBtu)	Number of Contracts
2014	(1,323,250)	448	(19,102,550)	273	(19,991,853)	445	(a)	25,065,000	105
2015	(465,000)	51	2,737,500	28	703,344	12		1,875,000	4
2016	(498,000)	14	—	—	—	—		—	—

(a) Includes 49 physical index based derivative contracts totaling (20,580,664) Bbls.

DCP Partners periodically enters into interest rate swap agreements to mitigate a portion of its floating rate interest exposure. As of December 31, 2013, DCP Partners had interest rate swaps outstanding with individual notional values of $70 million and $80 million, which, in aggregate, exchanged $150 million of DCP Partners' floating rate obligation to a fixed rate obligation through June 2014. These interest rate swap agreements settled in June 2014.

13. Equity-Based Compensation

We recorded equity-based compensation expense as follows, the components of which are further described below:

	Year Ended December 31,		
	2014	2013	2012
	(millions)		
DCP Midstream, LLC Long-Term Incentive Plan	$13	$18	$14
DCP Partners' Long-Term Incentive Plan (DCP Partners' LTIP)	1	2	2
Total	$14	$20	$16

	Unrecognized Compensation Expense at		Weighted-Average Remaining Vesting
		Estimated	(years)

	Vesting Period (years)	December 31, 2014 (millions)	Forfeiture Rate	
DCP Midstream LTIP:				
Strategic Performance Units (SPUs)	3	$5	0% - 15%	2
Phantom Units	1 - 3	$4	0% - 14%	2

DCP Midstream LTIP - Under the DCP Midstream LTIP, or LTIP, awards may be granted to our key employees. The DCP Midstream LTIP provides for the grant of Strategic Performance Units, or SPUs, and Phantom Units. The SPUs and Phantom

Units consist of a notional unit based on the value of common shares or units of Phillips 66, Spectra Energy and DCP Partners. Each award provides for the grant of dividend or distribution equivalent rights, or DERs. The LTIP is administered by the compensation committee of our board of directors. All awards are subject to cliff vesting.

Strategic Performance Units - The number of SPUs that will ultimately vest range in value of up to 200% of the outstanding SPUs, depending on the achievement of specified performance targets over a three year period. The final performance payout is determined by the compensation committee of our board of directors. The DERs are paid in cash at the end of the performance period. The following tables presents information related to SPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2012	255,975	$ 34.10	
Granted	173,129	$ 36.98	
Forfeited	(20,067)	$ 35.34	
Vested (a)	(141,650)	$ 30.35	
Outstanding at December 31, 2012	267,387	$ 37.86	
Granted	123,682	$ 41.01	
Forfeited	(43,658)	$ 38.71	
Vested (b)	(116,511)	$ 38.02	
Outstanding at December 31, 2013	230,900	$ 39.30	
Granted	116,790	$ 54.05	
Forfeited	(13,828)	$ 40.75	
Vested (c)	(114,499)	$ 37.72	
Outstanding at December 31, 2014	219,363	$ 47.89	$ 46.57
Expected to vest	203,142	$ 47.39	$ 46.57

(a) The 2010 grants vested at 130%.
(b) The 2011 grants vested at 142%.
(c) The 2012 grants vested at 115%.

The estimate of SPUs that are expected to vest is based on highly subjective assumptions that could change over time, including the expected forfeiture rate and achievement of performance targets. Therefore the amounts of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations.

The following table presents the fair value of units vested and the unit-based liabilities paid for unit-based awards related to the strategic performance units:

	Units	Fair Value of Units Vested (millions)	Unit-Based Liabilities Paid
Vested or paid in cash in 2012	141,650	$8	$14
Vested or paid in cash in 2013	116,511	$8	$7
Vested or paid in cash in 2014	114,499	$7	$8

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Phantom Units - The DERs are paid quarterly in arrears. The following table presents information related to Phantom Units:

	Units	Grant Date Weighted-Average Price	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2012	222,970	$ 34.68	
Granted	175,490	$ 37.14	
Forfeited	(18,590)	$ 35.34	
Vested	(139,670)	$ 31.98	
Outstanding at December 31, 2012	240,200	$ 38.00	
Granted	134,427	$ 41.78	
Forfeited	(23,215)	$ 39.81	
Vested	(143,890)	$ 38.10	
Outstanding at December 31, 2013	207,522	$ 40.18	
Granted	122,650	$ 53.73	
Forfeited	(11,130)	$ 41.96	
Vested	(147,840)	$ 42.10	
Outstanding at December 31, 2014	171,202	$ 48.11	$ 46.46
Expected to vest	159,659	$ 47.71	$ 46.48

The following table presents the fair value of units vested and the unit-based liabilities paid for unit based awards related to the phantom units:

	Units	Fair Value of Units Vested (millions)	Unit-Based Liabilities Paid
Vested or paid in cash in 2012	139,670	$6	$9
Vested or paid in cash in 2013	143,890	$5	$7
Vested or paid in cash in 2014	147,840	$5	$5

DCP Partners' LTIP -- Under DCP Partners' 2005 LTIP, which was adopted by DCP Midstream GP, LLC, equity instruments may be granted to key employees, consultants and directors of DCP Midstream GP, LLC and its affiliates who perform services for DCP Partners. The DCP Partners' 2005 LTIP provides for the grant of limited partner units, or LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of dividend equivalent rights, or DERs. The 2005 LTIP phantom units consist of a notional unit based on the value of DCP Partners' common units. Subject to adjustment for certain events, an aggregate of 850,000 LPUs may be delivered pursuant to awards under the DCP Partners' 2005 LTIP. Awards that are canceled or forfeited, or are withheld to satisfy DCP Midstream GP, LLC's tax withholding obligations, are available for delivery pursuant to other awards. On February 15, 2012, the board of directors of DCP Midstream GP, LLC adopted a 2012 LTIP for employees, consultants and directors of DCP Midstream GP, LLC and its affiliates who perform services for DCP Partners. The 2012 LTIP provides for the grant of phantom units and DERs. The 2012 LTIP phantom units consist of a notional unit based on the value of common units or shares of Phillips 66 and Spectra Energy. The LTIPs were administered by the compensation committee of DCP Midstream GP, LLC's board of directors through 2012, and by DCP Midstream GP, LLC's board of directors beginning in 2013. Awards are issued under both LTIPs and all awards are subject to cliff vesting.

Since DCP Partners has the intent and ability to settle certain awards within its control in units, DCP Partners classifies them as equity awards based on their fair value. The fair value of DCP Partners' equity awards is determined based on the closing price of DCP Partners' common units at the grant date. Compensation expense on equity awards is recognized ratably over each vesting period. DCP Partners accounts for other awards which are subject to settlement in cash, including DERs, as liability awards. Compensation expense on these awards is recognized ratably over each vesting period, and will be re-

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measured each reporting period for all awards outstanding until the units are vested. The fair value of all liability awards is determined based on the closing price of DCP Partners' common units at each measurement date.

As of December 31, 2014, there was less than $1 million of unrecognized compensation expense related to DCP Partners LTIP awards.

14. Benefits

All Company employees who have reached the age of 18 and work at least 20 hours per week are eligible for participation in our 401(k) and retirement plan, to which we contribute a range of 4% to 7% of each eligible employee's qualified earnings to the retirement plan, based on years of service. Additionally, we match employees' contributions in the 401(k) plan up to 6% of qualified earnings. During the years ended December 31, 2014, 2013 and 2012, we expensed plan contributions of $30 million, $28 million and $27 million, respectively.

We offer certain eligible executives the opportunity to participate in the EDC Plan. The EDC Plan allows participants to defer current compensation on a pre-tax basis and to receive tax deferred earnings on such contributions. The EDC Plan also has make-whole provisions for plan participants who may otherwise be limited in the amount that we can contribute to the 401(k) plan on the participant's behalf. During the third quarter of 2013, we liquidated the net cash surrender value of our company owned life insurance policies, in order to change service providers, and received proceeds of $29 million. We re-invested these proceeds with a new service provider in the fourth quarter of 2013. Under the new service plan, all amounts contributed to and earned by the EDC Plan's investments are held in a trust account for the benefit of the EDC Plan participants, or general creditors in the event of our insolvency, as defined in the trust agreement. The trust assets and liability to the EDC Plan participants are part of our general assets and liabilities, respectively.

15. Income Taxes

We are structured as a limited liability company, which is a pass-through entity for federal income tax purposes. We own a corporation that files its own federal, foreign and state corporate income tax returns. The income tax expense related to this corporation is included in our income tax expense, along with state and local taxes of the limited liability company and other subsidiaries.

The State of Texas imposes a margin tax that is assessed at 0.95% of taxable margin apportioned to Texas for the year ended December 31, 2014, 0.975% for the year ended December 31, 2013 and 1% for the year ended December 31, 2012. Accordingly, we have recorded current tax expense for the Texas margin tax.

Income tax expense consisted of the following:

	Year Ended December 31,		
	2014	2013	2012
	(millions)		
Current:			
State income tax expense	$(2)	$(6)	$(3)
Deferred:			
Federal income tax (expense) benefit	—	(1)	3
State income tax expense	(9)	(3)	(2)
Total income tax expense	$(11)	$(10)	$(2)

We had net long-term deferred tax liabilities of $105 million and $96 million as of December 31, 2014 and 2013, respectively. The net long-term deferred tax liabilities are included in deferred income taxes on the consolidated balance sheets. The deferred tax liabilities of $156 million and $144 million as of December 31, 2014 and 2013, respectively, are primarily associated with depreciation and amortization related to the acquired intangible assets and property, plant and equipment. Offsetting the deferred tax liabilities are deferred tax assets related to the net operating loss of an affiliate corporation of approximately $51 million and $48 million as of December 31, 2014 and 2013, respectively. The net operating losses begin expiring in 2027. We expect to fully utilize the net operating loss carryovers, and, accordingly we have not provided a valuation allowance for the net deferred tax asset.

Our effective tax rate differs from statutory rates primarily due to our structure as a limited liability company, which is a pass-through entity for federal income tax purposes, while being treated as a taxable entity in certain states. Additionally, one of our subsidiaries is a tax paying entity for federal income tax purposes.

16. Commitments and Contingent Liabilities

Litigation - The midstream industry has seen a number of class action lawsuits involving royalty disputes, mismeasurement and mispayment allegations. We are currently named as defendants in some of these cases and customers have asserted individual audit claims related to mismeasurement and mispayment. Management believes we have meritorious defenses to these cases and, therefore, will continue to defend them vigorously. These claims, however, can be costly and time consuming to defend. We are also a party to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business, including, from time to time, disputes with customers over various measurement and settlement issues.

Management currently believes that these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage and other indemnification arrangements, will not have a material adverse effect upon our consolidated results of operations, financial position or cash flows.

General Insurance - Our insurance coverage is carried with an affiliate of Phillips 66, an affiliate of Spectra Energy and third-party insurers. Our insurance coverage includes: (1) general liability insurance covering third-party exposures; (2) statutory workers' compensation insurance; (3) automobile liability insurance for all owned, non-owned and hired vehicles; (4) excess liability insurance above the established primary limits for general liability and automobile liability insurance; (5) property insurance, which covers the replacement value of real and personal property and includes business interruption; and (6) insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

Environmental - The operation of pipelines, plants and other facilities for gathering, processing, compressing, transporting, or storing natural gas, and fractionating, transporting, gathering, processing and storing NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities incorporates compliance with environmental laws and regulations and safety standards. In addition, there is increasing focus, from city, state and federal regulatory officials and through litigation, on hydraulic fracturing and the real or perceived environmental impacts of this technique, which indirectly presents some risk to our available supply of natural gas. Failure to comply with these various health, safety and environmental laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

We make expenditures in connection with environmental matters as part of our normal operations. As of December 31, 2014 and 2013, environmental liabilities included in the consolidated balance sheets as other current liabilities amounted to $5 million and $4 million, respectively. As of both December 31, 2014 and 2013, environmental liabilities included in the consolidated balance sheets as other long-term liabilities amounted to $9 million.

Operating Leases - We utilize assets under operating leases in several areas of operations. Consolidated rental expense, including leases with no continuing commitment, amounted to $31 million, $36 million and $36 million during the years ended December 31, 2014, 2013 and 2012, respectively. Rental expense for leases with escalation clauses is recognized on a straight line basis over the initial lease term.

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Minimum rental payments under our various operating leases in the year indicated are as follows:

	Minimum Rental Payments (millions)
2015	$59
2016	35
2017	33
2018	31
2019	30
Thereafter	90
Total minimum lease payments	$278

17. Guarantees and Indemnifications

We periodically enter into agreements for the acquisition, contribution or divestiture of assets. These agreements contain indemnification provisions that may provide indemnity for environmental, tax, employment, outstanding litigation, breaches of representations, warranties and covenants, performance of DCP Partners or other liabilities related to the assets being acquired, contributed or divested. Claims may be made by third parties or DCP Partners under these indemnification agreements for various periods of time depending on the nature of the claim. The effective periods on these indemnification provisions generally have terms of one to 15 years, although some are longer. Our maximum potential exposure under these indemnification agreements can vary depending on the nature of the claim and the particular transaction. We are unable to estimate the total maximum potential amount of future payments under indemnification agreements due to several factors, including uncertainty as to whether claims will be made under these indemnities. We have issued guarantees and indemnifications for certain of our consolidated subsidiaries.

18. Supplemental Cash Flow Information

	Year Ended December 31,		
	2014	2013	2012
	(millions)		
Cash paid for interest, net of capitalized interest	$274	$229	$169
Cash paid for income taxes, net of income tax refunds received	$4	$6	$6
Non-cash investing and financing activities:			
Property, plant and equipment acquired with accounts payable	$145	$82	$158
Other non-cash changes in property, plant and equipment	$27	$77	$59

During the years ended December 31, 2014, 2013 and 2012, we received distributions from DCP Partners of $173 million, $116 million and $75 million, respectively, which have been eliminated in consolidation.

19. Subsequent Events

We have evaluated subsequent events occurring through February 26, 2015, the date the consolidated financial statements were issued.

In February 2015, DCP Partners and Williams Partners L.P. announced that the new extended Discovery natural gas gathering pipeline system is now flowing natural gas. The Keathley Canyon Connector, a 20-inch diameter, 209-mile subsea natural gas gathering pipeline is capable of gathering more than 400 MMcf/d of natural gas, and originates in the southeast portion of the Keathley Canyon protraction area of the Gulf of Mexico, and terminates into Discovery's 30-inch diameter mainline near South Timbalier Block 283.

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DCP MIDSTREAM, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — Continued
Years Ended December 31, 2014, 2013 and 2012

In January 2015, we entered into a purchase and sale agreement with Mustang Gas Products, LLC to sell our approximate 44% membership interest in the Dover-Hennessey gas processing plant and gathering system, or Dover-Hennessey, for approximately $29 million, subject to customary purchase price adjustments. This transaction closed on January 30, 2015.

As part of an effort to reduce costs, we announced a reduction in force in January 2015 affecting approximately 20 percent of our corporate staff functions. With this corporate restructuring, we will also close or reduce the workforce of certain regional offices. We are also working on several other initiatives to either reduce costs or improve margins.

On January 29, 2015, DCP Partners announced that the board of directors of DCP Partners' general partner declared a quarterly distribution of $0.78 per unit, payable on February 13, 2015 to unitholders of record on February 9, 2015.

In January 2015, DCP Partners entered into an agreement with an affiliate of Enterprise Products Partners L.P., or Enterprise, to acquire a 15% ownership interest in Panola Pipeline Company, LLC, or Panola. The anticipated total consideration of approximately $26 million includes our proportionate share in construction costs for an anticipated expansion of the existing Panola NGL pipeline. Originating near Carthage, Texas, the 10-inch diameter expansion will extend approximately 60 miles to Lufkin, Texas and will have an initial capacity of approximately 50 thousand barrels per day, or MBbls/d, with expansion to 100 MBbls/d possible following installation of additional pump stations. DCP Partners, WGR Asset Holding Company LLC, which is an affiliate of Anadarko Petroleum Corporation, and MarkWest Panola Pipeline L.L.C. will each own a 15% interest in Panola. Enterprise will own a 55% interest in Panola and will construct and operate the expansion, which is expected to be in service in the first quarter of 2016.

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EXHIBIT INDEX

Exhibit No.	Exhibit Description
2.1	Separation and Distribution Agreement by and between Duke Energy Corporation and Spectra Energy Corp, dated as of December 13, 2006 (filed as Exhibit No. 2.1 to Form 8-K of Spectra Energy Corp on December 15, 2006).
2.2	Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and DCP Midstream, LLC, dated as of May 26, 2005 (filed as Exhibit No. 10.4 to Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2005, File No. 1-4928).
2.2.1	First Amendment to Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and DCP Midstream, LLC, dated as of June 30, 2005 (filed as Exhibit No. 10.4.1 to Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2005).
2.2.2	Second Amendment to Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and DCP Midstream, LLC, dated as of July 11, 2005 (filed as Exhibit No. 10.4.2 to Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2005).
2.3	Amended and Restated Combination Agreement, dated as of September 20, 2001, among Duke Energy Corporation, 3058368 Nova Scotia Company, 3946509 Canada Inc. and Westcoast Energy Inc. (filed as Exhibit No. 10.7 to Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2001).
2.4	Spectra Energy Support Agreement dated as of January 1, 2007, between Spectra Energy Corp, Duke Energy Canada Call Co. and Duke Energy Canada Exchangeco Inc. (filed as Exhibit No. 2.2 to Form S-3 of Spectra Energy Corp on January 17, 2007).
2.5	Spectra Energy Voting and Exchange Trust Agreement dated as of January 1, 2007, between Spectra Energy Corp, Duke Energy Canada Exchangeco Inc. and Computershare Trust Company, Inc. (filed as Exhibit No. 2.3 to Form S-3 of Spectra Energy Corp on January 17, 2007).
2.6	Plan of Arrangement, as approved by the Supreme Court of British Columbia by final order dated December 15, 2006 (filed as Exhibit No. 2.4 to Form S-3 of Spectra Energy Corp on January 17, 2007).
2.7	Securities Purchase Agreement by and among BPC Penco Corporation, Kinder Morgan Energy Partners, L.P., Ontario Teachers' Pension Plan Board, Blackhawk Holdings Trust, 2349466 (U.S.) Grantor Trust, Express US Holdings LP, Express Holdings (Canada) Limited Partnership and 6048935 Canada Inc, dated as of December 10, 2012 (filed as Exhibit No. 2.1 to Form 8-K of Spectra Energy Corp on December 11, 2012).
2.8	Contribution Agreement by and between Spectra Energy Corp and Spectra Energy Partners, LP, dated as of August 5, 2013 (filed as Exhibit No. 2.1 to Form 8-K of Spectra Energy Corp on August 6, 2013).
2.8.1	First Amendment to Contribution Agreement by and between Spectra Energy Corp and Spectra Energy Partners, LP, dated as of October 31, 2013 (filed as Exhibit No. 2.1 to Form 8-K of Spectra Energy Corp on November 1, 2013).
3.1	Amended and Restated Certificate of Incorporation of Spectra Energy Corp (filed as Exhibit No. 3.1 to Form 8-K of Spectra Energy Corp on December 15, 2006).
3.1.1	Certificate of Amendment to the Amended and Restated Certificate of Incorporation of Spectra Energy Corp (filed as Exhibit No. 3.1 to Form 8-K of Spectra Energy Corp on May 7, 2012).
3.2	The By-Laws of Spectra Energy Corp, as amended and restated on November 12, 2013 (filed as Exhibit No. 3.1 to Form 8-K of Spectra Energy Corp on November 18, 2013).
4.1	Senior Indenture between Duke Capital Corporation and The Chase Manhattan Bank, dated as of April 1, 1998 (filed as Exhibit No. 4.1 to Form S-3 of Duke Capital Corporation on April 1, 1998, File No. 333-71297).
4.2	First Supplemental Indenture, dated July 20, 1998, between Duke Capital Corporation and The Chase Manhattan Bank (filed as Exhibit No. 4.2 to Form 10-K of Duke Capital Corporation on March 16, 2004).
4.3	

Second Supplemental Indenture, dated September 28, 1999, between Duke Capital Corporation and The Chase Manhattan Bank (filed as Exhibit No. 4.3 to Form 10-K of Duke Capital Corporation on March 16, 2004).

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Exhibit No.	Exhibit Description
4.4	Fifth Supplemental Indenture, dated February 15, 2002, between Duke Capital Corporation and JPMorgan Chase Bank (filed as Exhibit No. 4.6 to Form 10-K of Duke Capital Corporation on March 16, 2004).
4.5	Ninth Supplemental Indenture, dated February 20, 2004, between Duke Capital Corporation and JPMorgan Chase Bank (filed as Exhibit No. 4.10 to Form 10-K of Duke Capital Corporation on March 16, 2004).
4.6	Eleventh Supplemental Indenture, dated August 19, 2004, between Duke Capital LLC and JPMorgan Chase Bank (filed as Exhibit No. 4.6 to Form S-3 of Spectra Energy Corp and Spectra Energy Capital, LLC on March 26, 2008, File No. 333-141982).
4.7	Twelfth Supplemental Indenture, dated December 14, 2007, among Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on December 20, 2007).
4.8	Thirteenth Supplemental Indenture, dated as of April 10, 2008, between Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K on April 10, 2008).
4.9	Fourteenth Supplemental Indenture, dated as of September 8, 2008, between Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York Mellon Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K on September 9, 2008).
4.10	Indenture, dated May 14, 2009, between Maritimes & Northeast Pipeline, LLC and Deutsche Bank Trust Company Americas (filed as Exhibit No. 4.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
4.11	First Supplemental Indenture, dated May 14, 2009, between Maritimes & Northeast Pipeline, LLC and Deutsche Bank Trust Company Americas (filed as Exhibit No. 4.2 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
4.12	Fifteenth Supplemental Indenture, dated as of August 28, 2009, between Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York Mellon Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K on August 28, 2009).
4.13	Sixteenth Supplemental Indenture, dated as of February 28, 2013, between Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York Mellon Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K on February 28, 2013).
10.1	Tax Matters Agreement by and among Duke Energy Corporation, Spectra Energy Corp, and The Other Spectra Energy Parties, dated as of December 13, 2006 (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.2	Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp, dated as of December 13, 2006 (filed as Exhibit No. 10.3 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.2.1	First Amendment to Employee Matters Agreement, dated as of September 28, 2007, by and between Duke Energy Corporation and Spectra Energy Corp (filed as Exhibit No. 10.3.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.3	Purchase and Sale Agreement, dated as of February 24, 2005, by and between Enterprise GP Holdings LP and DCP Midstream, LLC (filed as Exhibit No. 10.4 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
10.4	Term Sheet Regarding the Restructuring of DCP Midstream, LLC, dated as of February 23, 2005, between Duke Energy Corporation and ConocoPhillips (filed as Exhibit No. 10.26 to Form 10-K of Duke Energy Corporation for the year ended December 31, 2004).
10.5	Second Amended and Restated Limited Liability Company Agreement of DCP Midstream, LLC by and between ConocoPhillips Gas Company and Duke Energy Enterprises Corporation, dated as of July 5, 2005 (filed as Exhibit No. 10.5 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30,

2009).

Exhibit No.	Exhibit Description
10.5.1	First Amendment, dated August 11, 2006, to Second Amended and Restated Limited Liability Company Agreement of DCP Midstream, LLC, by and between ConocoPhillips Gas Company and Duke Energy Enterprises Corporation (filed as Exhibit No. 10.5.1 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2011).
10.5.2	Second Amendment, dated February 1, 2007, to Second Amended and Restated Limited Liability Company Agreement of DCP Midstream, LLC, by and between ConocoPhillips Gas Company and Spectra Energy DEFS Holding, LLC and Spectra Energy DEFS Holding Corp (filed as Exhibit No. 10.5.2 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2011).
10.5.3	Third Amendment, dated April 30, 2009, to Second Amended and Restated Limited Liability Company Agreement of DCP Midstream, LLC, by and between ConocoPhillips Gas Company and Spectra Energy DEFS Holding, LLC and Spectra Energy DEFS Holding Corp (filed as Exhibit No. 10.5.3 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2011).
10.5.4	Fourth Amendment, dated November 9, 2010, to Second Amended and Restated Limited Liability Company Agreement of DCP Midstream, LLC, by and between ConocoPhillips Gas Company and Spectra Energy DEFS Holding, LLC and Spectra Energy DEFS Holding Corp (filed as Exhibit No. 10.5.4 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2011).
10.5.5	Fifth Amendment, dated September 9, 2014, to Second Amended and Restated Limited Liability Company Agreement of DCP Midstream, LLC, by and between Phillips Gas Company and Spectra Energy DEFS Holding II, LLC and Spectra Energy DEFS Holding Corp (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp on November 6, 2014).
10.6	Limited Liability Company Agreement of Gulfstream Management & Operating Services, LLC, dated as of February 1, 2001, between Duke Energy Gas Transmission Corporation and Williams Gas Pipeline Company (filed as Exhibit No. 10.18 to Form 10-K of Duke Energy Corporation for the year ended December 31, 2002).
10.7	Loan Agreement, dated as of February 25, 2005, between DCP Midstream, LLC and Duke Capital LLC (filed as Exhibit No. 10.6 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2009).
+10.8	Spectra Energy Corp Directors' Savings Plan, as amended and restated (filed as Exhibit No. 10.2 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2012).
+10.9	Spectra Energy Corp Executive Savings Plan, as amended and restated (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2012).
+10.10	Spectra Energy Corp Executive Cash Balance Plan, as amended and restated (filed as Exhibit No. 10.3 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2011).
+10.11	Omnibus Amendment, dated June 20, 2014, to Spectra Energy Corp Executive Savings Plan, Spectra Energy Corp Executive Cash Balance Plan and Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp on August 7, 2014).
+10.12	Form of Change in Control Agreement (U.S.) (filed as Exhibit No. 10.11 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2011).
+10.13	Form of Change in Control Agreement (Canada) (filed as Exhibit No. 10.12 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2011).
+10.14	Form of Change in Control Agreement (U.S.) (2014) (filed as Exhibit No. 10.3 to Form 10-Q of Spectra Energy Corp on August 7, 2014).
+10.15	Form of Non-Qualified Stock Option Agreement pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.18 to Form 10-K of Spectra Energy Corp for the year ended December 31, 2006).
+10.16	Form of Change in Control Agreement (Canada) (2014) (filed as Exhibit No. 10.4 to Form 10-Q of Spectra Energy Corp on August 7, 2014).
10.17	Support Agreement among Spectra Energy Midstream Holdco Management Partnership, Spectra Energy Income Fund and Spectra Energy Commercial Trust, dated March 4, 2008 (filed as Exhibit No. 10.1 to

Form 10-Q of Spectra Energy Corp for the quarter ended March 31, 2008).

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Exhibit No.	Exhibit Description
+10.18	Form of Retention Stock Award Agreement (2010) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2010).
+10.19	Form of Retention Stock Award Agreement (2014) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.2 to Form 10-Q of Spectra Energy Corp on August 7, 2014).
+10.20	Spectra Energy Corp 2007 Long-Term Incentive Plan, as amended and restated (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on April 22, 2011).
+10.21	Spectra Energy Corp Executive Short-Term Incentive Plan, as amended and restated (filed as Exhibit No. 10.2 to Form 8-K of Spectra Energy Corp on April 22, 2011).
+10.22	Form of Phantom Stock Award Agreement (2011) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.3 to Form 10-Q of Spectra Energy Corp on May 5, 2011).
+10.23	Form of Performance Award Agreement (cash) (2011) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.4 to Form 10-Q of Spectra Energy Corp on May 5, 2011).
+10.24	Form of Performance Award Agreement (stock) (2011) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.5 to Form 10-Q of Spectra Energy Corp on May 5, 2011).
10.25	Acknowledgement and Waiver Agreement, dated as of September 6, 2011, by and among ConocoPhillips, ConocoPhillips Gas Company, Spectra Energy Corp, Spectra Energy DEFS Holding, LLC and Spectra Energy DEFS Holding Corp (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on September 12, 2011).
+10.26	Form of Phantom Stock Award Agreement (2012) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp on May 9, 2011).
+10.27	Form of Performance Award Agreement (cash) (2012) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.2 to Form 10-Q of Spectra Energy Corp on May 9, 2011).
+10.28	Form of Performance Award Agreement (stock) (2012) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.3 to Form 10-Q of Spectra Energy Corp on May 9, 2011).
+10.29	Form of Phantom Stock Award Agreement (2013) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp on May 8, 2013).
+10.30	Form of Performance Award Agreement (cash) (2013) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.2 to Form 10-Q of Spectra Energy Corp on May 8, 2013).
+10.31	Form of Performance Award Agreement (stock) (2013) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.3 to Form 10-Q of Spectra Energy Corp on May 8, 2013).
+10.32	Form of Phantom Stock Award Agreement (2014) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp on May 8, 2014).
+10.33	Form of Performance Stock Award Agreement (2014) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.2 to Form 10-Q of Spectra Energy Corp on May 8, 2014).
10.34	Amended and Restated Credit Agreement, dated as of November 1, 2013, by and among Spectra Energy Capital, LLC, as Borrower, Spectra Energy Corp, as Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on November 1, 2013).

10.35	Credit Agreement, dated as of November 1, 2013, by and among Spectra Energy Capital, LLC, as Borrower, Spectra Energy Corp, as Guarantor, Bank of America, N.A., as Administrative Agent, and the lenders party thereto (filed as Exhibit No. 10.2 to Form 8-K of Spectra Energy Corp on November 1, 2013).
10.36	Amendment No. 1 dated December 11, 2014 to Amended and Restated Credit Agreement, dated November 1, 2013, by and among Spectra Energy Capital, LLC, as Borrower, Spectra Energy Corp, as Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on December 16, 2014).

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Exhibit No.	Exhibit Description
*12.1	Computation of Ratio of Earnings to Fixed Charges.
*21.1	Subsidiaries of the Registrant.
*23.1	Consent of Independent Registered Public Accounting Firm.
*23.2	Consent of Independent Auditors.
*24.1	Power of Attorney.
*31.1	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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Exhibit No.	Exhibit Description
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Taxonomy Extension Schema.
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
*101.DEF	XBRL Taxonomy Extension Definition Linkbase.
*101.LAB	XBRL Taxonomy Extension Label Linkbase.
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

+ Denotes management contract or compensatory plan or arrangement.
* Filed herewith.
The total amount of securities of the registrant or its subsidiaries authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrant and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the Securities and Exchange Commission, to furnish copies of any or all of such instruments to it.