Spectra Energy Corp.
Form 10-K
February 28, 2014

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, 2013 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, 2013: $23,000,000,000

Number of shares of Common Stock, $0.001 par value, outstanding at January 31, 2014: 670,171,444
DOCUMENTS INCORPORATED BY REFERENCE
Portions of the proxy statement for the 2013 Annual Meeting of Shareholders are incorporated by reference in Part III.

SPECTRA ENERGY CORP
FORM 10-K FOR THE YEAR ENDED
DECEMBER 31, 2013
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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 and 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 305 billion cubic feet (Bcf) of net storage capacity in the United States and Canada. Our crude oil pipeline system, Express-Platte, acquired in March 2013, consists of over 1,700 miles of transmission pipeline. In 2013, Express pipeline receipts averaged 207 thousand barrels per day (MBbl/d) and Platte PADD II deliveries averaged 168 MBbl/d.

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Businesses

We currently 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, 100%-owned captive insurance subsidiaries, employee benefit plan assets and liabilities, 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.

On November 1, 2013, Spectra Energy contributed substantially all of its remaining U.S. transmission, storage and liquids assets to SEP, our master limited partnership (the U.S. Assets Dropdown). As a result of this transaction, we realigned our reportable segments structure. Amounts presented herein for segment information have been recast for all periods presented to conform to our current segment reporting presentation. There were no changes to consolidated data as a result of the recasting of our segment information. See Note 2 of Notes to Consolidated Financial Statements for further discussion of the transaction.

SPECTRA ENERGY PARTNERS

We currently own an 84% equity interest in SEP, a natural gas infrastructure and crude oil pipeline 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 US), 25% of Southeast Supply Header, LLC (SESH), 33% of DCP Sand Hills Pipeline, LLC (Sand Hills), 33% of DCP Southern Hills Pipeline, LLC (Southern Hills), 49% of Steckman Ridge, LP (Steckman Ridge) and 50% of Gulfstream Natural Gas System, L.L.C. (Gulfstream). Our remaining 25% interest in SESH and 1% interest in Steckman Ridge are currently held in "Other." We own another 17% indirect interest in Sand Hills and 17% indirect interest in Southern Hills through our ownership interest in DCP Midstream, which is considered our Field Services segment.

See Part II. Item 8. Financial Statements and Supplementary Data, Note 2 of Notes to Consolidated Financial Statements for further discussion of SEP. Spectra Energy Partners, LP is a publicly traded entity which trades on the New York Stock Exchange under the symbol “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 natural gas liquids (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 calendar 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 84% 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 three 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 65 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 72 Bcf, owned by Market Hub and Bobcat.

New Jersey-New York Expansion.

The New Jersey-New York expansion project is an 800 million cubic feet per day expansion of the Texas Eastern pipeline system consisting of a new 16-mile pipeline extension into lower Manhattan, New York and other associated facility upgrades. The project is designed to transport gas produced in the U.S. Gulf Coast, Mid-Continent, Rockies and Marcellus Shale regions into New York City. The project was placed into service during the fourth quarter of 2013.

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Algonquin

We have an effective 84% 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 Maritimes & Northeast Pipeline. The system consists of approximately 1,125 miles of pipeline with associated compressor stations.

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East Tennessee

We have an effective 84% 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 66% ownership interest in M&N US through our ownership of SEP. M&N US 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 US 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 US 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 US 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 84% ownership interest in Ozark Gas Transmission and Ozark Gas Gathering, which was acquired in 2009, 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 a 365-mile natural gas gathering system, with associated compressor stations, that primarily serves Arkoma basin producers in eastern Oklahoma.

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Big Sandy

We have an effective 84% 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 42% investment in Gulfstream through our ownership of SEP. Gulfstream owns a 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 46% total investment in SESH, a 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 24.95% directly by SEP and 25.05% directly by Spectra Energy as part of our "Other" segment, with the remaining 50% owned by Centerpoint and Enable Midstream Partners LP, collectively. Current plans are for Spectra Energy to contribute another 24.95% of its ownership interest in SESH to SEP at least 12 months after the initial November 1, 2013 U.S. Assets Dropdown to SEP, and to contribute its remaining 0.1% ownership interest at least 12 months thereafter. Our investment in SESH is accounted for under the equity method of accounting.

Market Hub

We have an effective 84% 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 50 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 84% 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 84% ownership interest in Bobcat through our ownership of SEP. Bobcat, a 22 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 42% investment in Steckman Ridge through our ownership of SEP. Steckman Ridge, which began operations in 2009, is a 12 Bcf depleted reservoir storage facility located in south central Pennsylvania that interconnects with the Texas Eastern and Dominion Transmission, Inc. systems. Steckman is owned 49% directly by SEP in our Spectra Energy Partners segment, and owned 1% directly by Spectra Energy as part of our "Other" segment, and 50% by NJR Steckman Ridge Storage Company. Current plans are for Spectra Energy to contribute its remaining 1% ownership interest to SEP at least 12 months after the initial November 1, 2013 U.S. Assets Dropdown. Our investment in Steckman Ridge is accounted for under the equity method of accounting.

Express-Platte

We have an effective 84% 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 November 2012, we acquired direct one-third ownership interests in Sand Hills and Southern Hills. DCP Midstream and Phillips 66 also each own a direct one-third interest in each of the two pipelines. With our effective ownership interests through SEP and our 50% ownership interest of DCP Midstream, we have 45% 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 consists of approximately 720 miles of pipeline with an initial capacity of 200,000 barrels of NGLs per day (Bbls/d) that provides NGL transportation from the Permian Basin and Eagle Ford shale region to the premium NGL markets on the Gulf Coast. The Southern Hills pipeline consists of approximately 800 miles of NGL pipeline. The Southern Hills pipeline is connected to several DCP Midstream processing plants and third-party producers and provides NGL transportation from the Mid-Continent to Mont Belvieu, Texas. The Sand Hills and Southern Hills pipelines were placed in 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 transportation 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 we transport 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, our Spectra Energy Partners 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. We also provide 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 market 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.

The Sand Hills and Southern Hills pipelines provide takeaway capacity from DCP Midstream and third-party plants, in the Permian and Eagle Ford basins for Sand Hills, and in the Midcontinent for Southern Hills, to fractionation facilities along the Texas Gulf Coast and the Mont Belvieu market hub. 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 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 39,000 miles of main and service pipelines. Distribution pipelines carry or control the supply of 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. Under that framework, Union Gas was required to share its long-term storage margins with ratepayers until 2011. 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 699 trillion British thermal units (TBtu) in 2013, compared to 662 TBtu in 2012 and 713 TBtu in 2011.

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 seven 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, seven 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.

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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 US, 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.

Fort Nelson Expansion. The Fort Nelson expansion program in British Columbia, the largest of our expansion projects in western Canada, consists of a series of 10 discrete gathering and processing projects. Nine of the ten projects were placed in service in 2009 and 2010. The new 250 million cubic-feet-per-day (MMcf/d) Fort Nelson North processing facility, which is the final phase and most significant capital outlay of the program, was placed in service in the first quarter of 2013. We now operate over 1.2 Bcf/d of raw gas processing capacity and associated gathering pipelines in the Fort Nelson area.

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). 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.

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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 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.

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, sells, markets and trades NGLs, and recovers and sells condensate. Phillips 66 owns the other 50% interest in DCP Midstream. DCP Midstream currently owns a 23% interest in DCP Midstream Partners, LP (DCP Partners), a publicly-traded master limited partnership which trades on the New York Stock Exchange under the symbol "DPM." As its general partner, DCP Midstream accounts for its investment in DCP Partners as a consolidated subsidiary.

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DCP Midstream operates in 26 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 gathers raw natural gas through gathering systems located in nine major conventional and non-conventional natural gas producing regions: Mid-Continent, Rocky Mountain, East Texas-North Louisiana, Barnett Shale, Gulf Coast, South Texas, Central Texas, Antrim Shale and Permian Basin. DCP Midstream owns or operates approximately 67,000 miles of gathering and transmission pipeline.

As of December 31, 2013, 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, 2013, 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 Spindletop 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 supported by ownership of the Spindletop storage facility and various intrastate pipelines which provide access to market centers/hubs such as Katy, Texas and the Houston Ship Channel.

DCP Midstream also owns direct one-third ownership interests in the Sand Hills and Southern Hills NGL pipelines. SEP also owns a direct one-third ownership interest. With our 50% ownership of DCP Midstream and our 84% ownership interest of SEP, we have a 45% effective ownership interest 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. Approximately 40% of its NGL production is committed to Phillips 66 and CPChem under an existing 15-year contract, which expires in December 2014. Should the contract not be renegotiated or renewed, it provides for a wind-down period through January 2019. The NGL contract also grants Phillips 66 the right to purchase, at index-based prices, certain quantities of NGLs produced at processing plants that are acquired and/or constructed by DCP Midstream in the future in various counties in the Mid-Continent and Permian Basin regions, and the Austin Chalk area. 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.

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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 from the sale of the residue natural gas and NGLs, or an agreed-upon percentage of the proceeds based on index-related prices for natural gas and NGLs regardless of the actual amount of sales proceeds which DCP Midstream receives. 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, crude oil and/or NGLs.
- Fee-based arrangements. DCP Midstream receives a fee or fees for one or more of the following services: gathering, processing, compressing, treating, storing or transporting 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 fees it would otherwise charge for gathering the natural gas from the wellhead location to the delivery point. The revenue DCP Midstream earns from these arrangements is directly related to the volume of natural gas or NGLs that flow 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 could 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. 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. Under these types of contracts, DCP Midstream benefits in periods when NGL prices are higher relative to natural gas prices.

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.

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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 Resources Conservation Board and the Ontario Technical Standards and Safety Authority.

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.

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- 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.
- The Alberta Climate Change and Emissions Management 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.
- The Alberta Environmental Protection and Enhancement Act which governing various aspects, including permitting and site remediation obligations.

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 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 5,800 employees as of December 31, 2013, including approximately 3,600 employees in Canada. In addition, DCP Midstream employed approximately 3,300 employees as of such date. Approximately 1,400 of our Canadian employees are subject to collective bargaining agreements governing their employment with us. Approximately 18% of those employees are covered under agreements that either have expired or will expire by December 31, 2014.

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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	49	President and Chief Executive Officer, Director
J. Patrick Reddy	61	Chief Financial Officer
Dorothy M. Ables	56	Chief Administrative Officer
Guy G. Buckley	53	Chief Development Officer
Julie A. Dill	54	Chief Communications Officer
Reginald D. Hedgebeth	46	General Counsel
Allen C. Capps	43	Vice President and Controller
Laura Buss Sayavedra	46	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 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.

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.

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, 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 would 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 for natural gas and oil, 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.

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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 2013 would have resulted in an estimated net loss on the translation of local currency earnings of approximately $45 million on our Consolidated Statement of Operations. In addition, if a 10% devaluation had occurred on December 31, 2013, the Consolidated Balance Sheet would have been negatively impacted by $488 million through a cumulative translation adjustment in Accumulated Other Comprehensive Income (AOCI). At December 31, 2013, one U.S. dollar translated into 1.06 Canadian dollars.

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, and to oil primarily in our Field Services segment. The effect of commodity price fluctuations on our earnings could be material.

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 United States 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 regulation 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 by 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 a material effect on our operations, earnings, financial condition and cash flows.

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In Canada, our interprovincial and international pipeline operations are subject to pipeline safety regulation 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 United States, 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 a material 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. We currently estimate that compliance with major Clean Air Act regulatory programs will cause us to incur capital expenditures of approximately $450 million through 2020 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 material 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, prescribes 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 United States; 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 and United Nations-sponsored international negotiations held in Durban, South Africa in 2011 resulted in a non-binding agreement to develop a roadmap aimed at creating a global agreement on climate action to be implemented by 2020. The United States 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 United States, 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). 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

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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 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. In 2012, these regulations, along with other GHG regulations and determinations issued by the EPA, were upheld by the D.C. Circuit Court of Appeals. In 2012, the EPA determined in Step 3 of the Tailoring Rule process that it would maintain the current GHG emissions thresholds for PSD and Title V applicability. This rule has also been appealed. We anticipate that in the future, new capital projects or modification of existing projects could be subject to additional permitting requirements related to GHG emissions that may result in delays in completing such projects.

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.

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.

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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. Approximately 90% of our credit exposures for transportation, 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, the percentage of our customers who are rated investment-grade may decline. 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 United States and its allies could be directed against companies operating in the United States. This risk is particularly high for companies, like us, operating in any energy infrastructure industry that handle 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.

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.

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Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

At December 31, 2013, 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, 2013.

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; Vancouver, British Columbia; Chatham, Ontario; Waltham, Massachusetts; Tampa, Florida; Halifax, Nova Scotia; Toronto, Ontario; and Nashville, Tennessee. 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 New York Stock Exchange under the symbol “SE.” As of January 31, 2014, there were approximately 121,000 holders of record of our common stock and approximately 506,000 beneficial owners.

Common Stock Data by Quarter

2013	Dividends Per	Stock Price Range (a)	
	Common Share	High	Low
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
2012			
First Quarter	0.28	32.27	30.17
Second Quarter	0.28	31.79	27.36
Third Quarter	0.28	31.00	28.02
Fourth Quarter	0.305	30.22	26.55

(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, 2009 through December 31, 2013 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,				
	2009	2009	2010	2011	2012	2013
Spectra Energy Corp	$100.00	$138.29	$176.27	$225.70	$208.93	$282.17
S&P 500 Stock Index	100.00	126.46	145.51	148.59	172.37	228.19
S&P 500 Storage & Transportation Index	100.00	139.74	178.02	263.33	295.58	355.89

Dividends

Our near-term objective is to increase our cash dividend by $0.12 per year through 2016. We expect to continue our policy of paying regular cash dividends. The declaration and payment of dividends is subject to the sole discretion of our Board of Directors and depends 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.

	2013 (Unaudited)	2012	2011	2010	2009
	(dollars in millions, except per-share amounts)				
Statements of Operations					
Operating revenues	$5,518	$5,075	$5,351	$4,945	$4,552
Operating income	1,666	1,575	1,763	1,674	1,475
Income from continuing operations	1,159	1,045	1,257	1,123	919
Net income—noncontrolling interests	121	107	98	80	75
Net income—controlling interests	1,038	940	1,184	1,049	849
Ratio of Earnings to Fixed Charges	2.9	2.8	3.4	3.1	2.8
Common Stock Data					
Earnings per share from continuing operations					
Basic	$1.55	$1.44	$1.78	$1.61	$1.31
Diluted	1.55	1.43	1.77	1.60	1.31
Earnings per share					
Basic	1.55	1.44	1.82	1.62	1.32
Diluted	1.55	1.43	1.81	1.61	1.32
Dividends per share	1.22	1.145	1.06	1.00	1.00

	December 31, 2013 (Unaudited)	2012	2011	2010	2009
	(in millions)				
Balance Sheets					
Total assets	$33,533	$30,587	$28,138	$26,686	$24,091
Long-term debt including capital leases, less current maturities	12,488	10,653	10,146	10,169	8,947

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.

On November 1, 2013, Spectra Energy contributed substantially all of its remaining U.S. transmission, storage and liquid assets to SEP (the U.S. Assets Dropdown). As a result of this transaction, we realigned our reportable segments structure. Amounts presented herein for segment information have been recast for all periods presented to conform to our current segment reporting presentation. There were no changes to consolidated data as a result of the recasting of our segment information. See Part II. Item 8. Financial Statements and Supplementary Data, Note 2 of Notes to Consolidated Financial Statements for further discussion of the transaction.

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EXECUTIVE OVERVIEW

Throughout 2013, 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 first quarter of 2014 to $0.335 per share, or $1.34 annually, representing a $0.03 increase from our fourth-quarter 2013 dividend and a $0.12, or nearly 10%, increase from our 2013 annual dividend level.

During 2013, our earnings benefited from the acquisition of Express-Platte and expansion projects at Spectra Energy Partners, higher earnings from our Empress NGL business at Western Canada Transmission & Processing and increased gains associated with the issuance of partnership units by DCP Partners at Field Services. These favorable results were partially offset by higher corporate costs, a change in state tax rates as a result of the U.S. Assets Dropdown and higher interest expense.

We reported net income from controlling interests of $1,038 million, and $1.55 of diluted earnings per share for 2013 compared to net income from controlling interests of $940 million, and $1.43 of diluted earnings per share for 2012. Earnings highlights for 2013 include the following:

- Spectra Energy Partners' earnings increased mainly due to the earnings of Express-Platte that was acquired in March 2013 and expansion projects at Texas Eastern, partially offset by lower storage revenues,
- Distribution's earnings reflected lower transportation and storage revenues and higher employee benefit 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 as a result of colder weather,
- Western Canada Transmission & Processing's earnings benefited mostly from higher NGL earnings at Empress due to lower production costs and higher sales prices in addition to higher earnings from expansions, partially offset by lower contracted volumes in the conventional gathering and processing business, and higher operating and maintenance costs, and
- Field Services' earnings reflected an increase in 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 to DCP Partners.

In March 2013, we acquired 100% of the ownership interests in Express-Platte for $1.5 billion, consisting of $1.25 billion in cash and $260 million of acquired debt, before working capital adjustments. In August 2013, subsidiaries of 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. In November 2013, we completed the first of three closings related to the U.S. Assets Dropdown, which included Spectra Energy's remaining 60% interest in the U.S. portion of Express-Platte. The U.S. Assets Dropdown provides SEP with both the scale and financial flexibility essential to efficiently access attractive capital markets to fund large U.S. growth projects, which enhances Spectra Energy's overall ability to pursue new strategic opportunities in both the United States and Canada while delivering accelerated dividend and distribution growth for investors. See Notes 2 and 3 of Notes to Consolidated Financial Statements for further discussions.

Excluding the acquisition of Express-Platte, we invested approximately $2.3 billion of capital and investment expenditures in 2013, including approximately $1.6 billion of expansion capital expenditures. Successful execution of our 2013 projects allowed us to continue to achieve aggregate returns over the last seven years consistent with our targeted 10%-12% 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 $1.3 billion planned for 2014. 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 2014, we plan to issue approximately

$1.8 billion of combined long-term debt and commercial paper, including the refinancing of approximately $1.2 billion of long-term debt maturities. As of December 31, 2013, our revolving credit facilities include Spectra Energy Capital, LLC's (Spectra Capital's) $1.0 billion facility, SEP's $2.0 billion facility, Westcoast Energy, Inc.'s (Westcoast's) 300 million Canadian dollar facility, and Union Gas' 400 million Canadian dollar facility. These facilities are used principally as back-stops for commercial paper programs and for the issuance of letters of credits. At December 31, 2013, our debt-to-capitalization ratio is at 58%. This leverage ratio increased from 2012 primarily due to higher debt balances related to the acquisition of Express-Platte.

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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 strengthen, and there is growing long-term potential for natural gas to be an effective solution for meeting the energy needs of North America. This causes us to be optimistic about future growth opportunities. Identified opportunities include natural gas-fired generation, growth in industrial markets, incremental gathering and processing requirements in western Canada, LNG exports from North America, and significant new liquids pipeline infrastructure. With our advantage of providing access from strong supply regions to growing natural gas, NGL and crude oil markets, we expect to continue expanding our assets and operations to meet these needs.

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. As such, we remain confident about our ability to grow our crude oil pipeline business and capture future opportunities.

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' energy needs as they evolve, and continued cost control and successful execution on 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.

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 cause a decline in the volume of natural gas distributed or gathered and processed at our plants, resulting in lower earnings and cash flows. This decline would mostly affect distribution revenues and gathering and processing revenues, potentially in the short term. Transmission revenues could be affected by long-term economic declines that result 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 strong, primarily driven by recent positive developments around unconventional gas reserves production in numerous locations within North America as discussed further below.

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 electric generation sector. 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, Mid-Continent, 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

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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. Any changes in market dynamics that adversely affect the availability and cost-competitiveness of North American crude oil supply would have a negative impact on our current business and associated growth opportunities.

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 unconventional shale gas supplies.

While current drilling levels are below recent historical averages, the relatively higher productivity of unconventional wells has led to increased production supporting continued growth of Western Canada Transmission & Processing's gathering and processing business in the areas of British Columbia and Alberta where unconventional gas development is prevalent.

In certain areas of Western Canada Transmission & Processing's operations served by conventional supply, lower natural gas prices resulting from increasing North American gas production, primarily unconventional, have reduced producer demand for expansions of the British Columbia conventional 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.

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. 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. 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 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. 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 in Western Canada Transmission & Processing, which are most sensitive to changes in NGL prices. We evaluate the risks associated with commodity price volatility on an ongoing basis and, as of December 31, 2013, have no material commodity hedges in place. Effective January 2014, we instituted a commodity hedging program at Western Canada Transmission & Processing's Empress NGL business and have elected to not apply cash flow hedge accounting.

Based on current projections, our expected effective income tax rate will approximate 24%–25% for 2014. 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 38%. 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 7% for 2014, 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.

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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.

RESULTS OF OPERATIONS

	2013	2012	2011
	(in millions)		
Operating revenues	$5,518	$5,075	$5,351
Operating expenses	3,852	3,502	3,596
Gains on sales of other assets and other, net	—	2	8
Operating income	1,666	1,575	1,763
Other income and expenses	569	465	606
Interest expense	657	625	625
Earnings from continuing operations before income taxes	1,578	1,415	1,744
Income tax expense from continuing operations	419	370	487
Income from continuing operations	1,159	1,045	1,257
Income from discontinued operations, net of tax	—	2	25
Net income	1,159	1,047	1,282
Net income—noncontrolling interests	121	107	98
Net income—controlling interests	$1,038	$940	$1,184

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 $350 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
- 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.

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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 is also due to higher allowance for funds used during construction (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 US 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.

2012 Compared to 2011

Operating Revenues. The $276 million, or 5%, decrease was driven mainly by:

- a decrease in customer usage of natural gas largely due to warmer weather in 2012, lower natural gas prices passed through to customers, and an unexpected decision by OEB in 2012 affecting transportation revenues at Distribution,
- lower NGL sales prices and volumes in the Empress NGL business and a decrease in contracted volumes in the conventional gathering and processing business at Western Canada Transmission & Processing, and
- lower storage revenues, lower rates, contract reductions and lower processing revenues at Spectra Energy Partners, partially offset by
- higher revenues from expansion projects at Western Canada Transmission & Processing and Spectra Energy Partners.

Operating Expenses. The $94 million, or 3%, decrease was driven mainly by:

- lower natural gas prices passed through to customers and lower natural gas purchased resulting from decreased volumes in natural gas sold primarily due to warmer weather in 2012, net of increased gas purchased due to growth in the number of customers at Distribution, and
- lower equipment repairs and maintenance expenses, pipeline integrity costs, employee benefits and other costs, net of accelerated amortization of software at Spectra Energy Partners, partially offset by
- higher depreciation and amortization from expansion projects placed in service at Western Canada Transmission & Processing and Spectra Energy Partners.

Operating Income. The $188 million decrease was attributable to a net loss in the Empress NGL business primarily due to lower NGL sales prices related to the Empress NGL business and lower contracted volumes from conventional areas in the gathering and processing business at Western Canada Transmission & Processing, and an unexpected decision by the OEB affecting prior year transportation revenues and lower customer usage of natural gas as a result of warmer weather at Distribution, partially offset by higher earnings from expansion projects at Western Canada Transmission & Processing and Spectra Energy Partners.

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Other Income and Expenses. The $141 million decrease was attributable to lower equity earnings from Field Services mostly due to lower commodity prices, partially offset by a reduction in depreciation expense attributable to an increase of the remaining useful lives of DCP Midstream's gathering, transmission, processing, storage and other assets in 2012 and an increase in gathering and processing margins as a result of higher volumes due to asset growth in 2012 and the impact of severe weather in the first quarter of 2011. In addition, the lower equity earnings from Field Services were partially offset by higher AFUDC due to increased capital spending on expansion projects at Western Canada Transmission & Processing and Spectra Energy Partners.

Income Tax Expense from Continuing Operations. The $117 million decrease was a result of lower earnings from continuing operations and a lower Canadian effective tax rate, partially offset by favorable tax adjustments in 2011. The effective tax rate for income from continuing operations was 26% in 2012 compared to 28% in 2011. The lower effective tax rate in 2012 was primarily due to a lower Canadian effective tax rate.

Income from Discontinued Operations, Net of Tax. The $23 million decrease was primarily attributable to lower income from propane deliveries in 2012 as a result of a final settlement of these activities in the second quarter of 2012.

Net Income—Noncontrolling Interests. The $9 million increase was driven by an increase in noncontrolling ownership interests resulting from the issuances of partnerships units by SEP to the public in 2011 and 2012, and higher earnings from Spectra Energy Partners, primarily as a result of the timing of expansion on East Tennessee and the timing of the acquisition of Big Sandy in 2011 and M&N US in 2012.

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). Cash, cash equivalents and investments are managed at the parent-company levels, so the gains and losses on foreign currency remeasurement 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 service 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 NGLs extraction, fractionation, transportation, storage and marketing to customers in western Canada, the northern tier of the United States and the Maritime Provinces in Canada.

Field Services gathers, compresses, treats, processes, transports, stores and sells natural gas. In addition, this segment produces, fractionates, transports, stores, sells, markets and trades NGLs, and recovers and sells condensate. 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 located in nine major conventional and non-conventional natural gas producing regions: Mid-Continent, Rocky Mountain, East Texas-North Louisiana, Barnett Shale, Gulf Coast, South Texas, Central Texas, Antrim Shale and Permian Basin. DCP Midstream has a 23% ownership interest in DCP Partners, a publicly-traded master limited partnership.

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

EBITDA by Business Segment

	2013	2012	2011
	(in millions)		
Spectra Energy Partners	$1,433	$1,259	$1,223
Distribution	574	587	633
Western Canada Transmission & Processing	736	694	812
Field Services	343	279	449
Total reportable segment EBITDA	3,086	2,819	3,117
Other	(86)	(36)	(43)
Total reportable segment and other EBITDA	3,000	2,783	3,074
Depreciation and amortization	772	746	709
Interest expense	657	625	625
Interest income and other	7	3	4
Earnings from continuing operations before income taxes	$1,578	$1,415	$1,744

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

Spectra Energy Partners

	2013	2012	Increase (Decrease)	2011	Increase (Decrease)
	(in millions, except where noted)				
Operating revenues	$1,965	$1,754	$211	$1,746	$8
Operating expenses					
Operating, maintenance and other	715	627	88	651	(24)
Gains on sales of other assets and other, net	—	1	(1)	7	(6)
Other income and expenses	183	131	52	121	10
EBITDA	$1,433	$1,259	$174	$1,223	$36
Express pipeline receipts, MBbl/d (a,b)	207	—	—	—	—
Platte PADD II deliveries, MBbl/d (b)	168	—	—	—	—

(a) Thousand barrels per day.

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

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 $88 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.

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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.

2012 Compared to 2011

Operating Revenues. The $8 million increase was driven by:

- a $51 million increase from expansion projects and the acquisition of Big Sandy in July 2011, and
- a $12 million increase in recoveries of electric power and other costs passed through to customers, partially offset by
- a $29 million decrease from lower storage revenues and contract reductions at Texas Eastern and Ozark Gas Transmission, and
- a $24 million decrease in processing revenues associated with pipeline operations caused by lower prices.

Operating, Maintenance and Other. The $24 million decrease was driven by:

- a $32 million decrease due to lower equipment repairs and maintenance expenses, pipeline integrity costs, employee benefits and other costs, partially offset by accelerated software amortization, and
- a $6 million decrease from project development costs expensed in 2011, partially offset by
- a $12 million increase in electric power and other costs passed through to customers.

Gains on Sales of Other Assets and Other, net. The $6 million decrease was driven by 2011 customer settlements.

Other Income and Expenses. The $10 million increase was primarily due to the increase in AFUDC as a result of higher capital spending in 2012.

EBITDA. The $36 million increase was driven by increased earnings from expansions and lower operating costs, partially offset by lower storage revenues, contract reductions at Texas Eastern and Ozark Gas Transmission 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 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. As a result, the value of storage assets and contracts has declined in recent years, negatively affecting the results of our storage facilities. 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 for our storage assets. NGL and natural gas price fluctuations will continue to affect processing revenues that are associated with transportation services.

On Express-Platte we plan to continue earnings growth by maximizing throughputs, 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, volume 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 also 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.

Our interstate pipeline operations are subject to pipeline safety regulation administered by 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.

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On January 3, 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:

- 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 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).

In 2011, PHMSA initiated an Advance Notice of Proposed Rulemaking announcing its consideration of substantial revisions in its regulations to increase pipeline safety. PHMSA also has issued an Advisory Bulletin which among other things, advises pipeline operators that if they are relying on design, construction, inspection, testing, or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. These legislative and regulatory changes, when implemented, will impose additional costs on new pipeline projects as well as on existing operations. Because the extent of the new requirements and the timing of their application is still uncertain, we cannot reasonably determine the effects that these changes will have on our operations, earnings, financial condition and cash flows at this time.

Distribution

	2013	2012	Increase (Decrease)	2011	Increase (Decrease)
	(in millions, except where noted)				
Operating revenues	$1,848	$1,666	$182	$1,831	$(165)
Operating expenses					
Natural gas purchased	826	638	188	760	(122)
Operating, maintenance and other	448	440	8	441	(1)
Loss on sales of other assets and other, net	—	(1)	1	—	(1)
Other income and expenses	—	—	—	3	(3)
EBITDA	$574	$587	$(13)	$633	$(46)
Number of customers, thousands	1,399	1,379	20	1,360	19
Heating degree days, Fahrenheit	7,540	6,385	1,155	7,122	(737)
Pipeline throughput, TBtu	907	818	89	846	(28)
Canadian dollar exchange rate, average	1.03	1.00	0.03	0.99	0.01

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 New York Mercantile Exchange (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 revenue, 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

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

Operating, Maintenance and Other. The $8 million increase was driven by:

- a $20 million increase primarily driven by higher employee benefit costs, partially offset by
- a $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.

2012 Compared to 2011

Operating Revenues. The $165 million decrease was driven by:

- a $114 million decrease in customer usage of natural gas primarily due to weather that was more than 10% warmer than in 2011,
- a $92 million decrease from lower natural gas prices passed through to customers,
- a $38 million decrease 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,
- a $12 million decrease resulting from a weaker Canadian dollar, and
- a $6 million decrease as a result of an unfavorable decision by the OEB affecting 2010 and 2011 storage revenues, partially offset by
- a $60 million increase from growth in the number of customers,
- an $18 million increase in short-term transportation service revenues, and
- a $16 million increase due to lower earnings to be shared with customers.

Natural Gas Purchased. The $122 million decrease was driven by:

- a $92 million decrease from lower natural gas prices passed through to customers, and
- an $88 million decrease due to lower volumes of natural gas sold primarily due to warmer weather, partially offset by
- a $53 million increase from growth in the number of customers.

EBITDA. The $46 million decrease was mainly a result of an unexpected decision from the OEB in 2012 requiring certain revenues realized from the optimization of upstream transportation contracts be refunded to customers, and lower customer usage due to warmer weather, partially offset by an increase in short-term transportation service revenues and lower earnings to be shared with customers.

Matters Affecting Future Distribution Results

Distribution plans to increase service reliability and continue earnings growth through the Parkway expansion projects, which in the case of the Brantford-Kirkwall pipeline and ancillary facilities project, regulatory approval is dependent on approval of a third-party project. 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 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 unconventional shale gas supplies. These market factors will continue to affect Union Gas' unregulated storage and regulated transportation revenues in the near term.

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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

	2013	2012	Increase (Decrease)	2011	Increase (Decrease)
	(in millions, except where noted)				
Operating revenues	$1,767	$1,679	$88	$1,816	$(137)
Operating expenses					
Natural gas and petroleum products purchased	391	437	(46)	432	5
Operating, maintenance and other	648	586	62	592	(6)
Gains (losses) on sales of other assets and other, net	(1)	1	(2)	—	1
Other income and expenses	9	37	(28)	20	17
EBITDA	$736	$694	$42	$812	$(118)
Pipeline throughput, TBtu	780	745	35	816	(71)
Volumes processed, TBtu	670	665	5	728	(63)
Empress inlet volumes, TBtu	460	504	(44)	619	(115)
Canadian dollar exchange rate, average	1.03	1.00	0.03	0.99	0.01

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,
- 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 $62 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.

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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.

2012 Compared to 2011

Operating Revenues. The $137 million decrease was driven by:

- a $134 million decrease due to lower NGL sales prices associated with the Empress NGL business,
- a $46 million decrease in contracted volumes in the conventional gathering and processing business due to decontracting as a result of low natural gas prices and the effect of customers' shift to unconventional developments,
- a $28 million decrease due to lower NGL sales volumes associated with the Empress NGL business primarily as a result of warmer weather,
- a $14 million decrease as a result of a weaker Canadian dollar, and
- a $9 million decrease due to lower rates at M&N Canada, partially offset by
- a $63 million increase in gathering and processing revenues due to contracted volumes from expansions associated with non-conventional supply discoveries in the Horn River and Montney areas of British Columbia,
- a $16 million increase in transmission revenues primarily due to expansion,
- a $10 million increase from recovery of British Columbia carbon tax and other non-income tax expense from customers, and
- a $5 million increase due primarily to higher sales volumes of residual natural gas in the Empress NGL business.

Natural Gas and Petroleum Products Purchased. The $5 million increase was driven by:

- a $14 million non-cash charge to reduce the book value of propane inventory at our Empress NGL business to estimated net realizable value, and
- an $11 million increase in natural gas purchases for extraction at the Empress extraction facility primarily due to increased volumes, partially offset by
- a $9 million decrease as a result of lower costs of natural gas purchased in the Empress NGL business caused primarily by lower extraction premiums,
- an $8 million decrease due primarily to lower volumes of make-up gas purchases in the Empress NGL business as a result of lower NGL production, and
- a $3 million decrease due to a weaker Canadian dollar.

Operating, Maintenance and Other. The $6 million decrease was driven by:

- an $18 million decrease due primarily to plant turnaround costs in 2011 that did not recur in the 2012 period,
- an $11 million decrease due primarily to lower plant fuel and electricity costs at the Empress NGL business,
- a $5 million decrease due to a weaker Canadian dollar, and
- a $3 million decrease primarily in the costs passed through to customers at M&N Canada, partially offset by
- a $14 million increase in maintenance costs for new and existing facilities mainly due to overhauls and deactivation of projects,
- a $10 million increase in British Columbia carbon tax and other non-income tax expense, and
- an $8 million increase in project development costs due primarily to LNG pipeline project development.

Other Income and Expenses. The $17 million increase was driven primarily by higher AFUDC resulting from increased capital spending on expansion projects.

EBITDA. The $118 million decrease was driven by a net loss in the Empress NGL business, including an adjustment to reduce the book value of propane inventory to estimated net realizable value, and lower contracted volumes in the conventional gathering and processing business, partially offset by higher gathering and processing earnings from expansions and 2011 plant turnaround costs that did not recur in 2012.

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Matters Affecting Future Western Canada Transmission & Processing Results

Western Canada Transmission & Processing plans to continue earnings growth through capital efficient “supply push” projects, primarily associated with gathering and processing expansion and incremental transportation capacity to support drilling activity in northern British Columbia as well as future LNG exports. 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.

While current drilling levels are below recent historical averages, the relatively higher productivity of unconventional wells has led to increased production supporting continued growth of Western Canada Transmission & Processing’s gathering and processing business in the areas of British Columbia and Alberta where unconventional gas development is prevalent.

In certain areas of Western Canada Transmission & Processing’s operations served by conventional supply, lower natural gas prices resulting from increasing North American gas production have reduced producer demand for both expansions of the British Columbia conventional 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.

Field Services

	2013	2012	Increase (Decrease)	2011	Increase (Decrease)
	(in millions, except where noted)				
Equity in earnings of unconsolidated affiliates	$343	$279	$64	$449	$(170)
EBITDA	$343	$279	$64	$449	$(170)
Natural gas gathered and processed/transported, TBtu/d (a,b)	7.1	7.1	—	7.0	0.1
NGL production, MBbl/d (a)	426	402	24	383	19
Average natural gas price per MMBtu (c,d)	$3.65	$2.79	$0.86	$4.04	$(1.25)
Average NGL price per gallon (e)	$0.76	$0.82	$(0.06)	$1.21	$(0.39)
Average crude oil price per barrel (f)	$98.04	$94.16	$3.88	$95.12	$(0.96)

(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.
(f) Average price based on NYMEX calendar month.

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

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- 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.

2012 Compared to 2011

EBITDA. Lower equity earnings of $170 million were mainly the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

- a $272 million decrease from commodity-sensitive processing arrangements due to decreased commodity prices,
- a $27 million decrease primarily attributable to higher operating costs, largely resulting from a planned increase in repairs and maintenance activities due to asset growth, and
- a $24 million decrease attributable to unfavorable results from gas and NGL marketing, partially offset by
- a $60 million increase due to decreased depreciation expense as a result of changes to the remaining useful lives of DCP Midstream's gathering, transmission, processing, storage and other assets during the second quarter of 2012. The key contributing factor to the change was an increase in producers' estimated remaining economically recoverable commodity reserves, resulting from advances in extraction processes, such as hydraulic fracturing and horizontal drilling, as well as improved technology used to locate commodity reserves,
- a $50 million increase in gathering and processing volumes, as a result of asset growth across certain geographic regions and the absence of severe weather which caused wellhead freeze-offs which shut in gas wells and reduced recoveries in 2011,
- a $19 million increase in gains associated with the issuance of partnership units by DCP Partners,
- a $10 million increase attributable to lower interest expense due to higher capitalized interest in 2012 as a result of growth, and
- a $9 million increase in earnings from DCP Partners as a result of growth and mark-to-market gains on derivative instruments used to protect distributable cash flows.

Supplemental Data

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

	2013	2012	2011
	(in millions)		
Operating revenues	$12,038	$10,171	$12,982
Operating expenses	11,230	9,427	11,868
Operating income	808	744	1,114
Other income and expenses	35	34	26
Interest expense, net	249	193	213
Income tax expense	10	2	3
Net income	584	583	924
Net income—noncontrolling interests	93	97	61
Net income attributable to members' interests	$491	$486	$863

Matters Affecting Future Field Services Results

Drilling levels vary by geographic area, but in general, drilling remains robust in areas with a high content of liquids in the gas stream and crude oil drilling with associated gas production. Drilling remains weak in certain areas with dry gas where relatively lower commodity prices currently do not support the economics of drilling. However, advances in technology, such as horizontal drilling and hydraulic fracturing in shale plays, have led to certain geographic areas becoming increasingly accessible. Crude oil prices have generally remained at favorable levels, while NGL and natural gas prices remain modest due to increasing supplies. Under DCP Midstream's contract structures, which are predominantly percent-of-proceeds contracts, DCP Midstream receives payments in-kind in the form of commodities and, as a result, typically has "long" natural gas and NGL positions. As such, a decrease in natural gas prices can negatively impact DCP Midstream's margins. However, any decline would be partially offset by its keep-whole contracts where gross margin is directly related to the price of NGLs and inversely related to the price of natural gas. DCP Midstream believes that future natural gas prices will be influenced by North American supply deliverability, the severity of winter and summer weather, the level of North American production, drilling activity and exports of LNG.

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Other

	2013	2012	Increase (Decrease)	2011	Increase (Decrease)
	(in millions)				
Operating revenues	$72	$89	$(17)	$87	$2
Operating expenses					
Operating, maintenance and other	186	141	45	140	1
Gains on sales of other assets and other, net	1	1	—	1	—
Other income and expenses	27	15	12	9	6
EBITDA	$(86)	$(36)	$(50)	$(43)	$7

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.

2012 Compared to 2011

EBITDA. The $7 million increase reflected primarily a gain related an early termination notice by Westcoast for capacity contracts held on Vector Pipeline in 2012.

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 $1,376 million as of December 31, 2013 and $1,264 million as of December 31, 2012. Total regulatory liabilities were $502 million as of December 31, 2013 and $630 million as of December 31, 2012.

Impairment of Goodwill

We had goodwill balances of $4,810 million at December 31, 2013 and $4,513 million at December 31, 2012. The increase in goodwill in 2013 was the result of the acquisition of Express-Platte, partially offset by foreign currency translation. 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 assessed reflect continued expansion of our assets, driven by new natural gas supplies such as shale gas in North America, 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. We assumed a weighted average long-term growth rate of 2.3% for our 2013 quantitative goodwill impairment analysis. Had we assumed a 100 basis point lower growth rate for each of the reporting units that we quantitatively assessed, there would have been no impairment of goodwill. We continue to monitor the effects of the global economic downturn with respect to the long-term cost of capital utilized to calculate our reporting units' fair values. For our 2013 quantitative goodwill impairment analysis, we assumed weighted-average costs of capital ranging from 5.8% to 7.9% that market participants would use. Had we assumed a 100 basis point increase in the weighted-average cost of capital for each of the reporting units that we quantitatively assessed, there would have been no impairment of goodwill. 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.

Certain commodity prices, specifically NGLs, have fluctuated in 2012 and 2013. Our Empress NGL business is significantly affected by fluctuations in commodity prices. We updated our Empress NGL reporting unit's impairment test using recent operational information, financial data and June 30, 2013 commodity prices, and concluded there was no impairment of goodwill related to Empress. The operating results of our Empress NGL reporting unit improved during 2013 due to, among other things, favorable commodity prices. Therefore, no additional impairment test was deemed necessary. Should NGL prices decline significantly from recent levels and reduce earnings at the Empress NGL business, this could result in a triggering event that would warrant a testing of impairment for goodwill relating to the Empress NGL reporting unit, which could result in an impairment. Effective January 2014, we instituted a commodity hedging program at Empress to economically hedge a significant portion of their NGL sales and related make-up gas purchases, which is expected to mitigate the effects of short-term commodity price fluctuations.

Based on the results of our annual goodwill impairment testing, no indicators of impairment were noted and the fair values of the reporting units that we assessed at April 1, 2013 (our testing date) were substantially in excess of their respective carrying values.

Other than the previously described update to our Empress NGL reporting unit's impairment test, no triggering events occurred with the other reporting units during the period April 1, 2013 through December 31, 2013 that would warrant re-testing for goodwill impairment.

Revenue Recognition

Revenues from the transportation, 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.

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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 experience 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 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, since 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 2013, the assumed average return was 7.40% for the U.S. pension plan assets, 7.10% for the Canadian pension plan assets and 6.51% 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 $2 million before tax for Canadian plans. The Canadian other post-retirement benefit plans are not funded.

Since pension and other post-retirement benefit liabilities are measured on a discounted basis, the discount rate is also a significant assumption. 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. The average discount rates of 3.59% for the U.S. plans and 4.16% for the Canadian plans used to calculate 2013 plan expenses represent a weighted average of the applicable rates. The applied discount rates increased approximately 0.76% for the U.S. plans and 0.65% for the Canadian plans in 2013 compared to 2012, resulting in a significant decrease in total benefit liabilities. A 25 basis-point change in the discount rates would impact annual before-tax benefit expense by approximately $1 million for U.S. plans and $5 million for Canadian plans.

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, 2013, we had negative net working capital of $1,958 million. This balance includes commercial paper liabilities totaling $1,032 million and current maturities of long-term debt of $1,197 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 2014. 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, 2013, our four revolving credit facilities consisted of Spectra Capital’s $1.0 billion facility, SEP’s $2.0 billion facility, Westcoast’s 300 million Canadian dollar facility and Union Gas’ 400 million Canadian dollar facility. These facilities are used principally as back-stops for commercial paper programs and for the issuance of letters of credit. 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, 2013, our capital structure was 58% debt, 34% common equity of controlling interests and 8% 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.

In particular, 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 $215 million in 2013, $203 million in 2012 and $395 million in 2011. These distributions are classified within Operating Cash Flows. We continually assess the effect of 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, 2013, $143 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. Distributions have typically been as much as $300 million per year. 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 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 $1.3 billion in 2014 and will continue to average approximately $2.0 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,		
	2013	2012	2011
	(in millions)		
Net cash provided by (used in):			
Operating activities	$2,030	$1,938	$2,186
Investing activities	(3,236)	(2,674)	(2,098)
Financing activities	1,316	654	(35)
Effect of exchange rate changes on cash	(3)	2	(9)
Net increase (decrease) in cash and cash equivalents	107	(80)	44
Cash and cash equivalents at beginning of the period	94	174	130
Cash and cash equivalents at end of the period	$201	$94	$174

Operating Cash Flows

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.

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Net cash provided by operating activities decreased $248 million to $1,938 million in 2012 compared to 2011. This change was driven mostly by:

- lower distributions received from DCP Midstream, and
- lower overall earnings.

Investing Cash Flows

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 proceeds of available-for-sale securities in 2013 compared to $130 million of net purchases in 2012.

Net cash flows used in investing activities increased $576 million to $2,674 million in 2012 compared to 2011. This change was driven mostly by:

- $513 million of initial and subsequent equity investments in Sand Hills and Southern Hills in 2012,
- a $110 million increase in capital expenditures in 2012, and
- $130 million of net purchases of available-for-sale securities in 2012 compared to $190 million of net proceeds from sales and maturities in 2011, partially offset by
- a $390 million cash outlay in 2011 for the acquisition of Big Sandy.

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.

	2013	2012	2011
	(in millions)		
Spectra Energy Partners (a,b)	$1,299	$1,443	$746
Distribution	357	276	292
Western Canada Transmission & Processing	561	760	781
Total reportable segments	2,217	2,479	1,819
Other	42	66	100
Total consolidated	$2,259	$2,545	$1,919

(a) Excludes the $1,254 million net cash outlay for the acquisition of Express-Platte in 2013, $30 million paid in 2012 for amounts previously withheld from the purchase price consideration of the acquisition of Bobcat in 2010 and the $390 million acquisition of Big Sandy in 2011. See Note 3 of Notes to Consolidated Financial Statements for further discussions.

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

On March 14, 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 2013 totaled $2,259 million and included $1,591 million for expansion projects and $668 million for maintenance and other projects. We project 2014 capital and investment expenditures of approximately $2.1 billion, consisting of approximately $1.2 billion for Spectra Energy Partners, $0.5 billion for Distribution and $0.4 billion for Western Canada Transmission & Processing. Total projected 2014 capital and investment expenditures include approximately $1.3 billion of expansion capital expenditures and $0.8 billion for maintenance and upgrades of existing plants, pipelines and infrastructure to serve growth.

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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 2013, including:

- Fort Nelson Expansion Program—The new 250 MMcf/d Fort Nelson North processing facility, which was the final phase and most significant capital outlay of the program, was placed into service during the first quarter of 2013.

- Dawson Expansion—The development of a sour gas processing plant and an additional pipeline in western Canada. Phase I of 100 MMcf/d was placed into service in 2012 and Phase II for an additional 100 MMcf/d was placed into service during the first quarter of 2013.

- New Jersey-New York Expansion—An 800 MMcf/d expansion of the Texas Eastern pipeline system consisting of a new 16-mile pipeline extension into lower Manhattan, New York and other associated facility upgrades. The project is designed to transport gas produced in the U.S. Gulf Coast, Mid-Continent, Rockies and Marcellus Shale regions into New York City and was placed into service during the fourth quarter of 2013.

- Sand Hills—Approximately 720 miles of NGL pipeline constructed by DCP Midstream, with an initial capacity of 200,000 Bbls/d, transporting NGLs from the Permian Basin and Eagle Ford shale regions to NGL markets on the Gulf Coast. Phase I was completed in the fourth quarter of 2012, with initial service from the Eagle Ford shale region to Mont Belvieu. Phase II provides service from the Permian Basin to the Eagle Ford shale region. This project was placed into service during the second quarter of 2013.

- Southern Hills—Approximately 800 miles of NGL pipeline also constructed by DCP Midstream, connecting several DCP Midstream processing plants and anticipated third-party producers, providing NGL transportation from the Mid-Continent to Mont Belvieu. This project was placed into service during the second quarter of 2013.

Significant 2014 expansion projects expenditures are expected to include:

- 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. In-service is scheduled by the second half of 2014.

- North Montney Expansion—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. In-service is scheduled by the first half of 2014.

- Kingsport—An additional 86 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. Approximately 25 MMcf/d of the project was placed in service in November 2013 and the remainder is scheduled to be in-service in the first quarter of 2015.

- 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 for the fourth quarter of 2015.

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Parkway—The Parkway West project includes the development of a greenfield site west of Toronto, the installation of a compressor unit and associated infrastructure. In addition, the Parkway D compressor, combined with the Brantford-Kirkwall pipeline loop, will provide growth volumes of 681 MMcf/d. These projects are due to be placed in-service throughout 2014 and 2015.

- 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 expected by the second quarter of 2017.

- 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

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gas from existing interconnects in New Jersey and New York to LDC markets in the northeast. In-service is expected by the fourth quarter of 2016.

Financing Cash Flows and Liquidity

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 Spectra Energy Corp's U.S. Assets Dropdown to SEP, 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.

Net cash provided by financing activities totaled $654 million in 2012 compared to $35 million used in financing activities in 2011. This $689 million change was driven mostly by:

- proceeds of $382 million in 2012 from the issuance of Spectra Energy common stock,
- a $299 million decrease in 2011 of SEP's revolving credit facility borrowings outstanding, and
- a $189 million increase in net long-term debt issuances in 2012.

Significant Financing Activities—2013

Debt Issuances. The following long-term debt issuances were completed during 2013 as part of our overall financing plan to fund capital expenditures, the acquisition of Express-Platte, the U.S. Assets Dropdown to SEP, to refinance maturing debt obligations and for other corporate purposes:

	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. 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. The continuous 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 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. Beginning in November, SEP issued 0.6 million common units to the public in 2013 under this 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 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.

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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 Issuance. In December 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 Issuance. In November 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.

Significant Financing Activities—2011

Debt Issuances. The following long-term debt issuances were completed during 2011:

	Amount (in millions)		Interest Rate		Due Date
SEP	$250		2.95	%	2016
SEP	250		4.60	%	2021
Westcoast	151	(a)	3.883	%	2021
Westcoast	151	(a)	4.791	%	2041
Union Gas	309	(a)	4.88	%	2041

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

SEP Common Unit Issuance. In June 2011, SEP issued 7.2 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 $218 million (net proceeds to Spectra Energy were $213 million), used to fund a portion of the acquisition of Big Sandy.

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Available Credit Facilities and Restrictive Debt Covenants

	Expiration Date	Total Credit Facilities Capacity	Outstanding at December 31, 2013			Available Credit Facilities Capacity
			Commercial Paper	Term Loan	Total	
		(in millions)				
Spectra Capital						
Multi-year syndicated (a)	2018	$1,000	$344	$ n/a	$344	$656
Delayed-draw syndicated term loan (a,b)	2018	300	n/a	—	—	300
SEP						
Multi-year syndicated (c)	2018	2,000	338	n/a	338	1,662
Westcoast						
Multi-year syndicated (d)	2016	282	34	n/a	34	248
Union Gas						
Multi-year syndicated (e)	2016	377	316	n/a	316	61
Total		$3,959	$1,032	$—	$1,032	$2,927

(a) Revolving credit facility and term loan contain a covenant requiring the Spectra Energy Corp consolidated debt-to-total capitalization ratio, as defined in the agreements, to not exceed 65%. This ratio was 58% at December 31, 2013.
(b) Term loan agreement allows for one borrowing prior to January 15, 2014.
(c) Revolving credit facility contains a covenant that requires SEP to maintain a ratio of total Consolidated Indebtedness-to-Consolidated EBITDA, as defined in the credit agreement, of 5.0 or less, provided that for three fiscal quarters subsequent to certain acquisitions (such as the November 1, 2013 U.S. Assets Dropdown from Spectra Energy Corp), the ratio may be 5.5 or less. As of December 31, 2013, this ratio was 4.4 after giving effect to the U.S. Assets Dropdown.
(d) U.S. dollar equivalent at December 31, 2013. The revolving credit facility is 300 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 44% at December 31, 2013.
(e) U.S. dollar equivalent at December 31, 2013. The revolving credit facility is 400 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 67% at December 31, 2013.

On November 1, 2013, we amended and restated the Spectra Capital and SEP credit agreements. The Spectra Capital credit facility was decreased to $1.0 billion, and the SEP credit facility was increased to $2.0 billion. Both facilities expire in 2018.
The issuances of commercial paper, letters of credit and revolving borrowings reduce the amounts available under the credit facilities. As of December 31, 2013, there were no letters of credit issued under the credit facilities or revolving borrowings outstanding.

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, 2013, 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, 2013. 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, 2013, however, it is not likely that a material adverse effect would occur as a result of a weakened Canadian dollar.

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Term Loan Agreements. On November 1, 2013, Spectra Capital entered into a five-year $300 million senior unsecured delayed-draw term loan agreement which allows 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 2018.

On November 1, 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 were used to pay Spectra Energy for the U.S. Assets Dropdown.

In December 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 at least $0.12 per year through 2016. 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 $0.335 per common share on January 3, 2014 payable on March 10, 2014 to shareholders of record at the close of business on February 14, 2014.

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 $476 million available as of December 31, 2013 for the issuance of limited partner common units and various debt securities under another effective shelf registration statement on file with the SEC. Westcoast and Union Gas have an aggregate 1.1 billion Canadian dollars (approximately $1.0 billion) available as of December 31, 2013 for the issuance of debt securities in the Canadian market under debt shelf prospectuses.

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.

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, 2013 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 2014.

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Contractual Obligations as of December 31, 2013

	Payments Due By Period				
	Total	2014	2015 & 2016	2017 & 2018	2019 & Beyond
	(in millions)				
Long-term debt (a)	$20,750	$1,879	$2,354	$3,779	$12,738
Operating leases (b)	380	47	87	69	177
Purchase Obligations: (c)					
Firm capacity payments (d)	583	256	235	35	57
Energy commodity contracts (e)	361	342	19	—	—
Other purchase obligations (f)	397	231	93	27	46
Other long-term liabilities on the Consolidated Balance Sheet (g)	73	73	—	—	—
Total contractual cash obligations	$22,544	$2,828	$2,788	$3,910	$13,018

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(a) See Note 16 of Notes to Consolidated Financial Statements. Amounts include estimated scheduled interest payments over the life of the associated debt.
(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, 2013.
(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 2014 retirement plan contributions and estimated 2014 payments related to uncertain tax positions, including interest (see Notes 6 and 25). We are unable to reasonably estimate the timing of uncertain tax positions and interest payments in years beyond 2014 due to uncertainties in the timing of cash settlements with taxing authorities and cannot estimate retirement plan contributions beyond 2014 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.

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 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.

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. There were no significant commodity hedge transactions by Spectra Energy during 2013, 2012 or 2011. Effective January 2014, we instituted a commodity hedging program at Empress and have elected to not apply cash flow hedge accounting.

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

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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, natural gas and oil primarily in our Field Services segment. Based on a sensitivity analysis as of December 31, 2013 and 2012, a 10¢ per-gallon move in NGL prices would affect our annual pre-tax earnings by approximately $59 million in 2014 and $65 million in 2013 for Field Services. For the same periods, a 50¢ per-MMBtu move in natural gas prices would affect our annual pre-tax earnings by approximately $21 million and $18 million, and a $10 per-barrel move in oil prices would affect our annual pre-tax earnings by approximately $27 million and $25 million, respectively.

With respect to the Empress assets in Western Canada Transmission & Processing, a 10¢ per-gallon move in NGL prices, primarily propane prices, would affect our annual pre-tax earnings by approximately $19 million in 2014, as compared with approximately $22 million in 2013. For the same periods, a 50¢ per-MMBtu move in natural gas prices would affect our annual pre-tax earnings by approximately $9 million and $13 million, respectively. Such sensitivities exclude the effects of hedging and assume normal operating conditions.

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. The principal customers for our integrated oil transportation pipeline are Canadian and U.S. producers that use the Express-Platte System to connect to refineries located in the U.S. Rocky Mountain and Midwest regions. 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.

Approximately 90% 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, the percentage of our customers who are rated investment-grade may decline.

We had no net exposure to any customer that represented greater than 10% of the gross fair value of trade accounts receivable at December 31, 2013.

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.

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As of December 31, 2013, 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 $1,243 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, 2013, it was estimated that if short-term interest rates average 100 basis points higher (lower) in 2014 than in 2013, interest expense, net of offsetting impacts in interest income, would increase (decrease) by $24 million. Comparatively, based on a sensitivity analysis as of December 31, 2012, had short-term interest rates averaged 100 basis points higher (lower) in 2013 than in 2012, it was estimated that interest expense, net of offsetting interest income, would have fluctuated by approximately $29 million. These amounts were estimated by considering the effect of the hypothetical interest rates on variable-rate debt outstanding, adjusted for interest rate hedges, investments, and cash and cash equivalents outstanding as of December 31, 2013 and 2012.

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 2013 would have resulted in an estimated net loss on the translation of local currency earnings of approximately $45 million on our Consolidated Statement of Operation. In addition, if a 10% devaluation had occurred on December 31, 2013, the Consolidated Balance Sheet would have been negatively impacted by $488 million through a cumulative translation adjustment in AOCI. At December 31, 2013, one U.S. dollar translated into 1.06 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 fluctuations on our consolidated equity, these fluctuations have a direct impact on our ability to maintain certain of these financial covenants.

OTHER ISSUES

Global Climate Change. Policymakers at regional, federal and international levels continue to evaluate potential legislative and regulatory compliance mechanisms to achieve reductions in global GHG emissions in an effort to address the challenge of climate change. Certain of our assets and operations in the U.S. and Canada are subject to direct and indirect effects of current global climate change regulatory actions in their respective jurisdictions, and it is likely that other assets and operations in the U.S. and Canada will become subject to direct and indirect effects of current and possible future global climate change regulatory actions.

The current international climate framework, the United Nations-sponsored Kyoto Protocol, prescribes specific targets to reduce GHG emissions for developed countries for the 2008-2012 period. The Kyoto Protocol expired in 2012 and had not been ratified by the United States. United Nations-sponsored international negotiations were held in Warsaw, Poland in November 2013 to continue laying the groundwork for a new global agreement on climate action to come into effect by 2020.

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An agreement was reached at the 2012 climate negotiations to amend the Kyoto Protocol extending it to 2020 when a potential new agreement could take effect.

In 2011, the Canadian government withdrew from the Kyoto Protocol. In 2008, the Canadian government outlined a regulatory framework mandating GHG reductions from large final emitters. Regulatory design details from the Canadian government remain forthcoming. We expect a number of our assets and operations in Canada will be affected by future federal climate change regulations. However, the materiality of any potential compliance costs is unknown at this time as the final form of the regulation and compliance options have yet to be determined by policymakers.

British Columbia introduced legislation establishing targets for the purpose of reducing GHG emissions to at least 33% less than 2007 levels by 2020 and to at least 80% less than 2007 levels by 2050. In 2008, the province established additional interim GHG reduction targets of 6% below 2007 levels by 2012 and 18% below by 2016. British Columbia has also issued consultation papers regarding potential development of a cap and trade program; however, no decision has been made on whether to implement the program. The materiality of any potential compliance costs is unknown at this time as the final form of additional regulations and compliance options has yet to be determined by policymakers.

In 2007, the province of Alberta adopted legislation which requires existing large emitters (facilities releasing 100,000 metric tons or more of GHG emissions annually) to reduce their annual emissions intensity by 12% beginning July 1, 2007. One of our facilities is subject to this regulation. The regulation has not had a material impact on our consolidated results of operations, financial position or cash flows.

In the United States, climate change action is evolving at state, regional and federal levels. We expect that some of our assets and operations in the United States could be affected by eventual mandatory GHG programs; however, the timing of and specific policy objectives in many jurisdictions, including at the federal level, remain uncertain.

The United States has not ratified the Kyoto Protocol, nor has the federal government adopted a mandatory GHG emissions reduction requirement for our sector. The EPA has issued a final Mandatory Greenhouse Gas Reporting rule in 2009 that required annual reporting of GHG emissions data from certain of our U.S. operations beginning in 2010. In 2010, the EPA released additional requirements for natural gas system reporting that have expanded the reporting requirements for GHG emissions starting in 2011. These reporting requirements have not had and are not anticipated to have a material impact on our consolidated results of operations, financial position or cash flows. In 2010, the EPA issued the PSD and Tailoring Rule. Beginning in January 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 emission thresholds that would subject facilities to these regulations. In June 2012, these regulations, along with other GHG regulations and determinations issued by the EPA, were upheld by the D.C. Circuit of Appeals. In July 2012, the EPA determined in Step 3 of the Tailoring Rule process that it would maintain the current GHG emissions thresholds for PSD and Title V applicability. This rule has also been appealed. We anticipate that in the future, new capital projects or modification of existing projects could be subject to additional permitting requirements related to GHG emissions that may result in delays in completing such projects.

In addition, several legislative proposals that would impose GHG emissions constraints have been considered by the U.S. Congress. To date, no such legislation has been enacted into law. A number of states in the United States are establishing or considering state or regional programs that would mandate reductions in GHG emissions. These regional programs include the Regional Greenhouse Gas Initiative which applies only to power producers in select northeastern states, the Western Climate Initiative which includes California and the provinces of British Columbia, Manitoba, Ontario and Quebec, and the Midwestern Greenhouse Gas Reduction Accord which includes six midwestern states and one Canadian province. We expect some of our assets and operations could be affected either directly or indirectly by state or regional programs. However, as the key details of future GHG restrictions and compliance mechanisms remain undefined, the likely future effects on our business are highly uncertain.

Due to the speculative outlook regarding any federal, provincial and state 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 continue to monitor the development of greenhouse gas regulatory policies in both countries.

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

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New Accounting Pronouncements

There were no significant accounting pronouncements issued during 2013, 2012 or 2011 that had or will have a material impact on our consolidated results of operations, financial position or cash flows.

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, 2013 based on the 1992 framework in Internal Control—Integrated Framework 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, 2013.

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, 2013 and 2012, 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, 2013. 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, 2013, based on criteria established in Internal Control - Integrated Framework (1992) 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, 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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, 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, 2013, based on the criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring

Organizations of the Treadway Commission.
/s/ DELOITTE & TOUCHE LLP
Houston, Texas
February 28, 2014

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

	Years Ended December 31,	
	2013	2012