Spectra Energy Corp.
Form 10-K
February 27, 2009
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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, 2008 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 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, 2008: $17,300,000,000

Number of shares of Common Stock, $0.001 par value, outstanding at February 19, 2009: 643,339,758

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2009 Annual Meeting of Shareholders are incorporated by reference in Part III.

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SPECTRA ENERGY CORP

FORM 10-K FOR THE YEAR ENDED

DECEMBER 31, 2008

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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 are based on management s beliefs and assumptions. 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 involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- state, 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 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, which can affect the long-term demand for natural gas and related services;
- potential effects arising from terrorist attacks and any consequential or other hostilities;
- changes in environmental, safety and other laws and regulations;
- results 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 infrastructure projects and the effects of competition;
- the performance of natural gas transmission and storage, distribution, and gathering and processing facilities;

- the extent of success in connecting natural gas supplies to gathering, processing and transmission systems and in connecting to expanding gas markets;

- the effects of accounting pronouncements issued periodically by accounting standard-setting bodies;

- conditions of the capital markets during the periods covered by the 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 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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PART I

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.

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. For close to 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 operate in three key areas of the natural gas industry: gathering and processing, transmission and storage, and distribution. Based in Houston, Texas, we provide transportation 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 have a 50% ownership in DCP Midstream, LLC (DCP Midstream), one of the largest natural gas gatherers and processors in the United States, based in Denver, Colorado.

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Our natural gas pipeline systems consist of approximately 18,300 miles of transmission pipelines. Our proportional throughput for our pipelines totaled 3,733 trillion British thermal units (TBtu) in 2008 compared to 3,642 TBtu in 2007. These amounts include throughput on wholly owned U.S. and Canadian pipelines and our proportional share of throughput on pipelines that are not wholly owned. Our storage facilities provide approximately 270 billion cubic feet (Bcf) of storage capacity in the United States and Canada.

Spin-off from Duke Energy Corporation

On January 2, 2007, Duke Energy Corporation (Duke Energy) completed the spin-off of Spectra Energy. Duke Energy contributed the natural gas businesses, primarily comprised of the Natural Gas Transmission and Field Services business segments of Duke Energy that were owned through Duke Energy s then wholly owned subsidiary, Spectra Energy Capital, LLC (Spectra Capital). Duke Energy contributed its ownership interests in Spectra Capital to us and all of our outstanding common stock was distributed to Duke Energy s shareholders.

Businesses

Subsequent to the reorganization and our spin-off from Duke Energy, we manage our business in four reportable segments: U.S. Transmission, Distribution, Western Canada Transmission & Processing, and Field Services. The remainder of our business operations is presented as Other and consists of unallocated corporate costs, wholly 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.

U.S. TRANSMISSION

Our U.S. Transmission business provides transportation and storage of natural gas for customers in various regions of the northeastern and southeastern United States and the Maritime Provinces in Canada. Our U.S. pipeline systems consist of more than 13,800 miles of transmission pipelines with six primary transmission systems: Texas Eastern Transmission, LP (Texas Eastern), Algonquin Gas Transmission, LLC (Algonquin), East Tennessee Natural Gas, LLC (East Tennessee), Maritimes & Northeast Pipeline, L.L.C. and Maritimes & Northeast Pipeline Limited Partnership (collectively, Maritimes & Northeast Pipeline), Gulfstream Natural Gas System, LLC (Gulfstream), and Southeast Supply Header, LLC (SESH), which began operations in September 2008. The pipeline systems in our U.S. Transmission business receive natural gas from major North American producing regions for delivery to their respective markets. U.S. Transmission s proportional throughput for its pipelines totaled 2,218 TBtu in 2008 compared to 2,202 TBtu in 2007. This includes throughput on wholly owned pipelines and our proportional share of throughput on pipelines that are not wholly owned. A majority of contracted transportation volumes are under long-term firm service agreements. Interruptible services are provided on a short-term or seasonal basis. U.S. Transmission provides storage services through Saltville Gas Storage Company, L.L.C. (Saltville), Market Hub Partners Holding s (Market Hub s) Moss Bluff and Egan storage facilities, and Texas Eastern s facilities. In the course of providing transportation services, U.S. Transmission also processes natural gas on its Texas Eastern system. Demand on the pipeline systems is seasonal, with the highest throughput occurring during colder periods in the first and fourth calendar quarters.

Most of U.S. Transmission s 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 in interstate commerce.

In July 2007, we completed our initial public offering (IPO) of Spectra Energy Partners, LP (Spectra Energy Partners), a newly formed, natural gas infrastructure master limited partnership which is part of the U.S. Transmission segment. Subsequent to an additional drop-down of assets into Spectra Energy Partners in 2008, we

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currently retain an 84% equity interest in Spectra Energy Partners, which owns 100% of East Tennessee, 100% of Saltville, 50% of Market Hub and a 24.5% interest in Gulfstream. Spectra Energy retained a 50% direct ownership interest in Market Hub and a 25.5% direct ownership interest in Gulfstream. Spectra Energy Partners is a separate, publicly traded entity which trades on the New York Stock Exchange under the symbol SEP.

Texas Eastern

The Texas Eastern 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 8,700 miles of pipeline and 73 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 500 miles of Texas Eastern s pipeline system. Texas Eastern has two joint-venture storage facilities in Pennsylvania and one wholly owned and operated storage field in Maryland. Texas Eastern s total working capacity in these three fields is 73 Bcf.

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Algonquin

The Algonquin pipeline 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 1,100 miles of pipeline with seven compressor stations.

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East Tennessee

East Tennessee s transmission system crosses Texas Eastern s system at two points in Tennessee and consists of two mainline systems totaling approximately 1,510 miles of pipeline in Tennessee, Georgia, North Carolina and Virginia, with 21 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.

We have an effective 84% ownership interest in East Tennessee through our ownership of Spectra Energy Partners.

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Maritimes & Northeast Pipeline

Maritimes & Northeast Pipeline s gas transmission system is operated through Maritimes & Northeast Pipeline Limited Partnership (the Canadian portion of this system) and Maritimes & Northeast Pipeline, L.L.C. (the U.S. portion). We have 78% ownership interests in both segments of the system and affiliates of Exxon Mobil Corporation and Emera, Inc. have the remaining interests. The Maritimes & Northeast Pipeline transmission system consists of approximately 900 miles of pipeline from producing fields in Nova Scotia through New Brunswick, Maine, New Hampshire and Massachusetts, connecting to Algonquin in Beverly, Massachusetts. There are seven compressor stations on the system.

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Gulfstream

We have an effective 46% investment in Gulfstream, a 745-mile interstate natural gas pipeline system operated jointly by us and The Williams Companies, Inc. Gulfstream transports natural gas from Mississippi, Alabama, Louisiana, and Texas, crossing the Gulf of Mexico to markets in central and southern Florida. Gulfstream has one compressor station. Gulfstream is owned 25.5% by Spectra Energy, 24.5% by Spectra Energy Partners and 50% by The Williams Companies, Inc. Our investment in Gulfstream is accounted for under the equity method of accounting.

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Southeast Supply Header LLC

We have a 50% investment in SESH, a 274-mile interstate natural gas pipeline system with three mainline compressor stations owned and operated jointly by us and CenterPoint Energy, Inc. SESH, which began operations in September 2008, extends from the Perryville Hub in northeastern Louisiana where the emerging shale gas production of eastern Texas and northern Louisiana, along with conventional production, is reached from four major interconnections. SESH extends to Alabama, interconnecting with 14 major north-south pipelines and three high deliverability storage facilities. Our investment in SESH is accounted for under the equity method of accounting.

Market Hub Partners Holding

We have an effective 92% ownership interest in Market Hub, which owns and operates two natural gas storage facilities, Moss Bluff and Egan, with a total storage capacity of approximately 37 Bcf. The Moss Bluff facility consists of three storage caverns located in Southeast Texas and has access to five pipeline systems including the Texas Eastern system. The Egan facility consists of three storage caverns located in South Central Louisiana and has access to seven pipeline systems including the Texas Eastern system. Market Hub is a general partnership in which Spectra Energy and Spectra Energy Partners each have a 50% interest.

Saltville Gas Storage L.L.C.

We have an effective 84% ownership interest in Saltville, through our ownership of Spectra Energy Partners. Saltville owns and operates natural gas storage facilities with a total storage capacity of approximately 5 Bcf. The storage facilities interconnect 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.

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Competition

Our U.S. Transmission transportation 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 rates, terms of service, and flexibility and reliability of service.

The natural gas that 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, the level of business activity, long-term economic conditions, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Customers and Contracts

In general, our U.S. Transmission pipelines provide transportation and storage services to 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. Transportation 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 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 to recover variable costs.

We also provide interruptible transportation and storage services where customers can use capacity if it is available at the time of the request. Interruptible revenues are dependent 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.

DISTRIBUTION

We provide distribution services in Canada through our subsidiary, Union Gas Limited (Union Gas). Union Gas owns pipeline, storage and compression facilities used in the transportation, storage and distribution of natural gas. Union Gas system consists of approximately 37,000 miles of distribution 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 155 Bcf in 22 underground facilities located in depleted gas fields. Its transmission system consists of approximately 3,000 miles of high-pressure pipeline and six mainline compressor stations.

Union Gas distributes natural gas to approximately 1.3 million residential, commercial and industrial customers in northern, southwestern and eastern Ontario and provides storage, transportation and related services to utilities and other energy market participants. Union Gas 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.

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Union Gas storage and transmission system forms an important link in moving natural gas from western Canadian and U.S. supply basins to central Canadian and northeastern U.S. markets.

Competition

As Union Gas distribution business is regulated by the OEB, it is not generally subject to third-party competition within its distribution franchise area. However, as a result of a 2006 decision by the OEB, physical bypass of Union Gas facilities even within its distribution franchise area may be permitted. In addition, other companies could enter Union Gas markets or regulations could change.

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 price changes, the availability of natural gas and other forms of energy, the level of business activity, economic conditions, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

In November 2006, the OEB issued a decision on the regulation of rates for gas storage services in Ontario involving, among other things, phase-out of the sharing with customers of margins on Union Gas long-term storage transactions. This phase-out will occur over a four-year period that began in 2008, with the share accruing to Union Gas increasing ratably over that period. As a result of its finding that the market for storage services is competitive, the OEB does not regulate the rates for storage services to customers outside Union Gas franchise area or the rates for new storage services to customers within its franchise area. For these unregulated services, Union Gas competes against third-party storage providers for storage on the basis of price, terms of service, and flexibility and reliability of service. Existing storage services to customers within Union Gas franchise area continue to be provided at cost-based rates and are not subject to third-party competition.

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Customers and Contracts

The rates that Union Gas charges for its regulated services are subject to the approval of the OEB. Union Gas distribution service area extends throughout northern Ontario from the Manitoba border to the North Bay/ Muskoka area, through southern Ontario from Windsor to just west of Toronto, and across eastern Ontario from Port Hope to Cornwall. Union Gas serves approximately 1.3 million customers in a franchise area with a population of approximately four million and a diversified commercial and industrial base.

Union Gas distribution services to power generation and industrial customers are affected by weather, economic conditions and the price of competitive energy sources. Most of Union Gas power generation, 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 the sale of the natural gas commodity, gas distribution margins are not affected by the source of customers gas supply.

Union Gas also provides natural gas storage and transportation 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. The average term of these contracts is approximately eight years, with the longest contract term being almost 25 years.

WESTERN CANADA TRANSMISSION & PROCESSING

Our Western Canada Transmission & Processing business is comprised of the BC Pipeline and BC Field Services operations, the Midstream operations and the natural gas liquids (NGL) marketing operations.

BC Pipeline and BC Field Services provide natural gas transportation and gas gathering and processing services. BC Pipeline is regulated by the National Energy Board (NEB) under full cost of service regulation, and transports processed natural gas from facilities primarily in northeast British Columbia (BC) to markets in the lower mainland of BC, Alberta and the U.S. Pacific Northwest. The BC Pipeline has approximately 1,800 miles of transmission pipeline in BC and Alberta, as well as 18 mainline compressor stations. Throughput for the BC Pipeline totaled 615 TBtu in 2008 compared to 596 TBtu in 2007.

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 five gas processing plants located in BC, 17 field compressor stations and approximately 1,500 miles of gathering pipelines.

The Midstream business provides similar gas gathering and processing services in BC and Alberta and consists of 11 natural gas processing plants and approximately 600 miles of gathering pipelines. In May 2008, we acquired the 24.4 million units of the Spectra Energy Income Fund (the Income Fund) that were held by non-affiliated holders. Prior to the acquisition, the Income Fund indirectly held 54% of our consolidated Midstream operations and we held the remaining 46%.

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The Empress NGL marketing 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, among other things, 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 and gas supply business. The Empress extraction and fractionation plant is located in Empress, Alberta.

Competition

Western Canada Transmission & Processing businesses compete with third-party midstream companies, exploration and production companies, and pipelines in the gathering, processing and transportation of natural gas and the extraction and marketing of NGL products. Western Canada Transmission & Processing competes directly with other pipeline facilities serving its market areas. The principal elements of competition are 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, the level 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 we serve.

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 premium or fee we pay to natural gas shippers.

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Customers & Contracts

BC Pipeline provides: (i) transportation 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 transportation services to the nearest natural gas trading hub; and (ii) transportation services primarily to downstream markets in the Pacific Northwest (both 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 transportation services where customers can use capacity if it is available at the time of request and payments under these services are based on volumes transported.

The BC Field Services and Midstream operations in western Canada provide raw natural gas gathering and processing services to exploration and production companies under agreements which are primarily fee-for-service contracts which do not expose us to commodity-price risk. These operations provide both firm and interruptible services.

The NGL extraction operation at Empress, Alberta has capacity to produce approximately 58,000 barrels of NGLs per day comprised of approximately 50% ethane, 32% propane, 12% butanes and 6% condensate. 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, or separate, 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 and are exposed to the difference between the selling prices and the shrinkage makeup price of natural gas plus the extraction premium and operating costs. The majority of propane is sold to propane retailers. Butane is sold mainly into the motor gasoline refinery market and condensate sales are directed to the crude blending and crude diluent markets. The prices we can obtain for these products is affected by numerous factors including competition, weather, transportation costs and supply and demand factors.

FIELD SERVICES

Field Services consists of our 50% investment in DCP Midstream, which is accounted for as an equity investment. DCP Midstream gathers and processes natural gas, and fractionates, markets and trades NGLs. ConocoPhillips owns the remaining 50% interest in DCP Midstream.

DCP Midstream operates in 27 states in the United States. DCP Midstream s gathering systems include connections to several interstate and intrastate natural gas and NGL pipeline systems and one natural gas storage facility. DCP Midstream gathers raw natural gas through gathering systems located in nine major 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 60,000 miles of gathering and transmission pipeline, with approximately 38,000 active receipt points.

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DCP Midstream s natural gas processing operations separate raw natural gas that has been gathered on its own systems and third-party systems into condensate, NGLs and residue gas. DCP Midstream processes the raw natural gas at 53 natural gas processing facilities.

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. DCP Midstream fractionates NGL raw mix at six processing facilities that it owns and operates and at four third-party-operated facilities in which it has an ownership interest. In addition, DCP Midstream operates a propane wholesale marketing business.

The residue gas 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 gas at its 8 Bcf natural gas storage facility located in Southeast Texas.

DCP Midstream uses NGL trading and storage at the Mont Belvieu, Texas and Conway, Kansas NGL market centers to manage its 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 undertakes these NGL and gas trading activities through the use of fixed-forward sales, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading.

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DCP Midstream s operating results are significantly affected by changes in average NGL and crude oil prices, which increased approximately 12% and 18%, respectively, in 2008 compared to 2007. DCP Midstream closely monitors the risks associated with these price changes. See 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 and processing natural gas and in marketing and transporting natural gas and NGLs, DCP Midstream competes with major integrated oil companies, major interstate and intrastate pipelines, national and local natural gas gatherers, and brokers, marketers and distributors of natural gas supplies. Competition for natural gas supplies is based primarily on the reputation, efficiency and reliability of operations, the availability of gathering and transportation to high-demand markets, the pricing arrangement offered by the gatherer/processor and the ability of the gatherer/processor to obtain a satisfactory price for the producer s residue gas and extracted NGLs. Competition for sales to customers is based primarily upon reliability, services offered and price of delivered natural gas and NGLs.

Customers and Contracts

DCP Midstream sells NGLs to a variety of customers ranging from large, multi-national petrochemical and refining companies to small regional retail propane distributors. Substantially all of DCP Midstream s NGL sales are made at market-based prices, including approximately 40% of its NGL production that is committed to ConocoPhillips and its affiliate, Chevron Phillips Chemical Company LLC, under existing contracts that have primary terms that are effective until January 1, 2015. In 2008, ConocoPhillips and Chevron Phillips Chemical Company LLC, combined, represented approximately 21% of DCP Midstream s consolidated revenues.

The residual natural gas (primarily methane) that results from processing raw natural gas is sold at market-based prices to marketers and end-users. End-users include 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. Of the gas that is gathered and processed, more than 70% of volumes are under percentage-of-proceeds contracts.

Percentage-of-proceeds arrangements. In general, DCP Midstream purchases natural gas from producers, transports and processes it and then sells the residue natural gas and NGLs in the market. The payment to the producer is an agreed upon percentage of the proceeds from those sales. DCP Midstream s revenues from these arrangements correlate directly with the price of natural gas and NGLs.

Fee-based arrangements. DCP Midstream receives a fee or fees for the various services it provides including gathering, compressing, treating, processing or transporting natural gas. The revenue DCP Midstream earns from these arrangements is directly related to the volume of natural gas that flows through its systems and is not directly dependent on commodity prices.

Keep-whole and wellhead purchase arrangement. DCP Midstream gathers or purchases raw natural gas from producers for processing and then markets the NGLs. DCP Midstream keeps the producer whole by returning an equivalent amount of natural gas after the processing is complete. DCP Midstream is exposed to the frac-spread, which is the price difference between NGLs and natural gas prices, representing the theoretical gross margin for processing liquids from natural gas.

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.

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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, 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. DCP Midstream performs its own supply chain management function.

The recent sharp declines in both economic activity and consumer prices are beginning to impact the costs of certain materials used in our maintenance and expansion projects. Specialty steel prices, in particular, have declined 10-15% from recent highs, and the effect is being seen in lower prices for steel pipe and related materials. The ultimate impact of consumer prices will depend upon the length and depth of the worldwide contraction in economic activity.

There can be no assurance that the ability to obtain sufficient equipment and materials will not be adversely affected by unforeseen developments. In addition, the price of equipment and materials may vary, perhaps substantially, from year to year.

Regulations

Most of our U.S. gas transmission pipeline and storage operations are regulated by the FERC. The FERC regulates natural gas transportation in U.S. interstate commerce including the establishment of rates for services. The FERC also regulates the construction of U.S. interstate pipelines and storage facilities including 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 transportation of gas by intrastate pipelines.

Our U.S. Transmission and the 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 concerning pipeline safety.

The natural gas transmission and distribution, 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 the Midstream operations for gathering and processing services in Western Canada are regulated on a complaints-basis by applicable provincial regulators. The Empress NGL businesses are not under any form of rate regulation.

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

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Environmental Matters

We are subject to various U.S. federal, state and local laws and regulations, as well as Canadian national and provincial regulations, with regard to air and water quality, hazardous and solid waste disposal and other environmental matters. These regulations often impose substantial testing and certification requirements.

Environmental laws and regulations affecting us 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, such as 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), was enacted in 1990 and amends parts of the Clean Water Act and other statutes as they pertain to the prevention of and response to oil spills. OPA imposes certain spill prevention, control and countermeasure requirements. Although we are primarily a natural gas business, OPA affects our business primarily because of the presence of liquid hydrocarbons (condensate) in our offshore pipelines.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which imposes liability for remediation costs associated with environmentally contaminated sites. Under CERCLA, any individual or entity that currently owns or in the past owned or operated a disposal site can be held liable and required to share in remediation costs, as well as transporters or generators of hazardous substances sent to a disposal site. Because of the geographical extent of our operations, we have disposed of waste at many different sites.

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 effect of proposed projects is a factor in determining whether we will be permitted to complete proposed projects.

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 each 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, will govern the reduction of greenhouse gas (GHG) emissions from our operations in Canada. Regulations to be promulgated under the Act will set emission-intensity reduction targets and deadlines for fixed emission caps for nitrogen oxides, sulphur oxides, volatile organic compounds and particulate matter.

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- The Alberta Climate Change and Emissions Management Act, which, pursuant to regulations that came into effect in 2007, requires certain facilities to meet annual reductions in emission intensity targets starting in 2007. The Act was applicable in 2008 to our Empress facility in Alberta.

For more information on environmental matters, including possible liability and capital costs, see Item 8. Financial Statements and Supplementary Data, Notes 5 and 18 of Notes to Consolidated Financial Statements.

Except to the extent discussed in Notes 5 and 18, 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 adverse effect on our competitive position, 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 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 20 of Notes to Consolidated Financial Statements.

Employees

We had approximately 5,200 employees as of December 31, 2008, including approximately 3,400 employees outside of the United States, all in Canada. In addition, DCP Midstream, our joint venture with ConocoPhillips, employed approximately 2,700 employees as of such date. Approximately 1,500 of our employees, all of whom are located in Canada, are subject to collective bargaining agreements governing their employment with us. Approximately 60% of those employees are covered under agreements that have expired or will expire by December 31, 2009.

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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	44	President and Chief Executive Officer, Director
J. Patrick Reddy	56	Chief Financial Officer
Dorothy M. Ables	51	Chief Administrative Officer
John R. Arensdorf	58	Chief Communications Officer
Alan N. Harris	55	Chief Development and Operations Officer
Allen C. Capps	38	Vice President and Treasurer
Sabra L. Harrington	46	Vice President and Controller

Gregory L. Ebel assumed his position as President and Chief Executive Officer on January 1, 2009. He previously served as Group Executive and Chief Financial Officer from January 2007. Mr. Ebel served as President of Union Gas from January 2005 until January 2007. Prior to then, Mr. Ebel served as Vice President, Investor & Shareholder Relations of Duke Energy from November 2002 until January 2005.

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 September 2000 to December 2008.

Dorothy M. Ables served as Vice President of Audit Services and as Chief Ethics and Compliance Officer from January 2007 until assuming her current position as Chief Administrative Officer in November 2008. Ms. Ables served as Vice President of Audit Services from April 2006 to December 2006 and Vice President, Audit Services and Chief Compliance Officer for Duke Energy Corporation from February 2004 to March 2006. Prior to then, Ms. Ables served as Senior Vice President and Chief Financial Officer at Duke Energy Gas Transmission from December 2002 to January 2004.

John R. Arensdorf assumed his current position in November 2008. He previously served as Vice President, Investor Relations from January 2007. Prior to then, Mr. Arensdorf served as General Manager, Investor Relations at Duke Energy from April 2006 to December 2006; General Manager, Internal Controls from November 2004 to April 2006; and Vice President, Investor Relations from May 2001 to November 2004.

Alan N. Harris assumed his position as Chief Development Officer and Chief Operations Officer in November 2008. He previously served as Group Executive and Chief Development Officer since January 2007. Mr. Harris served as Group Vice President and Chief Financial Officer of Duke Energy Gas Transmission from February 2004 to January 2007 and Executive Vice President of Duke Energy Gas Transmission from January 2003 until February 2004. Mr. Harris currently serves on the Board of Directors of DCP Midstream Partners, LP.

Allen C. Capps joined Spectra Energy in December 2007. Prior to then, Mr. Capps served as Director of Finance of EPCO, Inc. from April 2006. Mr. Capps served as Interim Controller of TEPPCO Partners, LP from June 2005 to April 2006; Director of Technical Accounting and Compliance from April 2004 until June 2005; and Manager of Technical Accounting and Compliance from April 2003 until April 2004.

Sabra L. Harrington served as Vice President, Financial Strategy of Duke Energy Gas Transmission from February 2006 until assuming her current position in January 2007. Prior to then, Ms. Harrington served as Vice President and Controller of Duke Energy Gas Transmission from August 2003 until February 2006.

In addition to the above executive and other officers, Fred J. Fowler served as President and Chief Executive Officer until his retirement on December 31, 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, proxies 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 web site at http://www.spectraenergy.com. Such reports are accessible at no charge through our web site 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 more significant risk factors relating to Spectra Energy.

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

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 or sluggishness in the economy, which could affect long-term demand and market prices for natural gas and NGLs, all of which 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 cause a decline in the volume of natural gas transported and distributed or gathered and processed at our plants, 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 that could result in the non-renewal of long-term contracts at the time of expiration. Lower demand for natural gas and lower prices for natural gas and NGLs could result from multiple factors that affect the markets where we operate, including:

- weather conditions, including abnormally mild winter or summer weather that cause lower energy usage for heating or cooling purposes, respectively;
- supply of and demand for energy commodities, including any decreases in the production of natural gas which could negatively affect our processing business 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 resources may cause customers to seek alternative energy resources, which could materially adversely affect our revenues, earnings and cash flows.

Our natural gas businesses are dependent on the continued availability of natural gas production and reserves. Prices for natural gas, regulatory limitations, 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 available to these assets could cause customers to seek alternative energy resources, thereby reducing their reliance on our services, which in turn would materially adversely 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 adversely affect our results of operations, cash flows and compliance with debt covenants.

We are exposed to foreign currency risk from investments and operations in Canada. An average 10% devaluation in the Canadian dollar exchange rate during 2008 would have resulted in an estimated net loss on the translation of local currency earnings of approximately $42 million on our Consolidated Statement of Operations. In addition, if a 10% devaluation had occurred on December 31, 2008, the Consolidated Balance Sheet would be negatively impacted by $523 million through a cumulative translation adjustment in Accumulated Other Comprehensive Income. At December 31, 2008, one U.S. dollar translated into 1.22 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 adversely affect cash flow 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 operations are subject to commodity price risk, which could result in losses 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 primarily exposed to market price fluctuations of NGL prices in the Field Services segment and to frac-spreads in the Empress operations in Canada. Since NGL prices historically track crude oil prices, we disclose our NGL price sensitivities in terms of crude oil price changes. Based on a sensitivity analysis as of December 31, 2008, at our forecasted NGL-to-oil price relationships, a $10 per barrel move in oil prices would affect our annual pre-tax earnings by approximately $120 million in 2009 ($110 million from Field Services and $10 million from U.S. Transmission). However, NGL prices lagged oil prices during oil s unprecedented upward price movement in the first half of 2008. Assuming crude oil prices average approximately $50 per barrel, each 1% change in the price relationship between NGLs and crude oil would change our annual pre-tax earnings by approximately $8 million. At crude oil prices above $50 per barrel, the impact of a 1% change in the NGL-to-oil price relationship would increase, and at crude oil prices below $50 per barrel, the impact of a 1% change in the NGL-to-oil price relationship would decrease.

With respect to the frac-spread risk related to Empress processing and NGL marketing activities in Western Canada, as of December 31, 2008, a $0.50 change in the difference between the Btu-equivalent price of propane (used as a proxy for Empress NGL production) and the price of natural gas in Alberta, Canada would affect our pre-tax earnings by approximately $16 million on an annual basis in 2009.

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.

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.

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

Execution of our capital projects subjects us to construction risks, increases in labor and material costs and other risks that may adversely 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;
- 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 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;
- 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 costs. As a result, new facilities may not achieve their expected investment return, which could adversely affect our results of operations, financial position or cash flows.

Gathering and processing, transmission and storage, and 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 and storage, and distribution activities, such as leaks, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in significant injury, loss of human 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 adverse effect on our business, earnings, financial condition and cash flows.

We are subject to numerous environmental laws and regulations, compliance with which requires significant capital expenditures, can increase our cost of operations, and may 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,

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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, and 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 operation 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 will be incurred to comply with environmental regulations in the future will not have a material adverse effect.

While Canada is a signatory to the United Nations-sponsored Kyoto Protocol, which prescribes specific targets to reduce GHG emissions for developed countries for the 2008-2012 period, the Canadian federal government has confirmed it will not achieve the targets within the timeframes specified. Instead, the federal government in 2008 outlined a regulatory framework mandating GHG reductions from large final emitters. The framework requires GHG emissions intensity reductions of 18% beginning in 2010, with further reductions of 2% per year thereafter. Regulatory design details from the Government of Canada associated with the framework remain forthcoming. We expect a number of our assets and operations will be affected by pending federal climate change regulations, but the materiality of any potential compliance costs is unknown at this time as the final form of the regulation 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 tons or more of GHG emissions annually) to reduce their annual emissions intensity by 12% beginning July 1, 2007. In 2008, two of our facilities were subject to this regulation. The regulation has not had a material impact on our consolidated results of operations, financial position or cash flows.

Due to the substantial uncertainty of the Canadian federal and provincial policies, we cannot estimate the potential effects of GHG regulation in Canada on business, earnings, financial condition and cash flows. When policies become sufficiently certain to support a meaningful assessment, we will do so.

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

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 adversely affected, particularly if we or our rated subsidiaries are unable to maintain an investment-grade credit rating, which could adversely 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 the 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. In addition, 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.

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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 adversely affect cash flow or restrict businesses. Furthermore, if our short-term debt rating were to be below tier 2 (e.g. A-2/P-2, S&P and Moody s, respectively), access to the commercial paper market could be significantly limited, although this would not affect our ability to draw under the credit facilities.

If we are not able to access capital at competitive rates, our ability to finance operations and implement our strategy may be adversely 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.

Conditions in the general credit markets have deteriorated since the third quarter of 2008, with widening credit spreads and a lack of liquidity, including certain debt markets being substantially closed. There can be no assurances that this credit crisis will not worsen or impact the availability and cost of debt financing, including any refinancings of the obligations described above.

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

In the future, we may be unable to secure long-term transportation agreements for our gas transmission business as a result of economic factors, lack of commercial gas supply to our systems, 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 adversely affect our business, earnings, financial condition and cash flows.

Market based natural gas storage operations are subject to commodity price volatility, which could result in variability in our earnings and cash flows.

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.

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 adverse 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 adverse effect on natural gas production in British Columbia and Alberta, which could have a material adverse effect on the volume of natural gas processed at our facilities and of NGLs and other products transported in the associated pipelines. We cannot predict the outcome of these claims or the effect they may ultimately have on our business and operations.

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Protecting against potential terrorist activities requires significant capital expenditures and a successful terrorist attack could adversely 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 great for companies, like ours, operating in any energy infrastructure industry that handles volatile gaseous and liquid hydrocarbons. The potential for terrorism has subjected our operations to increased risks that could have a material adverse 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 adversely affect our cash flows and business.

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

Our costs of providing non-contributory defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation and our required or voluntary 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 be required to fund our plans with significant amounts of cash. Such cash funding obligations could have a material effect on our earnings and cash flows.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

At December 31, 2008, 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 facilities 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 15 of Notes to Consolidated Financial Statements, none of our properties were secured by mortgages or other material security interests at December 31, 2008.

Our corporate headquarters are located at 5400 Westheimer Court, Houston, Texas 77056, which is a leased facility. The lease expires in April 2018.We also maintain major offices in 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. Our property, plant and equipment includes buildings, technical equipment and other equipment capitalized under capital lease agreements. For more details, refer to Note 13 of Notes to Consolidated Financial Statements.

Item 3. Legal Proceedings.

For information regarding legal proceedings, including regulatory and environmental matters, see Notes 5 and 18 of Notes to Consolidated Financial Statements.

Item 4. Submission of Matters to a Vote of Security Holders.

None.

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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 February 19, 2009, there were approximately 155,000 holders of record of our common stock and approximately 494,000 beneficial owners.

Common Stock Data by Quarter

	Dividends Per	Stock Price Range(a)	
2008	**Common Share**	**High**	**Low**
First Quarter	$ 0.23	$ 26.26	$ 21.41
Second Quarter	$ 0.23	$ 29.18	$ 22.67
Third Quarter	$ 0.25	$ 29.13	$ 22.00
Fourth Quarter	$ 0.25	$ 23.77	$ 13.36
2007			
First Quarter	$ 0.22	$ 30.00	$ 23.55
Second Quarter	$ 0.22	$ 27.34	$ 24.89
Third Quarter	$ 0.22	$ 27.73	$ 21.24
Fourth Quarter	$ 0.22	$ 26.34	$ 23.98

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

Stock Performance Graph

The following graph reflects the comparative changes in the value from January 3, 2007, the first trading day of Spectra Energy common stock on the New York Stock Exchange, through December 31, 2008 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 3,	December 31,	
	2007	**2007**	**2008**
Spectra Energy Corp	$ 100.00	$ 95.54	$ 60.86
S&P 500 Stock Index	100.00	105.49	66.46
S&P 500 Storage & Transportation Index	100.00	114.30	56.81

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Dividends

We currently anticipate an average dividend payout ratio over time of approximately 60% of our anticipated annual net income per share of common stock. The actual payout ratio, however, may vary from year to year depending on earnings levels. The declaration and payment of dividends are subject to the sole discretion of the board of directors and depends upon many factors, including our financial condition, earnings, capital requirements of our operating subsidiaries, covenants associated with certain of our debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by our board of directors.

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.

On January 2, 2007, Duke Energy completed the spin-off of its natural gas businesses, primarily comprised of the Natural Gas Transmission and Field Services business segments of Duke Energy that were owned through Duke Energy s then wholly owned subsidiary, Spectra Capital. Spectra Capital is treated as our predecessor entity for financial statement reporting purposes. Accordingly, the information presented below for periods prior to 2007 is that of Spectra Capital. This information is not necessarily indicative of future performance or what the financial position and results of operations would have been if we had operated as a separate, stand-alone entity for periods presented prior to 2007.

	2008	2007	2006	2005	2004
	(dollars in millions, except per-share amounts)				
Statements of Operations(a)					
Operating revenues	$ 5,074	$ 4,704	$ 4,501	$ 9,412	$ 13,373
Operating income	1,480	1,426	1,234	1,844	1,308
Income (loss) from continuing operations	1,129	940	932	1,404	(719)
Net income (loss)	1,129	957	1,244	674	(114)
Ratio of Earnings to Fixed Charges	3.6	3.1	3.0	4.3	1.7
Common Stock Data					
Earnings per share from continuing operations					
Basic	$ 1.82	$ 1.48	n/a	n/a	n/a
Diluted	1.81	1.48	n/a	n/a	n/a
Earnings per share total					
Basic	1.82	1.51	n/a	n/a	n/a
Diluted	1.81	1.51	n/a	n/a	n/a
Dividends per share	0.96	0.88	n/a	n/a	n/a

			December 31,		
	2008	2007	2006	2005	2004
			(in millions)		
Balance Sheet					
Total assets	$ 21,924	$ 22,970	$ 20,345	$ 35,056	$ 37,183
Long-term debt including capital leases, less current maturities	8,290	8,345	7,726	8,790	11,288

(a) Significant transactions reflected in the results include: the transfer of certain businesses to Duke Energy in December 2006 (see Item 8. Financial Statements and Supplementary Data, Note 1 of Notes to Consolidated Financial Statements), the 2006 transfer of Duke Energy North America (DENA) Midwestern assets to Duke Energy Ohio (see Note 8), the 2006 Crescent Resources joint venture transaction and subsequent deconsolidation (see Note 8), the 2005 DENA disposition, the deconsolidation of DCP Midstream effective July 1, 2005, the 2005 DCP Midstream sale of TEPPCO, a $1,030 million 2004 tax charge as a result of a reorganization relating to Duke Energy Americas, LLC and a $360 million pre-tax loss on the 2004 DENA sale of the Southeast plants.

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

INTRODUCTION

Management s Discussion and Analysis should be read in conjunction with Item 8. Financial Statements and Supplementary Data. The Consolidated Statements of Operations and related discussions contained in this report have been re-cast to reflect the operating results of certain Western Canada Transmission & Processing natural gas gathering and processing facilities as discontinued operations for all periods presented. See Note 8 of Notes to Consolidated Financial Statements for further discussion.

EXECUTIVE OVERVIEW

Throughout 2008, we continued to successfully execute on the strategies and objectives we outlined for our shareholders. These included exceeding our earnings objectives and the successful execution on significant capital expansion plans that underlie our growth objectives.

We reported net income of $1,129 million, and $1.81 of diluted earnings per share for 2008, exceeding the employee incentive target earnings per share, primarily as a result of the positive impact of higher NGL prices in 2008, which correlate to higher crude oil prices, on the earnings from Field Services and the Empress operations. Although these commodity prices dropped dramatically in the fourth quarter of 2008, crude oil averaged $100 per barrel for 2008 versus $73 per barrel in 2007. Earnings in 2008 also reflected new capital projects in service, partially offset by higher project development costs charged to expense, an impairment of the Islander East project and higher operating costs.

We reported $2.0 billion of capital and investment expenditures for 2008, including expansion capital of $1.5 billion. We successfully completed our 2008 expansion plans, with returns on these projects expected to be slightly above 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. Expansion expenditures for 2009 are currently expected to be significantly lower than the 2008 level of spending, mainly as a result of many of the larger projects that came into service in 2008 or early 2009, as well as our continuous assessment of the timing of projected long-term market requirements and general economic conditions. Based on our current assessment, we believe that expansion expenditures will continue to support our strategic objectives.

We successfully issued approximately $1.8 billion of new long-term debt in 2008, the need for which was driven by the significant 2008 capital expansion program. As of December 31, 2008, we continue to have ongoing access to approximately $2.6 billion in credit facilities and expect to continue to utilize commercial paper and revolving lines of credit, as needed, to fund liquidity needs throughout 2009. The level of borrowings in 2009 is expected to be significantly lower than in 2008, primarily as a result of lower anticipated expansion capital expenditures in 2009 and an equity issuance in February 2009.

In May 2008, our Board of Directors approved a share repurchase program, authorizing us to purchase in the aggregate up to $600 million of shares of our outstanding common stock. This share repurchase program was completed in August 2008.

In July 2008, we declared a 9% increase in our quarterly dividend from $0.23 to $0.25 per common share. The new annualized dividend rate is $1.00 per share, representing a nearly 14% increase over the 2007 level of $0.88 per share.

On February 13, 2009, in order to further protect our capitalization structure against a potential extreme decline in the Canadian dollar, we issued 32.2 million shares of our common stock and received net proceeds of $448 million.

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Our Strategy. Our primary business objective is to provide value-added, reliable and safe services to customers, which we believe will create opportunities to deliver increased earnings and dividends per share to our shareholders. We intend to accomplish this objective by executing the following overall business strategies:

- Deliver on 2009 financial commitments.
- Enhance and solidify our profile and position as a premier natural gas infrastructure company.
- Develop new opportunities and projects that add long-term shareholder value.
- Enhance core competencies of customer service, reliability, cost management and compliance.
- Build on our high-performance culture by focusing on safety, diversity, inclusion, leadership and employee development.
- Continue to focus on the future. We must be able to quickly change course when opportunities present themselves in order to be the company of choice for investors, employees, customers, communities, governments and regulators.

Through the continued execution of these strategies, we expect to grow and strengthen the overall business, capture new growth opportunities and deliver value to our stakeholders.

2008 Financial Results. We reported income from continuing operations of $1,129 million in 2008 compared to income from continuing operations of $940 million in 2007. The increase in income from continuing operations reflects higher earnings from Distribution, Western Canada Transmission & Processing and Field Services and lower corporate costs. Highlights for 2008 include the following:

- U.S. Transmission s earnings benefited from completed expansion projects and a customer bankruptcy settlement in the second quarter of 2008. These benefits were offset by higher project development costs charged to expense, an impairment of the Islander East project in the fourth quarter of 2008, and higher operating costs.
- Distribution results reflect higher storage and transportation revenues and less fuel used in operations, partially offset by earnings sharing under the incentive regulation framework implemented in 2008.
- Western Canada Transmission & Processing earnings increased primarily as a result of higher volumes and stronger NGL prices related to the Empress NGL business.
- Field Services earnings reflect higher NGL prices, improved efficiencies, higher volumes and non-cash mark-to-market gains from hedges used to protect the distributable cash flows at DCP Midstream Partners, LP (DCP Partners), DCP Midstream s master limited partnership.

Other corporate costs were lower in 2008 as a result of 2007 costs associated with our spin-off from Duke Energy, and the favorable resolution of an insurance indemnity in 2008.

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 or sluggishness in the economy, which could affect long-term demand and market prices for natural gas and 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. However, lower overall economic output would cause a decline in the volume of natural gas transported and distributed or gathered and processed at our plants, 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 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. Processing revenues and the earnings and distributions from our Field Services segment are also affected by volumes of natural gas made

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available to our systems, which are primarily driven by levels of natural gas drilling activity. While exploration and drilling activities slowed somewhat in 2006 and 2007, overall long-term growth rates associated with our Western Canada operations increased during 2008 as a result of strong indicators of interest for continued natural gas exploration and drilling in the areas of British Columbia and Alberta that are in close proximity to our facilities. We continue to monitor these growth activities.

Our key markets the northeastern and the southeastern United States, Ontario and the Pacific Northwest are projected to continue to exhibit higher than average annual growth in natural gas demand versus the North American and U.S. Lower 48 average growth rates through 2018. 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, onshore and offshore, as well as from fields in western Canada and, more recently, eastern Canada. The national supply profile is shifting to new sources of gas from basins in the Rockies, Mid-Continent, Appalachia, and East Texas. In addition, the natural gas supply outlook includes new LNG re-gasification facilities being built. LNG will clearly be an important new source of supply, but the timing and extent of incremental supply from LNG is yet to be determined and, at present, LNG remains a small percentage of the overall supply to the markets we serve. 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.

Our businesses in the United States are subject to regulations on the federal and state level. Regulations applicable to the gas transmission and storage industry 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. From 2002 through the third quarter of 2008, the Canadian dollar strengthened significantly compared to the U.S. dollar, which favorably affected earnings and equity during these periods. However, in the fourth quarter 2008, the Canadian dollar weakened significantly in a very short period of time. Changes in this exchange rate or other of these factors are difficult to predict and may affect our future results and financial position.

Certain of our earnings are affected by fluctuations in commodity prices, especially the earnings of DCP Midstream and the Empress NGL operations in Canada. We evaluate, on an ongoing basis, the risks associated with commodity price volatility and currently do not have any plans to enter into hedge positions around these earnings.

Our overall effective income tax rate largely depends on the proportion of earnings in the United States, taxed at a 35% federal rate, to the earnings of our Canadian operations which are generally taxed at rates below 30%. Based on current projections, it is expected that our effective income tax rate on continuing operations will approximate 29 - 30% for 2009, taking into consideration the U.S. and Canadian tax jurisdictions applicable to operations.

As we execute on our strategic objectives, capital expansion projects will continue to be an important part of our growth plan. We currently anticipate capital and investment expenditures in 2009 of approximately $1.0 billion. These capital requirements, along with the refinancings of normal maturities of existing debt, will require us to continue long-term borrowings, although not at the levels experienced in 2008. An inability to access capital at competitive rates could adversely affect our ability to implement our strategy. Market disruptions, or a downgrade in our credit ratings may increase the cost of borrowing or adversely affect the ability to access one or more sources of liquidity.

During the past several years, capital expansion projects have been exposed to cost pressures associated with the availability of skilled labor and the pricing of materials. Although certain costs have begun to decrease

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in the current economic conditions, there will be continual 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.

Spin-off from Duke Energy. On January 2, 2007, Duke Energy completed the spin-off of Spectra Energy. Duke Energy contributed its natural gas businesses, primarily comprised of the Natural Gas Transmission and Field Services business segments of Duke Energy that were owned through Duke Energy s then wholly owned subsidiary, Spectra Capital. Duke Energy contributed its ownership interests in Spectra Capital to Spectra Energy and all of our outstanding common stock was distributed to Duke Energy s shareholders. Duke Energy s shareholders received one share of Spectra Energy common stock for every two shares of Duke Energy common stock, resulting in the issuance of approximately 631 million shares of Spectra Energy on January 2, 2007.

Prior to the distribution by Duke Energy, Spectra Capital implemented an internal reorganization in which the operations and assets of Spectra Capital that were not associated with the natural gas businesses were contributed by Spectra Capital to Duke Energy or its subsidiaries. The contribution to Duke Energy included the International Energy business segment, Crescent Resources (Crescent, a real estate business), the remaining portion of Spectra Capital s business formerly known as DENA (Duke Energy North America), and other miscellaneous operations.

The results of operations of substantially all of the businesses retained by Duke Energy are reflected as discontinued operations in the accompanying Consolidated Statements of Operations for 2006. Transferred corporate services entities remain presented within continuing operations.

RESULTS OF OPERATIONS

	2008	2007	2006
		(in millions)	
Operating revenues	$ 5,074	$ 4,704	$ 4,501
Operating expenses	3,636	3,291	3,314
Gains on sales of other assets and other, net	42	13	47
Operating income	1,480	1,426	1,234
Other income and expenses	844	649	736
Interest expense	636	633	605
Minority interest expense	63	62	40
Earnings from continuing operations before income taxes	1,625	1,380	1,325
Income tax expense from continuing operations	496	440	393
Income from continuing operations	1,129	940	932
Income from discontinued operations, net of tax		17	312
Net income	$ 1,129	$ 957	$ 1,244

2008 Compared to 2007

Operating Revenues. The $370 million, or 8%, increase was driven primarily by:

higher NGL prices and volumes associated with the Empress operations, expansion projects placed in service in late 2007 and the fourth quarter of 2008 at U.S. Transmission, and

growth in the number of customers, an increase in customer usage due to colder weather, and higher storage and transportation revenues primarily due to favorable market conditions and growth of the transmission system at Distribution.

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Operating Expenses. The $345 million, or 10%, increase was driven primarily by:

- higher prices and volumes of natural gas and NGLs purchased for the Empress facility,
- an increase in project development costs as a result of growth projects in 2008 and the capitalization of previously expensed costs on northeast expansions in 2007 and increased operating costs at U.S. Transmission, and
- growth in the number of customers and an increase in customer usage at Distribution.

Gain on Sales of Other Assets and Other, net. The $29 million increase was primarily due to a 2008 customer bankruptcy settlement of $27 million.

Operating Income. The $54 million increase is primarily as a result of higher NGL margins from the Empress operations, a 2008 customer bankruptcy settlement and higher earnings from expansion projects, partially offset by higher project development costs charged to expense and higher operating costs.

Other Income and Expenses. The $195 million increase primarily represents higher equity in earnings from the Field Services segment, reflecting higher commodity prices in 2008 compared to 2007.

Interest Expense. The $3 million increase reflects the successful completion of our planned debt issuances in 2008, offset by lower balances and rates on commercial paper in 2008.

Minority Interest Expense. The $1 million increase primarily resulted from earnings from Spectra Energy Partners formed in July 2007, partially offset by the purchase of the Income Fund in the second quarter of 2008.

Income Tax Expense from Continuing Operations. The $56 million increase was a result of higher earnings from continuing operations. The effective tax rate for income from continuing operations was 30.5% compared to 31.9% for the same period in 2007. The lower effective tax rate for 2008 was primarily a result of reductions in Canadian and U.S. state tax rates.

Income from Discontinued Operations, net of tax. The $17 million decrease is driven by proceeds received from a litigation settlement in 2007. This decrease also reflects the operating results of certain Western Canada Transmission & Processing natural gas gathering and processing facilities. In December 2008, we closed on the sale of our interests in these facilities.

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

2007 Compared to 2006

Operating Revenues. The $203 million, or 5%, increase was driven primarily by:

- the effects of the strong Canadian dollar on revenues at Western Canada Transmission & Processing and Distribution, and
- the growth in revenues from higher demand for transmission and storage services and expansion projects.

Operating Expenses. The $23 million decrease was driven primarily by:

the capitalization of Northeast expansion project costs initially charged to operating expense. We expense project development costs until such time as recovery of costs is determined to be probable. At that time, these costs are capitalized to property, plant and equipment and operating expenses are reduced,

a decrease in corporate costs primarily as a result of the reduced portfolio and activity of the U.S. captive insurance entity, partially offset by

the stronger Canadian dollar in 2007 compared to 2006.

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Gain on Sales of Other Assets and Other, net. The $34 million decrease was primarily due to the 2006 gains of $28 million on settlements of customers transportation contracts at U.S. Transmission.

Operating Income. The $192 million increase primarily reflects growth in revenues and lower expenses resulting from the net capitalization in 2007 of Northeast expansion project costs.

Other Income and Expenses. The $87 million decrease represents lower equity earnings from the Field Services segment and management fees we billed to certain Duke Energy operations in 2006. These were partially offset by higher equity earnings on joint ventures that resulted primarily from capitalization of previously expensed project development costs.

Interest Expense. The $28 million increase was primarily due to interest costs capitalized in 2006 related to capital projects of businesses that were transferred to Duke Energy.

Minority Interest Expense. The $22 million increase primarily resulted from higher earnings on Maritimes & Northeast Pipeline, the formation in July 2007 of Spectra Energy Partners and a decrease in the ownership of the operations of the Income Fund in the third quarter of 2006.

Income Tax Expense from Continuing Operations. The $47 million increase was a result of higher earnings from continuing operations in 2007 and tax benefits recorded in 2006. The effective tax rate was 31.9% for 2007 compared to 29.7% for the same period in 2006. The lower effective tax rate in 2006 resulted from a reduction in the unitary state tax rate as a result of Duke Energy s merger with Cinergy Corp (Cinergy) and a 2006 tax benefit related to the impairment of an international investment no longer owned by us.

Income from Discontinued Operations, net of tax. Income from discontinued operations, net of tax was $17 million for 2007 and $312 million for 2006. These amounts primarily represent results of operations and gains (losses) on dispositions related to DENA s assets and contracts outside the Midwestern and Southeastern United States, which are included in Other, as well as the operations of International Energy and our effective 50% interest in Crescent, and a number of businesses previously included in Other, which are classified in discontinued operations as a result of transferring these businesses from Spectra Energy to Duke Energy in December 2006.

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

Segment Results

We evaluate segment performance based on earnings before interest and taxes from continuing operations (EBIT), after deducting minority interest expense related to those profits. On a segment basis, EBIT excludes discontinued operations, represents all profits from continuing operations (both operating and non-operating) before deducting interest and taxes, and is net of the minority interest expense related to those profits. Cash, cash equivalents and investments are managed centrally, so the gains and losses on foreign currency remeasurement, and interest and dividend income on those balances, are excluded from the segments EBIT. We consider segment EBIT to be a good indicator of each segment s operating performance from its continuing operations, as it represents the results of our ownership interest in operations without regard to financing methods or capital structures.

U.S. Transmission provides transportation and storage of natural gas for customers in various regions of the northeastern and southeastern United States and the Maritime Provinces in Canada.

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

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

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Field Services gathers and processes natural gas, and fractionates, markets and trades NGLs. It conducts operations through DCP Midstream, which is owned 50% by us and 50% by ConocoPhillips. Field Services gathers raw natural gas through gathering systems located in nine major 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.

Our segment EBIT may not be comparable to a similarly titled measure of another company because other entities may not calculate EBIT in the same manner. Segment EBIT is summarized in the following table and detailed discussions follow.

EBIT by Business Segment

	2008	2007	2006
		(in millions)	
U.S. Transmission	$ 844	$ 894	$ 816
Distribution	353	322	265
Western Canada Transmission & Processing	398	359	339
Field Services	716	533	569
Total reportable segment EBIT	2,311	2,108	1,989
Other	(78)	(112)	(77)
Total reportable segment and other EBIT	2,233	1,996	1,912
Interest expense	636	633	605
Interest income and other(a)	28	17	18
Consolidated earnings from continuing operations before income taxes	$ 1,625	$ 1,380	$ 1,325

(a) Other includes foreign currency transaction gains and losses and additional minority interest expense not allocated to the segment results. Minority interest expense as presented in the following segment-level discussions includes only minority interest expense related to EBIT of non-wholly owned entities. It does not include minority interest expense related to interest and taxes of those operations. The amounts discussed below include intercompany transactions that are eliminated in the consolidated financial statements.

U.S. Transmission

	2008	2007	Increase (Decrease)	2006	Increase (Decrease)
			(in millions, except where noted)		
Operating revenues	$ 1,600	$ 1,540	$ 60	$ 1,503	$ 37
Operating expenses					
Operating, maintenance and other	595	473	122	544	(71)
Depreciation and amortization	232	217	15	203	14
Gains on sales of other assets and other, net	42	8	34	44	(36)
Operating income	815	858	(43)	800	58
Other income and expenses	86	85	1	44	41
Minority interest expense	57	49	8	28	21
EBIT	$ 844	$ 894	$ (50)	$ 816	$ 78

Proportional throughput, TBtu(a)	2,218	2,202	16	1,930	272

(a) Revenues are not significantly affected by pipeline throughput fluctuations, since revenues are primarily composed of demand charges.

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2008 Compared to 2007

Operating Revenues. The $60 million increase was driven primarily by:

- a $69 million increase from expansion projects placed in service in late 2007 and the fourth quarter of 2008, partially offset by
- an $8 million decrease in processing revenues associated with pipeline operations, primarily from lower volumes, partially offset by higher prices.

Operating, Maintenance and Other. The $122 million increase was driven primarily by:

- a $60 million increase in project development costs, reflecting expensed project development costs of $43 million in 2008 and a net benefit of $17 million in 2007 due to the capitalization of previously expensed costs on northeast expansions during that period,
- a $39 million increase in operating costs including fuel, utilities, equipment repairs and software costs,
- a $12 million increase in ad valorem taxes primarily as a result of favorable property valuations in certain states and business expansion projects placed in service in late 2007, and
- a $12 million increase due to an impairment of Algonquin s Islander East project costs caused by adverse legal rulings and unfavorable economic conditions.

Depreciation and Amortization. The $15 million increase was primarily driven by expansion projects placed into service in late 2007.

Gains on Sales of Other Assets and Other, net. The $34 million increase primarily reflects a customer bankruptcy settlement in 2008.

Other Income and Expenses. The $1 million increase was primarily a result of higher equity income from unconsolidated affiliates attributable to the capitalization of interest on construction projects and lower project development costs charged to expense, both of which are primarily for the SESH project, offset by a $32 million impairment of the Islander East project.

Minority Interest Expense. The $8 million increase was driven primarily by earnings from Spectra Energy Partners formed in July 2007.

EBIT. The $50 million decrease was primarily due to an impairment of the Islander East project caused by adverse legal rulings and unfavorable economic conditions, development costs charged to expense and increased operating costs. These decreases were partially offset by higher earnings from expansion projects and a gain on a customer bankruptcy settlement.

2007 Compared to 2006

Operating Revenues. The $37 million increase was driven by:

- a $32 million increase from higher demand for pipeline and storage services, primarily attributable to higher volumes and rates on Maritimes & Northeast Pipeline, and a $21 million increase from expansion projects that were placed in service in 2006 and 2007, partially offset by

a $15 million decrease in processing revenues associated with pipeline operations, primarily from lower volumes compared to the 2006 period when utilization of the facilities was higher than normal due to hurricane effects.

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Operating, Maintenance and Other. The $71 million decrease was driven by:

- a $41 million decrease in project development costs charged to operations as a result of lower development costs incurred in 2007 and increased capitalization of Northeast expansion project costs in the 2007 period compared to 2006. In 2007, U.S. Transmission recognized a net reduction in operating expenses of $17 million, representing net development costs capitalized during that period, while 2006 included net project development costs of $24 million in operating expenses,
- a $14 million decrease in operating costs primarily associated with lower plant processing fees as a result of a renegotiated contract,
- a $12 million decrease in ad valorem taxes primarily as a result of favorable property valuations in certain states, and
- an $11 million decrease resulting from higher recoveries of pipeline compressor fuel by the East Tennessee pipeline, partially offset by
- a $16 million increase from higher labor and outside services costs for pipeline and storage operations.

Depreciation and Amortization. The $14 million increase was primarily driven by expansion projects placed into service in late 2006 and in 2007, an increase in the depreciation rate on Maritimes & Northeast Pipeline as part of a negotiated toll settlement that was effective on January 1, 2007, and Canadian dollar exchange effects on Maritimes & Northeast Pipeline (Canada) depreciation.

Gains on Sales of Other Assets and Other, net. The $36 million decrease was primarily due to a $28 million gain on the settlement of a customer s transportation contracts in 2006.

Other Income and Expenses. The $41 million increase was a result of higher equity earnings from unconsolidated affiliates primarily attributable to the capitalization of project development costs for the SESH and Gulfstream Phase IV projects.

Minority Interest Expense. The $21 million increase was driven primarily by higher revenues on Maritimes & Northeast Pipeline and earnings from Spectra Energy Partners.

EBIT. The $78 million increase was primarily due to strong revenues in all pipeline and storage businesses, attributable to high demand for services, increased revenues from in-service expansion projects, and the capitalization of previously expensed development costs, partially offset by a gain on the settlement of a customer s transportation contracts in 2006.

Matters Affecting Future U.S. Transmission Results

U.S. Transmission 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. 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, the ability to continue renewing service contracts and continued regulatory stability. NGL prices will continue to affect processing revenues that are associated with transportation services.

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Distribution

	2008	2007	Increase (Decrease)	2006	Increase (Decrease)
			(in millions, except where noted)		
Operating revenues	$ 1,991	$ 1,899	$ 92	$ 1,822	$ 77
Operating expenses					
Natural gas purchased	1,094	1,059	35	1,091	(32)
Operating, maintenance and other	372	361	11	322	39
Depreciation and amortization	175	162	13	144	18
Gains on sales of other assets and other, net		5	(5)		5
Operating income	350	322	28	265	57
Other income and expenses	3		3		
EBIT	$ 353	$ 322	$ 31	$ 265	$ 57
Number of customers, thousands	1,309	1,289	20	1,268	21
Heating degree days, Fahrenheit	7,491	7,070	421	6,489	581
Pipeline throughput, TBtu	900	844	56	736	108

2008 Compared to 2007

Operating Revenues. The $92 million increase was driven primarily by:

- a $43 million increase due to growth in the number of customers primarily as a result of increased residential customer attachments,
- a $39 million increase in storage and transportation revenues primarily due to favorable market conditions and growth of the transmission system,
- a $33 million increase in customer usage of natural gas due to colder weather, and
- a $14 million increase resulting from a stronger Canadian dollar, partially offset by
- a $14 million decrease as a result of earnings sharing under the incentive regulation framework implemented in 2008,
- a $15 million decrease due to an unfavorable decision from the OEB on unregulated storage revenues in 2008, and
- an $8 million decrease from lower natural gas prices passed through to customers without a mark-up.

Natural Gas Purchased. The $35 million increase was driven primarily by:

a $40 million increase due to growth in the number of customers primarily as a result of increased residential customer attachments, and

a $28 million increase in customer usage of natural gas due to colder weather, partially offset by

a $23 million decrease related to fuel used in operations, and

an $8 million decrease related to lower natural gas prices passed through to customers without a mark-up.

Operating, Maintenance and Other. The $11 million increase was driven primarily by higher payroll and contractor costs partially offset by lower pension costs.

Depreciation and Amortization. The $13 million increase was due to a higher asset base resulting primarily from completion of Phase II of the Dawn-Trafalgar expansion of the transmission system.

Gains on Sales of Other Assets and Other, net. The $5 million decrease was due to a gain on the sale of land in 2007.

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EBIT. The $31 million increase was primarily attributable to higher storage and transportation revenues and less fuel used in operations, partially offset by earnings sharing under the incentive regulation framework implemented in 2008.

2007 Compared to 2006

Operating Revenues. The $77 million increase was driven by:

- a $144 million increase in customer usage of natural gas primarily associated with winter weather that was approximately 9% colder than the previous year,
- a $92 million increase caused by a stronger Canadian dollar,
- a $21 million increase in storage and transmission revenues primarily due to favorable market conditions and growth of the transmission system,
- a $19 million increase due to higher distribution rates approved by the regulator, and
- a $12 million increase as a result of an earnings sharing requirement in 2006, partially offset by
- a $213 million decrease from lower natural gas prices passed through to customers without a mark-up.

Natural Gas Purchased. The $32 million decrease resulted from:

- a $213 million decrease related to lower natural gas prices passed through to customers, partially offset by
- a $111 million increase in customer usage of natural gas associated with colder winter weather than the previous year,
- a $49 million increase caused by Canadian dollar exchange effects, and
- a $24 million increase related to gas volumes used in operations.

Operating, Maintenance & Other. The $39 million increase was driven primarily by:

- a $22 million increase caused by Canadian dollar exchange effects, and
- a $13 million increase in labor costs.

Depreciation and Amortization. The $18 million increase was primarily driven by completion of Phase I of the Dawn-Trafalgar transmission system expansion and Canadian dollar exchange effects.

EBIT. The $57 million increase primarily resulted from higher gas distribution margins, favorable storage market conditions and a stronger Canadian dollar, partially offset by higher operating and gas costs.

Matters Affecting Future Distribution Results

We expect that the long-term demand for natural gas in North America will continue to grow. However, given the current economic recession, we expect retail and industrial gas usage by Distribution s customers to decrease in 2009 and 2010. The extent of these demand reductions is dependent on the length and the extent of the current economic downturn.

Distribution s earnings are affected significantly by weather during the winter heating season. From 2002 through the third quarter of 2008, the Canadian dollar strengthened significantly compared to the U.S. dollar, which favorably affected earnings during these periods. However in the fourth quarter 2008, the Canadian dollar weakened significantly in a very short period of time. In addition, changes in the exchange rate are difficult to predict and may affect future results. As with all of our regulated entities, regulatory changes may affect future earnings.

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In January 2008, a multi-year incentive rate structure became effective for Union Gas. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The allowed return on equity (ROE) for Union Gas is formula-based and is periodically established by the OEB. The established ROE for 2008 will remain unchanged throughout the five-year incentive regulation period (2008-2012). The incentive regulation framework includes a provision for a review of the pricing mechanism contained in that framework. That review is triggered if there is a variance of 3% or more between Union Gas actual utility ROE as normalized for weather and the utility ROE determined by the OEB. Union Gas weather-normalized utility ROE for 2008 exceeded the upper review threshold, and accordingly, Union Gas will file for a review by the OEB. Changes to the incentive regulation parameters by the OEB could affect Union Gas future earnings. While we cannot estimate what changes might occur, we currently expect that the changes will not have a material effect on our consolidated future earnings, financial position or cash flows.

Western Canada Transmission & Processing

	2008	2007	Increase (Decrease)	2006	Increase (Decrease)
			(in millions, except where noted)		
Operating revenues	$ 1,482	$ 1,266	$ 216	$ 1,173	$ 93
Operating expenses					
Natural gas and petroleum products purchased	496	361	135	349	12
Operating, maintenance and other	445	405	40	380	25
Depreciation and amortization	147	135	12	126	9
Operating income	394	365	29	318	47
Other income and expenses	5		5	26	(26)
Minority interest expense	1	6	(5)	5	1
EBIT	$ 398	$ 359	$ 39	$ 339	$ 20
Pipeline throughput, TBtu	615	596	19	594	2
Volumes processed, TBtu	698	709	(11)	730	(21)
Empress inlet volumes, TBtu	820	722	98	811	(89)

2008 Compared to 2007

Operating Revenues. The $216 million increase was driven primarily by:

- a $155 million increase primarily due to stronger NGL sales prices and higher volumes associated with the Empress operations. The higher volumes were a result of successful marketing efforts for NGL extraction rights in 2008, as well as a plant maintenance turnaround which reduced inlet volumes for a period during 2007.

- a $25 million increase mainly due to higher sales prices and processing volumes in the Pine River area of northeastern BC. The higher volumes were as a result of new contracts in 2008 and a plant maintenance turnaround that caused the plant to be unavailable for processing during this period in 2007.

- an $18 million increase resulting from a stronger Canadian dollar, and

- an $8 million increase in carbon tax revenue as levied by the BC government effective July 1, 2008 that is recoverable from customers.

Natural Gas and Petroleum Products Purchased. The $135 million increase was driven primarily by higher prices and volumes of natural gas and NGLs purchased for the Empress facility.

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Operating, Maintenance and Other. The $40 million increase was driven primarily by:

- an $18 million increase due to higher labor and benefit costs, as well as higher maintenance costs related to year over year price escalations,
- a $12 million increase in plant fuel and electricity costs at the Empress facility, and
- an $8 million increase in carbon tax expense offsetting the carbon tax revenue.

Depreciation and Amortization. The $12 million increase was driven primarily by increased pipeline depreciation rates as a result of a rate settlement with customers.

Other Income and Expenses. The $5 million increase was driven primarily by higher equity earnings from the McMahon cogeneration facility due to increased gas sales and electricity revenue in 2008, as well as the negative mark-to-market impact of the McMahon gas contract hedge during the fourth quarter of 2007 prior to this position being designated as a cash flow hedge.

Minority Interest Expense. The $5 million decrease was driven primarily by the purchase of the Income Fund in the second quarter of 2008. Prior to the acquisition, the Income Fund indirectly held 54% of Spectra Energy s consolidated Midstream operations and Westcoast indirectly held the remaining 46%.

EBIT. The $39 million increase was driven primarily by higher NGL prices and volumes that benefited the Empress operations, higher processing revenues and a stronger Canadian dollar. These increases were partially offset by higher operating expenses, including higher plant fuel and electricity costs.

2007 Compared to 2006

Operating Revenues. The $93 million increase was driven by:

- an $81 million increase caused by the strengthening Canadian dollar in 2007, and
- a $33 million increase due to higher NGL prices associated with the Empress operations, partially offset by lower NGL sales volumes, mainly as a result of a plant maintenance turnaround in 2007, partially offset by,
- an $18 million decrease resulting from lower processing volumes in the Fort Nelson area of northeastern British Columbia.

Natural Gas and Petroleum Products Purchased. The $12 million increase included:

- a $21 million increase caused by Canadian dollar exchange effects in 2007, partially offset by
- a $10 million decrease from lower volumes of natural gas purchased for the Empress facility, mainly as a result of a plant maintenance turnaround in 2007.

Operating, Maintenance and Other. The $25 million increase was driven by:

a $25 million increase caused by Canadian dollar exchange effects in 2007, and

an $8 million increase due to higher plant maintenance turnaround costs in 2007 (Empress and Pine River) compared to 2006 (Fort Nelson), partially offset by

a $6 million decrease in plant fuel costs at the Empress facility, mainly as a result of a plant maintenance turnaround in 2007.

Depreciation and Amortization. The $9 million increase was driven primarily by Canadian dollar exchange effects in 2007.

Other Income and Expenses and Other, net. The 2006 amount included a $15 million gain resulting from the Income Fund s issuance of units for the purchase of Westcoast Gas Services Inc.

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Minority Interest Expense. The $1 million increase was driven primarily by the decrease in the ownership of the operations of the Income Fund in the third quarter of 2006, from 58% to 46%, when additional trust units were sold by the Income Fund.

EBIT. The $20 million increase resulted from higher NGL prices and Canadian dollar exchange effects partially offset by lower natural gas processing volumes, and the 2006 gain resulting from the sale of Income Fund units.

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 to support drilling activity in northern British Columbia. Earnings will also continue to benefit through optimizing the performance of the existing system and through organizational efficiencies. Earnings can fluctuate from period-to-period as a result of the timing of processing plant turnarounds that reduce revenues while the plant is out of service and increase operating costs as a result of the turnaround maintenance work. Western Canada Transmission and Processing s 17 processing plants are generally scheduled for turnaround work every two to three years, with the work being staggered to prevent significant outages at any given time in a single geographic area. In addition, future earnings will 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 both gas flows and the effects of natural gas and NGL commodity prices.

From 2002 through the third quarter of 2008, the Canadian dollar strengthened significantly compared to the U.S. dollar, which has favorably affected earnings during these periods. However in the fourth quarter 2008, the Canadian dollar weakened significantly in a very short period of time. Changes in the exchange rate or any other factors are difficult to predict and may affect future results.

During the period 2004 through 2006, Western Canada experienced historic levels of natural gas drilling activity. While exploration and drilling activities slowed somewhat in certain of our Western Canadian business areas in 2006 and 2007, overall long-term growth rates associated with our Western Canada operations increased during 2008 as a result of strong indicators of interest for continued natural gas exploration and drilling in the areas of British Columbia and Alberta that are in close proximity to our facilities. In addition, although the actual effects will not be known for some time, the Alberta government s recently announced New Royalty Framework, which was effective January 1, 2009, could affect certain of our Alberta operations. The operations in British Columbia could be positively affected by this change in royalties if producers reduce drilling in Alberta and increase drilling in British Columbia. We continue to believe that low-to-moderate growth in Western Canada is reasonable over the long-term.

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Field Services

	2008	2007	Increase (Decrease)	2006	Increase (Decrease)
		(in millions, except where noted)			
Operating expenses				5	(5)
Operating loss				(5)	5
Equity in earnings of unconsolidated affiliates	716	533	183	574	(41)
EBIT	$ 716	$ 533	$ 183	$ 569	$ (36)
Natural gas gathered and processed/transported, TBtu/d(a,b)	7.1	6.8	0.3	6.8	
NGL production, MBbl/d(a,c)	360	363	(3)	361	2
Average natural gas price per MMBtu(d)	$ 9.03	$ 6.86	$ 2.17	$ 7.23	$ (0.37)
Average NGL price per gallon(e)	$ 1.23	$ 1.11	$ 0.12	$ 0.94	$ 0.17

(a) Reflects 100% of volumes
(b) Trillion British thermal units per day
(c) Thousand barrels per day
(d) Million British thermal units. Average price based on NYMEX Henry Hub
(e) Does not reflect results of commodity hedges

2008 Compared to 2007

EBIT. Higher equity in earnings of $183 million was primarily the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

a $175 million increase from commodity-sensitive processing arrangements, due to increased commodity prices,

a $22 million increase in earnings from DCP Midstream Partners, primarily as a result of mark-to-market gains on hedges used to protect distributable cash flows,

a $20 million increase in gathering and processing margins primarily attributable to increased natural gas and NGL volumes and improved efficiencies in non-weather impacted areas and contract yields, partially offset by hurricane and adverse weather events,

a $9 million increase in marketing margins related to timing, and

a $6 million increase in other income, which is primarily due to gains on the sale of assets in the fourth quarter 2008, partially offset by

a $36 million decrease resulting from higher depreciation expense and increased operating and maintenance expenses due to growth and asset acquisitions, partially offset by decreased general and administrative costs as a result of $12 million of costs in 2007 associated with DCP Midstream s initiative to create stand alone corporate functions separate from its two partners, and

a $22 million decrease due to higher net interest expense resulting from the increased debt associated with acquisitions in 2007 and 2008.

2007 Compared to 2006

EBIT. Lower equity in earnings of $36 million was primarily the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

a $60 million decrease in marketing margins, including a $39 million loss on hedges related to commodity non-trading activity that were executed by DCP Midstream Partners,

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a $59 million decrease in gathering and processing margins attributable to decreased natural gas and NGL volumes, primarily from the effects of severe weather, including downtime for repairs, as well as an increase in plant inefficiencies and contract renegotiations at less favorable terms,

a $56 million decrease resulting from higher operating costs of $24 million, administrative costs of $16 million and depreciation costs of $16 million primarily attributable to asset acquisitions, industry price pressures on materials, contract services and labor and higher repairs and maintenance costs, including $12 million in costs associated with DCP Midstream s initiative to create stand-alone corporate functions,

an $18 million decrease due to higher net interest expense resulting from the increased debt associated with acquisitions in 2007,

a $14 million decrease as a result of a gain on the sale of gathering assets during 2006, and

a $9 million decrease resulting from decreased physical volume related to natural gas asset based trading and marketing, partially offset by

a $156 million increase from commodity sensitive processing arrangements due to increased commodity prices,

a $15 million increase attributable to lower minority interest expense as a result of lower earnings at DCP Midstream Partners, and

a $6 million increase as a result of lower income tax expense primarily due to a 2006 adjustment to establish deferred tax liabilities for the new Texas margin tax.

Supplemental Data

Below is supplemental information for DCP Midstream s operating results:

	Years Ended December 31,		
	2008	2007	2006
		(in millions)	
Operating revenues	$ 16,398	$ 13,154	$ 12,335
Operating expenses	14,704	11,959	11,063
Operating income	1,694	1,195	1,272
Other income and expenses	(68)	44	5
Interest expense, net	198	154	119
Income tax expense (benefit)	(3)	11	23
Net income	$ 1,431	$ 1,074	$ 1,135

Matters Affecting Future Field Services Results

Field Services, through its 50% investment in DCP Midstream, has developed significant size and scope in natural gas gathering, processing and NGL marketing and plans to focus on operational excellence and organic growth (growth due to the expansion or optimization of existing assets). DCP Midstream s revenues and expenses are significantly dependent on prevailing commodity prices for NGLs and natural gas, and past and current trends in price changes of these commodities may not be indicative of future trends. DCP Midstream anticipates that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather and the level of worldwide economic growth. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could reduce North American drilling activity in the future. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would have a negative effect on natural gas volumes gathered and processed, but would likely increase commodity prices. DCP Midstream believes that an increase in United States drilling activity, additional sources of supply such as LNG, and imports of natural gas will be required for the natural gas industry to meet an expected

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increased demand for, and to compensate for the declining production of, natural gas in the United States. A number of the areas in which DCP Midstream operates have seen significant drilling activity, new drilling for deeper natural gas formations and the implementation of new exploration and production techniques to tap non-conventional resources. Although the prevailing price of residue natural gas has less short-term significance to its operating results than the price of NGLs, in the long term, the growth and sustainability of DCP Midstream s business depends on natural gas prices being at levels sufficient to provide incentives and capital for producers to increase natural gas exploration and production. Future equity in earnings of DCP Midstream will continue to be sensitive to commodity prices that have historically been cyclical and volatile. There are many important factors that could cause actual results to differ materially from the expectations expressed, including but not limited to future commodity prices, drilling activity, inflation and the effects of severe weather. We can provide no assurances regarding the effect of these factors.

Other

	2008	2007	Increase (Decrease)	2006	Increase (Decrease)
			(in millions)		
Operating revenues	$ 45	$ 31	$ 14	$ 29	$ 2
Operating expenses	125	150	(25)	175	(25)
Gains on sales of other assets and other, net				2	(2)
Operating loss	(80)	(119)	39	(144)	25
Other income and expenses, net	2	7	(5)	67	(60)
EBIT	$ (78)	$ (112)	$ 34	$ (77)	$ (35)

2008 Compared to 2007

EBIT. The $34 million increase was primarily due to $23 million of costs associated with the spin-off of Spectra Energy in 2007 and the favorable resolution of an insurance indemnity for $8 million in 2008.

2007 Compared to 2006

EBIT. The $35 million decrease was primarily due to management fees earned from a Duke Energy affiliate in 2006 partially offset by 2006 net hedge losses associated with the Field Services segment and lower 2007 net corporate costs.

Matters Affecting Future Other Results

Future Other 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 impacted by the number and severity of insured property losses, particularly during hurricane season.

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 various assumptions that we believe are reasonable at the time of application. The estimates and judgments may change as time passes and more information becomes available. If estimates and judgments 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.

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Regulatory Accounting

We account for certain of our regulated operations under the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation. As a result, we record assets and liabilities that result from the regulated ratemaking process that would not be recorded under generally accepted accounting principles (GAAP) 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 for previous collections for costs that either are not likely to or have yet to be incurred. 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 continual assessment, we believe the existing regulatory assets 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, asset write-offs would be required to be recognized in operating income. 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 $862 million as of December 31, 2008 and $889 million as of December 31, 2007. Total regulatory liabilities were $452 million as of December 31, 2008 and $568 million as of December 31, 2007.

We recorded a $44 million charge in the fourth quarter of 2008 representing our share of impaired assets associated with the Islander East pipeline project. Triggered by certain fourth quarter 2008 legal and economic events, costs associated with this project were evaluated pursuant to SFAS No. 71 as to probability of recovery under FERC-approved tariff rates associated with any future alternative project plan. See Note 11 of the Notes to Consolidated Financial Statements for further discussion.

Impairment of Goodwill

We had goodwill balances of $3,381 million at December 31, 2008 and $3,948 million at December 31, 2007. The reduction in goodwill in 2008 was primarily the result of foreign currency translation. There was no impairment of goodwill recorded during 2008. We evaluate for the impairment of goodwill under SFAS No. 142, Goodwill and Other Intangible Assets. The majority of our goodwill relates to the acquisition of Westcoast in March 2002, which owns the majority 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 required by SFAS No. 142, we perform an annual goodwill impairment test and update the test if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying amount. Key assumptions used in the analysis include, but are not limited to, the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected growth rates, regulatory stability, the ability to renew contracts, and foreign currency exchange rates, as well as other factors that affect our revenue and expense forecasts.

The long-term cash flows and resulting reporting unit values of our Western Canada gathering and processing operations remain sensitive to projected growth rate assumptions. While exploration and drilling activities slowed somewhat in 2006 and 2007, overall long-term growth rates associated with these Western Canada operations increased during 2008 as a result of strong indicators of interest for continued natural gas exploration and drilling in the areas of British Columbia and Alberta that are in close proximity to our facilities. We continue to monitor these growth activities.

We are also monitoring the effects of the economic downturn and equity market declines that have occurred in recent months. If these conditions continue over the long-term, these factors could increase the long-term cost of capital utilized to calculate reporting unit fair values. Any such increase would primarily affect our BC Pipeline unit in Western Canada and our Distribution segment. However, if an increase in the cost of capital occurred, the effect on reporting unit fair values would be ultimately offset by a similar increase in these units regulated revenues since those rates include a component that is based on the units cost of capital.

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Revenue Recognition

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

Pension and Other Post-Retirement Benefits

The calculations of pension and other post-retirement expense and liabilities require the use of numerous assumptions. Changes in these assumptions can result in different reported expense and liability amounts, and future actual experience can differ from the assumptions. We believe that the most critical assumptions for pension and other post-retirement benefits are the expected long-term rate of return on plan assets and the assumed discount rate. 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. The discount rate for our U.S. pension plan purposes is developed from yields on available high-quality bonds and reflects the plan s expected cash flows. For our Canadian pension plans, the discount rate is the yield on Canadian corporate AA bonds with cash flows that match the timing and amount of the expected benefit payments under the plan. In addition, medical and prescription drug cost trend rate assumptions are critical for other post-retirement benefits.

Capital market declines experienced during the last half of 2008 have adversely impacted the market value of investment assets used to fund Spectra Energy s defined benefit employee retirement plans. See further discussion of the expected impact of these changes under Market Risk. 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 liabilities.

LIQUIDITY AND CAPITAL RESOURCES

Known Trends and Uncertainties

We will rely primarily upon cash flows from operations and additional financing transactions to fund our liquidity and capital requirements for 2009. As of December 31, 2008, we had negative working capital of approximately $1,594 million. This balance includes short-term borrowings and commercial paper totaling $936 million and current maturities of long-term debt of $821 million which we expect to refinance during 2009. We also have access to four revolving credit facilities, with total combined capacities of approximately $2.6 billion. These facilities will be used principally as back-stops for commercial paper programs.

Cash flows from operations for our businesses are fairly stable given that over 80% of revenues are derived from regulated operations that primarily represent fee-based services. However, these 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, and the timing of associated regulatory cost recovery approval. See Part I, Item 1A. Risk Factors for further discussion.

Commercial paper markets in the U.S. and Canada have recently experienced varying degrees of credit volatility and contraction that has limited the demand for and reduced our ability to issue commercial paper. This volatility has been caused by many factors, including concerns about creditworthiness in the overall market, especially the financial services sector, which has culminated in the failure or consolidation of several large financial and investment institutions. During this credit contraction, we have been able to issue commercial paper or draw on our committed and available credit facilities in amounts sufficient to fund liquidity needs. Our commercial paper borrowings are not asset-backed nor are they related to real estate financing, the two sectors facing the most severe credit contraction.

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Capital market declines experienced during the last half of 2008 have adversely impacted the market value of investment assets used to fund our defined benefit employee retirement plans. However, based on December 31, 2008 valuations, we do not currently expect to make significantly higher contributions in 2009 to the plans. If the market value of these assets does not improve during 2009, higher levels of contributions would be required in 2010 and beyond.

As we execute on our strategic objectives around organic growth and expansion projects, expansion expenditures could range from $500 million to $1 billion per year over the next few years. The timing and extent of these expenditures are likely to vary significantly from year to year, depending primarily on general economic conditions and market requirements. Given that we expect to continue to pursue expansion opportunities over the next several years and also given the normal scheduled maturities of our existing debt instruments, capital resources will continue to include significant long-term borrowings. The level of borrowings in 2009, however, is expected to be significantly lower than the 2008 borrowings of $1.8 billion. This is primarily a result of lower expansion capital levels of approximately $0.5 billion expected in 2009 compared with $1.5 billion in 2008. We remain committed to maintaining a capital structure and liquidity profile that continues to support an investment-grade credit rating. As part of this commitment and in response to the risks to our capital structure that would be posed by the further weakening of the Canadian dollar, on February 13, 2009, we issued 32.2 million shares of our common stock and received net proceeds of $448 million. We continue to monitor market requirements and our available liquidity and will make adjustments to these long-term plans as needed.

Operating Cash Flows

Net cash provided by operating activities increased $338 million to $1,805 million in 2008 compared to 2007. This change was driven primarily by:

- an increase of $208 million in distributions received from unconsolidated affiliates in 2008, primarily from DCP Midstream, and
- a January 2007 payment of $100 million, which was accrued at December 31, 2006, to resolve certain litigation matters associated with discontinued LNG operations.

Net cash provided by operating activities increased $773 million to $1,467 million in 2007 compared to 2006. This change was driven primarily by:

- a $600 million payment to Barclays in 2006 in connection with the sale of certain commodity, energy marketing and management contracts of DENA,
- approximately $400 million of net settlement cash outflows in 2006 related to remaining DENA contracts, and
- capital expenditures of $322 million in 2006 for residential real estate, partially offset by
- collateral of $540 million received in 2006 from Barclays, and
- net payments in 2007 of $82 million to resolve certain litigation matters associated with discontinued LNG operations.

Investing Cash Flows

Net cash flows used in investing activities increased $344 million to $1,888 million in 2008 compared to 2007. This change was driven primarily by:

a $543 million increase in capital and investment expenditures and loans to unconsolidated affiliates in 2008 as a result of expansion projects underway, primarily at U.S. Transmission, and

the $274 million acquisition on May 1, 2008 of the units of the Income Fund that were held by non-affiliated holders, partially offset by

- a net increase of $269 million in proceeds from the sales and maturities of available-for-sale securities primarily at Spectra Energy Partners,
- increased returns of capital, primarily from DCP Midstream, of $131 million in 2008, and
- an increase of $90 million in net proceeds from the sales of other assets, primarily the sale of the Nevis and Brazeau plants in December 2008.

Net cash flows used in investing activities totaled $1,544 million in 2007 compared to net cash flows provided by investing activities of $1,569 million in 2006. This $3,113 million decrease was driven primarily by:

- approximately $2.0 billion in proceeds received in 2006 from the sales of equity investments and other assets, primarily the sale of DENA assets and an interest in Crescent,
- a $672 million increase in capital and investment expenditures in 2007 associated with the U.S. Transmission, Distribution and Western Canada Transmission & Processing segments,
- net purchases of available-for-sale securities of $145 million in 2007 compared to net sales of $485 million in 2006, and
- proceeds totaling $254 million in the 2006 period from real estate sales activity of operations transferred to Duke Energy in December 2006, partially offset by
- capital expenditures of $695 million in 2006 associated with the operations that were transferred to Duke Energy.

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.

	2008	2007	2006
		(in millions)	
Capital and Investment Expenditures			
U.S. Transmission	$ 1,400	$ 898	$ 343
Distribution	373	369	315
Western Canada Transmission & Processing	222	195	132
International Energy			58
Crescent(a)			185
Other	35	39	130
Total consolidated	$ 2,030	$ 1,501	$ 1,163

(a) Amounts exclude capital expenditures associated with residential real estate of $322 million for the period from January 1, 2006 through September 7, 2006, the date of the deconsolidation of Crescent.

Capital and investment expenditures for 2008 totaled $2,030 million and included $1,503 million for expansion projects and $527 million for maintenance and other projects. We project 2009 capital and investment expenditures of approximately $1.0 billion, consisting of approximately $0.4 billion for U.S. Transmission, $0.2 billion for Distribution and $0.4 billion for Western Canada Transmission & Processing. Total projected 2009 capital and investment expenditures include approximately $0.5 billion of expansion capital expenditures and $0.5 billion for maintenance and upgrades of existing plants, pipelines and infrastructure to serve growth. As previously discussed, we will continue to assess short and long-term market requirements and will adjust our capital plans as required.

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Expansion capital expenditures included several key projects placed into service in 2008 and early 2009, such as: SESH, our 50%-owned, 274-mile natural gas pipeline system that extends from northeastern Louisiana to Alabama; the Maritimes & Northeast Phase IV project, an expansion of capacity of the existing U.S. portion of the Maritimes & Northeast Pipeline; Ramapo, an Algonquin capacity expansion; and Gulfstream s Phase III and Phase IV projects, which included additional pipeline and increased compression.

Significant 2009 expansion project expenditures are expected to include:

Time III Expansion of Texas Eastern pipeline system from Oakford, Pennsylvania to an eastern Pennsylvania interconnection with a major interstate pipeline to transport an additional 60 million cubic feet per day (MMcf/d) of natural gas. In-service anticipated in 2010.

TEMAX Expansion of Texas Eastern pipeline system from Clarington, Ohio to an eastern Pennsylvania interconnection with a major interstate pipeline. Incremental transportation of 395 MMcf/d of natural gas, with anticipated in-service in 2010.

South Peace Pipeline 60 miles of gathering line which will deliver 220 MMcf/d of raw gas to our McMahon gas plant in British Columbia. In-service is anticipated to be in late 2009.

Market Hub Storage A multi-phase plan to increase the Egan and Moss Bluff facilities combined capacity to 54 Bcf. These projects will expand working capacity by 15 Bcf through cavern leaching, additional loop line and meter facilities. Partial in-service is anticipated to be in late 2009, with final in-service anticipated to be in 2011.

West Doe 75 MMcf/d expansion of our existing West Doe gas processing facility in the Peace River Arch region of northeast British Columbia. In-service dates are anticipated for early 2009 for West Doe II and late 2009 for West Doe III.

Financing Cash Flows and Liquidity

Our consolidated capital structure as of December 31, 2008, including short-term borrowings and commercial paper, was 62% debt, 34% stockholders equity and 4% minority interests. During the fourth quarter of 2008, the weakening Canadian dollar decreased our equity percentage by approximately 2%. See Quantitative and Qualitative Disclosures About Market Risk Foreign Currency Risk discussion for further information about the effects of changing Canadian dollar exchange rates on our balance sheets. The issuance of common stock on February 13, 2009 discussed above resulted in a December 31, 2008 pro forma capital structure of 59% debt, 37% stockholders equity and 4% minority interests, assuming proceeds from the issuance were used to repay commercial paper and other short-term borrowings.

Net cash provided by financing activities totaled $214 million in 2008 compared to $191 million used in financing in 2007. This $405 million change was driven primarily by:

$1,157 million of net issuances of long-term debt in 2008 compared to $198 million of net redemptions in 2007, partially offset by

repurchases of our common shares in 2008 of $600 million,

proceeds of $230 million in 2007 from the issuance of Spectra Energy Partners common shares, and a $366 million increase in short-term borrowings and commercial paper in 2007 compared to a $249 million increase in 2008.

Net cash used in financing activities totaled $191 million in 2007 compared to $2,454 million in 2006. This change was driven primarily by:

approximately $2.4 billion of distributions to Duke Energy in 2006 primarily due to the Crescent joint venture transaction,

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- $230 million of net proceeds received in 2007 from Spectra Energy Partners, as discussed further below, and
- $366 million of commercial paper issued in 2007 compared to $261 million during 2006, partially offset by
- a $335 million decrease in 2007 in proceeds from issuances of long-term debt, net of redemptions, and
- dividends paid on common stock of $558 million in the 2007 period as compared with $89 million of advances made to Duke Energy in 2006.

Significant Financing Activities 2008

Debt Issuances. The following debt issuances were completed during 2008 as part of our overall financing plan to fund capital expenditures and for other corporate purposes.

	Amount (in millions)	Interest Rate	Due Date
Spectra Capital	$ 500	6.20%	2018
Spectra Capital	250	5.90%	2013
Spectra Capital	250	7.50%	2038
Union Gas	198(a)	5.35%	2018
Union Gas	281(a)	6.05%	2038
Westcoast	48(a)	5.60%	2019
Westcoast	250(a)	5.60%	2019

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

On July 31, 2008, Maritimes & Northeast Pipeline, L.L.C. paid $288 million to retire its outstanding bonds and bank debt and an additional $54 million early-extinguishment premium for the bonds. The payment of the premium, a regulatory asset, is presented within Cash Flows from Financing Activities Other on the Consolidated Statements of Cash Flows.

Common Stock Repurchases. We repurchased a cumulative total of $600 million of our outstanding common stock during the second and third quarters of 2008. The share repurchase program was concluded on August 8, 2008.

Significant Financing Activities 2007

In July 2007, we completed the IPO of Spectra Energy Partners and received total proceeds of approximately $345 million as a result of the transaction, including the debt issued as discussed below. Net cash of approximately $230 million was received by Spectra Energy Partners upon closing of the IPO. Approximately $26 million of these proceeds was distributed to us, $194 million was used by Spectra Energy Partners to purchase qualifying investment grade securities, and $10 million was retained by Spectra Energy Partners to meet working capital requirements. Spectra Energy Partners borrowed $194 million in term debt using the investment grade securities as collateral and borrowed an additional $125 million of revolving debt. Proceeds from these borrowings, totaling $319 million, were distributed to us. In conjunction with the IPO, Spectra Energy Partners entered into a five-year $500 million facility that included both term and revolving borrowing capacity.

In July 2007, Union Gas replaced the existing $400 million Canadian 364-day credit facility with a $500 million Canadian five-year credit facility.

In May 2007, Spectra Capital entered into a $1.5 billion credit facility that replaced two existing facilities that totaled $950 million.

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Significant Financing Activities 2006

Union Gas issued 125 million Canadian dollars (approximately $108 million as of the issuance date) of 4.85% fixed-rate debentures due 2022, and 165 million Canadian dollars (approximately $148 million as of the issuance date) of 5.46% fixed-rate debentures due 2036.

In September 2006, prior to the completion of the partial sale of Crescent as discussed in Note 8 of Notes to Consolidated Financial Statements, Crescent issued approximately $1.23 billion principal amount of debt. The net proceeds from the debt issuance of approximately $1.21 billion were recorded as financing activity on the Consolidated Statements of Cash Flows. As a result of our deconsolidation of Crescent effective September 7, 2006, Crescent s outstanding debt balance of $1,298 million was removed from our Consolidated Balance Sheets.

The Income Fund, a Canadian income trust fund, sold approximately 9 million previously unissued Trust Units for proceeds of $94 million, net of commissions and other expenses of issuance. The sale of these Trust Units reduced our ownership interest in the Income Fund to approximately 46% at December 31, 2006. As a result of the sale of additional Trust Units, we recognized a $15 million pre-tax gain on the sale of subsidiary stock. The proceeds from the offering plus the draw down of 39 million Canadian dollars on an available credit facility were used by the Income Fund to acquire a 100% interest in Westcoast Gas Services, Inc. from Spectra Energy.

During 2006, we advanced $89 million to Duke Energy and forgave advances to Duke Energy of $602 million. Additionally during 2006, we distributed $2,361 million to Duke Energy to provide funding support for Duke Energy s dividend payments and share repurchase plan. The distribution was principally obtained from the proceeds received on our sale of 50% of Crescent.

Available Credit Facilities and Restrictive Debt Covenants

			Outstanding at December 31, 2008				
	Expiration Date	Credit Facilities Capacity	Commercial Paper	Term Loan	Revolving Credit	Letters of Credit	Total
			(in millions)				
Spectra Capital	2012	$ 1,500(a)	$ 259	$	$ 508	$ 5	$ 772
Westcoast	2011	164(b)					
Union Gas	2012	410(c)	169				169
Spectra Energy Partners	2012	500(d)		31	209		240
Total		$ 2,574	$ 428	$ 31	$ 717	$ 5	$ 1,181

(a) Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 65%. Amounts outstanding under the revolving credit facility are classified within Short-Term Borrowings and Commercial Paper on the Consolidated Balance Sheets.
(b) U.S. dollar equivalent at December 31, 2008. Credit facility is denominated in Canadian dollars totaling 200 million Canadian dollars and contains a covenant that requires the debt-to-total capitalization ratio to not exceed 75%.
(c) U.S. dollar equivalent at December 31, 2008. Credit facility is denominated in Canadian dollars totaling 500 million Canadian dollars and contains a covenant that requires the debt-to-total capitalization ratio to not exceed 75%. The facility also contains 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.
(d) Contains a covenant requiring the borrower to collateralize the term loan with qualifying investment-grade securities in an amount equal to or greater than the outstanding principal amount of the loan. Amounts outstanding under the revolving credit facility are classified within Long-Term Debt.

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The terms of the Spectra Energy Partners credit facility allow for liquidation of collateral to fund capital expenditures or certain acquisitions provided that an equal amount of term loan is converted to a revolving loan. Investments in marketable securities totaling $32 million at December 31, 2008 and $155 million at December 31, 2007 were pledged as collateral against the term loan. These investments are classified as Investments and Other Assets Other on the Consolidated Balance Sheets.

Our credit agreements contain various financial and other 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, 2008, we were in compliance with those covenants. In addition, our credit agreements allow for the 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. None of the debt or credit agreements contain material adverse change clauses.

The issuance of commercial paper, letters of credit and other borrowings reduces the amount available under the credit facilities.

As noted above, the terms of our Spectra Capital credit agreement requires our consolidated debt-to-total-capitalization ratio to be 65% or lower. As of December 31, 2008, this ratio was 62%. Equity, and therefore this percentage, is sensitive to significant weakening of the Canadian dollar as discussed in Quantitative and Qualitative Disclosures About Market Risk Foreign Currency Risk.

Credit Ratings Summary as of February 19, 2009

	Standard and Poor s	Moody s Investor Service	Dominion Bond Rating Service
Spectra Capital(a)	BBB	Baa1	Not applicable
Texas Eastern(a)	BBB+	A3	Not applicable
Westcoast(a)	BBB+	Not applicable	A(low)
Union Gas(a)	BBB+	Not applicable	A
Maritimes & Northeast Pipeline, LP(b)	A	A2	A
Maritimes & Northeast Pipeline, L.L.C.(a)	BBB	Baa3	Not applicable

(a) Represents senior unsecured credit rating
(b) Represents senior secured credit rating

The above credit ratings are dependent upon, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures, while maintaining the strength of the current balance sheet. These credit ratings could be negatively affected if, as a result of market conditions or other factors, they are unable to maintain the current balance sheet strength or if earnings or cash flow outlooks deteriorate materially.

Dividends. We currently anticipate an average dividend payout ratio over time of approximately 60% of estimated annual net income per share of common stock. The actual payout ratio, however, may vary from year to year depending on earnings levels. 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. A dividend of $0.25 per common share was declared on January 5, 2009 and will be paid on March 16, 2009.

Other Financing Matters. We have automatic shelf registration statements on file with the SEC to register the issuance of unspecified amounts of various equity and debt securities. In addition, as of the date of this filing,

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certain of our subsidiaries have 800 million Canadian dollars (approximately $656 million) available under shelf registrations for issuances in the Canadian market, of which 400 million expires in August 2010 and 400 million expires in September 2010.

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 Item 8. Financial Statements and Supplementary Data, Note 19 of Notes to Consolidated Financial Statements for further discussion of guarantee arrangements.

Most of the guarantee arrangements that we enter into enhance the credit standing of certain subsidiaries, non-consolidated entities or less than wholly owned entities, enabling them to conduct business. As such, these guarantee arrangements involve elements of performance and credit risk which are not included on the 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 the consolidated results of operations, financial position or cash flows.

In connection with our spin-off from Duke Energy, certain guarantees that were previously issued by us were assigned to, or replaced by, Duke Energy in 2006. For any remaining guarantees of other Duke Energy obligations, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements.

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 equity investment pipeline and field services operations. For additional information on these commitments, see Notes 18 and 19 of Notes to Consolidated Financial Statements.

Contractual Obligations

We enter into contracts that require payment of cash at certain specified 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 Current Liabilities on the Consolidated Balance Sheets other than Current Maturities of Long-Term Debt. It is expected that the majority of current liabilities on the Consolidated Balance Sheets will be paid in cash in 2009.

Contractual Obligations as of December 31, 2008

		Payments Due By Period			
	Total	2009	2010 & 2011	2012 & 2013	2014 & Beyond
	(in millions)				
Long-term debt(a)	$ 15,108	$ 1,413	$ 1,985	$ 2,489	$ 9,221
Capital leases(a)	1	1			
Operating leases(b)	172	28	52	42	50
Purchase Obligations:(c)					
Firm capacity payments(d)	910	172	164	173	401
Energy commodity contracts(e)	710	641	27	29	13
Other purchase obligations(f)	236	136	46	39	15
Other long-term liabilities on the Consolidated Balance Sheet(g)	87	87			
Total contractual cash obligations	$ 17,224	$ 2,478	$ 2,274	$ 2,772	$ 9,700

(a) See Note 15 of Notes to Consolidated Financial Statements. Amounts include scheduled interest payments over the life of debt or capital lease.
(b) See Note 18 of Notes to Consolidated Financial Statements.
(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 per SFAS No. 133, Accounting for Derivative Financial Instruments and Hedging Activities. For contracts where the price paid is based on an index, the amount is based on forward market prices at December 31, 2008.
(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 2009 retirement plan contributions and estimated 2009 payments related to FIN 48 liabilities, including interest (see Notes 7 and 23 of Notes to Consolidated Financial Statements). We are unable to reasonably estimate the timing of FIN 48 liability and interest payments in years beyond 2009 due to uncertainties in the timing of cash settlements with taxing authorities and cannot estimate retirement plan contributions beyond 2009 due primarily to uncertainties about market performance of plan assets. Excludes cash obligations for asset retirement activities (see Note 14). 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, environmental remediation and self-insurance claims (see Note 18), annual insurance premiums that are necessary to operate our business (see Note 18) and regulatory liabilities (see Note 5) because we are uncertain as to the amount and/or timing of when cash payments will be required. Also, amounts 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 effect of market fluctuations in the prices of NGLs and natural gas as a result of our investment in DCP Midstream, and ownership of the Empress assets in Western Canada and processing plants 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 established policies and procedures to manage our risks associated with these market fluctuations, which may include the use of forward physical transactions as well as commodity derivatives, primarily within DCP Midstream, such as swaps and options. To the extent that instruments accounted for as hedges are effective in offsetting the transaction being hedged, there is no impact to the Consolidated Statements of Operations until delivery or settlement occurs. In the event the hedge is not effective, derivative gains and losses affect consolidated earnings. Several factors influence the effectiveness of a hedge contract, including the use of contracts with different commodities or unmatched terms and counterparty credit risk. When hedge accounting is used, hedge effectiveness is monitored regularly and measured at least quarterly.

We are primarily exposed to market price fluctuations of NGL prices in the Field Services segment and to frac-spreads in the Empress operations in Canada. Since NGL prices historically track crude oil prices, we disclose our NGL price sensitivities in terms of crude oil price changes. Based on a sensitivity analysis as of

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December 31, 2008 and 2007, at our forecasted NGL-to-oil price relationships, a $10 per barrel move in oil prices would affect our annual pre-tax earnings by approximately $120 million in 2009 ($110 million from Field Services and $10 million from U.S. Transmission) as compared with approximately $135 million in 2008 ($120 million from Field Services and $15 million from U.S. Transmission). However, NGL prices lagged oil prices during oil s unprecedented upward price movement in the first half of 2008. Assuming crude oil prices average approximately $50 per barrel, each 1% change in the price relationship between NGLs and crude oil would change our annual pre-tax earnings by approximately $8 million. At crude oil prices above $50 per barrel, the impact of a 1% change in the crude NGL-to-oil price relationship would increase, and at crude oil prices below $50 per barrel, the impact of a 1% change in the crude NGL-to-oil price relationship would decrease.

With respect to the frac-spread risk related to Empress processing and NGL marketing activities in Western Canada, as of December 31, 2008 and 2007, a $0.50 change in the difference between the Btu-equivalent price of propane (used as a proxy for Empress NGL production) and the price of natural gas in Alberta, Canada would affect our pre-tax earnings by approximately $16 million on an annual basis in 2009 and approximately $16 million in 2008.

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 Item 8. Financial Statements and Supplementary Data, Notes 1 and 20 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 transportation, storage, and gathering and processing services are industrial end-users, marketers, exploration and production companies, LDCs and utilities located throughout the U.S. and Canada. We have concentrations of receivables from these industry sectors. These concentrations of customers may affect our overall credit risk in that risk factors can negatively affect the credit quality of an 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 counterparties 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 cash, letters of credit or parental guarantees 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 transaction. Approximately 80% of our credit exposures for transportation, storage, and gathering and processing services are with customers who have an investment-grade rating or equivalent based on our evaluation.

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. We discontinued investing in both asset-backed commercial paper and auction-rate securities in late 2007. One of our Canadian operating companies has a $13 million net investment in asset-backed commercial paper outstanding in Canada as of December 31, 2008 and is participating in a plan to restructure this paper. The restructuring agreement proposed through a Companies Creditors Protection Act (Canada) filing is currently being supported by many large Canadian financial institutions as well as several international banks. The restructuring contemplates the replacement of the commercial paper with marketable long-term instruments, but the restructuring has not been finalized as of December 31, 2008.

We had no net exposure to any one customer that represented greater than 10% of the gross fair value of trade accounts receivable at December 31, 2008.

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Based on our policies for managing credit risk, our exposures and our credit and other reserves, we do not anticipate a materially adverse 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 investments in short and long-term securities. We manage interest rate exposure by limiting our variable-rate exposures to percentages of total capitalization 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 U.S. Treasury lock agreements to manage and mitigate interest rate risk exposure. See also Notes 1, 15 and 20 of Notes to Consolidated Financial Statements.

Based on a sensitivity analysis as of December 31, 2008, it was estimated that if market interest rates average 1% higher (lower) in 2009 than in 2008, interest expense, net of offsetting impacts in interest income, would increase (decrease) by $20 million. Comparatively, based on a sensitivity analysis as of December 31, 2007, had interest rates averaged 1% higher (lower) in 2008 than in 2007, it was estimated that interest expense, net of offsetting interest income, would have fluctuated by approximately $13 million. These amounts were estimated by considering the effect of the hypothetical interest rates on variable-rate securities outstanding, adjusted for interest rate hedges, investments, and cash and cash equivalents outstanding as of December 31, 2008 and 2007. If interest rates changed significantly, we would likely take action to manage our exposure to the change. However, due to the uncertainty of the specific actions that would be taken and their possible effects, the sensitivity analysis assumes no changes in our financial structure.

In January 2009, as a result of low interest rates, we settled existing fixed-to-floating interest rate swaps on approximately $848 million of long-term debt. The settlement of these swaps decreases our exposure to changes in market interest rates on variable-rate based securities by approximately $9 million as compared to the sensitivity analysis as of December 31, 2008 provided above.

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. As previously discussed, equity markets have recently experienced significant declines. These declines not only impact our cost of providing retirement and postretirement benefits, but also impact the funding level requirements of those benefits.

Foreign Currency Risk

We are exposed to foreign currency risk from investments and operations in Canada. To mitigate risks associated with foreign currency fluctuations, investments are naturally hedged through debt denominated or issued in the foreign currency. We may also use foreign currency derivatives from time to time to manage our risk related to foreign currency fluctuations. 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 2008 would have resulted in an estimated net loss on the translation of local currency earnings of approximately $42 million on our Consolidated Statement of Operations. In addition, if a 10% devaluation had occurred on December 31, 2008, the Consolidated Balance Sheet would be negatively impacted by $523 million through a cumulative translation adjustment in Accumulated Other Comprehensive Income (AOCI). At December 31, 2008, one U.S. dollar translated into 1.22 Canadian dollars.

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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 the revolving credit facility and could require other affiliates to immediately pay down any outstanding drawn amounts under other revolving credit agreements which could adversely affect cash flow or restrict business. Foreign currency 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 the effort to address the challenge of climate change. It is likely that our assets and operations in the U.S. and Canada are or will become subject to direct and indirect effects of current and possible future global climate change regulatory actions in the jurisdictions in which those assets and operations are located.

While Canada is a signatory to the United Nations-sponsored Kyoto Protocol, which prescribes specific targets to reduce GHG emissions for developed countries for the 2008-2012 period, the Canadian federal government has confirmed it will not achieve the targets within the timeframes specified. Instead, the federal government in 2008 outlined a regulatory framework mandating GHG reductions from large final emitters. The framework requires GHG emissions intensity reductions of 18% beginning in 2010, with further reductions of 2% per year thereafter. Regulatory design details from the Government of Canada associated with the framework remain forthcoming. We expect a number of our assets and operations in Canada will be affected by pending 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 has yet to be determined by policymakers.

The province of British Columbia enacted a carbon tax, effective July 1, 2008. The tax applies to the purchase or use of fossil fuels, including natural gas. This tax is being recovered from customers through service tolls. British Columbia has also 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. 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 July 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%. In 2008, two of our facilities were 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 a number of our assets and operations could be affected by eventual mandatory GHG programs; however, the timing and specific policy objectives in many jurisdictions, including at the federal level, remain uncertain.

The United States is not a signatory to the United Nations-sponsored Kyoto Protocol, nor has the federal government adopted a mandatory GHG emissions reduction requirement. However, in 2008, the EPA initiated an Advanced Notice of Proposed Rulemaking to examine whether GHG emissions could be effectively regulated under the existing Clean Air Act. In addition, several legislative proposals have been introduced and discussed in the U.S. Congress that would impose GHG emissions constraints, though final legislation has yet to advance.

A number of states in the United States, primarily in the northeast and west, are establishing or considering state or regional programs that would mandate reductions in GHG emissions. These regional programs include the Regional Greenhouse Gas Initiative (RGGI) which applies only to power producers in select northeastern states, the

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Western Climate Initiative (WCI) which includes a number of Western states and the provinces of British Columbia, Ontario, and Quebec, and the Midwestern Greenhouse Gas Reduction Accord which includes six Midwestern states and one Canadian province. We expect a number 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 U.S. federal and state policies and the uncertainty of the Canadian federal and provincial policies, we cannot estimate the potential effect of GHG policies on our future consolidated results of operations, financial position or cash flows. We continue to monitor the development of greenhouse gas regulatory policies in both countries.

Other. For additional information on other issues related to us, see Item 8. Financial Statements and Supplementary Data, Notes 5 and 18 of Notes to Consolidated Financial Statements.

New Accounting Pronouncements

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

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

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

Item 8. Financial Statements and Supplementary Data.

Management s Annual Report on Internal Control over Financial Reporting

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

Our management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2008 based on the 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 as of December 31, 2008.

Our independent registered public accounting firm has audited and issued a report on the effectiveness of our internal control over financial reporting, which is included in its Report of Independent Registered Public Accounting Firm.

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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, 2008 and 2007, and the related consolidated statements of operations, stockholders equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2008. 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, 2008, based on criteria established in *Internal Control Integrated Framework* 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion,

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such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents 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, 2008, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 1 to the consolidated financial statements, in 2006 the Company changed its method of accounting for defined benefit pension and other postretirement plans as a result of adopting Statement of Financial Accounting Standard No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*.

As discussed in Note 1 to the consolidated financial statements, in 2007 the Company changed its method of accounting for income tax positions as a result of adopting *FIN 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109.*

As discussed in Note 1 to the consolidated financial statements, on January 2, 2007, Duke Energy Corporation (Duke Energy) completed the spin-off of Spectra Energy Corp. Duke Energy contributed its ownership interests in Spectra Energy Capital, LLC to Spectra Energy Corp and all of the outstanding common stock of Spectra Energy Corp was distributed to Duke Energy s shareholders.

/s/ Deloitte & Touche LLP

Houston, Texas

February 26, 2009

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SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF OPERATIONS

(In millions, except per-share amounts)

	Years Ended December 31, 2008	2007	2006
Operating Revenues			
Transportation, storage and processing of natural gas	$ 2,343	$ 2,200	$ 2,095
Distribution of natural gas	1,731	1,664	1,623
Sales of natural gas liquids	772	601	531
Other	228	239	252
Total operating revenues	5,074	4,704	4,501
Operating Expenses			
Natural gas and petroleum products purchased	1,586	1,416	1,435
Operating, maintenance and other	1,235	1,148	1,189
Depreciation and amortization	569	518	482
Property and other taxes	246	209	208
Total operating expenses	3,636	3,291	3,314
Gains on Sales of Other Assets and Other, net	42	13	47
Operating Income	1,480	1,426	1,234
Other Income and Expenses			
Equity in earnings of unconsolidated affiliates	778	596	609
Gain on sale of subsidiary stock			15
Other income and expenses, net	66	53	112
Total other income and expenses	844	649	736
Interest Expense	636	633	605
Minority Interest Expense	63	62	40
Earnings From Continuing Operations Before Income Taxes	1,625	1,380	1,325
Income Tax Expense From Continuing Operations	496	440	393
Income From Continuing Operations	1,129	940	932
Income From Discontinued Operations, net of tax		17	312
Net Income	$ 1,129	$ 957	$ 1,244
Common Stock Data			
Weighted-average shares outstanding			
Basic	622	632	n/a(a)
Diluted	624	635	n/a

Earnings per share from continuing operations			
Basic	$ 1.82	$ 1.48	n/a
Diluted	$ 1.81	$ 1.48	n/a
Earnings per share-total			
Basic	$ 1.82	$ 1.51	n/a
Diluted	$ 1.81	$ 1.51	n/a
Dividends per share	$ 0.96	$ 0.88	n/a

(a) not applicable

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SPECTRA ENERGY CORP

CONSOLIDATED BALANCE SHEETS

(In millions)

	December 31, 2008	December 31, 2007
ASSETS		
Current Assets		
Cash and cash equivalents	$ 214	$ 94
Receivables (net of allowance for doubtful accounts of $12 and $22 at December 31, 2008 and 2007, respectively)	795	907
Inventory	279	287
Other	162	91
Total current assets	1,450	1,379
Investments and Other Assets		
Investments in and loans to unconsolidated affiliates	2,152	1,780
Goodwill	3,381	3,948
Other	417	631
Total investments and other assets	5,950	6,359
Property, Plant and Equipment		
Cost	17,569	18,154
Less accumulated depreciation and amortization	3,930	3,854
Net property, plant and equipment	13,639	14,300
Regulatory Assets and Deferred Debits	885	932
Total Assets	$ 21,924	$ 22,970

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SPECTRA ENERGY CORP

CONSOLIDATED BALANCE SHEETS

(In millions, except per-share amounts)

	December 31, 2008	December 31, 2007
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 285	$ 363
Short-term borrowings and commercial paper	936	715
Taxes accrued	105	85
Interest accrued	158	146
Current maturities of long-term debt	821	338
Other	739	775
Total current liabilities	3,044	2,422
Long-term Debt	8,290	8,345
Deferred Credits and Other Liabilities		
Deferred income taxes	2,789	2,883
Regulatory and other	1,566	1,657
Total deferred credits and other liabilities	4,355	4,540
Commitments and Contingencies		
Minority Interests	695	806
Stockholders Equity		
Preferred stock, $0.001 par, 22 million shares authorized, no shares outstanding		
Common stock, $0.001 par, 1 billion shares authorized, 611 million and 632 million shares outstanding at December 31, 2008 and 2007, respectively	1	1
Additional paid-in capital	4,104	4,658
Retained earnings	899	368
Accumulated other comprehensive income	536	1,830
Total stockholders equity	5,540	6,857
Total Liabilities and Stockholders Equity	$ 21,924	$ 22,970

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SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

	Years Ended December 31,		
	2008	**2007**	**2006**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 1,129	$ 957	$ 1,244
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	581	534	606
Gains on sales of investments in commercial and multi-family real estate, equity investments and other assets			(509)
Impairment charges			48
Deferred income tax expense	161	110	104
Minority interest expense	63	71	60
Equity in earnings of unconsolidated affiliates	(778)	(596)	(712)
Distributions received from unconsolidated affiliates	777	569	707
Decrease (increase) in			
Receivables	(36)	59	167
Inventory	(76)	147	115
Other current assets	(36)	14	1,288
Increase (decrease) in			
Accounts payable	24	(93)	(690)
Taxes accrued	8	(61)	53
Other current liabilities	(52)	(198)	(461)
Capital expenditures for residential real estate			(322)
Cost of residential real estate sold			143
Other, assets	83	(2)	(796)
Other, liabilities	(43)	(44)	(351)
Net cash provided by operating activities	1,805	1,467	694
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,502)	(1,202)	(987)
Investments in and loans to unconsolidated affiliates	(528)	(285)	(87)
Acquisitions, net of cash acquired	(274)	(14)	(89)
Purchases of available-for-sale securities	(1,132)	(1,550)	(9,290)
Proceeds from sales and maturities of available-for-sale securities	1,256	1,405	9,775
Net proceeds from the sales of equity investments and other assets, and sales of and collections on notes receivable	105	15	2,025
Proceeds from the sales of commercial and multi-family real estate			254
Settlement of net investment hedges and other investing derivatives			(163)
Distributions received from unconsolidated affiliates	218	87	152
Other	(31)		(21)
Net cash provided by (used in) investing activities	(1,888)	(1,544)	1,569
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the issuance of long-term debt	3,557	783	1,799
Payments for the redemption of long-term debt	(2,400)	(981)	(1,662)
Net increase in short-term borrowings and commercial paper	249	366	261
Distributions to minority interests	(70)	(57)	(304)
Contributions from minority interests	115	9	247
Proceeds from issuances of subsidiary stock		230	104
Repurchases of Spectra Energy common shares	(600)		
Dividends paid	(598)	(558)	
Distributions and advances to parent			(2,450)

Cash associated with operations transferred to Duke Energy Corporation			(427)
Other	(39)	17	(22)
Net cash provided by (used in) financing activities	214	(191)	(2,454)
Effect of exchange rate changes on cash	(11)	63	(1)
Net increase (decrease) in cash and cash equivalents	120	(205)	(192)
Cash and cash equivalents at beginning of period	94	299	491
Cash and cash equivalents at end of period	$ 214	$ 94	$ 299
Supplemental Disclosures			
Cash paid for interest, net of amount capitalized	$ 611	$ 627	$ 679
Cash paid for income taxes	$ 322	$ 393	$ 238

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SPECTRA ENERGY CORP

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME

(In millions)

					Accumulated Other Comprehensive Income			
	Common Stock	Additional Paid-in Capital	Retained Earnings	Member s Equity	Foreign Currency Translation Adjustments	Net Gains (Losses) on Cash Flow Hedges	Other	Total
December 31, 2005	$	$	$	$ 10,848	$ 783	$ (86)	$ (41)	$ 11,504
Net income				1,244				1,244
Other comprehensive income								
Foreign currency translation adjustments					106			106
Unrealized mark-to-market net loss on hedges(a)						(6)		(6)
Reclassification of cash flow hedges into earnings(b)						39		39
Net unrealized gains on SFAS No. 115 securities(c)							14	14
Reclassification of SFAS No. 115 investments into earnings(d)							(33)	(33)
Transfer of taxes on net investment hedge and other hedges from parent					62	7		69
Transfer of various entities to affiliate					205			205
Transfer of Midwestern assets to affiliate(e)						40		40
Minimum pension liability adjustment(f)								