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 (State or other jurisdiction of incorporation or organization)	20-5413139 (I.R.S. Employer Identification No.)
5400 Westheimer Court, Houston, Texas (Address of principal executive offices)	77056 (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 (in millions)	2006
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

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- 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 (in millions)	2006
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)

	Common Stock	Additional Paid-in Capital	Retained Earnings	Member s Equity	Accumulated Other Comprehensive Income: 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)							(1)	(1)
Total comprehensive income								1,677
Transfer of Midwestern assets to affiliate				(1,462)				(1,462)
Transfer of Bison Insurance Company Limited to affiliate				(60)				(60)
Forgiveness of advances to parent				(602)				(602)
Distribution to parent, net				(796)				(796)
Distribution to parent associated with sale of Crescent				(1,602)				(1,602)
Transfer of non-gas entities to affiliate				(2,952)				(2,952)
Pension adjustment SFAS 158 transition(f)							(48)	(48)
Other, net				(20)				(20)
December 31, 2006				4,598	1,156	(6)	(109)	5,639
Net income			957					957
Other comprehensive income								
Foreign currency translation adjustments					877			877
						(2)		(2)

Reclassification of cash flow hedges into earnings(b)								
Pension and benefits impact per SFAS 158							14	14
Total comprehensive income								1,846
Conversion to Spectra Energy Corp	1	4,597		(4,598)				
FIN 48 implementation			(26)					(26)
Transfer of net assets and liabilities from Duke Energy Corporation		12					(100)	(88)
Dividends on common stock			(558)					(558)
Effect of changing measurement date per SFAS 158			(5)					(5)
Stock-based compensation		49						49
December 31, 2007	1	4,658	368		2,033	(8)	(195)	6,857
Net income			1,129					1,129
Other comprehensive income (loss)								
Foreign currency translation adjustments					(1,152)			(1,152)
Unrealized mark-to-market net loss on hedges(a)						(11)		(11)
Reclassification of cash flow hedges into earnings(b)						2		2
Pension and benefits impact per SFAS 158							(133)	(133)
Total comprehensive income (loss)								(165)
Common stock repurchases		(600)						(600)
Dividends on common stock			(598)					(598)
Stock-based compensation		38						38
Other, net		8						8
December 31, 2008	$ 1	$ 4,104	$ 899	$	$ 881	$ (17)	$ (328)	$ 5,540

(a) Net of $3 tax benefit in 2006 and $5 tax benefit in 2008.
(b) Net of $20 tax benefit in 2006, $1 tax expense in 2007 and $1 tax benefit in 2008.
(c) Net of $8 tax expense in 2006.
(d) Net of $18 tax benefit in 2006.
(e) Net of $24 tax expense in 2006.
(f) Net of $27 tax benefit in 2006.

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SPECTRA ENERGY CORP

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1. Summary of Operations and Significant Accounting Policies

The terms we, our, us, and Spectra Energy as used in this report refer collectively to Spectra Energy Corp and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Spectra Energy.

Nature of Operations. Spectra Energy Corp, through its subsidiaries and equity affiliates, owns and operates a large and diversified portfolio of complementary natural gas-related energy assets, operating in three key areas of the natural gas industry: gathering and processing, transmission and storage, and distribution. 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. In addition, we own a 50% interest in DCP Midstream, LLC (DCP Midstream), one of the largest natural gas gatherers and processors in the United States.

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

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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. Duke Energy s shareholders received one share of our 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.

In conjunction with the spin-off, on January 2, 2007, Duke Energy transferred to us the assets and liabilities, including related tax effects, associated with our employee benefits and captive insurance positions, as well as miscellaneous corporate assets and liabilities. The net effect of these non-cash transfers is reflected as an increase of $12 million to Additional Paid-in Capital and a decrease of $100 million to Accumulated Other Comprehensive Income (AOCI) in the Consolidated Statement of Stockholders Equity and Comprehensive Income during the year ended December 31, 2007. The following summarizes the effect on the Consolidated Balance Sheet in 2007 as a result of the transfers:

	Increase (Decrease) to Equity (in millions)
Receivables	$ (9)
Other assets	186
Taxes accrued	(5)
Other current liabilities	(65)
Deferred income taxes	94
Other liabilities	(289)
Net equity decrease	$ (88)

See also Notes 10 and 23 for further discussion of captive insurance and employee benefit plans.

Other Significant Changes. On April 1, 2006, we transferred the operations of our wholly owned captive insurance subsidiary, Bison Insurance Company Limited (Bison), to Duke Energy. Accordingly, Bison s operations are not included in our results of operations, financial position or cash flows subsequent to its transfer to Duke Energy. Due to continuing involvement between Bison and our entities, the results of operations of Bison did not qualify for discontinued operations treatment.

Additionally, in April 2006, we indirectly transferred to Duke Energy Ohio, Inc. (Duke Energy Ohio), our ownership interest in Duke Energy North America s (DENA s) Midwestern assets, representing a mix of combined cycle and peaking plants. In connection with this transfer, we transferred to Duke Energy Ohio approximately $1.6 billion of assets and approximately $0.1 billion of liabilities at carrying value, for a net transfer of approximately $1.5 billion. This transfer was accounted for as a capital distribution at historical cost. The results of operations for DENA s Midwestern assets have been reflected as discontinued operations in the accompanying Consolidated Statements of Operations up through the date of transfer.

In September 2006, we deconsolidated Crescent Resources, LLC (Crescent) due to a reduction in ownership and our inability to exercise control over Crescent. See Note 8 for further discussion. Crescent was accounted for as an equity method investment from the date of deconsolidation. Crescent was one of the entities we contributed to Duke Energy in anticipation of the spin-off.

Basis of Presentation. The accompanying consolidated financial statements include our accounts, our majority-owned subsidiaries where we have control and those variable interest entities, if any, where we are the primary beneficiary. As a result of the spin-off, Spectra Capital is treated as our predecessor entity for financial statement reporting purposes. Accordingly, the 2006 information presented herein is that of Spectra Capital. Additionally, in anticipation of the spin-off, and as further described in Note 8, Spectra Capital implemented an internal reorganization in December 2006 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 2006 results of operations of most of these transferred businesses are included in Income From Discontinued Operations, Net of Tax in the accompanying Consolidated Statements of Operations. Corporate service companies that were transferred to Duke Energy in December 2006 are reported within continuing operations since corporate services continue to be provided at Spectra Energy to support operations. Information presented for 2006 in the Consolidated Statements of Cash Flows does not include any reclassifications or adjustments to amounts historically reported for these transferred businesses.

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

Fair Value Measurements. Effective January 1, 2008, we adopted the required provisions of Statement of Financial Accounting Standards (SFAS) No. 157, Fair Value Measurements, for financial assets and liabilities. SFAS No. 157 defines fair value, establishes a consistent framework for measuring fair value and expands disclosure requirements about fair value measurements. SFAS No. 157 requires entities to, among other things, maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

SFAS No. 157 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date.

SFAS No. 157 specifies a hierarchy of valuation techniques based on whether the inputs to those valuation techniques are observable or unobservable. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect our market assumptions. In accordance with SFAS No. 157, these two types of inputs have created the following fair value hierarchy:

Level 1 Quoted unadjusted prices for identical instruments in active markets.

Level 2 Quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets.

Level 3 Model-derived valuations in which one or more significant inputs or significant value drivers are unobservable.

Cash and Cash Equivalents. Highly liquid investments with original maturities of three months or less at the date of acquisition, except for the investments that are pledged as collateral against long-term debt as discussed in Note 15, are considered cash equivalents.

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

	December 31,	
	2008	2007
	(in millions)	
Natural gas	$ 180	$ 154
Natural gas liquids	16	25
Materials and supplies	83	108
Total inventory	$ 279	$ 287

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Natural Gas Imbalances. The Consolidated Balance Sheets include in-kind balances as a result of differences in gas volumes received and delivered for customers. Since settlement of imbalances is in-kind, changes in the balances do not have an effect on our Consolidated Statements of Cash Flows. Accounts Receivable includes $134 million of natural gas imbalances as of December 31, 2008 and $119 million as of December 31, 2007. Other Current Liabilities includes $134 million as of December 31, 2008 and $136 million as of December 31, 2007, related to gas imbalances. Natural gas volumes owed to or by us are valued at natural gas market index prices as of the balance sheet dates.

Accounting for Risk Management and Hedging Activities and Financial Instruments. In 2007 and 2008, our use of derivative instruments was limited to interest rate positions, a small percentage of gas purchase hedges around the regulated operations at Union Gas Limited (Union Gas) and commodity derivatives at DCP Midstream. All derivative instruments that do not qualify for the normal purchases and normal sales exception under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, are recorded on the Consolidated Balance Sheets at fair value. Cash inflows and outflows related to derivative instruments, except those related to net investment hedges and other investing activities, are a component of operating cash flows in the accompanying Consolidated Statements of Cash Flows. Cash inflows and outflows related to net investment hedges and derivatives related to other investing activities are a component of investing cash flows.

Cash Flow and Fair Value Hedges. Qualifying energy commodity and other derivatives may be designated as either a hedge of a forecasted transaction (cash flow hedge) or a hedge of a recognized asset, liability or firm commitment (fair value hedge). For all hedge contracts, we prepare documentation of the hedge in accordance with SFAS No. 133 and assess whether the hedge contract is highly effective, both at inception and on a quarterly basis, in offsetting changes in cash flows or fair values of hedged items. We document hedging activity by transaction type (futures/swaps) and risk management strategy (commodity price risk/interest rate risk).

Changes in the fair value of a derivative designated and qualified as a cash flow hedge, to the extent effective, are included in the Consolidated Statements of Stockholders Equity and Comprehensive Income as AOCI until earnings are affected by the hedged transaction. We discontinue hedge accounting prospectively when we have determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market model of accounting (MTM Model) prospectively. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the underlying transaction is reflected in earnings, unless it is probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in AOCI are immediately recognized in current earnings.

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

Valuation. When available, quoted market prices or prices obtained through external sources are used to measure a contract s fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on internally developed valuation techniques or models. For derivatives recognized under the MTM Model, valuation adjustments are also recognized in the Consolidated Statements of Operations. See Note 20 for further information.

Investments. We may actively invest a portion of our available cash and restricted cash balances in various financial instruments, including taxable or tax-exempt debt securities. In addition, we invest in short-term money market securities, some of which are restricted due to debt collateral and insurance requirements. We have classified all investments that are debt securities with maturity dates over one year as available-for-sale under SFAS No. 115, Accounting For Certain Investments in Debt and Equity Securities, and they are carried at fair market value. Investments in money-market securities are accounted for at fair value. Realized gains and losses and dividend and interest income related to these securities, including any amortization of discounts or premiums arising at acquisition, are included in earnings. The cost of securities sold is determined using the specific identification method. Purchases and sales of available-for-sale securities are presented on a gross basis within Investing Cash Flows in the accompanying Consolidated Statements of Cash Flows. Restricted cash balances, primarily related to debt collateral and insurance requirements, totaled $69 million at December 31, 2008 and $25 million at December 31, 2007, and are classified within Investments and Other Assets Other on the Consolidated Balance Sheets.

Goodwill. We evaluate goodwill for potential impairment under the guidance of SFAS No. 142, Goodwill and Other Intangible Assets. Under this standard, goodwill is subject to an annual test for impairment. We have designated August 31 as the date we perform the annual review for goodwill impairment for our reporting units. Under the provisions of SFAS No. 142, we perform the annual review for goodwill impairment at the reporting unit level, which we have determined to be an operating segment or one level below.

Impairment testing of goodwill consists of a two-step process. The first step involves a comparison of the implied fair value of a reporting unit with its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, the second step of the process involves a comparison of the fair value and carrying value of the goodwill of that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess. Additional impairment tests are performed between the annual reviews if events or changes in circumstances make it more likely than not that the fair value of a reporting unit is below its carrying amount.

We completed our annual goodwill impairment test as of August 31, 2008 and no impairments were identified. We primarily use a discounted cash flow analysis to determine fair value for each reporting unit. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in key markets served by our operations, regulatory stability, the ability to renew contracts, commodity prices (where appropriate), and foreign currency exchange rates, as well as other factors that affect our revenue, expense and capital expenditure projections.

Property, Plant and Equipment. Property, plant and equipment are stated at historical cost less accumulated depreciation. We capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Indirect costs include general engineering, taxes and the cost of funds used during construction. The cost of renewals and betterments that extend the useful life or increase the expected output of property, plant and equipment is also capitalized. The cost of repairs, replacements and major maintenance projects, that do not extend the useful life or increase the expected output of property, plant and equipment, is expensed as incurred. Depreciation is generally computed over the asset s estimated useful life using the straight-line method. The composite weighted-average depreciation rates, including depreciation associated with businesses included in discontinued operations, were 3.29% for 2008, 3.14% for 2007 and 3.32% for 2006. See also Allowance for Funds Used During Construction (AFUDC) discussed below.

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

Asset Retirement Obligations. We recognize asset retirement obligations (AROs) in accordance with SFAS No. 143, Accounting For Asset Retirement Obligations, for legal obligations associated with the

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retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and FIN 47, Accounting for Conditional Asset Retirement Obligations, for conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within our control. Both SFAS No. 143 and FIN 47 require that the fair value of a liability for an ARO be recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset.

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

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

We use the criteria in SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, to determine when an asset is classified as held for sale. Upon classification as held for sale, the long-lived asset or asset group is measured at the lower of its carrying amount or fair value less cost to sell, depreciation is ceased and the asset or asset group is separately presented on the Consolidated Balance Sheet. When an asset or asset group meets the SFAS No. 144 criteria for classification as held for sale within the Consolidated Balance Sheet, we do not retrospectively adjust prior period balance sheets to conform to current year presentation.

We use the criteria in SFAS No. 144 and Emerging Issues Task Force (EITF) 03-13, Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations, to determine whether components of our operations that are being disposed of or are classified as held for sale are required to be reported as discontinued operations in the Consolidated Statements of Operations. To qualify as a discontinued operation under SFAS No. 144, the component being disposed of must have clearly distinguishable operations and cash flows. Additionally, pursuant to EITF 03-13, we must not have significant continuing involvement in the operations after the disposal (i.e. we must not have the ability to influence the operating or financial policies of the disposed component) and cash flows of the operations being disposed of must have been eliminated from our ongoing operations (i.e. we do not expect to generate significant direct cash flows from activities involving the disposed component after the disposal transaction is completed). Assuming both preceding conditions are met, the related results of operations for the current and prior periods, including any related impairments, are reflected as Income From Discontinued Operations, Net of Tax, in the Consolidated Statements of Operations. If an asset held for sale does not meet the requirements for discontinued operations classification, any impairments and gains or losses on sales are recorded in continuing operations as Gains on Sales of Other Assets and Other, Net.

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

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

Cost-Based Regulation. We account for certain of our regulated operations under the provisions of SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. The economic effects of regulation can result in a regulated company recording assets for costs that have been or are expected to be approved for recovery from customers or recording liabilities for amounts that are expected to be returned to customers in the rate-setting process in a period different from the period in which the amounts would be recorded by an unregulated enterprise. Accordingly, we record assets and liabilities that result from the regulated ratemaking process that may not be recorded under GAAP for non-regulated entities. We continually assess whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders applicable to other regulated entities. Based on this continual assessment, we believe the existing regulatory assets are probable of recovery. These regulatory assets and liabilities are primarily classified in the Consolidated Balance Sheets as Regulatory Assets and Deferred Debits, and Deferred Credits and Other Liabilities. We periodically evaluate the applicability of SFAS No. 71, and consider factors such as regulatory changes and the effect of competition. If cost-based regulation ends or competition increases, we may have to reduce our asset balances to reflect a market basis less than cost and write-off the associated regulatory assets and liabilities. See Note 5 for further discussion.

Captive Insurance Reserves. Effective January 2007, we have captive insurance subsidiaries which provide insurance coverage to our entities as well as certain third parties, on a limited basis, for various business risks and losses, such as workers compensation, property, business interruption and general liability. Liabilities include provisions for estimated losses incurred but not yet reported, as well as provisions for known claims which have been estimated on a claims-incurred basis. Incurred but not yet reported reserve estimates involve the use of assumptions and are primarily based upon historical loss experience, industry data and other actuarial assumptions. Reserve estimates are adjusted in future periods as actual losses differ from historical experience. From April 2006 through December 2006, we were provided insurance coverage through a captive insurance company of our then-parent, Duke Energy, as well as certain third parties. Effective January 2007, this coverage and the associated insurance assets and liabilities applicable to our ongoing operations were transferred to our new captive insurance subsidiaries.

Guarantees. We account for guarantees and related contracts, for which we are the guarantor, under FIN 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others. In accordance with FIN 45, upon issuance or modification of a guarantee, we recognize a liability at the time of issuance or material modification for the estimated fair value of the obligation we assume under that guarantee, if any. Fair value is estimated using a probability-weighted approach. We reduce the obligation over the term of the guarantee or related contract in a systematic and rational method as risk is reduced under the obligation. Any additional contingent loss for guarantee contracts outside the scope of FIN 45 is accounted for and recognized in accordance with SFAS No. 5, Accounting for Contingencies.

Stock-Based Compensation. We account for stock-based compensation under the provisions of SFAS No. 123(R), Share-Based Payment. SFAS No. 123(R) establishes accounting for stock-based awards exchanged for employee and certain non-employee services. Accordingly, for employee awards, equity classified stock-based compensation cost is measured at the grant date based on the fair value of the award and is recognized as expense over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests or the date the employee becomes retirement eligible. Awards, including stock options, granted to employees that are already retirement eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted. See Note 22 for further discussion.

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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, historical data adjusted for heating degree days, commodity prices and preliminary throughput and allocation measurements. Final bills for the current month are billed and collected in the following month. Differences between actual and estimated unbilled revenues are immaterial. There were no customers accounting for 10% or more of consolidated revenues during 2008, 2007 or 2006.

Allowance for Funds Used During Construction (AFUDC). AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction of certain new regulated facilities, consists of two components, an equity component and an interest expense component. The equity component is a non-cash item. AFUDC is capitalized as a component of Property, Plant and Equipment cost, with offsetting credits to the Consolidated Statements of Operations through Other Income and Expenses, Net for the equity component and Interest Expense for the interest expense component. After construction is completed, we are permitted to recover these costs through inclusion in the rate base and in the depreciation provision. The total amount of AFUDC included in the Consolidated Statements of Operations was $58 million in 2008 (an equity component of $33 million and an interest expense component of $25 million), $40 million in 2007 (an equity component of $22 million and an interest expense component of $18 million) and $21 million in 2006 (an equity component of $11 million and an interest expense component of $10 million).

Preliminary Project Costs. Project development costs, including expenditures for preliminary surveys, plans, investigations, environmental studies, regulatory applications and other costs incurred for the purpose of determining the feasibility of capital expansion projects, are initially included in operating expenses for U.S. rate-regulated enterprises that apply the principles of SFAS No. 71. If and when it is determined that recovery of such costs through regulated revenues of the completed project is probable, the inception-to-date costs of the project are recognized as Property, Plant and Equipment in accordance with the provisions of SFAS No. 71 and operating expenses are reduced.

Accounting For Sales of Stock by a Subsidiary. Prior to the adoption on January 1, 2009 of SFAS No. 160, Noncontrolling Interest in Consolidated Financial Statements, we accounted for sales of stock by a subsidiary under Staff Accounting Bulletin (SAB) No. 51, Accounting for Sales of Stock of a Subsidiary. Under SAB No. 51, companies could elect, via an accounting policy decision, to record a gain on the sale of stock of a subsidiary equal to the amount of proceeds received in excess of the carrying value of the shares. We had elected to treat such excesses as gains in earnings, which are reflected in Gain on Sale of Subsidiary Stock in the Consolidated Statements of Operations. Effective upon the adoption of SFAS No. 160, sales of stock by a subsidiary are required to be accounted for as equity transactions in those instances where a change in control does not take place, which effectively nullified the SAB No. 51 gain alternative. As a result of the adoption of SFAS No. 160, a $60 million deferred gain associated with the formation of Spectra Energy Partners, LP (Spectra Energy Partners) was reclassified from Regulatory and Other Deferred Credits and Other Liabilities to Stockholders Equity in the Consolidated Balance Sheet on January 1, 2009.

During 2006, we recognized a gain of $15 million related to the sale of securities of the Spectra Energy Income Fund (the Income Fund). See Note 3 for further discussion.

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

As a result of Duke Energy s merger with Cinergy Corp (Cinergy), we entered into a tax sharing agreement with Duke Energy, effective April 1, 2006, where the separate return method was used to allocate income taxes

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to Duke Energy s subsidiaries based on the results of their operations. The accounting for income taxes essentially represented the income taxes that we would incur if we were a separate company filing our own tax return as a C-Corporation. Prior to entering into this tax sharing agreement, we were a pass-through entity for U.S. income tax purposes.

We adopted FIN 48, Accounting for Uncertainty in Income Taxes, an Interpretation of FAS 109, on January 1, 2007, resulting in an increase of $26 million in the liability for uncertain tax benefits, which was accounted for as a cumulative effect decrease to the January 1, 2007 balance of Retained Earnings in the Consolidated Balance Sheet. The financial statement effects on tax positions are recognized in the period in which it is more-likely-than-not that the position will be sustained upon examination, the position is effectively settled or when the statute of limitations to challenge the position has expired. Interest and penalties related to unrecognized tax benefits are recorded as interest expense and other expense, respectively.

Segment Reporting. SFAS No. 131, Disclosures about Segments of an Enterprise and Related Information, establishes standards for a public company to report financial and descriptive information about its reportable operating segments in interim and annual financial reports. Operating segments are components of an enterprise about which separate financial information is available and evaluated regularly by the chief operating decision maker in deciding how to allocate resources and evaluate performance. Two or more operating segments may be aggregated into a single reportable segment provided aggregation is consistent with the objective and basic principles of SFAS No. 131, if the segments have similar economic characteristics, and the segments are considered similar under criteria provided by SFAS No. 131. There is no aggregation within our defined business segments. A description of our reportable segments, consistent with how business results are reported internally to management and the disclosure of segment information in accordance with SFAS No. 131, is presented in Note 4.

Foreign Currency Translation. The local currencies of our foreign operations, which represent Canadian operations subsequent to the spin-off from Duke Energy, have been determined to be their functional currencies, except for certain foreign operations (prior to 2007) included in discontinued operations whose functional currency has been determined to be the U.S. Dollar, based on an assessment of the economic circumstances of the foreign operation, in accordance with SFAS No. 52, Foreign Currency Translation. Assets and liabilities of foreign operations, except for those whose functional currency is the U.S. Dollar, are translated into U.S. Dollars at current exchange rates. Translation adjustments resulting from fluctuations in exchange rates are included as a separate component of AOCI. Revenue and expense accounts of these operations are translated at average exchange rates prevailing during the year. Gains and losses arising from transactions denominated in currencies other than the functional currency, which were not material for all periods presented, are included in the results of operations of the period in which they occur. Deferred taxes are not provided on translation gains and losses where we expect earnings of a foreign operation to be permanently reinvested. Gains and losses relating to derivatives designated as hedges of the foreign currency exposure of a net investment in foreign operations are reported in foreign currency translation as a separate component of AOCI.

Consolidated Statements of Cash Flows. We have made certain classification elections within our Consolidated Statements of Cash Flows related to discontinued operations, cash received from insurance proceeds and cash overdrafts. Cash flows from discontinued operations are combined with cash flows from continuing operations within operating, investing and financing cash flows. Cash received from insurance proceeds are classified depending on the activity that resulted in the insurance proceeds. For example, business interruption insurance proceeds are included as a component of operating activities while insurance proceeds from damaged property are included as a component of investing activities. With respect to cash overdrafts, book overdrafts are included within operating cash flows while bank overdrafts are included within financing cash flows.

Distributions from Unconsolidated Affiliates. We consider dividends received from unconsolidated affiliates which do not exceed cumulative equity in earnings subsequent to the date of investment to be a return

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on investment and classify these amounts as operating activities within the accompanying Consolidated Statements of Cash Flows. Cumulative dividends received in excess of cumulative equity in earnings subsequent to the date of investment are considered to be a return of investment and are classified as investing activities.

New Accounting Pronouncements 2008. The following new accounting pronouncements were adopted during 2008 and the effect of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

SFAS No. 157, Fair Value Measurements. SFAS No. 157, defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. In February 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. FAS 157-1, Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements that Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13. Also in February 2008, the FASB issued FSP No. FAS 157-2, Effective Date of FASB Statement No. 157, which delays the effective date of SFAS No. 157 to fiscal years beginning after November 15, 2008 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The adoption of SFAS No. 157 and FSP No. FAS 157-1 effective January 1, 2008 did not have a material impact on our consolidated results of operations, financial position or cash flows. See Note 17 for further discussion. As permitted under FSP No. FAS 157-2, we have elected to defer the adoption of SFAS No. 157 for our goodwill impairment test and the measurement of asset retirement obligations until January 1, 2009. We do not expect that the adoption of FSP No. FAS 157-2 will have a material impact on our consolidated results of operations, financial position or cash flows.

In October 2008, the FASB issued FSP No. FAS 157-3, Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active, which clarifies the application of SFAS No. 157 in determining the fair value of a financial asset when the market for that financial asset is not active. FSP No. FAS 157-3 was effective upon issuance, including prior periods for which financial statements have not been issued. Revisions in fair values resulting from a change in the valuation technique or its application would be accounted for as a change in accounting estimate. The adoption of FSP No. FAS 157-3 had no impact on our consolidated results of operations, financial position or cash flows.

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities. In February 2007, the FASB issued SFAS No. 159, which permits entities to choose to measure certain financial instruments at fair value. We have determined to not elect fair value measurements for financial assets and financial liabilities included in the scope of SFAS No. 159.

EITF 06-11 Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. In June 2007, the EITF reached a consensus that a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital. The amount recognized in additional paid-in capital for the realized income tax benefit from dividends on those awards should be included in the pool of excess tax benefits available to absorb tax deficiencies on share-based payment awards. EITF 06-11 is applied prospectively to the income tax benefits that result from dividends on equity-classified employee share-based payment awards that are declared after December 31, 2007. The effect of adopting EITF 06-11 was not material to our consolidated results of operations, financial position or cash flows in 2008 and is not expected to be material to future periods.

FSP No. FAS 133-1 and FIN 45-4 Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of Statement No. 161 In September 2008, the FASB issued this guidance applicable to credit derivatives within the scope of SFAS No. 133, hybrid instruments that have embedded credit derivatives, and guarantees within the scope of FIN 45. We do not have any credit derivatives within the scope of SFAS No. 133 or hybrid instruments with

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embedded credit derivatives. This FSP also amends paragraph 13(a) of FIN 45 to require disclosure of the current status of the payment/performance risk of the guarantee. For example, the current status of the payment/performance risk of a credit-risk-related guarantee could be based on either recently issued external credit ratings or current internal groupings used by the guarantor to manage its risk. An entity that uses internal groupings shall disclose how those groupings are determined and used for managing risk. The provisions of this FSP that amend SFAS No. 133 and FIN 45 shall be effective for reporting periods (annual or interim) ending after November 15, 2008. We have adopted the disclosure requirements for guarantees effective December 31, 2008. The additional disclosure for our guarantees is contained in Note 19.

2007. The following significant accounting pronouncements were adopted during 2007 and the effect of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

FIN 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109. FIN 48, provides guidance on accounting for income tax positions about which we have concluded there is a level of uncertainty with respect to the recognition in our financial statements. We implemented FIN 48 effective January 1, 2007. As discussed further in Note 7, the implementation resulted in a cumulative effect decrease of $26 million to beginning Retained Earnings on the Consolidated Statements of Stockholders Equity and Comprehensive Income. Uncertain tax positions on consolidated or combined tax returns filed by Duke Energy which are now indemnified by us, were recorded as payables to Duke Energy.

2006. The following significant accounting pronouncements were adopted during 2006 and the effect of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

SFAS No. 158, Employer s Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R). SFAS No. 158, changes the recognition and disclosure provisions and measurement date requirements for an employer s accounting for defined benefit pension and other postretirement plans. We were required to initially recognize the funded status of our defined benefit pension and other postretirement plans and to provide the required additional disclosures as of December 31, 2006. The adoption of SFAS No. 158 recognition and disclosure provisions resulted in an increase in total assets of approximately $21 million (consisting of an increase in deferred tax assets of $27 million, offset by a decrease in intangible assets of $6 million), an increase in total liabilities of approximately $69 million and an increase in AOCI of approximately $48 million as of December 31, 2006.

Under the measurement date requirements of SFAS No. 158, an employer is required to measure defined benefit plan assets and obligations as of the date of its fiscal year-end statement of financial position (with limited exceptions). Historically, we had measured our plan assets and obligations up to three months prior to our fiscal year-end, as allowed under authoritative accounting literature. We adopted the change in measurement date early as was permitted, effective January 1, 2007, by re-measuring plan assets and benefit obligations as of that date, pursuant to the transition requirements of SFAS No. 158. Net periodic benefit cost for the three-month period between September 30, 2006 and December 31, 2006 was recognized, net of tax, as a separate adjustment of retained earnings as of January 1, 2007. Additionally, changes in plan assets and plan obligations between September 30, 2006 and December 31, 2006 not related to net periodic benefit cost were recognized, net of tax, as an adjustment to Other Comprehensive Income.

Pending. The following new accounting pronouncements have been issued, but have not yet been adopted as of December 31, 2008:

SFAS No. 141R, Business Combinations. In December 2007, the FASB issued SFAS No. 141R which replaces SFAS No. 141, Business Combinations. SFAS No. 141R requires the acquiring entity in a business combination to recognize all and only the assets acquired and liabilities assumed in the transaction, establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed, and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and

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understand the nature and financial effect of the business combination. SFAS No. 141R applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 and cannot be early adopted.

SFAS No. 160, Noncontrolling Interest in Consolidated Financial Statements. In December 2007, the FASB issued SFAS No. 160 which requires all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. SFAS No. 160 eliminates the diversity that currently exists in accounting for transactions between an entity and noncontrolling interests by requiring they be treated as equity transactions. We adopted the provisions of SFAS No. 160 effective January 1, 2009 as required.

When adopting the presentation and disclosure items, retrospective application to conform previously reported financial statements to the new presentation requirements is required. Changes to reflect the new measurement guidance for increases or decreases in ownership and other changes must be done prospectively. The new requirements for noncontrolling interests, results of operations and comprehensive income of subsidiaries change the presentation of operating results, related per-share information, and equity. SFAS No. 160 requires net income and comprehensive income to be displayed for both the controlling and the noncontrolling interests. Additional required disclosures and reconciliations include a separate schedule that shows the effects of any transactions with the noncontrolling interests on the equity attributable to the controlling interest.

As discussed in Note 2, a deferred gain associated with the formation of Spectra Energy Partners totaling approximately $60 million at December 31, 2008 and 2007 was classified within Regulatory and Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheets. This deferred gain was reclassified to Stockholders Equity upon the adoption of SFAS No. 160 on January 1, 2009. Other than this reclassification, the adoption of this standard did not have a material impact on consolidated results of operations, financial position or cash flows.

SFAS No. 161 Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133. In March 2008, the FASB issued SFAS No. 161 which amends and expands the disclosure requirements for SFAS No. 133 with the intent to provide users of financial statements an enhanced understanding of how and why derivative instruments are used, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. We adopted the provisions of SFAS No. 161 effective January 1, 2009 as required.

FSP No. FAS 142-3, Determination of the Useful Life of Intangible Assets. In April 2008, the FASB issued FSP No. FAS 142-3 which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, Goodwill and Other Intangible Assets. The adoption of the provisions of FSP No. FAS 142-3 on January 1, 2009 had no impact on our consolidated results of operations, financial position or cash flows.

EITF 07-01 Accounting for Collaborative Arrangements. In December 2007, the FASB ratified a consensus reached by the EITF to define collaborative arrangements and to establish reporting requirements for transactions between participants in a collaborative arrangement and between participants in the arrangement and third parties. A collaborative arrangement is a contractual arrangement that involves a joint operating activity. These arrangements involve two (or more) parties who are both (a) active participants in the activity and (b) exposed to significant risks and rewards dependent on the commercial success of the activity. An entity should report the effects of applying EITF 07-01 as a change in accounting principle through retrospective application to all prior periods presented for all arrangements existing as of the effective date. The adoption of the provisions of EITF 07-01 on January 1, 2009 had no impact on our consolidated results of operations, financial position or cash flows.

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2. Spectra Energy Partners, LP

In July 2007, Spectra Energy completed its initial public offering (IPO) of Spectra Energy Partners, a newly formed natural gas infrastructure master limited partnership. Spectra Energy contributed to Spectra Energy Partners 100% of the ownership of East Tennessee Natural Gas, LLC (East Tennessee), 50% of the ownership of Market Hub Partners, LLC, including the Moss Bluff and Egan natural gas storage operations, and a 24.5% interest in Gulfstream Natural Gas System, LLC (Gulfstream). Spectra Energy Partners issued 11.5 million common units to the public in the offering, representing 17% of Spectra Energy Partners outstanding equity. Spectra Energy retained an 83% equity interest in Spectra Energy Partners, including its common units, subordinated units and a 2% general partner interest. Net cash of approximately $230 million was received by Spectra Energy Partners upon closing of the IPO.

In accordance with SAB 51, recognition of a gain associated with such a sale is only appropriate if the class of securities sold by the subsidiary does not contain any preference over the subsidiary s other classes of securities. Since the common units of Spectra Energy Partners have preferential cash distribution rights as compared to the subordinated units, we deferred recognition of the gain associated with the sale of the common units until the subordinated units owned by Spectra Energy are converted into common units with rights equivalent to the remaining unitholders. The deferred gain totaled approximately $60 million at December 31, 2008 and 2007 and is included in Regulatory and Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheets. As previously discussed, the deferred gain was reclassified to Stockholders Equity on January 1, 2009 upon the adoption of SFAS No. 160.

In April 2008, Spectra Energy completed the sale of Saltville Gas Storage Company L.L.C. and the P-25 pipeline to Spectra Energy Partners for $107 million. Proceeds from the sale consisted of 4,207,641 Spectra Energy Partners common units, 85,870 general partner units and $5 million in cash. Spectra Energy s ownership of Spectra Energy Partners increased from 83% to 84% as a result of the issuance of the new common and general partner units. No gain or loss was recognized on the disposition since this transaction represented a transfer of entities under common control.

3. Acquisitions and Dispositions

Acquisitions (excluding acquisitions made by discontinued operations that are discussed in Note 8). We consolidate assets and liabilities from acquisitions as of the purchase date, and include earnings from acquisitions in consolidated earnings after the purchase date. Assets acquired and liabilities assumed are recorded at estimated fair values on the date of acquisition. The purchase price minus the estimated fair value of the acquired assets and liabilities meeting the definition of a business is recorded as goodwill. The allocation of the purchase price may be adjusted if additional information is received during the allocation period, which generally does not exceed one year from the consummation date. This allocation period may be longer for certain income tax items.

In May 2008, we acquired the 24.4 million units of the Income Fund that were held by non-affiliated holders at a purchase price of 11.25 Canadian dollars per unit, for a total purchase price of 279 million Canadian dollars (approximately $274 million). We now own 100% of the Midstream operations. Prior to the acquisition, the Income Fund indirectly held 54% of our consolidated Midstream operations and we indirectly held the remaining 46%. The Income Fund is included in the Western Canada Transmission & Processing business segment. The transaction, primarily driven by changes in Canadian federal tax rules as related to income trusts, was accounted for as a step acquisition, using the purchase method of accounting in accordance with SFAS No. 141, Business Combinations.

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The following table summarizes the fair values of the assets acquired and liabilities assumed as of May 1, 2008.

	Purchase Price Allocation (in millions)
Purchase price	$ 274
Current assets	20
Property, plant and equipment, net	340
Current liabilities	(11)
Long-term debt (intercompany)	(89)
Deferred credits and other liabilities	(9)
Deferred income taxes	(43)
Total assets acquired/liabilities assumed	208
Goodwill	$ 66

The pro forma results of operations as if this acquisition occurred as of the beginning of the periods presented do not materially differ from reported results.

Dispositions (excluding dispositions made by discontinued operations that are discussed in Note 8). In April 2008, Spectra Energy sold Saltville Gas Storage Company L.L.C. and the P-25 pipeline to Spectra Energy Partners for $107 million. See Note 2 for further discussion.

For the year ended December 31, 2006, the sale of other assets and businesses resulted in $80 million in proceeds and net pre-tax gains of $47 million recorded in Gains on Sales of Other Assets and Other, Net on the Consolidated Statements of Operations. Significant sales of assets and businesses during 2006 are detailed as follows:

U.S. Transmission s sale of certain Stone Mountain natural gas gathering system assets resulted in proceeds of $18 million (which is reflected in Net Proceeds From the Sales of Equity Investments and Other Assets, and Sales of and Collections on Notes Receivable within Cash Flows from Investing Activities in the Consolidated Statements of Cash Flows), and a pre-tax gain of $5 million which was recorded in Gains on Sales of Other Assets and Other, Net. In addition, U.S. Transmission s sale of stock, received as consideration for the settlement of a customer s transportation contract, resulted in proceeds of $29 million which is reflected in Other, Assets within Cash Flows from Operating Activities and a pre-tax gain of $29 million, of which $28 million was recorded in Gains on Sales of Other Assets and Other, Net and $1 million was recorded in Other Income and Expenses, Net. See Note 10 for further discussion.

As a result of a settlement of a property insurance claim, U.S. Transmission received proceeds of $30 million and recognized a pre-tax gain of $10 million, which was recorded in Gains on Sales of Other Assets, and Other, Net.

In September 2006, the Income Fund created in 2005 sold 9 million previously unissued Trust Units for total proceeds of $94 million, net of commissions and other expenses of issuance, which is included in Proceeds from Issuances of Subsidiary Stock within Cash Flows from Financing Activities. The sale of these units reduced our ownership interest in the businesses of 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 SAB 51 gain on the sale of subsidiary stock, which is classified in Gain on 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. There were no deferred taxes recorded as a result of this transaction.

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See Note 8 for discussion of businesses acquired or disposed of during 2006 that were included in the operations transferred to Duke Energy during 2006 and, accordingly, are included in Income From Discontinued Operations, Net of Tax.

4. Business Segments

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.

Our chief operating decision maker regularly reviews financial information about each of these business units in deciding how to allocate resources and evaluate performance. All of the business units are considered reportable segments under SFAS No. 131. There is no aggregation within our defined business segments.

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. The natural gas transmission and storage operations in the U.S. are primarily subject to the Federal Energy Regulatory Commission s (FERC s) rules and regulations.

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. These services are provided by Union Gas, and are primarily subject to the rules and regulations of the OEB.

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. This segment conducts business primarily through BC Pipeline, BC Field Services, NGL marketing and Midstream businesses. BC Pipeline and BC Field Services operations are primarily subject to the rules and regulations of Canada s National Energy Board (NEB).

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 reportable segments offer different products and services and are managed separately as business units. Management evaluates segment performance based on earnings before interest and taxes (EBIT) from continuing operations, 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 short-term investments are managed centrally, so the associated realized and unrealized gains and losses from foreign currency transactions and interest and dividend income on those balances are excluded from the segments EBIT.

Transactions between reportable segments are accounted for on the same basis as transactions with unaffiliated third parties.

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Business Segment Data

	Unaffiliated Revenues	Intersegment Revenues	Total Revenues(a)	Segment EBIT/ Consolidated Earnings from Continuing Operations before Income Taxes(a)	Depreciation and Amortization(a)	Capital and Investment Expenditures(a)	Segment Assets
				(in millions)			
2008							
U.S. Transmission	$ 1,595	$ 5	$ 1,600	$ 844	$ 232	$ 1,400	$ 9,636
Distribution	1,991		1,991	353	175	373	4,505
Western Canada Transmission & Processing	1,482		1,482	398	147	222	3,709
Field Services				716			858
Total reportable segments	5,068	5	5,073	2,311	554	1,995	18,708
Other	6	39	45	(78)	15	35	3,460
Eliminations		(44)	(44)				(244)
Interest expense				(636)			
Interest income and other(b)				28			
Total consolidated	$ 5,074	$	$ 5,074	$ 1,625	$ 569	$ 2,030	$ 21,924
2007							
U.S. Transmission	$ 1,535	$ 5	$ 1,540	$ 894	$ 217	$ 898	$ 8,763
Distribution	1,899		1,899	322	162	369	4,968
Western Canada Transmission & Processing	1,266		1,266	359	135	195	4,637
Field Services				533			1,076
Total reportable segments	4,700	5	4,705	2,108	514	1,462	19,444
Other	4	27	31	(112)	4	39	3,876
Eliminations		(32)	(32)				(350)
Interest expense				(633)			
Interest income and other(b)				17			
Total consolidated	$ 4,704	$	$ 4,704	$ 1,380	$ 518	$ 1,501	$ 22,970
2006							
U.S. Transmission	$ 1,516	$ (13)	$ 1,503	$ 816	$ 203	$ 343	
Distribution	1,822		1,822	265	144	315	
Western Canada Transmission & Processing	1,173		1,173	339	126	132	
Field Services				569			
Total reportable segments	4,511	(13)	4,498	1,989	473	790	
Other	(10)	39	29	(77)	9	40	
Eliminations		(26)	(26)				
Interest expense				(605)			
Interest income and other(b)				18			

Total consolidated	$ 4,501	$	$ 4,501	$ 1,325	$ 482	$ 830

(a) Excludes amounts associated with entities included in discontinued operations.
(b) Other includes foreign currency transaction gains and losses, and additional minority interest expense not allocated to the segment results.

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Geographic Data

	U.S.	Canada	Other Foreign	Consolidated
		(in millions)		
2008				
Consolidated revenues(a)	$ 1,423	$ 3,651	$	$ 5,074
Consolidated long-lived assets	7,984	10,096		18,080
2007				
Consolidated revenues(a)	1,393	3,311		4,704
Consolidated long-lived assets	7,015	12,447		19,462
2006				
Consolidated revenues(a)	1,381	3,110	10	4,501

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

5. Regulatory Matters

Regulatory Assets and Liabilities. Our regulated operations are subject to SFAS No. 71. Accordingly, we record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. See Note 1 for further discussion.

Regulatory Assets and Liabilities

	December 31,		Recovery/ Refund
	2008	2007	Period Ends
	(in millions)		
Regulatory Assets(a,b)			
Net regulatory asset related to income taxes(c)	$ 732	$ 809	(d)
Project costs	35	45	2024
Hedge costs and other deferrals		1	2008
Vacation accrual	12	11	2009
Deferred debt expense/premium(e)	60	8	(d)
Environmental clean-up costs	6	6	2017
Other	17	9	(f)
Total Regulatory Assets	$ 862	$ 889	
Regulatory Liabilities(b)			
Removal costs(e)(g)	$ 343	$ 397	(h)
Gas purchase costs(i)	15	100	2009
Pipeline rate credit(g)	33	35	2041
Storage and transportation liability(i)	27	7	2009
Earnings sharing liability(i)	14		2009
Other(g)	20	29	2010
Total Regulatory Liabilities	$ 452	$ 568	

(a) Included in Regulatory Assets and Deferred Debits.
(b) All regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(c) All amounts are expected to be included in future rate filings.
(d) Recovery/refund is over the life of the associated asset or liability.
(e) Included in rate base.
(f) Recovery/Refund period currently unknown.
(g) Included in Regulatory and Other Deferred Credits and Other Liabilities.
(h) Liability is extinguished as the associated assets are retired.
(i) Included in Other Current Liabilities.

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Rate Related Information

Maritimes & Northeast Pipeline, L.L.C. (M&N LLC). M&N LLC operates under rates approved by FERC in May 2006. M&N LLC is required to file a new rate case within six months after its Phase IV expansion facilities go into service, which is anticipated to be the summer of 2009.

Maritimes & Northeast Pipeline Limited Partnership (M&N LP). In 2007, M&N LP operated under an NEB-approved toll settlement that expired December 31, 2007. A toll settlement agreement for 2008 was approved by the NEB in January 2008. The settlement-approved tolls for 2008 did not change significantly from those approved for 2007. M&N LP is in negotiations with its customers for a 2009 tolls settlement to be effective January 1, 2009, and in the interim, has received approval of an interim tolls application which sets the tolls effective January 1, 2009 at the approved 2008 rate. This interim rate will continue throughout 2009 until a 2009 tolls settlement agreement is approved by the NEB.

Algonquin Gas Transmission, LLC (Algonquin). In April 2005, Algonquin filed and the FERC accepted new negotiated rate agreements with the Algonquin customers that include a rate moratorium provision through December 2008. Algonquin and its customers have agreed to extend the previously agreed rates through October 2010.

Gulfstream Natural Gas System, L.L.C. Gulfstream operates under rates approved by FERC in 2007. In June 2007, the FERC issued an order approving Gulfstream s Phase III expansion project. That order also required Gulfstream to file a Cost and Revenue Study three years after the Phase III facilities go in service. The projected filing date would be the fall of 2011.

East Tennessee Natural Gas, LLC. On November 1, 2005, East Tennessee placed into effect new rates approved by FERC as a result of a rate settlement with customers. The settlement agreement includes a five-year rate moratorium and certain operational changes.

Texas Eastern Transmission, L.P. (Texas Eastern). Texas Eastern continues to operate under rates approved by FERC in 1998 in an uncontested settlement between Texas Eastern and its customers.

Southeast Supply Header, LLC (SESH). SESH operates under rates approved by FERC order in May 2007. That order required SESH to file a Cost and Revenue Study at the end of three years of operation. The projected filing date would be the summer of 2011.

Union Gas. Union Gas has rates that are approved by the OEB. Final 2008 rates, reflecting the incentive regulation settlement agreement accepted by the OEB, were implemented April 1, 2008, retroactive to January 1, 2008. The settlement allows for annual inflationary rate increases, offset by a productivity factor that is fixed for each of the next five years. The rates for most small-volume customers increased by less than 2%, and the rates for large-volume customers increased by less than 1%.

Union Gas applied for new rates under the incentive regulation framework. The OEB s decision, issued in January 2009, provides for slight increases for small-volume customers and slight decreases for large-volume customers. Beginning April 1, 2009, the new rates will be retroactively applied to January 1, 2009.

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. 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.

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In November 2006, Union Gas received a decision from the OEB on the regulation of rates for gas storage services in Ontario (the Storage Forbearance Decision). The OEB determined that it would 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. The Storage Forbearance Decision requires Union Gas to continue to share long-term storage margins with ratepayers over a four-year phase-out period that started in 2007.

In March 2008, Union Gas applied to the OEB for the annual disposition of its 2007 non-commodity deferral account balances. The OEB issued its decision on this application in June 2008 finding that Union Gas should share revenue on all long-term storage contracts. Union Gas had previously interpreted the Storage Forbearance Decision to apply only to those contracts that were in existence as of the date of the Storage Forbearance Decision. Union Gas appealed this decision, and the OEB denied the appeal in October 2008. Union Gas recorded a $15 million charge to Transportation, Storage and Processing of Natural Gas operating revenues on the Consolidated Statement of Operations in the second quarter of 2008 as a result of the June 2008 decision.

Union Gas recorded regulatory assets of $164 million as of December 31, 2008 and $148 million as of December 31, 2007 related to deferred income tax liabilities. Under the current OEB-authorized rate structure, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since most of these timing differences are related to property, plant and equipment costs, this recovery is expected to occur over the life of those assets.

Union Gas recorded removal costs of $330 million as of December 31, 2008 and $380 million December 31, 2007. These regulatory liabilities represent collections from customers under approved rates for future removal activities that are expected to occur associated with the regulated facilities.

In addition, Union Gas has recorded regulatory liabilities of $15 million as of December 31, 2008 and $100 million as of December 31, 2007, representing gas cost collections from customers under approved rates that exceeded the actual cost of gas for the associated periods. Union Gas files quarterly with the OEB to ensure that customers rates reflect future expected prices based on published forward-market prices. The difference between the approved and the actual cost of gas is deferred for future repayment to customers and is a component of quarterly gas commodity rates.

BC Pipeline and BC Field Services. A two-year BC Pipeline settlement agreement for transmission tolls reached with customers and approved by the NEB expired on December 31, 2007. In 2008, BC Pipeline and its customers reached a settlement agreement regarding the determination of final tolls for transmission services for 2008, 2009 and 2010. The NEB approved this settlement agreement on November 4, 2008. Rates per the new agreement did not significantly change from prior rates.

The BC Field Services gathering and processing facilities currently operate under a Framework for Light-Handed Regulation (the Framework) approved by the NEB. The Framework established policies and guidelines which, among other things, permit the negotiation by BC Field Services of contracts for gathering and processing services with new and existing shippers. The Framework also provides that BC Field Services operation is responsible for the level of utilization of its gathering and processing facilities and, consequently, bears the opportunities and risks associated with that responsibility. BC Field Services tolls and other service conditions for gathering and processing services are subject to NEB oversight.

The BC Pipeline and BC Field Services businesses in Western Canada recorded regulatory assets of $456 million as of December 31, 2008 and $558 million as of December 31, 2007 related to deferred income tax liabilities. Under the current NEB-authorized rate structure, income tax costs are recovered in tolls based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is

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expected that the transportation and field services tolls will be adjusted to recover these taxes. Since most of these timing differences are related to property, plant and equipment costs, this recovery is expected to occur over a 20 to 30 year period.

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

We believe that the effects of the above matters will not have a material adverse effect on our future consolidated results of operations, financial position or cash flows.

6. Other Income and Expenses, net

The components are as follows:

	2008	2007	2006
		(in millions)	
Income (Expense)			
Interest income	$ 22	$ 26	$ 32
Foreign currency exchange gains (losses)	11	(2)	
AFUDC allowance (equity component)	33	23	11
Realized and unrealized mark-to-market effect on discontinued hedges			(19)
Other(a)		6	88
Total	$ 66	$ 53	$ 112

(a) 2006 primarily represents management fees charged by us to an unconsolidated affiliate. See Note 11 for further discussion.

7. Income Taxes

The following details the components of income tax expense:

	2008	2007	2006
		(in millions)	
Current income taxes			
Federal	$ 240	$ 316	$ 270
State	19	21	(35)
Foreign	78	32	129
Total current income taxes	337	369	364
Deferred income taxes			
Federal	108	(15)	83
State	6	4	(22)
Foreign	45	82	(32)
Total deferred income taxes	159	71	29

Income tax expense from continuing operations	496	440	393
Income tax expense from discontinued operations	3	10	63
Total income tax expense	$ 499	$ 450	$ 456

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Earnings from Continuing Operations before Income Taxes

	2008	2007 (in millions)	2006
Domestic	$ 1,097	$ 926	$ 945
Foreign	528	454	380
Total earnings from continuing operations before income taxes	$ 1,625	$ 1,380	$ 1,325

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

	2008	2007 (in millions)	2006
Income tax expense, computed at the statutory rate of 35%	$ 569	$ 483	$ 464
State income tax, net of federal income tax effect(a)	9	16	(37)
Tax differential on foreign earnings	(62)	(45)	(36)
Pass-through of income tax expense(b)			26
Impairment of Bolivian investment(c)			(25)
Domestic production activities deduction	(13)	(11)	
Other items, net	(7)	(3)	1
Total income tax expense from continuing operations	$ 496	$ 440	$ 393
Effective tax rate	30.5%	31.9%	29.7%

(a) In 2006, a state income tax benefit of approximately $30 million was recognized due to a reduction in the unitary state tax rate as a result of Duke Energy s merger with Cinergy.

(b) Prior to April 2006, the effective date of the tax sharing agreement with Duke Energy, tax expenses and benefits were passed through to Duke Energy.

(c) In 2006, a tax benefit was recognized for an impairment of an investment in Bolivia due to a change in tax status, which is included in continuing operations.

Net Deferred Income Tax Liability Components

	December 31, 2008	2007
	(in millions)	
Deferred credits and other liabilities	$ 183	$ 212
Federal effects of uncertain tax benefits	18	16
Other	12	16
Total deferred income tax assets	213	244
Valuation allowance	(12)	(15)
Net deferred income tax assets	201	229

Investments and other assets	(928)	(1,039)
Accelerated depreciation rates	(1,962)	(1,400)
Regulatory assets and deferred debits	(126)	(645)
Total deferred income tax liabilities	(3,016)	(3,084)
Total net deferred income tax liabilities	$ (2,815)	$ (2,855)

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

	December 31, 2008	December 31, 2007
	(in millions)	
Other current assets	$ 28	$ 46
Other current liabilities	(54)	(18)
Deferred credits and other liabilities	(2,789)	(2,883)
Total net deferred income tax liabilities	$ (2,815)	$ (2,855)

At December 31, 2008, we had an unused state net operating loss carryforward of $159 million that expires beginning in 2012. The tax benefits associated with the state net operating losses of $12 million are expected to be fully recoverable within the applicable statutory expiration periods.

At December 31, 2008, we had a foreign net operating loss carryforward of $28 million and a foreign capital loss carryforward of $93 million that expires at various times beginning in 2027. We have established a valuation allowance of $12 million at December 31, 2008 and $15 million at December 31, 2007 against the deferred tax asset related to the foreign capital loss carryforward.

Reconciliation of Gross Unrecognized Income Tax Benefits

	2008	2007
	(in millions)	
Balance at January 1	$ 86	$ 75
Increases related to prior year tax positions	10	3
Decreases related to prior year tax positions	(10)	(5)
Increases related to current year tax positions	7	16
Decreases related to settlements with taxing authorities		(2)
Reductions due to lapse of statute of limitations	(10)	(6)
Foreign currency translation	(7)	5
Balance at December 31	$ 76	$ 86

Unrecognized tax benefits totaled $76 million at December 31, 2008. Of this, $67 million would reduce the annual effective tax rate if recognized on or after January 1, 2009.

We recorded a net decrease of $10 million in gross uncertain tax benefits during 2008. Of this, $1 million was attributable to increased income tax expense and the remainder was attributable to uncertain tax benefits associated with deferred tax liabilities and goodwill.

We recognize potential accrued interest and penalties related to unrecognized tax benefits as interest expense and as other expense, respectively. In accordance with FIN 48, we recognized $4 million of interest expense during 2008 and $7 million during 2007. Accrued interest and penalties totaled $21 million at December 31, 2008 and $19 million at December 31, 2007.

Although uncertain, we believe it is reasonably possible that prior to December 31, 2009 the total amount of unrecognized tax benefits could decrease by approximately $31 million. The anticipated changes in unrecognized tax benefits relate to expiration of statutes of limitations and expected audit settlements focused primarily on the classification of certain tax attributes, transfer pricing and income allocation.

Prior to January 1, 2007, we were included in the consolidated federal income tax return and certain combined and unitary state tax returns of Duke Energy. In connection with the spin-off, we indemnified Duke Energy for Spectra Energy s share of taxes on such returns. Accordingly, obligations of $39 million for uncertain

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federal and state income tax positions for periods in which we were included in a Duke Energy consolidated, combined or unitary filing have been recorded as guarantee obligations within Regulatory and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheet as of December 31, 2008. We have no liability to Duke Energy for federal income tax liabilities prior to 1999 and for state income tax liabilities prior to 1997 as those tax years have been closed.

We remain subject to examination for Canada income tax return filings for years 2002 through 2007 and U.S. income tax return filings for 2007.

Cumulative undistributed earnings of our foreign subsidiaries at December 31, 2008 totaled $98 million for which we have not provided U.S. deferred income taxes and foreign withholding taxes since we intend to permanently reinvest such earnings in our foreign operations. Unrecognized U.S. deferred income taxes and foreign withholding taxes on these undistributed earnings are expected to be $35 million.

8. Discontinued Operations

In anticipation of the spin-off from Duke Energy, Spectra Capital implemented an internal reorganization in December 2006 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. Operations transferred included International Energy, Spectra Capital s effective 50% interest in Crescent and certain operations within Other, primarily Duke Energy Trading and Marketing, LLC, DukeNet Communications, LLC, Duke Energy Merchants, LLC and Spectra Capital s 50% interest in Duke/Fluor Daniel. Approximately $5.1 billion of assets, $1.9 billion of liabilities (which includes approximately $0.9 billion of debt), $0.2 billion of minority interest and $3.0 billion of member s equity were transferred from Spectra Capital to Duke Energy in December 2006. In April 2006, Spectra Capital transferred its ownership interest in DENA s Midwestern generation assets to a Duke Energy subsidiary. No gain or loss was recognized on the transfer of operations to Duke Energy as the transfers were among entities under common control. In addition, in 2005, Duke Energy s Board of Directors authorized and directed management to execute the sale or disposition of substantially all of DENA s remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets. We do not anticipate significant continuing involvement in any of the businesses transferred to Duke Energy or sold to third parties. Therefore, the results of operations for 2006 for these operations have been reflected as discontinued operations in the accompanying Consolidated Statements of Operations. Information presented for 2006 in the Consolidated Statements of Cash Flows does not include any reclassifications or adjustments to amounts historically reported for these transferred businesses.

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

	Operating Revenues	Pre-tax Earnings (Loss)	Income Tax Expense (Benefit)	Income (Loss) From Discontinued Operations, Net of Tax
		(in millions)		
2008				
Western Canada Transmission & Processing	$ 24	$	$	$
Other	86			
Total consolidated	$ 110	$	$	$
2007				
Western Canada Transmission & Processing	$ 38	$ 8	$ 4	$ 4
Other	1	20	7	13
Total consolidated	$ 39	$ 28	$ 11	$ 17
2006				
Western Canada Transmission & Processing	$ 31	$ 6	$ 2	$ 4
Commercial Power	15	(16)	(2)	(14)
International Energy	961	64	54	10
Crescent	221	518	206	312
Other(a)	788	(197)	(197)	
Total consolidated	$ 2,016	$ 375	$ 63	$ 312

(a) Other includes the results for DENA s discontinued operations, excluding the operations of the Midwest and Southeast plants.

The following significant transactions, the effects of which are included in Income From Discontinued Operations, Net of Tax on the Consolidated Statements of Income, occurred during 2008, 2007 and 2006.

2008

On December 1, 2008, we closed on the sale of our interests in the Nevis and Brazeau River natural gas gathering and processing facilities, which were part of the Western Canada Transmission & Processing segment. Total proceeds from the sale were 129 million Canadian dollars (approximately $104 million) and we recognized a $2 million pre-tax gain (a negligible amount after tax) on the sale.

In June 2007, Spectra Energy LNG Sales, Inc. (Spectra Energy LNG) reached a settlement agreement related to an arbitration proceeding regarding Spectra Energy LNG s claims for the period prior to May 2002 under certain liquefied natural gas (LNG) transportation contracts with Sonatrach and Sonatrading Amsterdam B.V. (Sonatrach). See 2007 below for impacts of this settlement. In June 2008, the parties entered into a settlement agreement under which Spectra Energy LNG s claims for the period after May 2002 were satisfied pursuant to commercial transactions involving the purchase of propane from Sonatrach. We entered into associated agreements with an affiliate of DCP Midstream and another party for the sale of these propane volumes. Net purchases and sales of propane under these arrangements are reflected as Other discontinued operations.

2007

In 2007, $18 million of income ($11 million, net of tax), was recorded related to the settlement of the Sonatrach proceeding described above.

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2006

Acquisitions. During 2006, International Energy closed on two transactions which resulted in the acquisition of an additional 27% interest in the Aguaytia Integrated Energy Project (Aguaytia), located in Peru, for approximately $31 million (approximately $18 million net of cash acquired). These acquisitions increased International Energy s ownership in Aguaytia to 66% and resulted in the accounting for Aguaytia as a consolidated entity. Prior to the acquisition of this additional interest, Aguaytia was accounted for as an equity method investment. No goodwill was recorded as a result of this acquisition.

Also in 2006, we acquired the remaining 33.3% interest in Bridgeport Energy LLC (Bridgeport) from United Bridgeport Energy LLC (UBE) for approximately $71 million. No goodwill was recorded as a result of this acquisition. The assets and liabilities of Bridgeport were included as part of DENA s power generation assets that were sold. See below for further discussion.

Dispositions. Significant sales of other assets and equity investments during 2006 were as follows:

Crescent. In 2006, a wholly owned subsidiary closed an agreement to create a joint venture of Crescent (the Crescent JV) with Morgan Stanley Real Estate Fund V U.S., L.P. (MSREF) and other affiliated funds controlled by Morgan Stanley (collectively the MS Members). Under the agreement, our subsidiary contributed all of the membership interests in Crescent to a newly-formed joint venture, which was ascribed an enterprise value of approximately $2.1 billion as of December 31, 2005. In conjunction with the formation of the Crescent JV, the joint venture, Crescent and Crescent s subsidiaries entered into a credit agreement with third party lenders under which Crescent borrowed approximately $1.21 billion, net of transaction costs, of which approximately $1.19 billion was immediately distributed to us. Immediately following the debt transaction, the MS Members collectively acquired a 49% membership interest in the Crescent JV from us for a purchase price of approximately $415 million. A 2% interest in the Crescent JV was also issued by the joint venture to the President and Chief Executive Officer of Crescent. In conjunction with the Crescent JV transaction, we recognized a pre-tax gain on the sale of approximately $250 million in 2006. As a result of the Crescent transaction, we no longer controlled the Crescent JV and in September 2006 deconsolidated our investment in Crescent and accounted for our investment in the Crescent JV under the equity method of accounting. The proceeds from the sale were recorded on the Consolidated Statements of Cash Flows as follows: approximately $1.2 billion in long-term debt proceeds, net of issuance costs, were classified as Proceeds From the Issuance of Long-term Debt within Financing Activities, and approximately $380 million, which represents cash received from the MS Members net of cash held by Crescent as of the transaction date, were classified as Net Proceeds From the Sales of and Distributions From Equity Investments and Other Assets, and Sales of and Collections on Notes Receivable within Investing Activities.

For the period from January 1, 2006 to September 7, 2006, Crescent commercial and multi-family real estate sales resulted in $254 million of proceeds and $201 million of net pre-tax gains. Sales primarily consisted of two office buildings for a pre-tax gain of $81 million and land for a pre-tax gain of $52 million, as well as several other large land tract sales.

Other. As discussed above, during 2005, Duke Energy s Board of Directors authorized and directed management to execute the sale or disposition of substantially all of DENA s remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets. Approximately $700 million was incurred from the announcement date through December 31, 2006, of which approximately $230 million was incurred during 2006. In January 2006, we signed an agreement to sell DENA s entire fleet of power generation assets outside the Midwest. This transaction closed in May 2006. Total proceeds from the sale were approximately $1.6 billion. As of December 31, 2006, the exit activities of DENA were substantially complete. In 2006, we recognized a $51 million pre-tax gain on the sale of available-for-sale securities, primarily related to DENA.

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Impairments. In 2006, International Energy recorded a $50 million pre-tax other-than-temporary impairment charge related to an investment in Campeche, a natural gas compression facility in the Cantarell oil field in the Gulf of Mexico. Campeche project revenues were generated from a gas compression services agreement with the Mexican national oil company (PEMEX). It was determined that there was a limited future need for Campeche s gas compression services. Management of International Energy determined that it was probable that the Campeche investment would ultimately be sold or the gas compression services agreement would be renewed for a significantly lower rate. An other-than-temporary impairment loss was recorded to reduce the carrying value to our best estimate of realizable value. The charges consisted of a $17 million impairment of the carrying value of the equity method investment and a $33 million reserve against notes receivable from Campeche.

In December 2006, we engaged in discussions with a potential buyer of International Energy s assets in Bolivia. Such discussions to sell the assets were subject to a binding agreement between the parties, which was finalized in February 2007 (subsequent to the December 2006 transfer of International Energy to Duke Energy), and resulted in the sale of International Energy s 50% ownership interest in two hydroelectric power plants near Cochabamba, Bolivia for $20 million. Based on the agreed upon selling price of the assets, in 2006 we recorded pre-tax impairment charges of $28 million. The impairment charges reduced the carrying value of the assets to the estimated selling price pursuant to the aforementioned agreement.

In the first quarter of 2006, a pre-tax allowance of $19 million ($12 million after tax) was recorded against a receivable due from the 2003 purchaser of International Energy s European operations. As a result of a settlement, a pre-tax write-up of the receivable of $9 million ($5 million after tax) was recorded in the second quarter of 2006 as a reduction in the valuation allowance. International Energy received the settlement proceeds in July 2006.

9. Earnings per Common Share

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

The following table presents our basic and diluted EPS calculations:

	2008	2007
	(in millions, except per-share amounts)	
Income from continuing operations	$ 1,129	$ 940
Income from discontinued operations, net of tax		17
Net income	$ 1,129	$ 957
Weighted average common shares, outstanding		
Basic	622	632
Diluted	624	635
Basic earnings per common share		
Continuing operations	$ 1.82	$ 1.48
Discontinued operations, net of tax		0.03
Total basic earnings per common share	$ 1.82	$ 1.51
Diluted earnings per common share		
Continuing operations	$ 1.81	$ 1.48
Discontinued operations, net of tax		0.03
Total diluted earnings per common share	$ 1.81	$ 1.51

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Weighted-average shares used to calculate diluted EPS includes the effect of certain options and restricted stock awards. Certain other options and stock awards related to approximately ten million and nine million shares for 2008 and 2007, respectively, were not included in the calculation of diluted EPS because either the option exercise prices were greater than the average market price of the shares during these periods or performance measures related to the awards had not yet been met.

Weighted-average shares outstanding and EPS data for 2006 are not presented since Spectra Capital, our predecessor entity for financial reporting purposes, was a wholly owned subsidiary of Duke Energy during 2006. As discussed in Note 1, approximately 631 million shares of our common stock were issued to Duke Energy shareholders on January 2, 2007 in connection with the spin-off.

10. Marketable Securities

At December 31, 2008, we had $13 million of short-term and $53 million of long-term investments. At December 31, 2007, there were no outstanding short-term and $244 million of long-term investments.

Purchases and sales of available-for-sale securities are presented on a gross basis within Cash Flows from Investing Activities in the accompanying Consolidated Statements of Cash Flows.

Short-term investments. During 2008, we transferred $13 million in short-term investments associated with captive insurance from restricted reserves and had no other sales or purchases. During 2006, we purchased $9,132 million and received proceeds on sales of $9,653 million of short-term investments. There were no purchases or sales of short-term investments in 2007.

During 2008, the U.S. Transmission segment received shares of stock as consideration for a customer bankruptcy settlement and recorded a gain based on the quoted market price on the date of receipt of $31 million ($21 million after tax) which is reflected in Gains on Sales of Other Assets and Other, Net in the Consolidated Statements of Operations. The stock was subsequently sold in 2008, resulting in net proceeds of $27 million, reflected in Cash Flows from Operating Activities on the Consolidated Statements of Cash Flows, and a loss of $4 million recorded as Other Income and Expenses, Net.

During 2006, the U.S. Transmission segment received shares of stock as consideration for settlement of a customer s transportation contracts. The market value of the equity securities, determined by quoted market prices on the date of receipt of $28 million is reflected in Gains on Sales of Other Assets and Other, Net in the Consolidated Statements of Operations. These securities were subsequently sold in 2006 and an additional gain of $1 million was recognized in Other Income and Expenses, Net in the Consolidated Statements of Operations.

Long-term investments. We invested a portion of the proceeds from Spectra Energy Partners IPO in 2007 in financial instruments, including money market and debt securities that frequently have stated maturities of 20 years or more. These investments, which totaled $32 million as of December 31, 2008 and $155 million as of December 31, 2007, are pledged as collateral against Spectra Energy Partners term loan and are classified as Investments and Other Assets Other on the Consolidated Balance Sheets. We purchased $1,132 million and received proceeds on sales of $1,256 million of these investments in 2008, and purchased $1,439 million and received proceeds on sales of $1,284 million of these investments in 2007.

On January 2, 2007, Duke Energy distributed to us certain corporate assets and liabilities, including $96 million of marketable securities held in a grantor trust account associated with captive insurance losses of approximately the same amount transferred to us. These securities, which are generally comprised of short-term debt instruments, are classified as long-term since they are restricted for insurance reserves. We purchased $1 million and received proceeds on sales of $36 million of other long-term investments in 2008 within the captive insurance portfolio, and purchased $93 million and received proceeds on sales of $121 million in 2007.

On April 1, 2006, we transferred the operations of Bison, a captive insurance entity, to Duke Energy. Prior to the transfer of Bison, we invested in debt and equity securities that were held in the captive insurance

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investment portfolio. During 2006, we purchased $158 million and received proceeds on sales of $122 million on other long-term investments within the captive insurance portfolio.

The estimated fair values of long-term investments at December 31, 2008 and 2007, classified as available-for-sale, are as follows:

	December 31,					
	2008			2007		
	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value
	(in millions)					
Corporate debt securities	$	$	$ 25	$	$	$ 125
U.S. Government securities			21			
Other			7			47
Total long-term investments	$	$	$ 53	$	$	$ 172

The average contractual maturity of the above securities was either less than one year at December 31, 2008 and 2007 or the security had been sold as of the date of this report.

11. Investments in and Loans to Unconsolidated Affiliates and Related Party Transactions

Investments in affiliates for which we are not the primary beneficiary, but over which we have significant influence, are accounted for using the equity method. As of December 31, 2008 and 2007, the carrying amount of investments in affiliates approximated the amount of underlying equity in net assets. We received dividends from our equity investments of $995 million in 2008, $656 million in 2007 and $859 million in 2006. Cumulative undistributed earnings of unconsolidated affiliates totaled $58 million at December 31, 2008 and $20 million at December 31, 2007.

U.S. Transmission. As of December 31, 2008, investments primarily include 50% interests in Gulfstream, SESH, and Steckman Ridge, LP (Steckman Ridge). Gulfstream is an interstate natural gas pipeline that extends from Mississippi and Alabama across the Gulf of Mexico to Florida. SESH, which was placed in service in the second half of 2008, is an interstate natural gas pipeline that extends from Northeast Louisiana to Mobile County, Alabama where it connects to the Gulfstream system. Steckman Ridge is a storage project located in Bedford County, Pennsylvania.

In 2007, we and CenterPoint Energy Gas Transmission Company (the co-owner of SESH) entered into a loan agreement with SESH whereby each member agreed to loan funds to SESH, as needed and on a pro rata basis, in connection with the construction of SESH pipeline facilities. The loans bear interest based on the London Interbank Offered Rate (LIBOR) and are payable the earlier of December 31, 2009 or when SESH obtains permanent construction financing. The loan receivable from SESH, including accrued interest, totaled $327 million at December 31, 2008 and $148 million at December 31, 2007, and is classified as Investments in and Loans to Unconsolidated Affiliates on the Consolidated Balance Sheets. We recorded interest income on the SESH loan of $10 million in 2008 and $2 million in 2007.

Also during 2008 and 2007, we made loans to Steckman Ridge in connection with the construction of Steckman Ridge storage facilities. The loan receivable from Steckman Ridge, including accrued interest, totaled $45 million at December 31, 2008 and $3 million at December 31, 2007. We recorded interest income on the Steckman Ridge loan of $1 million in 2008 and less than $1 million in 2007.

Through our U.S. Transmission segment, we are a 50% equity partner and operator for Islander East Pipeline Company, L.L.C. (Islander East), an entity formed to develop and own a pipeline that would connect natural gas supplies to markets on Long Island, New York. Algonquin, a wholly owned subsidiary, also has a companion project, the AGT Islander East Lease Project. During the fourth quarter of 2008, Islander East was

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denied a petition for certiorari by the U.S. Supreme Court with respect to a water quality certificate that had been denied by the State of Connecticut. This certificate was an essential component required in order for the originally proposed project to proceed. In addition, during the fourth quarter 2008, as Islander East considered various project path alternatives for connecting natural gas supplies to Long Island, it became evident that credit and recessionary pressures would likely result in significant further delay of any alternative project ultimately agreed upon with the appropriate customers.

Islander East had capitalized cumulative development costs of approximately $66 million (100% Islander East project level) and Algonquin had capitalized cumulative development costs of $24 million associated with this project. Our share of the combined cumulative costs was $57 million, with approximately $11 million representing assets that are expected to be recovered through sale to third parties or the transfer, at cost, to another capital project. The remaining project development costs represented primarily environmental and engineering studies, legal services and accumulated AFUDC on such costs. Triggered by certain fourth quarter 2008 legal and economic events, these costs were evaluated pursuant to SFAS No. 71 as to probability of recovery under FERC-approved tariff rates associated with any future alternative project plan. Given the span of time between the performance of these studies and any likely approval of final project costs for recovery, and also considering that any future plans would be required to utilize a different path through Long Island Sound, it was determined that costs incurred to date were no longer deemed probable of recovery.

We evaluated the likelihood of various project outcomes in order to estimate the fair value of recoverable costs. This analysis resulted in an impairment charge in the fourth quarter 2008 of $44 million before tax ($12 million in Operating, Maintenance and Other expenses and $32 million in Equity in Earnings of Unconsolidated Affiliates), representing our share of impaired assets associated with Islander East.

Islander East remains committed to serving this market area through the development of a future firm transportation project.

Field Services. Our most significant investment in unconsolidated affiliates is our 50% investment in DCP Midstream which is accounted for under the equity method of accounting. DCP Midstream is a limited liability company which is a pass-through entity for U.S. income tax purposes. DCP Midstream also owns corporations who file their own respective federal, foreign and state income tax returns. Income tax expense related to these corporations is included in the income tax expense of DCP Midstream. Therefore, DCP Midstream s net income does not include income taxes for earnings which are passed through to the members based upon their ownership percentage. We recognize the tax effects of our share of DCP Midstream s pass-through earnings in Income Tax Expense from Continuing Operations in the accompanying Consolidated Statements of Operations.

In 2005, DCP Midstream formed DCP Midstream Partners, LP (DCP Partners), a master limited partnership and also in 2005, DCP Partners completed its IPO. Throughout 2006, 2007 and 2008, there were a series of transactions including equity issuances and asset drop-downs from DCP Midstream into DCP Partners resulting in net proceeds of $270 million. As a result, at December 31, 2008, DCP Midstream has a 30% ownership interest in DCP Partners, consisting of a 29% limited partner ownership interest and a 1% general partner ownership interest. DCP Midstream s ownership interest in the general partner of DCP Partners is 100%.

Investments in and Loans to Unconsolidated Affiliates

	December 31, 2008			December 31, 2007		
	Domestic	International	Total	Domestic	International	Total
			(in millions)			
U.S. Transmission	$ 1,281	$	$ 1,281	$ 747	$	$ 747
Western Canada Transmission & Processing		13	13		19	19
Field Services	858		858	1,014		1,014
Total	$ 2,139	$ 13	$ 2,152	$ 1,761	$ 19	$ 1,780

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Equity in Earnings of Unconsolidated Affiliates(a)

	2008			2007			2006		
	Domestic	International	Total	Domestic	International	Total	Domestic	International	Total
					(in millions)				
U.S.Transmission	$ 59	$	$ 59	$ 62	$	$ 62	$ 33	$	$ 33
Western Canada Transmission & Processing		4	4		2	2		2	2
Field Services	715		715	532		532	574		574
Total	$ 774	$ 4	$ 778	$ 594	$ 2	$ 596	$ 607	$ 2	$ 609

(a) Excludes amounts in discontinued operations, which primarily represent equity earnings of investments within the following: International Energy, Crescent and the equity investments within Other, which were transferred by us to Duke Energy in December 2006.

Summarized Combined Financial Information of Unconsolidated Affiliates

Statements of Operations(a)

	2008			2007			2006		
	DCP Midstream	Other	Total	DCP Midstream	Other	Total	DCP Midstream	Other(a)	Total
					(in millions)				
Operating revenues	$ 16,398	$ 330	$ 16,728	$ 13,154	$ 272	$ 13,426	$ 12,335	$ 1,251	$ 13,586
Operating expenses	14,704	222	14,926	11,959	117	12,076	11,063	792	11,855
Operating income	1,694	108	1,802	1,195	155	1,350	1,272	459	1,731
Net income	1,431	102	1,533	1,074	124	1,198	1,135	430	1,565

(a) Other includes amounts of unconsolidated affiliates of the International Energy and Crescent segments which were transferred to Duke Energy in December 2006 and presented as discontinued operations in 2006. See Note 8 for further discussion of discontinued operations.

Balance Sheets

	December 31, 2008			December 31, 2007		
	DCP Midstream	Other	Total	DCP Midstream	Other	Total
			(in millions)			
Current assets	$ 1,665	$ 236	$ 1,901	$ 2,248	$ 182	$ 2,430
Non-current assets	6,127	3,513	9,640	5,757	2,383	8,140
Current liabilities	(1,771)	(744)	(2,515)	(2,460)	(86)	(2,546)
Non-current liabilities	(4,371)	(1,161)	(5,532)	(3,582)	(1,249)	(4,831)
Net Assets	$ 1,650	$ 1,844	$ 3,494	$ 1,963	$ 1,230	$ 3,193

Related Party Transactions

DCP Midstream. We had the following transactions with DCP Midstream and its affiliates during 2008, 2007 and 2006: Sales of Natural Gas Liquids of $7 million in 2008, $9 million in 2007 and $12 million in 2006; and $2 million of Natural Gas and Petroleum Products Purchased in 2007. In addition, as previously discussed in Note 8, we entered into a propane sales agreement with an affiliate of DCP Midstream in the second quarter of 2008. During 2008, we recorded revenues of $49 million associated with this agreement, classified within Income From Discontinued Operations, Net of Tax. Product purchases of $14 million in 2006 are included in Income From Discontinued Operations, Net of Tax.

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We had receivables from DCP Midstream and its affiliates of $1 million at December 31, 2008 and $64 million at December 31, 2007. Total distributions received from DCP Midstream were $930 million in 2008, $618 million in 2007 and $725 million in 2006. Of these distributions, $715 million in 2008, $532 million in 2007 and $573 million in 2006 were recorded within Cash Flows from Operating Activities, and $215 million in 2008, $86 million in 2007 and $152 million in 2006 were recorded within Cash Flows from Investing Activities.

Duke Energy. Duke Energy and its affiliates are no longer considered related parties effective with our spin-off from Duke Energy on January 2, 2007.

We recorded income of $82 million in 2006 related to management fees charged to Duke Power Company (Duke Power), an unconsolidated affiliate. These amounts are recorded in Other Income and Expenses, Net on the Consolidated Statements of Operations. Additionally, we recognized recoveries of expenses of $777 million in 2006. These amounts represent recoveries of direct and allocated corporate governance and shared service costs charged to unconsolidated affiliates and are reflected as an offset within Operating, Maintenance and Other Expenses, and Depreciation and Amortization. Also included in Operating, Maintenance and Other Expenses in 2006 is $23 million of allocated costs charged to us by an affiliate of Cinergy. An additional $6 million of such costs are included in Income From Discontinued Operations, Net of Tax.

Also included in Operating, Maintenance and Other Expenses in 2006 is $22 million related primarily to insurance premiums paid to Bison subsequent to the transfer of Bison to Duke Energy in April 2006.

During 2006, we advanced $89 million to Duke Energy and also forgave advances to Duke Energy of $602 million. The advance is presented as Distributions and Advances to Parent within Cash Flows from Financing Activities in the Consolidated Statements of Cash Flows. The advances forgiven are considered non-cash financing activity.

Also during 2006, we distributed $2,361 million to Duke Energy. The distribution was principally obtained from the proceeds received on our sale of 50% of Crescent as discussed further in Note 8.

See Notes 1 and 8 for discussion of direct and indirect transfers of certain business from us to Duke Energy and Duke Energy Ohio during 2006.

Other. We provide certain administrative and other services to our equity investment operating entities. We recorded recoveries of costs from these affiliates of $54 million in 2008, $78 million in 2007 and $19 million in 2006. Outstanding receivables from these affiliates totaled $4 million at December 31, 2008 and $8 million at December 31, 2007.

International Energy loaned money to Campeche, a 50%-owned affiliate, to assist in the costs to build. International Energy received principal and interest payments of $11 million from Campeche during 2006.

An indirect, wholly owned subsidiary contributed its membership interest in Crescent to a newly formed joint venture causing us to deconsolidate Crescent as of September 7, 2006. Our 50% share of the earnings of Crescent for the period from September 8, 2006 through December 31, 2006 was $15 million. As discussed in Note 1, in December 2006 we transferred our investment in Crescent to Duke Energy. As a result of this transfer, the results of operations, as well as the equity earnings for the period subsequent to September 7, 2006, are included in Income From Discontinued Operations, Net of Tax. For the period September 8, 2006 through December 31, 2006, Crescent had operating revenues of $179 million, operating expenses of $152 million, operating income of $27 million and net income of $30 million.

See also Notes 3, 15 and 19 for additional related party information.

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12. Goodwill

The following tables show the components and activity within goodwill for the years ended December 31, 2008 and 2007, based on the reporting unit determination.

	December 31, 2007	Decreases(a) (in millions)	December 31, 2008
U.S. Transmission	$ 2,334	$ (315)	$ 2,019
Distribution	874	(147)	727
Western Canada Transmission & Processing	740	(105)(b)	635
Total consolidated	$ 3,948	$ (567)	$ 3,381

	December 31, 2006	Increases(a) (in millions)	December 31, 2007
U.S. Transmission	$ 2,098	$ 236	$ 2,334
Distribution	762	112	874
Western Canada Transmission & Processing	647	93	740
Total consolidated	$ 3,507	$ 441	$ 3,948

(a) Activity consists primarily of foreign currency translation.
(b) Includes goodwill associated with the 2008 acquisition of additional units of the Income Fund. See Note 3 for further discussion.

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

	December 31, 2008	2007
	(in millions)	
U.S. Transmission	$ 1,559	$ 1,874
Distribution	725	871
Western Canada Transmission & Processing	603	725

We completed our annual goodwill impairment test as of August 31, 2008 and no impairments were identified. We primarily use a discounted cash flow analysis to determine fair value for each reporting unit. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in key markets served by our operations, regulatory stability, the ability to renew contracts, commodity prices (where appropriate), and foreign currency exchange rates, as well as other factors that affect our revenue, expense and capital expenditure projections.

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

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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.

13. Property, Plant and Equipment

	Estimated Useful Life (years)	December 31, 2008	2007
		(in millions)	
Plant			
Natural gas transmission	20 82	$ 10,241	$ 10,056
Natural gas distribution	25 60	2,026	2,337
Gathering and processing facilities(a)	25 40	2,398	2,914
Storage	17 122	1,103	1,066
Other buildings and improvements	16 50	84	94
Equipment(a)	3 40	329	381
Vehicles	2 20	86	99
Land and land rights	45-60	156	177
Construction in process		690	557
Other	4 82	456	473
Total property, plant and equipment		17,569	18,154
Total accumulated depreciation(b)		(3,930)	(3,854)
Total net property, plant and equipment		$ 13,639	$ 14,300

(a) Capital leases totaled $4 million at December 31, 2008 and $21 million at December 31, 2007.
(b) Includes no material accumulated amortization of capitalized leases.

14. Asset Retirement Obligations

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

Asset retirement obligations are adjusted each period for liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Reconciliation of Changes in Asset Retirement Obligation Liabilities

	2008	2007
	(in millions)	
Balance at beginning of year	$ 112	$ 85
Accretion expense	6	5

Revisions in estimated cash flows	(7)	9
Asset dispositions	(8)	
Foreign currency exchange impact	(19)	13
Balance at end of year(a)	$ 84	$ 112

(a) Amounts included in Deferred Credits and Other Liabilities in the Consolidated Balance Sheets.

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15. Debt and Credit Facilities

Summary of Debt and Related Terms

	Weighted-Average Interest Rate	Year Due	December 31, 2008	2007
			(in millions)	
Unsecured debt	6.5%	2009 2038	$ 9,154	$ 7,707
Secured debt	4.8%	2009 2019	407	965
Capital leases	6.7%	2009	1	3
Commercial paper(a)	4.1%		428	715
Fair value hedge carrying value adjustment		2009 2018	68	15
Unamortized debt discount and premium, net			(11)	(7)
Total debt(b)			10,047	9,398
Current maturities of long-term debt			(821)	(338)
Short-term borrowings and commercial paper(c)			(936)	(715)
Total long-term debt			$ 8,290	$ 8,345

(a) The weighted-average days to maturity was 11 days as of December 31, 2008 and 13 days as of December 31, 2007.
(b) As of December 31, 2008 and 2007, $3,766 million and $4,144 million of debt were denominated in Canadian dollars, respectively.
(c) Weighted-average rates on outstanding short-term borrowings and commercial paper was 2.8% as of December 31, 2008 and 5.4% as of December 31, 2007.

M&N LLC paid $288 million in 2008 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.

Secured Debt. Secured debt includes project financing for M&N LP. Ownership interests in M&N LP and certain of its accounts, revenues, business contracts and other assets are pledged as collateral. Secured debt also includes the term debt of Spectra Energy Partners, which is collateralized by investment-grade securities.

Floating Rate Debt. Unsecured debt, secured debt and other debt included approximately $1,339 million of floating-rate debt as of December 31, 2008 and $1,276 million as of December 31, 2007. The weighted average interest rate of borrowings outstanding that contained floating rates was 2.7% at December 31, 2008 and 5.5% at December 31, 2007.

Annual Maturities

	December 31, 2008
	(in millions)
2009	$ 821
2010	713
2011	233
2012	735
2013	878

Thereafter	5,731
Total long-term debt(a)	$ 9,111

(a) Excludes short-term borrowings and commercial paper of $936 million.

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

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% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year.

(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.

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.

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

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.

16. Preferred and Preference Stock of Subsidiaries

In connection with the Westcoast acquisition in 2002, we assumed preferred and preference shares at Westcoast and Union Gas. These preferred and preference shares at Westcoast and Union Gas totaled $225 million at both December 31, 2008 and 2007. Since these preferred and preference shares are redeemable at the option of holder, as well as Westcoast and Union Gas, these preferred and preference shares do not meet the

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definition of a mandatorily redeemable instrument under SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. As such, these preferred and preference shares are considered contingently redeemable shares and are included in Minority Interests on the Consolidated Balance Sheets as of December 31, 2008 and 2007.

17. Fair Value Measurements

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

Description	Balance Sheet Caption	December 31, 2008 Total	Level 1	Level 2	Level 3
		(in millions)			
Available-for-sale securities	Cash and cash equivalents	$ 171	$ 66	$ 105	$
Short-term investments	Current assets-other	13	13		
Short-term derivative assets	Current assets-other	13		13	
Long-term investments	Investments and other assets-other	53	28	25	
Employee benefit assets	Investments and other assets-other	23	23		
Long-term derivative assets	Investments and other assets-other	89		53	36
Total Assets		$ 362	$ 130	$ 196	$ 36
Long-term derivative liabilities	Deferred credits and other liabilities-regulatory and other	23		23	
Total Liabilities		$ 23	$	$ 23	$

The following table reconciles assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

	Short-Term Derivative Asset	Short-Term Derivative Liability	Long-Term Derivative Asset	Long-Term Derivative Liability
Fair value at December 31, 2007	$	$	$ 47	$ (21)
Total gains or losses (realized/unrealized):				
Included in earnings			(1)	(11)
Included in regulatory assets				
Included in Other Comprehensive Income		(5)	(10)	
Normal purchases and sales election under SFAS No. 133				32
Purchases, issuances and settlements		5		
Fair value at December 31, 2008	$	$	$ 36	$
Total gains (losses) for the period included in earnings (or changes in net assets) attributable to the changes in unrealized gains or losses relating to assets held at December 31, 2008	$	$	$ (1)	$ (11)

Level 2 Valuation Techniques

Fair values of our available-for-sale securities, primarily fixed-income debt instruments and money market funds that are actively traded in the secondary market, are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency.

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Level 3 Valuation Techniques

Financial instruments are considered Level 3 when their values are determined using pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation.

The fair values of Level 3 derivative instruments are estimated using proprietary valuation models that utilize both market observable and unobservable parameters. The long-term derivative asset and liability is valued using internal valuation models and techniques that include such inputs as forward natural gas and power prices, forward interest rates and foreign currency assumptions. The short-term derivative asset is valued based upon interest rates, natural gas options pricing for current and future months including volatility, foreign exchange fluctuations and swap values.

Gains and losses associated with the long-term derivative asset and liability are reported in Other Income and Expenses, net on the Consolidated Statement of Operations and are of offsetting amounts.

During 2008, there were no adjustments to assets and liabilities measured at fair value on a nonrecurring basis.

18. Commitments and Contingencies

General Insurance

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

Environmental

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

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

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Included in Deferred Credits and Other Liabilities-Regulatory and Other on the Consolidated Balance Sheets are accruals related to extended environmental-related activities totaling $17 million at December 31, 2008 and $22 million at December 31, 2007. These accruals represent provisions for costs associated with remediation activities at some of our current and former sites, as well as other environmental contingent liabilities.

Litigation

Duke Energy Retirement Cash Balance Plan. A class action lawsuit was filed in federal court in South Carolina in 2006 against Duke Energy and the Duke Energy Retirement Cash Balance Plan. A second similar class action was also filed in 2006 alleging similar claims and seeking to represent the same class of plaintiffs, but this second case was dismissed without prejudice, and only the first case has moved forward. Various causes of action were alleged in the class action lawsuit, including violations of the Employee Retirement Income Security Act of 1974 (ERISA) and the Age Discrimination in Employment Act. These allegations arise out of the conversion of the Duke Power Company Employees Retirement Plan into the Duke Power Company Retirement Cash Balance Plan. The plaintiffs seek to represent present and former participants in the Duke Energy Retirement Cash Balance Plan. This group is estimated to include approximately 36,000 persons. Duke Energy filed its answer in March 2006, and various motions were thereafter filed by the parties, including plaintiffs motion to certify a class, Duke Energy s motion to dismiss, and cross motions for summary judgment filed by both the plaintiffs and Duke Energy. The Court issued a series of rulings in June 2008 denying the plaintiffs class certification motion, dismissing certain of the causes of action originally filed by plaintiffs and allowing other causes of action to proceed. As a result of these rulings, the plaintiffs re-filed a new Amended Class Action Complaint in June 2008 asserting and re-pleading the claims which the Court is allowing to proceed. Duke Energy filed a motion to dismiss in July 2008 requesting the dismissal of plaintiffs breach of fiduciary claims. Plaintiffs filed a new motion to certify a class action in August 2008 and Duke Energy has filed a response to this motion. All motions are pending before the Court. A new scheduling order has been entered and it is expected that certain discovery activities will ensue with respect to the surviving causes of action.

In connection with the spin-off from Duke Energy in January 2007, we agreed to share with Duke Energy any liabilities or damages associated with this matter that relate to our employees that may be members of a plaintiff class if one is certified. At mediation, plaintiffs quantified their claims as being in excess of $150 million. It is not possible to predict with certainty the damages, if any, that we might incur in connection with this matter. However, based our current estimate of our employees that could be included in any plaintiff class, we believe that the final disposition of this matter will not have a material adverse effect on our consolidated results of operations, financial position or cash flows. We await the Court s decision on class certification of the remaining claims.

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

We had no material reserves as of December 31, 2008 or 2007 related to litigation matters in accordance with our best estimate of probable loss as defined by SFAS No. 5, Accounting for Contingencies.

Legal costs related to the defense of loss contingencies are expensed as incurred.

Other Commitments and Contingencies

See Note 19 for a discussion of guarantees and indemnifications.

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Operating and Capital Lease Commitments

We lease assets in several areas of our operations. Consolidated rental expense for operating leases classified in Income From Continuing Operations was $50 million in 2008, $45 million in 2007 and $36 million in 2006, which is included in Operating, Maintenance and Other on the Consolidated Statements of Operations. We recorded pre-tax consolidated rental expense for operating leases classified in Income From Discontinued Operations, Net of Tax of $37 million in 2006. Amortization of assets recorded under capital leases included in continuing operations was included in Depreciation and Amortization. The following is a summary of future minimum lease payments under operating leases, which at inception had a noncancelable term of more than one year, and capital leases as of December 31, 2008:

	Long-term Operating Leases	Capital Leases
	(in millions)	
2009	$ 28	$ 1
2010	27	
2011	25	
2012	23	
2013	19	
Thereafter	50	
Total future minimum lease payments	$ 172	$ 1

19. Guarantees and Indemnifications

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

We have issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-wholly owned entities. 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 as guarantor in 2006. For any remaining guarantees of other Duke Energy obligations, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements. The maximum potential amount of future payments we could have been required to make under these performance guarantees as of December 31, 2008 was approximately $432 million, which has been indemnified by Duke Energy, as discussed above. Approximately $5 million of the performance guarantees will expire in the years 2009 and 2010, with the remaining performance guarantees expiring after 2010 or having no contractual expiration.

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

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Westcoast has issued performance guarantees to third parties guaranteeing the performance of unconsolidated entities, such as equity method investments, and of entities previously sold by Westcoast to third parties. Those guarantees require Westcoast to make payment to the guaranteed third party upon the failure of such unconsolidated or sold entity to make payment under some of its contractual obligations, such as debt, purchase contracts and leases. Certain guarantees that were previously issued by Westcoast for obligations of entities that remained a part of Duke Energy are considered guarantees of third party performance; however, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements. The maximum potential amount of future payments Westcoast could have been required to make under those performance guarantees of non-wholly owned entities and third-party entities as of December 31, 2008 was $51 million. These guarantees have no contractual expiration.

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

At December 31, 2008, the amounts recorded for the guarantees and indemnifications, described above, including the indemnifications by Duke Energy to us, are not material, both individually and in the aggregate.

20. Risk Management and Hedging Activities, Credit Risk and Financial Instruments

We are exposed to the impact of market fluctuations in the prices of NGLs and natural gas marketed and purchased primarily as a result of the investment in DCP Midstream and ownership of the Empress operations in Canada. Exposure to interest rate risk exists as a result of the issuance of variable and fixed-rate debt and commercial paper. We are exposed to foreign currency risk from the Canadian operations. 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 other commodity derivatives, primarily within DCP Midstream, such as swaps and options.

Spectra Energy s Derivative Portfolio Carrying Value as of December 31, 2008

Asset/(Liability)	Maturity in 2009	Maturity in 2010	Maturity in 2011	Maturity in 2012 and Thereafter	Total Carrying Value
			(in millions)		
Hedging	$ 18	$ 8	$ 9	$ 67	$ 102
Undesignated				(23)	(23)
Total	$ 18	$ 8	$ 9	$ 44	$ 79

The amounts in the table above represent the combination of amounts presented as assets (liabilities) for unrealized gains and losses on mark-to-market and hedging transactions on our Consolidated Balance Sheets and do not include derivative positions recorded by DCP Midstream.

As a result of the transfer of a 19.7% interest in DCP Midstream to ConocoPhillips and the subsequent deconsolidation of our investment in DCP Midstream in 2005, we discontinued hedge accounting for certain contracts we held related to Field Services commodity price risk, which were previously accounted for as cash flow hedges. These contracts were originally entered into as hedges of forecasted future sales by Field Services, and subsequent to deconsolidation, were retained as undesignated derivatives through their termination at the end of 2006. After the discontinuance of hedge accounting, these contracts were marked-to-market in the Consolidated Statements of Operations through the contract termination date in 2006. As a result, $19 million of realized and unrealized pre-tax losses related to these contracts were recognized in our earnings in 2006. The 2006 mark-to-market impacts have been classified in the accompanying Consolidated Statements of Operations as a component of Other Income and Expenses, Net. Cash settlements on these contracts in 2006 of $163 million are classified as a component of Settlement of Net Investment Hedges and Other Investing Derivatives included in net cash used in investing activities in the accompanying Consolidated Statements of Cash Flows.

Commodity Cash Flow Hedges. Certain of our operations are exposed to market fluctuations in the prices of natural gas and NGLs related to natural gas gathering, distribution, processing and marketing activities. We closely monitor the potential effects of commodity price changes and may choose to enter into contracts to protect margins for a portion of future sales and fuel expenses by using financial commodity instruments, such as swaps, forward contracts and options, as cash flow hedges for natural gas and NGL transactions, primarily within the operations of DCP Midstream and Western Canada Transmission & Processing.

The ineffective portion of commodity cash flow hedges from continuing operations resulted in insignificant amounts and is reported in Other Revenues in the Consolidated Statements of Operations.

As of December 31, 2008, $1 million of pre-tax deferred net loss on derivative instruments related to commodity cash flow hedges were accumulated on the Consolidated Balance Sheets in AOCI and are expected to be recognized in earnings during the next twelve months as the hedged transactions occur. However, due to the volatility of the commodity markets, the corresponding value in AOCI will likely change prior to its reclassification into earnings.

Interest Rate (Fair Value or Cash Flow) Hedges. Changes in interest rates expose us to risk as a result of our issuance of variable and fixed-rate debt and commercial paper. We manage our interest rate exposure by limiting our variable-rate exposures to percentages of total 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. Our fair value and cash flow interest rate hedge ineffectiveness were not material to our consolidated results of operations in 2008, 2007 or 2006.

Foreign Currency (Fair Value, Net Investment or Cash Flow) Hedges. We are exposed to foreign currency risk from investments and operations in international affiliate businesses, which is limited to Canada since the spin-off from Duke Energy. To mitigate risks associated with foreign currency fluctuations, contracts may be denominated in or indexed to the U.S. dollar and/or local inflation rates, or investments may be naturally hedged through debt denominated or issued in the foreign currency. We may also use foreign currency derivatives, where possible, to manage risk related to foreign currency fluctuations. There were no foreign currency derivative transactions during 2008, 2007 or 2006. To monitor our currency exchange rate risks, we use sensitivity analysis, which measures the effect of devaluation of the Canadian dollar.

Credit Risk. Our principal customers for natural gas transportation, storage and gathering and processing services are industrial end-users, marketers, exploration and production companies, local distribution companies and utilities located throughout the United States and Canada. We have concentrations of receivables from natural gas utilities and their affiliates, industrial customers and marketers throughout these regions, as well as retail distribution customers in Canada. These concentrations of customers may affect our overall credit risk in that risk factors can negatively affect the credit quality of the entire sector. Where exposed to credit risk, we analyze the 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 parental guarantees, cash or letters of credit from customers to provide credit support, where appropriate, based on our financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each transaction.

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Included in Other Current Liabilities and Regulatory and Other Deferred Credits and Other Liabilities are collateral liabilities of $121 million at December 31, 2008 and $81 million at December 31, 2007, which represent cash collateral posted by third parties with us.

Financial Instruments. The fair value of financial instruments, excluding derivatives included elsewhere in this Note and in Note 15, is summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of December 31, 2008 and 2007, are not necessarily indicative of the amounts we could have realized in current markets.

Financial Instruments

	December 31,			
	2008		2007	
	Book Value	Approximate Fair Value	Book Value	Approximate Fair Value
	(in millions)			
Long-term debt(a)	$ 9,111	$ 8,996	$ 8,683	$ 9,461
Long-term SFAS No. 115 securities	46	46	172	172
Other long-term assets	430	427	265	265

(a) Includes current maturities.

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

21. Common Stock Repurchases

In May 2008, our Board of Directors authorized a share repurchase program of up to $600 million under which purchases of our common stock under the program were made from time to time in the open market. During the second and third quarters of 2008, we repurchased a total of 22.3 million shares for $600 million, and the share repurchase program was concluded. The shares were retired upon repurchase and are presented as a reduction to Additional Paid-in Capital on the Consolidated Balance Sheets.

22. Stock-Based Compensation

We account for stock-based awards under the provisions of SFAS No. 123(R), Share-Based Payment, which established the accounting for stock-based awards exchanged for employee and certain non-employee services. Accordingly, for employee awards, equity classified stock-based compensation cost is measured at the grant date based on the fair value of the award and is recognized as expense over the requisite service period.

Prior to our spin-off from Duke Energy in 2007, certain of our employees participated in Duke Energy s stock-based compensation programs. Prior to the adoption of SFAS 123(R), we applied APB Opinion No. 25, Accounting for Stock Issued to Employees, and FIN 44, Accounting for Certain Transactions Involving Stock Compensation (an Interpretation of APB Opinion 25), and provided the required pro forma disclosures of SFAS No. 123. Since the exercise prices for all Duke Energy options granted during these years under those plans were equal to the market value of the underlying common stock on the grant date, no compensation cost was allocated from Duke Energy.

Impact of Spin-off on Equity Compensation Awards of Employees

In anticipation of the spin-off, on December 19, 2006, we adopted the Spectra Energy Corp 2007 Long-Term Incentive Plan (the 2007 LTIP). The 2007 LTIP provides for the granting of stock options, restricted stock

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awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for us. A maximum of 30 million shares of common stock may be awarded under the 2007 LTIP.

Options granted under the 2007 LTIP are issued with exercise prices equal to the fair market value of our common stock on the grant date, have ten year terms and vest immediately or over terms not to exceed five years. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible.

Restricted, performance and phantom stock awards granted under the 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. The fair value of the awards granted is measured based on the fair market value of the shares on the date of grant, and the related compensation expense is recognized over the requisite service period which is the same as the vesting period.

At the time of the spin-off, Duke Energy converted stock options, restricted stock awards, performance awards and phantom stock awards (collectively, Stock-Based Awards) of Duke Energy common stock held by our employees and Duke Energy employees. One replacement Duke Energy Stock-Based Award and one-half Spectra Energy Stock-Based Award were distributed to each holder of Duke Energy Stock-Based Awards for each award held at the time of the spin-off. In the case of stock options, in accordance with the separation agreements, the option price conversion was based on the pre-distribution Duke Energy closing price of $19.14 relative to the Spectra Energy when-issued closing price of $28.62 on January 3, 2007. The revised awards therefore maintained both the pre-conversion aggregate intrinsic value of each award and the ratio of the exercise price per share to the fair market value per share. Substantially all converted Stock-Based Awards are subject to the terms and conditions applicable to the original Duke Energy stock options, restricted stock awards, performance awards and phantom stock awards. The Spectra Energy Stock-Based Awards resulting from the conversion are considered to have been issued under the 2007 LTIP.

The conversion of Duke Energy stock awards to Spectra Energy stock awards constituted a modification of those stock awards under the provisions of SFAS No. 123(R). However, under the provisions of FSP No. 123(R)-5, since the modification was made to stock awards issued to employees for instruments that were originally issued as compensation and then modified, and that modification was made to the terms of the instrument solely to reflect an equity restructuring that occurs when the holders are no longer employees, no change in the recognition or the measurement (due to a change in classification) of those instruments occurred as (a) there was no increase in fair value of the awards (the holders were made whole) and (b) all holders of the same class of equity instruments (for example, stock options) were treated in the same manner.

After the spin-off, we receive all cash proceeds related to the exercise of Spectra Energy stock options held by Duke Energy employees; however, Duke Energy will recognize all associated expense and resulting tax benefits relating to such stock options. Similarly, we will recognize all associated expense and tax benefits relating to Duke Energy awards held by our employees. We recognize compensation expense, receive all cash proceeds and retain all tax benefits relating to Spectra Energy awards held by our employees.

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We recorded pre-tax stock-based compensation expense included in continuing operations for 2008, 2007 and 2006 as follows, the components of which are further described below:

	2008	2007	2006(a)
		(in millions)	
Stock options	$ 3	$ 10	$ 2
Stock appreciation rights(b)		(3)	2
Phantom stock	10	7	7
Performance awards	6	5	7
Total	$ 19	$ 19	$ 18

(a) Allocated from Duke Energy.

(b) Stock appreciation rights settled in cash must be marked to market with the increases/decreases resulting in a change to the measured compensation cost until exercise or expiration.

The tax benefit in income from continuing operations associated with the recorded expense was $7 million in 2008, 2007 and 2006. Excluded from amounts above is pre-tax stock-based compensation expense of $31 million in 2006 that is included in Income From Discontinued Operations, Net of Tax on the Consolidated Statements of Operations. The tax benefits associated with the amounts that are included in Income From Discontinued Operations, Net of Tax is $11 million in 2006. There were no material differences in income from continuing operations, income tax expense, net income or cash flows from the adoption of SFAS No. 123(R). We recognized tax benefits from stock-based compensation cost of approximately $14 million in additional paid in capital in 2008 and $20 million in 2007.

Stock Option Activity

	Options (in thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Life (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2007	14,370	$ 25	4.9	$ 46
Exercised	(600)	19		
Forfeited or expired	(923)	26		
Outstanding at December 31, 2008	12,847	25	4.2	6
Exercisable at December 31, 2008	11,621	25	3.7	6
Options Expected to Vest	1,180	26	8.2	

We did not award non-qualified stock options to employees during 2008. In addition to the conversion of the Duke Energy stock options previously discussed, we granted 2,199,600 non-qualified stock options (fair value of $15 million, market price of $6.71/share) during 2007. Under the terms of the LTIP, the exercise price of a non-qualified stock option shall not be less than 100% of the fair market value of our common stock on the date of grant, and the maximum option term is ten years. The options issued in 2007 vest ratably over three years. We issue new shares upon exercising or vesting of share-based awards. The Black-Scholes option-pricing model was used to estimate the fair value of options at grant date.

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Weighted-Average Assumptions for Option Pricing

	2007
Risk-free rate of return	4.4%
Expected life	7 years
Expected volatility	29.5%
Expected dividend yield	3.4%

The risk-free rate of return was determined based on a yield curve of U.S. Treasury rates ranging from six months to ten years and a period commensurate with the expected life of the options granted. The expected volatility was established based on historical volatility and implied volatility of a group of 12 peer company stock prices. The expected dividend yield was determined based on our annual dividend amount as a percentage of the average stock price at the time of grant.

There were no options granted to our employees during 2006. On December 31, 2006, our employees had six million exercisable Duke Energy options with weighted-average exercise prices of $31. Coincident with our spin-off, all exercisable Duke Energy options were converted in accordance with the share conversion guidelines on a two to one basis, with no change to overall intrinsic value. The total intrinsic value of options exercised during 2008, 2007 and 2006 was $4 million, $6 million and $22 million, respectively. Cash received by us from options exercised was $12 million in 2008 and $18 million in 2007. We recognized a nominal tax benefit in both 2008 and 2007 since the options exercised were predominately held by Duke Energy employees. As of December 31, 2008, we expect to recognize $2 million of future compensation cost related to stock options over a weighted-average period of one year.

Stock Awards Activity

	Performance Awards		Phantom Stock Awards		Other Stock Awards	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
			(shares in thousands)			
Outstanding at December 31, 2007	1,248	$ 23	1,107	$ 27	161	$ 28
Granted	497	31	545	24		
Vested	(369)	28	(363)	28	(30)	25
Forfeited	(327)	28	(151)	25	(22)	29
Outstanding at December 31, 2008	1,049	24	1,138	26	109	29
Awards expected to vest	997	24	1,082	26	104	29

Performance Awards

Stock-based performance awards generally vest over three years. Vesting for certain converted stock-based performance awards can occur in three years, at the earliest, if performance metrics are met. The unvested and outstanding performance awards outstanding as of our spin-off date contain market conditions based on the total shareholder return (TSR) of Duke Energy stock relative to a pre-defined peer group (relative TSR). These awards are valued using a path-dependent model that incorporates expected relative TSR into the fair value determination of Duke Energy s performance-based share awards with the adoption of SFAS No. 123(R). The model uses three year historical volatilities and correlations for all companies in the pre-defined peer group, including Duke Energy, to simulate Duke Energy s relative TSR as of the end of the performance period. For each simulation, Duke Energy s relative TSR associated with the simulated stock price at the end of the performance period plus expected dividends within the period results in a value per share for the award portfolio.

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The average of these simulations is the expected portfolio value per share. Actual life-to-date results of Duke Energy s relative TSR for each grant is incorporated within the model. Other awards not containing market conditions are measured at grant date price. Coincident with the spin-off, each outstanding Duke Energy Performance award was converted into a Spectra Energy Performance Share and a Duke Energy Performance Share. Measurement of the TSR is now based upon the two equity components, weighted 50% each, consisting of Duke Energy common stock and Spectra Energy common stock, using the post-distribution Duke Energy stock price and the post-distribution Spectra Energy stock price, respectively, as the basis of measurement.

Under the Spectra Energy 2007 LTIP, we can also grant performance awards. The terms of the awards under Spectra s plan are substantially the same as the performance awards described under the Duke plan above. Under the Spectra plan, the TSR of Spectra Energy common stock is compared to a revised group of peer companies. We granted 497,500 performance awards (fair value of $15 million) during 2008. The unvested and outstanding performance awards granted contain market conditions based on the TSR of Spectra Energy common stock relative to a pre-defined peer group (relative TSR). These awards are valued using the Monte Carlo valuation method.

Weighted-Average Assumptions for Performance Awards

	2008
Risk-free rate of return	2.3%
Expected life	3 years
Expected volatility Spectra Energy	24.3%
Expected volatility peer group	14.2% 28.8%
Market index	14.3%
Expected dividend yield	

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

We did not award shares to employees in 2007, and Duke Energy awarded 790,230 shares (fair value of $14 million) to our employees in 2006.

The total fair value of shares vested was $10 million in 2008, $16 million in 2007 and $3 million in 2006. As of December 31, 2008, we expect to recognize $10 million of future compensation cost related to performance awards over a weighted-average period of less than one year.

Phantom Stock Awards

Phantom stock awards outstanding as of the spin-off generally vest over periods from immediate to five years. Stock-based phantom awards granted under the 2007 LTIP generally vest over three years. We awarded 545,000 phantom awards (fair value of $13 million) to our employees in 2008 and 377,500 phantom awards (fair value of $10 million) in 2007.

Phantom stock awards outstanding under Duke Energy s 1998 Long-term Incentive Plan (the 1998 Plan) generally vest over periods from immediate to five years. Duke Energy awarded 582,040 shares (fair value of $17 million) to our employees based on the market price of Duke Energy s common stock at the grant dates in 2006.

The total fair value of the shares vested was $10 million in 2008, $13 million in 2007 and $16 million in 2006. As of December 31, 2008, we expect to recognize $13 million of future compensation cost related to phantom stock awards over a weighted-average period of one year.

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Other Stock Awards

Other stock awards outstanding under the 1998 Plan generally vest over periods from three to five years. Duke Energy awarded 41,000 shares (fair value of $1 million) to our employees based on the market price of Duke Energy s common stock at the grant dates in 2006.

The total fair value of the shares vested was less than $1 million for each of 2008, 2007 and 2006. As of December 31, 2008, we do not expect to recognize any future compensation cost related to other stock awards.

23. Employee Benefit Plans

Retirement Plans. Up until the January 2, 2007 spin-off of the natural gas businesses by Duke Energy, Spectra Energy and its U.S. subsidiaries participated in Duke Energy s qualified and non-qualified non-contributory defined benefit (DB) retirement plans. The qualified plan covered U.S. employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits that are based upon a percentage (which may vary with age and years of service) of current eligible earnings and current interest credits.

Effective with the separation from Duke Energy, we established a new qualified non-contributory DB retirement plan for U.S. employees and new non-qualified plans for various executive retirement and savings plans. In accordance with the separation agreement with Duke Energy, net qualified pension plan assets of $49 million and $52 million in liabilities associated with various executive retirement and savings plans were transferred to us in 2007.

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

Our policy is to fund amounts for our U.S. qualified retirement plans on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants. We did not make any contributions to our U.S. retirement plan in 2008 or 2007 and do not currently anticipate making contributions to our U.S. retirement plan in 2009.

Our policy is to fund our DB retirement plans in Canada on an actuarial basis and in accordance with Canadian pension standards legislation in order to accumulate assets sufficient to meet benefit obligations. Contributions to the DC plan are determined in accordance with the terms of the plan. We made contributions to the Canadian qualified DB plans of $36 million in 2008, $41 million in 2007 and $44 million in 2006. We also made contributions to the DC plan of $4 million in 2008, $5 million in 2007 and $4 million in 2006. We anticipate making contributions of approximately $55 million to the Canadian qualified DB plans in 2009.

Actuarial gains and losses are amortized over the average remaining service period of the active employees. The average remaining service period of the active employees covered by the qualified DB retirement plans is 10 years for both the U.S. and Canadian plans. The average remaining service period of the active employees covered by the non-qualified DB retirement plans is nine years for the U.S. and 14 years for the Canadian plans, respectively. We determine the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets over five years for the U.S. plans and over three years for the Canadian plans.

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Qualified Pension Plans

The table below provides the fair value of plan assets and the projected benefit obligation for the U.S. and Canadian plans.

Qualified Pension Plans Change in Projected Benefit Obligation and Change in Fair Value of Plan Assets

	U.S.		Canada	
	2008	2007	2008	2007
	(in millions)			
Change in Projected Benefit Obligation				
Projected benefit obligation, January 1	$ 464	$ 476	$ 778	$ 653
Effects of eliminating early measurement date				5
Service cost	9	9	16	15
Interest cost	27	26	38	35
Actuarial loss (gains)	2	(7)	(103)	(6)
Participant contributions			3	3
Benefits paid	(41)	(40)	(33)	(33)
Prior service cost			4	
Foreign currency translation effect			(133)	106
Projected benefit obligation, December 31	461	464	570	778
Change in Fair Value of Plan Assets				
Plan assets, January 1	525	525	670	525
Effects of eliminating early measurement date				39
Actual return on plan assets	(131)	40	(133)	7
Benefits paid	(41)	(40)	(33)	(33)
Employer contributions			41	38
Plan participants contributions			3	3
Foreign currency translation effect			(106)	91
Plan assets, December 31	353	525	442	670
Net amount recognized(a)	$ (108)	$ 61	$ (128)	$ (108)

(a) Recognized in Deferred Credits and Other Liabilities Regulatory and Other (2008) and Investments and Other Assets Other (2007) in the Consolidated Balance Sheets for the U.S. plans, and Deferred Credits and Other Liabilities Regulatory and Other (2008 and 2007) for the Canadian plans on the Consolidated Balance Sheets.

Qualified Pension Plans Amounts Recognized in Accumulated Other Comprehensive Income

	U.S. December 31,		Canada December 31,	
	2008	2007	2008	2007
	(in millions)			
Prior service costs	$ 1	$ 2	$ 8	$ 7
Net actuarial loss	214	47	182	146

Net reduction of AOCI	$ 215	$ 49	$ 190	$ 153

Qualified Pension Plans Accumulated Benefit Obligation

The accumulated benefit obligation for the U.S. plan was $443 million and $448 million at December 31, 2008 and 2007, respectively, and $520 million and $703 million at December 31, 2008 and 2007, respectively, for the Canadian plans.

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Qualified Pension Plans with Benefit Obligation in Excess of Plan Assets

	U.S. December 31,	Canada December 31,	
	2008	2008	2007
	(in millions)		
Projected benefit obligation	$ 461	$ 570	$ 492
Accumulated benefit obligation	443	520	457
Fair value of plan assets	353	442	419

Qualified Pension Plans Components of Net Periodic Pension Costs

The following table shows the components of the pre-tax net periodic pension costs for our U.S. and Canadian retirement plans for 2008 and 2007 and the Canadian retirement plan for 2006. Our pre-tax net periodic pension benefit cost for the U.S. plans included in continuing operations, as allocated by Duke Energy, was $1 million in 2006. This amount excludes pre-tax pension cost of $11 million in 2006 related to entities transferred to Duke Energy, which are reflected in Income From Discontinued Operations, Net of Tax, in the Consolidated Statements of Operations.

	U.S.		Canada		
	2008	2007	2008	2007	2006
			(in millions)		
Net Periodic Pension Cost					
Service cost benefit earned during the year	$ 9	$ 9	$ 16	$ 15	$ 13
Interest cost on projected benefit obligation	27	26	38	35	31
Expected return on plan assets	(36)	(36)	(46)	(42)	(33)
Amortization of prior service cost		1	1	1	1
Amortization of loss	3	6	5	7	10
Net periodic pension cost	3	6	14	16	22
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income					
Current year actuarial loss (gain)	169	(11)	77	30	
Amortization of actuarial loss	(3)	(6)	(5)	(7)	
Amortization of prior service credit		(1)	(1)	(1)	
Current year prior service cost			4		
Effects of eliminating early measurement date				(27)	
Foreign currency translation effect			(38)	18	
Total decrease (increase) in other comprehensive income	166	(18)	37	13	
Total recognized in net periodic pension cost and other comprehensive income	$ 169	$ (12)	$ 51	$ 29	$ 22

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At December 31, 2008, approximately $4 million and $3 million of actuarial losses will be amortized from AOCI on the Consolidated Balance Sheets into net periodic benefit cost in 2009 for the U.S. and Canadian pension plans, respectively.

Qualified Pension Plans Assumptions Used for Pension Benefits Accounting

	U.S.		Canada		
	2008	2007	2008	2007	2006
Benefit Obligations					
Discount rate	5.91%	6.00%	6.46%	5.25%	5.00%
Salary increase	5.77	5.71	3.50	3.50	3.50
Net Periodic Benefit Cost					
Discount rate	6.00	5.75	5.25	5.00	5.00
Salary increase	5.71	5.71	3.50	3.50	3.25
Expected long-term rate of return on plan assets	7.50	8.00	7.25	7.25	7.25

The discount rate used to determine the pension obligation is the rate at which the pension obligations could be effectively settled. This rate is developed from yields on available high-quality bonds in the U.S. and Canada, as applicable, and reflects each plan s expected cash flows.

Qualified Pension Plan Assets

	U.S.			Canada		
	Target	December 31,		Target	December 31,	
Asset Category	Allocation	2008	2007	Allocation	2008	2007
U.S. equity securities	45%	41%	44%	15%	14%	15%
Canadian equity securities				30	24	33
Other equity securities	20	16	20	15	14	15
Debt securities	35	43	36	40	48	37
Total	100%	100%	100%	100%	100%	100%

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

The long-term rates of return of 7.50% and 7.00% as of December 31, 2008 for U.S. and Canadian assets, respectively, were developed using a weighted-average calculation of expected returns based primarily on future expected returns across classes considering the use of active asset managers applied against the U.S. plans asset mix of approximately 35% income securities and 65% equities and the Canadian plans mix of 40% income securities and 60% equities.

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Qualified Pension Plans Expected Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid over the next five years and thereafter:

	U.S.	Canada
	(in millions)	
2009	$ 41	$ 31
2010	40	31
2011	41	33
2012	45	34
2013	50	36
2014 2018	234	214

Non-Qualified Pension Plans

We maintain a non-qualified, non-contributory defined benefit retirement plan which covers certain U.S. executives. There are no plan assets. The projected benefit obligation was $20 million as of December 31, 2008 and $19 million as of December 31, 2007.

We also maintain a non-qualified, non-contributory defined benefits plan for our Canadian employees. There are no plan assets. The projected benefit obligation was $72 million as of December 31, 2008 and $99 million as of December 31, 2007.

Non-Qualified Pension Plans Change in Projected Benefit Obligation and Fair Value of Plan Assets

	U.S.		Canada	
	2008	2007	2008	2007
	(in millions)			
Change in Projected Benefit Obligation				
Projected benefit obligation, January 1	$ 19	$ 18	$ 99	$ 88
Effects of eliminating early measurement date				(1)
Service cost		1	1	1
Interest cost	1	1	5	5
Actuarial loss (gain)	2	1	(5)	(2)
Benefits paid	(2)	(2)	(12)	(5)
Foreign currency translation effect			(16)	13
Projected benefit obligation, December 31	20	19	72	99
Change in Fair Value of Plan Assets				
Plan assets, January 1				
Benefits paid	(2)	(2)	(5)	(5)
Employer contributions	2	2	5	5
Fair value of plan assets, December 31				
Amount recognized, December 31(a)	$ (20)	$ (19)	$ (72)	$ (99)

(a) Amounts are reflected in Deferred Credits and Other Liabilities Regulatory and Other within the Consolidated Balance Sheets.

The accumulated benefit obligation of the U.S. plan was $18 million at December 31, 2008 and $16 million at December 31, 2007. The accumulated benefit obligation of the Canadian plan was $66 million at December 31, 2008 and $98 million at December 31, 2007.

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Non-Qualified Pension Plans Amounts Recognized in Accumulated Other Comprehensive Income

Net actuarial losses for the Canadian non-qualified pension plans totaling $9 million at December 31, 2008 and $24 million at December 31, 2007 were recognized in AOCI. At December 31, 2008, the amount recognized in AOCI for the U.S. plan was $1 million.

At December 31, 2008, less than $1 million of unrecognized losses was included in AOCI that will be recognized in net periodic non-qualified pension costs in 2009 for the U.S. and Canadian plans.

Non-Qualified Pension Plans Accumulated Benefit Obligation

	U.S. December 31,		Canada December 31,	
	2008	2007	2008	2007
	(In millions)			
Projected benefit obligation	$ 20	$ 19	$ 72	$ 99
Accumulated benefit obligation	18	16	66	98

All of the non-qualified plans have an accumulated benefit obligation greater than the plan assets.

Non-Qualified Pension Plans Components of Net Periodic Pension Costs

The following tables show the components of the net periodic pension costs for our U.S. and Canadian non-qualified retirement plans for 2008 and 2007 and the Canadian non-qualified retirement plan for 2006. Pre-tax net periodic pension cost for the U.S. plan, as allocated by Duke Energy, was $1 million for 2006. This amount excludes pre-tax pension cost of $3 million in 2006 related to entities transferred to Duke Energy, which are reflected in Income From Discontinued Operations, Net of Tax.

	U.S.		Canada		
	2008	2007	2008	2007	2006
			(in millions)		
Net Periodic Pension Cost					
Service cost benefit earned during the year	$ 1	$ 1	$ 1	$ 1	$ 1
Interest cost on projected benefit obligation	1	1	5	5	4
Amortization of loss			1	1	1
Net periodic pension cost	2	2	7	7	6
Other Changes in Plan Assets and Benefits Obligations Recognized in Other Comprehensive Income					
Current year actuarial loss (gain)	1		(12)	(3)	
Amortization of actuarial loss			(1)	(1)	
Effects of eliminating early measurement date				(1)	
Foreign currency translation effect			(2)	4	
Total decrease (increase) in other comprehensive income	1		(15)	(1)	
Total recognized in net periodic pension cost and other comprehensive income	$ 3	$ 2	$ (8)	$ 6	$ 6

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Non-Qualified Pension Plans Assumptions Used for Pension Benefits Accounting

	U.S.		Canada		
	2008	**2007**	**2008**	**2007**	**2006**
Benefit Obligations					
Discount rate	5.91%	6.00%	6.46%	5.25%	5.00%
Salary increase	4.77	5.10	3.50	3.50	3.50
Net Periodic Benefit Cost					
Discount rate	6.00	5.75	5.25	5.00	5.00
Salary increase	5.08	5.10	3.50	3.50	3.25

The discount rate used to determine the pension obligation is the rate at which the pension obligations could be effectively settled. The rate is developed from yields on available high-quality bonds in the U.S. and Canada, as applicable, and reflects the plan s expected cash flows.

Non-Qualified Pension Plans Expected Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid over the next five years and thereafter:

	U.S.	Canada
	(in millions)	
2009	$ 4	$ 4
2010	2	5
2011	3	5
2012	2	5
2013	2	5
2014 2018	9	19

Contributions for the non-qualified pension plans are equal to that of benefit payments, therefore, we expect to contribute $4 million to the U.S. plan in 2009 and $4 million to the Canadian plan in 2009.

Other Post-Retirement Benefit Plans

U.S. Other Post-Retirement Benefits. We provide certain health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. In accordance with the separation agreement, $194 million in liabilities associated with other post-retirement benefits were transferred to us upon separation from Duke Energy.

These benefit costs are accrued over an employee s active service period to the date of full benefits eligibility. The net unrecognized transition obligation resulting from the adoption in 1993 of SFAS No. 106, Employers Accounting for Postretirement Benefits Other than Pensions, is amortized over approximately 20 years, with five years remaining. Actuarial gains and losses are amortized over the average remaining service period of the active employees. The average remaining service period of the active employees covered by the plan is 12 years.

Canadian Other Post-Retirement Benefits. We provide health care and life insurance benefits for retired employees on a non-contributory basis for our Canadian operations. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. Effective December 31, 2003, a new plan was implemented for all non bargaining employees and the majority of bargaining employees. The new plan applies for employees retiring on and after January 1, 2006. The new plan is predominantly a defined contribution plan as compared to the existing defined benefit program.

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Other Post-Retirement Benefit Plans Change in Projected Benefit Obligation and

Fair Value of Plan Assets

	U.S. 2008	U.S. 2007	Canada 2008	Canada 2007
	(in millions)			
Change in Benefit Obligation				
Accumulated post-retirement benefit obligation, January 1	$ 248	$ 279	$ 108	$ 91
Effects of eliminating early measurement date				1
Service cost	1	1	3	3
Interest cost	14	15	5	5
Plan participants contribution	3	2		
Actuarial gain	(4)	(28)	(13)	(2)
Medicare subsidy receivable	3	3		
Benefits paid	(23)	(24)	(4)	(4)
Foreign currency translation effect			(19)	14
Accumulated post-retirement benefit obligation, December 31	242	248	80	108
Change in Fair Value of Plan Assets				
Plan assets, January 1	86	89		
Actual return on plan assets	(13)	3		
Benefits paid	(23)	(24)	(4)	(4)
Employer contributions	15	16	4	4
Plan participants contributions	3	2		
Plan assets, December 31	68	86		
Amount recognized, December 31(a)	$ (174)	$ (162)	$ (80)	$ (108)

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

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

	U.S. December 31, 2008	U.S. December 31, 2007	Canada December 31, 2008	Canada December 31, 2007
	(in millions)			
Prior service costs (credits)	$	$	$ (9)	$ (11)
Net actuarial loss (gain)	51	38	(1)	13
SFAS No. 106 transition obligation	20	26		
Net decrease (increase) in AOCI	$ 71	$ 64	$ (10)	$ 2

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At December 31, 2008, approximately $5 million of transition obligations and $2 million of actuarial losses were included in AOCI in the Consolidated Balance Sheets that will be recognized in net periodic costs in 2009 for the U.S. plan. At December 31, 2008, approximately $1 million of prior service costs were included in AOCI that will be recognized in net periodic costs in 2009 for the Canadian plans.

	U.S.		Canada		
	2008	2007	2008	2007	2006
		(in millions)			
Other Post-Retirement Benefit Plans Components of Net Periodic Benefit Cost					
Service cost benefit earned during the year	$ 1	$ 1	$ 3	$ 3	$ 4
Interest cost on accumulated post-retirement benefit obligation	14	15	5	5	7
Expected return on plan assets	(5)	(6)			
Amortization of net transition liability	5	4			
Amortization of prior service credit		(2)		(1)	(1)
Amortization of loss	2	6			2
Net periodic other post-retirement benefit cost(a)	17	18	8	7	12
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income					
Current year actuarial loss (gain)	14	(26)	(13)	(2)	
Amortization of actuarial loss	(2)	(4)		(1)	
Amortization of prior service credit		2		1	
Amortization of transition asset/obligation	(5)	(5)			
Foreign currency translation effect			1	1	
Total decrease (increase) in other comprehensive income	7	(33)	(12)	(1)	
Total recognized in net periodic benefit cost and other comprehensive income	$ 24	$ (15)	$ (4)	$ 6	$ 12

(a) Pre-tax net periodic post-retirement benefit cost included in continuing operations, as allocated by Duke Energy, was $9 million for 2006. This amount excludes pre-tax post retirement benefit cost of $10 million in 2006 related to entities transferred to Duke Energy, which are reflected in Income From Discontinued Operations, Net of Tax.

Other Post-Retirement Benefits Plans Assumptions Used

	U.S.		Canada		
	2008	2007	2008	2007	2006
Benefit Obligations					
Discount rate	6.01%	6.00%	6.57%	5.25%	5.00%
Salary increase	5.71	5.70	3.50	3.50	3.50
Net Periodic Benefit Cost					
Discount rate	6.00	5.75	5.25	5.00	5.00
Salary increase	5.71	5.70	3.50	3.50	3.25
Expected return on plan assets for post-retirement medical plans	6.29	6.65	n/a	n/a	n/a
Expected return on plan assets for post-retirement life plans	7.25	6.90	n/a	n/a	n/a

n/a indicates not applicable.

The discount rate used to determine the post-retirement obligation is the rate at which the pension obligations could be effectively settled. This rate is developed from yields on available high-quality bonds in the U.S. and Canada, as applicable, and reflects each plan s expected cash flows.

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Assumed Health Care Cost Trend Rates

	U.S.		Canada	
	2008	2007	2008	2007
Health care cost trend rate assumed for next year	8.00%	7.50%	8.00%	8.00%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.00%	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2015	2013	2015	2010

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

	U.S.		Canada	
	1% Point Increase	1% Point Decrease	1% Point Increase	1% Point Decrease
	(in millions)			
Effect on total service and interest costs	$ 1	$ (1)	$ 1	$ (1)
Effect on post-retirement benefit obligation	13	(12)	8	(7)

Other Post-Retirement Plan Assets

	U.S. December 31,	
Asset Category	2008	2007
Equity securities	35%	51%
Debt securities	49	40
Other assets	16	9
Total	100%	100%

Our post-retirement plan assets are maintained within the two master trusts discussed under pension plans above.

We also invest other post-retirement assets in the Spectra Energy Corp Employee Benefits Trust (VEBA I) and the Spectra Energy Corp Post-Retirement Medical Benefits Trust (VEBA II). The investment objective of the VEBAs is to achieve sufficient returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of promoting the security of plan benefits for participants. The VEBA trusts are passively managed.

The asset allocation table above includes the other post-retirement benefit assets held in the master trusts, VEBA I and VEBA II. Assets held in the master trust represent 35% of the total, while the assets of VEBA I represent 35% of the total and the assets of VEBA II represent 30% of the total.

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Other Post-Retirement Plans Benefit Payments and Receipts

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

Benefit Payments	U.S.	Canada
	(in millions)	
2009	$ 24	$ 4
2010	25	4
2011	25	4
2012	25	5
2013	24	5
2014 2018	114	23

Medicare Part D Subsidy Receipts	U.S. (in millions)
2009	$ 3
2010	3
2011	3
2012	3
2013	3
2014 2018	12

We anticipate making contributions of $21 million in 2009 for the U.S. plans and $4 million for the Canadian plans.

Retirement Savings Plan

During 2006, Duke Energy sponsored, and we participated in, employee savings plans that covered substantially all U.S. employees. Most employees participated in a matching contribution formula where Duke Energy provided a matching contribution generally equal to 100% of before-tax employee contributions, of up to 6% of eligible pay per pay period. Effective with the separation from Duke Energy, we established an employee savings plan that provides benefits substantially the same as those provided under the Duke Energy plan. We expensed pre-tax employer matching contributions of $10 million in 2008 and $9 million in 2007, and, as allocated by Duke Energy, $8 million in 2006. This amount excludes pre-tax expenses of $14 million in 2006 related to entities transferred to Duke Energy, which are reflected in Income From Discontinued Operations, Net of Tax.

24. Consolidating Financial Information

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

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Spectra Energy Corp

Condensed Consolidating Statement of Operations

Year Ended December 31, 2008

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Total operating revenues	$	$	$ 5,074	$	$ 5,074
Total operating expenses	7		3,629		3,636
Gains on sales of other assets and other, net			42		42
Operating income (loss)	(7)		1,487		1,480
Equity in earnings of unconsolidated affiliates			778		778
Equity in earnings of subsidiaries	1,123	1,648		(2,771)	
Other income and expenses, net	1	23	42		66
Interest expense		249	387		636
Minority interest expense			63		63
Earnings from continuing operations before income taxes	1,117	1,422	1,857	(2,771)	1,625
Income tax expense from continuing operations	(12)	299	209		496
Net income	$ 1,129	$ 1,123	$ 1,648	$ (2,771)	$ 1,129

Spectra Energy Corp

Condensed Consolidating Statement of Operations

Year Ended December 31, 2007

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Total operating revenues	$	$	$ 4,704	$	$ 4,704
Total operating expenses	46	6	3,239		3,291
Gains on sales of other assets and other, net			13		13
Operating income (loss)	(46)	(6)	1,478		1,426
Equity in earnings of unconsolidated affiliates			596		596
Equity in earnings of subsidiaries	986	1,439		(2,425)	
Other income and expenses, net	3	1	49		53
Interest expense		218	415		633

Minority interest expense			62		62
Earnings from continuing operations before income taxes	943	1,216	1,646	(2,425)	1,380
Income tax expense (benefit) from continuing operations	(14)	230	224		440
Income from continuing operations	957	986	1,422	(2,425)	940
Income from discontinued operations, net of tax			17		17
Net income	$ 957	$ 986	$ 1,439	$ (2,425)	$ 957

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Spectra Energy Corp

Condensed Consolidating Statement of Operations

Year Ended December 31, 2006

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Total operating revenues	$	$ (26)	$ 4,527	$	$ 4,501
Total operating expenses		2	3,312		3,314
Gains on sales of other assets and other, net			47		47
Operating income (loss)		(28)	1,262		1,234
Equity in earnings of unconsolidated affiliates			609		609
Equity in earnings of subsidiaries		1,184		(1,184)	
Other income and expenses, net		41	86		127
Interest expense		373	232		605
Minority interest expense			40		40
Earnings from continuing operations before income taxes		824	1,685	(1,184)	1,325
Income tax expense (benefit) from continuing operations		(151)	544		393
Income from continuing operations		975	1,141	(1,184)	932
Income from discontinued operations, net of tax		269	43		312
Net income	$	$ 1,244	$ 1,184	$ (1,184)	$ 1,244

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Spectra Energy Corp

Condensed Consolidating Balance Sheet

December 31, 2008

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Cash and cash equivalents	$	$ 60	$ 154	$	$ 214
Receivables (payables) consolidated subsidiaries	(25)	250	(220)	(5)	
Receivables other	1	11	783		795
Other current assets	39	35	367		441
Total current assets	15	356	1,084	(5)	1,450
Investments in and loans to unconsolidated affiliates		368	1,784		2,152
Investments in consolidated subsidiaries	7,375	10,482		(17,857)	
Advances receivable (payable) consolidated subsidiaries	(1,937)	3,298	(992)	(369)	
Goodwill			3,381		3,381
Other assets	40	66	311		417
Property, plant and equipment, net			13,639		13,639
Regulatory assets and deferred debits	1	15	869		885
Total Assets	$ 5,494	$ 14,585	$ 20,076	$ (18,231)	$ 21,924
Accounts payable (receivable) consolidated subsidiaries	$ 5	$ 41	$ (41)	$ (5)	$
Accounts payable other	1	124	160		285
Short-term borrowings and commercial paper		1,137	168	(369)	936
Accrued taxes payable (receivable)	(297)	266	136		105
Current maturities of long-term debt		648	173		821
Other current liabilities	19	106	772		897
Total current liabilities	(272)	2,322	1,368	(374)	3,044
Long-term debt		3,009	5,281		8,290
Deferred credits and other liabilities	226	1,879	2,250		4,355
Minority interests			695		695
Total stockholders equity	5,540	7,375	10,482	(17,857)	5,540
Total Liabilities and Stockholders Equity	$ 5,494	$ 14,585	$ 20,076	$ (18,231)	$ 21,924

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Spectra Energy Corp

Condensed Consolidating Balance Sheet

December 31, 2007

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Cash and cash equivalents	$	$	$ 94	$	$ 94
Receivables (payables) consolidated subsidiaries	(9)	269	(255)	(5)	
Receivables other	2	8	897		907
Other current assets	8	1	369		378
Total current assets	1	278	1,105	(5)	1,379
Investments in and loans to unconsolidated affiliates		3	1,777		1,780
Investments in consolidated subsidiaries	7,434	10,281		(17,715)	
Advances receivable (payable) consolidated subsidiaries	(752)	2,369	(1,617)		
Goodwill			3,948		3,948
Other assets	100	210	321		631
Property, plant and equipment, net		2	14,298		14,300
Regulatory assets and deferred debits	5	7	920		932
Total Assets	$ 6,788	$ 13,150	$ 20,752	$ (17,720)	$ 22,970
Accounts payable (receivable) consolidated subsidiaries	$ 5	$ 42	$ (42)	$ (5)	$
Accounts payable other	7	107	249		363
Accrued taxes payable (receivable)	(278)	233	130		85
Current maturities of long-term debt			338		338
Other current liabilities	26	544	1,066		1,636
Total current liabilities	(240)	926	1,741	(5)	2,422
Long-term debt		2,975	5,370		8,345
Deferred credits and other liabilities	171	1,815	2,554		4,540
Minority interests			806		806
Total stockholders equity	6,857	7,434	10,281	(17,715)	6,857
Total Liabilities and Stockholders Equity	$ 6,788	$ 13,150	$ 20,752	$ (17,720)	$ 22,970

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Spectra Energy Corp

Condensed Consolidating Statements of Cash Flows

Year Ended December 31, 2008

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 1,129	$ 1,123	$ 1,648	$ (2,771)	$ 1,129
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization			581		581
Equity in earnings of unconsolidated affiliates			(778)		(778)
Equity in earnings of subsidiaries	(1,123)	(1,648)		2,771	
Distributions received from unconsolidated affiliates			777		777
Other	(63)	112	47		96
Net cash provided by (used in) operating activities	(57)	(413)	2,275		1,805
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(1,502)		(1,502)
Investments in and loans to unconsolidated affiliates		(219)	(309)		(528)
Acquisitions, net of cash acquired			(274)		(274)
Purchases of available-for-sale securities			(1,132)		(1,132)
Proceeds from sales and maturities of available-for-sale securities			1,256		1,256
Net proceeds from the sales of equity investments and other assets, and sales of and collections on notes receivable			105		105
Distributions received from unconsolidated affiliates			218		218
Other			(31)		(31)
Net cash used in investing activities		(219)	(1,669)		(1,888)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt		1,000	2,557		3,557
Payments for the redemption of long-term debt			(2,400)		(2,400)
Net increase in short-term borrowings and commercial paper		290	(41)		249
Distributions to minority interests			(70)		(70)
Contributions from minority interests			115		115
Repurchases of Spectra Energy common shares	(600)				(600)
Dividends paid	(598)	(13)		13	(598)
Distributions and advances to parent	1,241	(585)	(643)	(13)	
Other	14		(53)		(39)
Net cash provided by (used in) financing activities	57	692	(535)		214

Effect of exchange rate changes on cash			(11)		(11)
Net increase in cash and cash equivalents		60	60		120
Cash and cash equivalents at beginning of period			94		94
Cash and cash equivalents at end of period	$	$ 60	$ 154	$	$ 214

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Spectra Energy Corp

Condensed Consolidating Statements of Cash Flows

Year Ended December 31, 2007

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 957	$ 986	$ 1,439	$ (2,425)	$ 957
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization			534		534
Equity in earnings of unconsolidated affiliates			(596)		(596)
Equity in earnings of subsidiaries	(986)	(1,439)		2,425	
Distributions received from unconsolidated affiliates			569		569
Other	(179)	322	(140)		3
Net cash provided by (used in) operating activities	(208)	(131)	1,806		1,467
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures		(2)	(1,200)		(1,202)
Investments in and loans to unconsolidated affiliates		(152)	(133)		(285)
Acquisitions, net of cash acquired			(14)		(14)
Purchases of available-for-sale securities			(1,550)		(1,550)
Proceeds from sales and maturities of available-for-sale securities			1,405		1,405
Net proceeds from the sales of equity investments and other assets, and sales of and collections on notes receivable			15		15
Distributions received from unconsolidated affiliates			87		87
Net cash used in investing activities		(154)	(1,390)		(1,544)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt		369	783	(369)	783
Payments for the redemption of long-term debt			(981)		(981)
Net increase in short-term borrowings and commercial paper		129	237		366
Distributions to minority interests			(57)		(57)
Contributions from minority interests			9		9
Proceeds from issuances of subsidiary stock			230		230
Dividends paid	(558)	(5)		5	(558)
Distributions and advances to parent	766	(164)	(966)	364	
Other			17		17
Net cash provided by (used in) financing activities	208	329	(728)		(191)
Effect of exchange rate changes on cash			63		63

Net increase (decrease) in cash and cash equivalents		44	(249)		(205)
Cash and cash equivalents at beginning of period		(44)	343		299
Cash and cash equivalents at end of period	$	$	$ 94	$	$ 94

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Spectra Energy Corp

Condensed Consolidating Statements of Cash Flows

Year Ended December 31, 2006

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$	$ 1,244	$ 1,184	$ (1,184)	$ 1,244
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization			606		606
Equity in earnings of unconsolidated affiliates			(712)		(712)
Equity in earnings of subsidiaries		(1,184)		1,184	
Distributions received from unconsolidated affiliates			707		707
Other		56	(1,207)		(1,151)
Net cash provided by operating activities		116	578		694
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(987)		(987)
Investments in and loans to unconsolidated affiliates			(87)		(87)
Acquisitions, net of cash acquired			(89)		(89)
Purchases of available-for-sale securities		(9,132)	(158)		(9,290)
Proceeds from sales and maturities of available-for-sale securities		9,653	122		9,775
Net proceeds from the sales of equity investments and other assets, and sales of and collections on notes receivable			2,025		2,025
Proceeds from the sales of commercial and multi-family real estate			254		254
Settlements of net investment hedges and other investing derivatives			(163)		(163)
Distributions received from unconsolidated affiliates			152		152
Other			(21)		(21)
Net cash provided by investing activities		521	1,048		1,569
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt			1,799		1,799
Payments for the redemption of long-term debt		(3,927)	(899)	3,164	(1,662)
Net increase in short-term borrowings and commercial paper		(348)	(88)	697	261
Distributions to minority interests			(304)		(304)
Contributions from minority interests			247		247
Proceeds from issuances of subsidiary stock			104		104
Distributions and advances to parent		3,593	(2,182)	(3,861)	(2,450)
Cash associated with operations transferred to Duke Energy			(427)		(427)
Other			(22)		(22)
Net cash used in financing activities		(682)	(1,772)		(2,454)

Effect of exchange rate changes on cash			(1)		(1)
Net decrease in cash and cash equivalents		(45)	(147)		(192)
Cash and cash equivalents at beginning of period		1	490		491
Cash and cash equivalents at end of period	$	$ (44)	$ 343	$	$ 299

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25. Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(in millions, except per share amounts)				
2008(a)					
Operating revenues	$ 1,600	$ 1,133	$ 1,080	$ 1,261	$ 5,074
Operating income	493	343	340	304	1,480
Net income	367	295	296	171	1,129
Earnings per share total(b)					
Basic	$ 0.58	$ 0.47	$ 0.48	$ 0.28	$ 1.82
Diluted	$ 0.58	$ 0.47	$ 0.48	$ 0.28	$ 1.81
2007(a)					
Operating revenues	$ 1,392	$ 975	$ 950	$ 1,387	$ 4,704
Operating income	415	297	330	384	1,426
Net income	236	196	234	291	957
Earnings per share total(b)					
Basic	$ 0.37	$ 0.31	$ 0.37	$ 0.46	$ 1.51
Diluted	$ 0.37	$ 0.31	$ 0.37	$ 0.46	$ 1.51

(a) Quarterly results have been re-cast to reflect the operating results of certain natural gas gathering and processing facilities as discontinued operations for all periods presented. See Note 8 for further discussion.

(b) Quarterly earnings-per-share amounts are stand-alone calculations and may not be additive to full-year amounts due to rounding.

Unusual or Infrequent Items

During the fourth quarter of 2008, we recorded a $44 million charge ($30 million after tax) representing our share of impaired assets associated with the Islander East pipeline project, of which $12 million is included in Operating, Maintenance and Other expense and $32 million is included in Equity in Earnings of Unconsolidated Affiliates in the Consolidated Statements of Operations. See Note 11 for further discussion.

During the second quarter of 2008, we recorded a $31 million gain ($21 million after tax) related to consideration received for a customer bankruptcy settlement which is included in Gains on Sales of Other Assets and Other, Net. See Note 10 for further discussion.

During the second quarter of 2007, we recorded an $18 million gain ($11 million after tax) related to settlement proceeds of the Sonatrach/Sonatrading Amsterdam B.V. (Sonatrach) 2001 arbitration proceeding which is included in Income From Discontinued Operations, Net of Tax. See Note 8 for further discussion.

26. Subsequent Event

On February 13, 2009, we issued 32.2 million shares of our common stock and received net proceeds of $448 million. We expect to use the net proceeds to fund capital expenditures and for other general corporate purposes. Pending the use of proceeds for such purposes, we expect to use the net proceeds to repay commercial paper and other short-term borrowings as they mature or invest them temporarily in short-term marketable securities. Borrowings from the commercial paper and other short-term borrowings we intend to repay were used primarily for capital expenditures.

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SPECTRA ENERGY CORP

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

	Balance at Beginning of Period	Additions: Charged to Expense	Additions: Charged to Other Accounts	Deductions(a)	Balance at End of Period
			(in millions)		
December 31, 2008:					
Allowance for doubtful accounts	$ 22	$ 7	$	$ 17	$ 12
Other(b)	204	34	5	68	175
	$ 226	$ 41	$ 5	$ 85	$ 187
December 31, 2007:					
Allowance for doubtful accounts	$ 13	$ 17	$	$ 8	$ 22
Other(b)	236	20	98	150	204
	$ 249	$ 37	$ 98	$ 158	$ 226
December 31, 2006:					
Allowance for doubtful accounts	$ 121	$ 23	$ 14	$ 145	$ 13
Other(b)	708	226	67	765	236
	$ 829	$ 249	$ 81	$ 910	$ 249

(a) Principally cash payments and reserve reversals. Also includes transfer of certain operations to Duke Energy in April 2006 and December 2006 as discussed in Note 8.

(b) Principally income tax reserves, insurance related reserves, litigation and other reserves, included primarily in Regulatory and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized, and reported, within the time periods specified by the SEC s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2008, and, based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective.

Changes in Internal Control over Financial Reporting

As previously reported, the Board of Directors appointed J. Patrick Reddy to the position of Chief Financial Officer of Spectra Energy, effective January 1, 2009. Mr. Reddy replaced Gregory L. Ebel as Chief Financial Officer, who was appointed President and Chief Executive Officer of Spectra Energy effective January 1, 2009, the date of Fred J. Fowler s retirement.

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Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated changes in internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended December 31, 2008 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Management s Annual Report on Internal Control over Financial Reporting

The report of management required under this Item 9A is contained in Item 8. Financial Statements and Supplementary Data, Management s Annual Report on Internal Control over Financial Reporting.

Attestation Report of Independent Registered Public Accounting Firm

The attestation report required under this Item 9A is contained in Item 8. Financial Statements and Supplementary Data, Report of Independent Registered Public Accounting Firm.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Reference to Executive Officers is included in Item 1. Business of this report. Other information in response to this item is incorporated by reference from our Proxy Statement relating to our 2009 annual meeting of shareholders.

Item 11. Executive Compensation.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2009 annual meeting of shareholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2009 annual meeting of shareholders.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2009 annual meeting of shareholders.

Item 14. Principal Accounting Fees and Services.

Information in response to this item is incorporated by reference from our Proxy Statement relating to our 2009 annual meeting of shareholders.

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PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Spectra Energy Corp:

Report of Independent Registered Accounting Firm

Consolidated Statements of Operations for the Years Ended December 31, 2008, 2007 and 2006

Consolidated Balance Sheets as of December 31, 2008 and 2007

Consolidated Statements of Cash Flows for the Years Ended December 31, 2008, 2007 and 2006

Consolidated Statements of Stockholders Equity and Comprehensive Income for the Years Ended December 31, 2008, 2007 and 2006

Notes to Consolidated Financial Statements

Consolidated Financial Statement Schedule II Valuation and Qualifying Accounts and Reserves for the Years Ended December 31, 2008, 2007 and 2006

DCP Midstream, LLC:

Independent Auditors Report

Consolidated Balance Sheets

Consolidated Statements of Operations and Comprehensive Income

Consolidated Statements of Cash Flows

Consolidated Statements of Members Equity

Notes to Consolidated Financial Statements

Consolidated Financial Statement Schedule II Valuation and Qualifying Accounts and Reserves for the Years Ended December 31, 2008, 2007 and 2006

All other schedules are omitted because they are not required or because the required information is included in the Consolidated Financial Statements or Notes.

(c) Exhibits See Exhibit Index immediately following the signature page.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 27, 2009

SPECTRA ENERGY CORP

By: /s/ Gregory L. Ebel
Gregory L. Ebel

President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

(i) Gregory L. Ebel*
President and Chief Executive Officer (Principal Executive Officer and Director)

(ii) J. Patrick Reddy*
Chief Financial Officer (Principal Financial Officer)

(iii) Sabra L. Harrington*
Vice President and Controller (Principal Accounting Officer)

(iv) Paul M. Anderson*
Chairman of the Board of Directors

Austin A. Adams*

Director

Pamela L. Carter*

Director

Tony Comper*

Director

William T. Esrey*

Director

Peter B. Hamilton*

Director

Dennis R. Hendrix*

Director

Michael McShane*

Director

Michael E.J. Phelps *

Director

Date: February 27, 2009

J. Patrick Reddy, by signing his name hereto, does hereby sign this document on behalf of the registrant and on behalf of each of the above-named persons previously indicated by asterisk pursuant to a power of attorney duly executed by the registrant and such persons, filed with the Securities and Exchange Commission as an exhibit hereto.

By: /s/ J. Patrick Reddy
J. Patrick Reddy

Attorney-In-Fact

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DCP MIDSTREAM, LLC

CONSOLIDATED FINANCIAL STATEMENTS

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INDEPENDENT AUDITORS   REPORT

To the Board of Directors and Members of

DCP Midstream, LLC

Denver, Colorado

We have audited the accompanying consolidated balance sheets of DCP Midstream, LLC and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations and comprehensive income, members   equity, 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. These consolidated financial statements and financial statement schedule are the responsibility of the Company   s management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company   s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of DCP Midstream, LLC and subsidiaries at 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, 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.

/s/   Deloitte & Touche LLP

Denver, Colorado

February 18, 2009

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DCP MIDSTREAM, LLC

CONSOLIDATED BALANCE SHEETS

(millions)

	December 31, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 133	$ 71
Short-term investments		9
Accounts receivable:		
Customers, net of allowance for doubtful accounts of $6 million and $5 million, respectively	735	1,254
Affiliates	221	386
Other	44	48
Inventories	43	117
Unrealized gains on derivative instruments	419	301
Other	70	62
Total current assets	1,665	2,248
Property, plant and equipment, net	4,836	4,443
Restricted investments	60	101
Investments in unconsolidated affiliates	179	204
Intangible assets, net	319	312
Goodwill	565	556
Unrealized gains on derivative instruments	119	69
Other long-term assets	49	45
Other long-term assets affiliates		27
Total assets	$ 7,792	$ 8,005
LIABILITIES AND MEMBERS EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 888	$ 1,499
Affiliates	48	122
Other	46	54
Short-term borrowings	100	
Unrealized losses on derivative instruments	398	347
Distributions payable to members		123
Accrued interest payable	59	56
Accrued taxes	44	55
Other	188	204
Total current liabilities	1,771	2,460
Long-term debt	3,602	2,930
Unrealized losses on derivative instruments	81	120

Other long-term liabilities		376		339
Non-controlling interest		312		193
Commitments and contingent liabilities				
Members equity:				
Members interest		1,667		1,974
Accumulated other comprehensive loss		(17)		(11)
Total members equity		1,650		1,963
Total liabilities and members equity	$	7,792	$	8,005

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(millions)

	Year Ended December 31,		
	2008	**2007**	**2006**
Operating revenues:			
Sales of natural gas and petroleum products	$ 12,456	$ 10,009	$ 9,137
Sales of natural gas and petroleum products to affiliates	3,507	2,884	2,813
Transportation, storage and processing	334	304	308
Trading and marketing gains (losses), net	101	(43)	77
Total operating revenues	16,398	13,154	12,335
Operating costs and expenses:			
Purchases of natural gas and petroleum products	12,489	10,097	9,322
Purchases of natural gas and petroleum products from affiliates	1,045	781	789
Operating and maintenance	586	510	462
Depreciation and amortization	365	316	284
General and administrative	234	258	234
Gain on sales of assets and unconsolidated affiliates	(15)	(3)	(28)
Total operating costs and expenses	14,704	11,959	11,063
Operating income	1,694	1,195	1,272
Equity in earnings of unconsolidated affiliates	20	29	20
Non-controlling interest in (income) loss	(88)	15	(15)
Interest income	12	16	26
Interest expense	(210)	(170)	(145)
Income before income taxes	1,428	1,085	1,158
Income tax benefit (expense)	3	(11)	(23)
Net income	1,431	1,074	1,135
Other comprehensive (loss) income:			
Net unrealized (losses) gains on cash flow hedges	(11)	(8)	5
Reclassification of cash flow hedges into earnings	5		
Total other comprehensive (loss) income	(6)	(8)	5
Total comprehensive income	$ 1,425	$ 1,066	$ 1,140

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions)

	Year Ended December 31,		
	2008	2007	2006
Cash flows from operating activities:			
Net income	$ 1,431	$ 1,074	$ 1,135
Adjustments to reconcile net income to net cash provided by operating activities:			
Gain on sales of assets and unconsolidated affiliates	(15)	(3)	(28)
Depreciation and amortization	365	316	284
Equity in earnings of unconsolidated affiliates, net of distributions	24	3	
Deferred income tax (benefit) expense	(13)	(1)	17
Non-controlling interest in income (loss)	88	(15)	15
Other, net	42	11	(3)
Changes in operating assets and liabilities which provided (used) cash, net of effects of acquisitions:			
Accounts receivable	715	(398)	314
Inventories	74	(30)	23
Net unrealized (gains) losses on derivative instruments	(181)	99	(1)
Accounts payable	(693)	33	(495)
Accrued interest payable	3	9	1
Other	(52)	50	(16)
Net cash provided by operating activities	1,788	1,148	1,246
Cash flows from investing activities:			
Capital and acquisition expenditures	(625)	(600)	(325)
Acquisition of Momentum Energy Group, Inc., net of cash acquired		(604)	
Acquisition of Michigan Pipeline & Processing, LLC, net of cash acquired	(146)		
Investments in unconsolidated affiliates	(7)	(4)	(44)
Distributions from unconsolidated affiliates			2
Purchases of available-for-sale securities	(1,157)	(15,812)	(19,666)
Proceeds from sales of available-for-sale securities	1,207	16,243	20,121
Proceeds from sales of assets and unconsolidated affiliates	41	1	81
Other	(2)	2	
Net cash (used in) provided by investing activities	(689)	(774)	169
Cash flows from financing activities:			
Payment of dividends and distributions to members	(1,861)	(1,364)	(1,451)
Proceeds from issuance of equity securities of a subsidiary, net of offering costs	132	229	
Proceeds from debt	2,230	1,477	378
Payment of debt	(1,494)	(667)	(320)
Payment of debt acquired		(20)	
Net cash paid to non-controlling interests	(42)	(22)	(10)
Other	(2)	(4)	(3)
Net cash used in financing activities	(1,037)	(371)	(1,406)

Net change in cash and cash equivalents	62	3	9
Cash and cash equivalents, beginning of period	71	68	59
Cash and cash equivalents, end of period	$ 133	$ 71	$ 68

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC

CONSOLIDATED STATEMENTS OF MEMBERS EQUITY

(millions)

	Members Interest	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, January 1, 2006	$ 2,107	$ 411	$ (8)	$ 2,510
Dividends and distributions		(1,393)		(1,393)
Net income		1,135		1,135
Net unrealized gains on cash flow hedges			5	5
Balance, December 31, 2006	2,107	153	(3)	2,257
Dividends and distributions	(133)	(1,227)		(1,360)
Net income		1,074		1,074
Net unrealized losses on cash flow hedges			(8)	(8)
Balance, December 31, 2007	1,974		(11)	1,963
Dividends and distributions	(307)	(1,431)		(1,738)
Net income		1,431		1,431
Net unrealized losses on cash flow hedges			(11)	(11)
Reclassification of cash flow hedges			5	5
Balance, December 31, 2008	$ 1,667	$	$ (17)	$ 1,650

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2008, 2007 and 2006

1. General and Summary of Significant Accounting Policies

Basis of Presentation DCP Midstream, LLC, with its consolidated subsidiaries, us, we, our, or the Company, is a joint venture owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips. We operate in the midstream natural gas industry. Our primary operations consist of gathering, processing, compressing, transporting and storing of natural gas, and fractionating, transporting, gathering, treating, processing and storing of natural gas liquids, or NGLs, as well as marketing, from which we generate revenues primarily by trading and marketing natural gas and NGLs.

DCP Midstream Partners, LP, or DCP Partners, is a master limited partnership, of which our subsidiary, DCP Midstream GP, LP, acts as general partner. As of December 31, 2008 and December 31, 2007, we owned an approximately 29% and 34% limited partnership interest, respectively, and an approximately 1% and 2% general partnership interest, respectively, in DCP Partners, as well as incentive distribution rights that entitle us to receive an increasing share of available cash as pre-defined distribution targets are achieved. As the general partner of DCP Partners, we have responsibility for its operations. Since we exercise control over DCP Partners, we account for them as a consolidated subsidiary.

Prior to January 2, 2007, we were owned 50% by Duke Energy Corporation, or Duke Energy. On January 2, 2007, Duke Energy created two separate publicly traded companies by spinning off their natural gas businesses, including their 50% ownership interest in us, to Duke Energy shareholders. As a result of this transaction, Duke Energy s 50% ownership interest in us was transferred to a new company, Spectra Energy. This transaction is referred to in this report as the Spectra spin. For periods prior to January 2, 2007, references to Spectra Energy are interchangeable with Duke Energy. Effective January 2, 2007, Spectra Energy refers to the newly formed public company.

We are governed by a five member board of directors, consisting of two voting members from each parent and our Chief Executive Officer and President, a non-voting member. All decisions requiring board of directors approval are made by simple majority vote of the board, but must include at least one vote from both a Spectra Energy and ConocoPhillips board member. In the event the board cannot reach a majority decision, the decision is appealed to the Chief Executive Officers of both Spectra Energy and ConocoPhillips.

The consolidated financial statements include the accounts of the Company and all majority-owned subsidiaries where we have the ability to exercise control, variable interest entities where we are the primary beneficiary, and undivided interests in jointly owned assets. We also consolidate DCP Partners, which we control as the general partner and where the limited partners do not have substantive kick-out or participating rights. Investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence, are accounted for using the equity method. Intercompany balances and transactions have been eliminated.

Use of Estimates Conformity with accounting principles generally accepted in the United States of America, or GAAP, requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and notes. Although these estimates are based on management s best available knowledge of current and expected future events, actual results could be different from these estimates.

Cash and Cash Equivalents Cash and cash equivalents include all cash balances and highly liquid investments with an original maturity of three months or less.

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Short-Term and Restricted Investments We may invest available cash balances in various financial instruments, such as commercial paper, money market instruments and tax-exempt debt securities that have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through features, which allow for the redemption of the investment at its face amount plus earned income. As we generally intend to sell these instruments within one year or less from the balance sheet date, and as they are available for use in current operations, they are classified as current assets, unless otherwise restricted. We have classified all short-term and restricted debt investments as available-for-sale and they are carried at fair market value. Unrealized gains and losses on available-for-sale securities are recorded in the consolidated balance sheets as accumulated other comprehensive income or loss, or AOCI. No such gains or losses were deferred in AOCI at December 31, 2008 or 2007. Restricted investments consist of collateral for DCP Partners term loan. The costs, including accrued interest on investments, approximates fair value due to the short-term, highly liquid nature of the securities held by us and as interest rates are re-set on a daily, weekly or monthly basis.

Inventories Inventories consist primarily of natural gas and NGLs held in storage for transportation and processing and sales commitments. Inventories are valued at the lower of weighted average cost or market. Transportation costs are included in inventory on the consolidated balance sheets.

Accounting for Risk Management and Derivative Activities and Financial Instruments Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for derivatives associated with managing DCP Partners commodity price risk. We have used the mark-to-market method of accounting for all commodity derivative instruments associated with managing DCP Partners commodity price risk since July 2007. As a result, the remaining net loss deferred in AOCI is being reclassified to sales of natural gas and petroleum products through December 2011, as the underlying transactions impact earnings.

Each derivative not qualifying for the normal purchases and normal sales exception is recorded on a gross basis in the consolidated balance sheets at its fair value as unrealized gains or unrealized losses on mark-to-market and hedging instruments. Derivative assets and liabilities remain classified in the consolidated balance sheets as unrealized gains or unrealized losses on mark-to-market and hedging instruments at fair value until the contractual delivery period impacts earnings.

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We designate each energy commodity derivative as either trading or non-trading. Certain non-trading derivatives are further designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or a normal purchase or normal sale contract. The remaining non-trading derivatives (which are related to asset based activity) for which hedge accounting or the normal purchase or normal sale exception are not elected, are recorded at fair value on the balance sheet, with changes in the fair value recognized in the consolidated statements of operations and comprehensive income are as follows:

Classification of Contract	Accounting Method	Presentation of Gains & Losses or Revenue & Expense
Trading Derivatives	Mark-to-market method[b]	Net basis in trading and marketing gains and losses
Non-Trading Derivatives:		
Cash Flow Hedge [a]	Hedge method[c]	Gross basis in the same consolidated statements of operations and comprehensive income category as the related hedged item
Fair Value Hedge	Hedge method[c]	Gross basis in the same consolidated statements of operations and comprehensive income category as the related hedged item
Normal Purchase or Normal Sale	Accrual method[d]	Gross basis upon settlement in the corresponding consolidated statements of operations and comprehensive income category based on purchase or sale
Non-Trading Derivatives	Mark-to-market method[b]	Net basis in trading and marketing gains and losses

a Effective July 1, 2007, all commodity cash flow hedges relating to derivatives associated with managing DCP Partners commodity price risk are classified as non-trading derivative activity. Our other commodity cash flow hedges and our interest rate swaps continue to be accounted for as cash flow hedges.

b Mark-to-market An accounting method whereby the change in the fair value of the asset or liability is recognized in the consolidated statements of operations and comprehensive income in trading and marketing gains and losses during the current period.

c Hedge method An accounting method whereby the change in the fair value of the asset or liability is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on mark-to-market and hedging instruments. For cash flow hedges, there is no recognition in the consolidated statements of operations and comprehensive income for the effective portion until the service is provided or the associated delivery period impacts earnings. For fair value hedges, the changes in the fair value of the asset or liability, as well as the offsetting changes in value of the hedged item, are recognized in the consolidated statements of operations and comprehensive income in the same category as the related hedged item.

d Accrual method An accounting method whereby there is no recognition in the consolidated balance sheets or consolidated statements of operations and comprehensive income for changes in fair value of a contract until the service is provided or the associated delivery period impacts earnings.

Cash Flow and Fair Value Hedges For derivatives designated as a cash flow hedge or a fair value hedge, we maintain formal documentation of the hedge. In addition, we formally assess both at the inception of the hedge and on an ongoing basis, whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. All components of each derivative gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

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The fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on mark-to-market and hedging instruments. The effective portion of the change in fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as AOCI and the ineffective portion is recorded in the consolidated statements of operations and comprehensive income. During the period in which the hedged transaction impacts earnings, amounts in AOCI associated with the hedged transaction are reclassified to the consolidated statements of operations and comprehensive income in the same accounts as the item being hedged. We discontinue hedge accounting prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is probable that the hedged transaction will not occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the consolidated balance sheets at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction impacts earnings, unless it is probable that the hedged transaction will not occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

For derivatives designated as fair value hedges, we recognize the gain or loss on the derivative instrument, as well as the offsetting changes in value of the hedged item in earnings in the current period. All derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in the consolidated statements of operations and comprehensive income.

Valuation When available, quoted market prices or prices obtained through external sources are used to determine a contract s fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on internally developed pricing models developed primarily from historical and expected correlations with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Property, Plant and Equipment Property, plant and equipment are recorded at original cost. The cost of maintenance and repairs, which are not significant improvements, are expensed when incurred. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

Asset retirement obligations associated with tangible long-lived assets are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled. We recognize a liability for conditional asset retirement obligations as soon as the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is defined as an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity.

Investments in Unconsolidated Affiliates We use the equity method to account for investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence.

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We evaluate our investments in unconsolidated affiliates for impairment when events or changes in circumstances indicate, in management s judgment, that the carrying value of such investments may have experienced an other than temporary decline in value. When evidence of loss in value has occurred, management compares the estimated fair value of the investment to the carrying value of the investment to determine whether any impairment has occurred. Management assesses the fair value of our unconsolidated affiliates using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. If the estimated fair value is less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized in the financial statements as an impairment loss.

Intangible Assets and Goodwill Intangible assets consist primarily of customer contracts and related relationships, including commodity purchase, transportation and processing contracts. These intangible assets are amortized on a straight-line basis over the term of the contract or anticipated relationship, ranging from less than one to 25 years. Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business.

We evaluate goodwill for impairment annually in the third quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Impairment testing of goodwill consists of a two-step process. The first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, the second step of the process involves comparing the fair value and carrying value of the goodwill of that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the fair value of that goodwill, the excess of the carrying value over the fair value is recognized as an impairment loss.

Long-Lived Assets We evaluate whether the carrying value of long-lived assets, excluding goodwill, has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. The carrying amount is not recoverable if it exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. We consider various factors when determining if these assets should be evaluated for impairment, including but not limited to:

- a significant adverse change in legal factors or business climate;
- a current period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- a significant adverse change in the market value of an asset; and

a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset s carrying value over its fair value. Management assesses the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales

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and discounted cash flow models. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management s intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets.

Upon classification as held for sale, a long-lived asset is measured at the lower of its carrying amount or fair value less cost to sell, depreciation is ceased and the asset is separately presented on the consolidated balance sheets.

If an asset held for sale or sold (1) has clearly distinguishable operations and cash flows, generally at the plant level, (2) has direct cash flows that will be eliminated (from the perspective of the held for sale or sold component), and (3) if we are unable to exert significant influence over the disposed component, then the related results of operations for the current and prior periods, including any related impairments and gains or losses on sales are reflected as income from discontinued operations in the consolidated statements of operations and comprehensive income. If an asset held for sale or sold does not have clearly distinguishable operations and cash flows, impairments and gains or losses on sales are recorded as gain on sale of assets in the consolidated statements of operations and comprehensive income.

Unamortized Debt Premium, Discount and Expense Premiums, discounts and expenses incurred with the issuance of long-term debt are amortized over the terms of the debt using the effective interest method. These premiums and discounts are recorded on the consolidated balance sheets within long-term debt. These unamortized expenses are recorded on the consolidated balance sheets as other long-term assets.

Fair Value Measurements We measure our derivative financial assets and liabilities related to our commodity trading activity and our interest rate swaps at fair value as of each balance sheet date. While we utilize as much information as is readily observable in the marketplace in determining fair value, to the extent that information is not available we may use a combination of indirectly observable facts or, in certain instances may develop our own expectation of the fair value. Calculating the fair value of an instrument is a highly subjective process and involves a significant level of judgment based on our interpretation of a variety of market conditions. The resulting fair value may be significantly different from one measurement date to the next. All realized and unrealized gains and losses, and settlements of commodity derivative instruments are recorded in the consolidated statements of operations and comprehensive income as trading and marketing gains or losses, net. All unrealized gains and losses resulting from changes in the fair value of our interest rate swaps are recorded in the consolidated balance sheets within AOCI and long-term debt.

Distributions Under the terms of the Second Amended and Restated LLC Agreement dated July 5, 2005, as amended, or the LLC Agreement, we are required to make quarterly distributions to Spectra Energy and ConocoPhillips based on allocated taxable income. The LLC Agreement provides for taxable income to be allocated in accordance with Internal Revenue Code Section 704(c).

This Code Section accounts for the variation between the adjusted tax basis and the fair market value of assets contributed to the joint venture. The distribution is based on the highest taxable income allocated to either member with a minimum of each member s tax, with the other member receiving a proportionate amount to maintain the ownership capital accounts at 50% for both Spectra Energy and ConocoPhillips. During the years ended December 31, 2008, 2007 and 2006, we paid distributions of $721 million, $497 million and $650 million, respectively, based on estimated annual taxable income allocated to the members according to their respective ownership percentages at the date the distributions became due.

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Our board of directors determines the amount of the periodic dividends to be paid to Spectra Energy and ConocoPhillips, by considering net income, cash flow or any other criteria deemed appropriate. The LLC Agreement restricts payment of dividends except with the approval of both members. During the years ended December 31, 2008, 2007 and 2006, we paid dividends of $1,140 million, $867 million and $801 million, respectively, to the members, allocated in accordance with their respective ownership percentages.

DCP Partners considers the payment of a quarterly distribution to the holders of its common units and subordinated units, to the extent DCP Partners has sufficient cash from its operations after establishment of cash reserves and payment of fees and expenses, including payments to its general partner, a wholly-owned subsidiary of ours. There is no guarantee, however, that DCP Partners will pay the minimum quarterly distribution on the units in any quarter. DCP Partners will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under its credit agreement. Our limited partner interest in DCP Partners consisted of both subordinated units and common units. The subordinated units were entitled to receive the minimum quarterly distribution only after DCP Partners common unitholders received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. However, the subordination period ended, and the subordinated units were converted into common units, on a one for one basis, as certain distribution requirements, as defined in DCP Partners partnership agreement, were met. The subordination period had an early termination provision that permitted 50% of the subordinated units, or 3,571,428 units, to convert into common units on a one-for-one basis in February 2008 and permitted the other 50% of the subordinated units, or 3,571,429 units, to convert into common units on a one-for-one basis in February 2009, following the satisfactory completion of the tests for ending the subordination period contained in DCP Partners partnership agreement. During the years ended December 31, 2008, 2007 and 2006, DCP Partners paid distributions of approximately $45 million, $25 million and $13 million, respectively, to its public unitholders. In addition to our partnership interests we hold incentive distribution rights, which entitle us to receive an increasing share of available cash as pre-defined distribution targets are achieved.

Revenue Recognition We generate the majority of our revenues from natural gas gathering, processing, compression, transportation and storage, and NGL fractionation, transportation, gathering, treating, processing and storage, as well as trading and marketing of natural gas and NGLs. We realize revenues either by selling the residue natural gas and NGLs, or by receiving fees from the producers.

We obtain access to natural gas and provide our midstream natural gas services principally under contracts that contain a combination of one or more of the following arrangements.

Fee-based arrangements Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing, or transporting of natural gas. Our fee-based arrangements include natural gas purchase arrangements pursuant to which we purchase natural gas at the wellhead, or other receipt points, at an index related price at the delivery point less a specified amount, generally the same as the fees we would otherwise charge for gathering of natural gas from the wellhead location to the delivery point. The revenue we earn is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. To the extent a sustained decline in commodity prices results in a decline in volumes, however, our revenues from these arrangements would be reduced.

Percent-of-proceeds/index arrangements Under percent-of-proceeds/index arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the

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resulting residue natural gas and NGLs based on index prices from published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas and the NGLs, regardless of the actual amount of the sales proceeds we receive. Certain of these arrangements may also result in our returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. Our revenues under percent-of-proceeds/index arrangements correlate directly with the price of natural gas and/or NGLs.

Keep-whole arrangements and wellhead purchase arrangements Under the terms of a keep-whole processing contract, we gather natural gas from the producer for processing, sell the NGLs and return to the producer residue natural gas with a British thermal unit, or Btu, content equivalent to the Btu content of the natural gas gathered. This arrangement keeps the producer whole to the thermal value of the natural gas received. Under the terms of a wellhead purchase contract, we purchase natural gas from the producer at the wellhead or defined receipt point for processing and then market the resulting NGLs and residue gas at market prices. Under these types of contracts, we are exposed to the frac spread. The frac spread is the difference between the value of the NGLs extracted from processing and the value of the Btu equivalent of the residue natural gas. We benefit in periods when NGL prices are higher relative to natural gas prices.

Our trading and marketing of natural gas and petroleum products, consists of physical purchases and sales, as well as derivative instruments.

We recognize revenue for sales and services under the four revenue recognition criteria, as follows:

Persuasive evidence of an arrangement exists Our customary practice is to enter into a written contract, executed by both us and the customer.

Delivery Delivery is deemed to have occurred at the time custody is transferred, or in the case of fee-based arrangements, when the services are rendered. To the extent we retain product as inventory, delivery occurs when the inventory is subsequently sold and custody is transferred to the third party purchaser.

The fee is fixed or determinable We negotiate the fee for our services at the outset of our fee-based arrangements. In these arrangements, the fees are nonrefundable. For other arrangements, the amount of revenue, based on contractual terms, is determinable when the sale of the applicable product has been completed upon delivery and transfer of custody.

Collectibility is probable Collectibility is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates the customers financial position (for example, credit metrics, liquidity and credit rating) and their ability to pay. If collectibility is not considered probable at the outset of an arrangement in accordance with our credit review process, revenue is recognized when the cash is collected.

We generally report revenues gross in the consolidated statements of operations and comprehensive income, as we typically act as the principal in these transactions, take custody of the product, and incur the risks and rewards of ownership. Effective April 1, 2006, any new or amended contracts for certain sales and purchases of inventory with the same counterparty, when entered into in contemplation of one another, are reported net as one transaction. We recognize revenues for our NGL and residue gas derivative trading activities net in the

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consolidated statements of operations and comprehensive income as trading and marketing gains and losses. These activities include mark-to-market gains and losses on energy trading contracts, and the settlement of financial or physical energy trading contracts.

Revenue for goods and services provided but not invoiced is estimated each month and recorded along with related purchases of goods and services used but not invoiced. These estimates are generally based on estimated commodity prices, preliminary throughput measurements and allocations and contract data. There are no material differences between the actual amounts and the estimated amounts of revenues and purchases recorded at December 31, 2008, 2007 and 2006.

Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as other receivables or other payables using current market prices or the weighted average prices of natural gas or NGLs at the plant or system. These balances are settled with deliveries of natural gas or NGLs, or with cash. Included in the consolidated balance sheets as accounts receivable other as of December 31, 2008 and 2007 were imbalances totaling $44 million and $48 million, respectively. Included in the consolidated balance sheets as accounts payable other, as of December 31, 2008 and 2007 were imbalances totaling $46 million and $54 million, respectively.

Significant Customers ConocoPhillips, an affiliated company, was a significant customer in each of the past three years. Total revenues from ConocoPhillips, including its 50% owned equity method investment, Chevron Phillips Chemical Company LLC, or CP Chem, totaled approximately $3,430 million, $2,804 million and $2,689 million during 2008, 2007 and 2006, respectively.

Environmental Expenditures Environmental expenditures are expensed or capitalized as appropriate, depending upon the future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not generate current or future revenue, are expensed. Liabilities for these expenditures are recorded on an undiscounted basis when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Environmental liabilities as of December 31, 2008 and 2007, included in the consolidated balance sheets, totaled $7 million and $6 million, respectively, recorded as other current liabilities, and $11 million and $6 million, respectively, recorded as other long-term liabilities.

Equity-Based Compensation Equity classified equity-based compensation cost is measured at fair value, based on the closing unit price at grant date, and is recognized as expense over the vesting period. Liability classified equity-based compensation cost is remeasured at each reporting date at fair value, based on the closing common unit price, and is recognized as expense over the requisite service period. Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award. Awards granted to non-employees for acquiring, or in conjunction with selling goods and services, are measured at the estimated fair value of the goods or services, or the fair value of the award, whichever is more reliably measured.

Effective January 1, 2006, we adopted the provisions of Statement of Financial Accounting Standard, or SFAS, No. 123(R) (Revised 2004) *Share-Based Payment,* or SFAS 123R, which establishes accounting for equity-based awards exchanged for employee and non-employee services. Accordingly, equity classified equity-based compensation cost is measured at grant date, based on the fair value of the award, and is recognized as expense over the requisite service period. Liability classified equity-based compensation cost is remeasured at each reporting date, and is recognized over the requisite service period.

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Accounting for Sales of Units by a Subsidiary We account for sales of units by a subsidiary by recording a gain or loss on the sale of common equity of a subsidiary equal to the amount of proceeds received in excess of the carrying value of the units sold. As a result, we have deferred approximately $270 million and $228 million of gain on sale of common units in DCP Partners as of December 31, 2008 and 2007, respectively, which is included in other long-term liabilities in the consolidated balance sheets. This gain is comprised of approximately $42 million related to DCP Partners public offering in March 2008, $36 million related to DCP Partners private placement in August 2007, $43 million related to DCP Partners private placement in June 2007, and approximately $149 million related to DCP Partners initial public offering in December 2005. As a result of our adoption of SFAS 160 on January 1, 2009, we will reclassify the deferred gain from long-term liabilities to members equity in the consolidated balance sheets and the gain had no impact on our consolidated statements of operations and comprehensive income.

Income Taxes We are structured as a limited liability company, which is a pass-through entity for U.S. income tax purposes. We own a corporation that files its own federal, foreign and state corporate income tax returns. The income tax expense related to this corporation is included in our income tax expense, along with state, local, franchise and margin taxes of the limited liability company and other subsidiaries.

We follow the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized for the tax consequences of temporary differences between the financial statement carrying amounts and the tax basis of the assets and liabilities.

Recent Accounting Pronouncements Financial Accounting Standards Board, or FASB, Statement of Financial Accounting Standards, or SFAS, No. 162 The Hierarchy of Generally Accepted Accounting Principles, **or SFAS 162** In May 2008, the FASB issued SFAS 162, which is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with GAAP for nongovernmental entities. SFAS 162 is effective 60 days following the Securities and Exchange Commission, or SEC s, approval of the Public Company Accounting Oversight Board amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles. We have assessed the impact of the adoption of SFAS 162, and believe that there will be no impact on our consolidated results of operations, cash flows or financial position.

FASB Staff Position, or FSP No. SFAS 142-3 Determination of the Useful Life of Intangible Assets, **or FSP 142-3** In April 2008, the FASB issued FSP 142-3 which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible. FSP 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We are in the process of assessing the impact of FSP 142-3 but do not expect a material impact on our consolidated results of operations, cash flows and financial position as a result of adoption.

SFAS No. 161 Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 **or SFAS 161** In March 2008, the FASB issued SFAS 161, which requires disclosures of how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 is effective for us on January 1, 2009. We are in the process of assessing the impact of SFAS 161 on our disclosures, and will make the required disclosures in our March 31, 2009 consolidated financial statements.

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***SFAS No. 160 Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51,* or SFAS 160** In December 2007, the FASB issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent s ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 was effective for us on January 1, 2009 and did not have a significant impact on our consolidated results of operations, cash flows or financial position. As a result of adoption, effective January 1, 2009 we will reclassify our non-controlling interest and deferred gain relating to the sale of common units in DCP Partners to members equity.

***SFAS No. 141(R) Business Combinations (revised 2007),* or SFAS 141(R)** In December 2007, the FASB issued SFAS 141(R), which requires the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 141(R) is effective for us on January 1, 2009. As this standard will be applied prospectively upon adoption, we will account for all transactions with closing dates subsequent to the adoption date in accordance with the provisions of the standard.

***SFAS No. 159 The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FAS 115,* or SFAS 159** In February 2007, the FASB issued SFAS 159, which allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item s fair value in subsequent reporting periods must be recognized in current earnings. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities. SFAS 159 became effective for us on January 1, 2008. We have not elected the fair value option relative to any of our financial assets and liabilities which are not otherwise required to be measured at fair value by other accounting standards. Therefore, there is no effect of adoption reflected in our consolidated results of operations, cash flows or financial position.

***SFAS No. 157, Fair Value Measurements,* or SFAS 157** In September 2006, the FASB issued SFAS 157, which was effective for us on January 1, 2008. SFAS 157:

- defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date;

- establishes a framework for measuring fair value;

- establishes a three-level hierarchy for fair value measurements based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date;

- nullifies the guidance in Emerging Issues Task Force, or EITF, 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Involved in Energy Trading and Risk Management Activities*, which required the deferral of profit at inception of a transaction involving a derivative financial instrument in the absence of observable data supporting the valuation technique; and significantly expands the disclosure requirements around instruments measured at fair value.

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Upon the adoption of this standard we incorporated the marketplace participant view as prescribed by SFAS 157. Such changes included, but were not limited to, changes in valuation policies to reflect an exit price methodology, the effect of considering our own non-performance risk on the valuation of liabilities, and the effect of any change in our credit rating or standing. As a result of adopting SFAS 157, we recorded a transition adjustment of approximately $2 million as an increase to earnings during the three months ended March 31, 2008. All changes in our valuation methodology have been incorporated into our fair value calculations subsequent to adoption.

Pursuant to FASB Staff Position 157-2, the FASB issued a partial deferral, ending on December 31, 2008, of the implementation of SFAS 157 as it relates to all non-financial assets and liabilities where fair value is the required measurement attribute by other accounting standards. While we have adopted SFAS 157 for all financial assets and liabilities effective January 1, 2008, we are in the process of assessing the impact SFAS 157 will have on our non-financial assets and liabilities, but do not expect a material impact on our consolidated results of operations, cash flows or financial positions upon adoption.

***FSP, No. 157-3 Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active,* or FSP 157-3** In October 2008, the FASB issued FSP 157-3, which provides guidance in situations where a) observable inputs do not exist, b) observable inputs exist but only in an inactive market and c) how market quotes should be considered when assessing the relevance of observable and unobservable inputs to determine fair value. FSP 157-3 was effective upon issuance, including prior periods for which financial statements have not been issued. We believe that the financial assets that are reflected in our financial statements are transacted within active markets, and therefore, there is no effect on our consolidated results of operations, cash flows or financial positions as a result of the adoption of this FSP.

***FSP of Financial Interpretation, or FIN, 39-1, Amendment of FASB Interpretation No. 39,* or FSP FIN 39-1** In April 2008 the FASB issued FSP FIN 39-1, which permits, but does not require, a reporting entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. FSP 39-1 became effective for us beginning on January 1, 2008; however, we have elected to continue our policy of reflecting our derivative asset and liability positions, as well as any cash collateral, on a gross basis in our consolidated balance sheets.

***EITF, 08-06 Equity Method Investment Accounting Considerations,* or EITF 08-06** In November 2008, the EITF issued ETIF 08-06. Although the issuance of FAS 141(R) and FAS 160 were not intended to reconsider the accounting for equity method investments, the application of the equity method is affected by the issuance of these standards. This issue addresses a) how the initial carrying value of an equity method investment should be determined; b) how an impairment assessment of an underlying indefinite-lived intangible asset of an equity method investment should be performed; c) how an equity method investee s issuance of shares should be accounted for and d) how to account for a change in an investment from the equity method to the cost method. This issue is effective for us effective January 1, 2009, and although we do not expect any changes to the manner in which we apply equity method accounting, this guidance will be considered on a prospective basis to transactions with equity method investees.

2. Acquisitions and Dispositions

Acquisitions

Acquisition of Various Gathering, Pipeline and Compression Assets On October 1, 2008, DCP Partners acquired Michigan Pipeline & Processing, LLC, or MPP, a privately held company engaged in natural gas gathering and treating services for natural gas produced from the Antrim Shale of northern Michigan and natural

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gas transportation within Michigan. The results of MPP s operations have been included in the consolidated financial statements since that date. Under the terms of the acquisition, DCP Partners paid a purchase price of $145 million, plus net working capital and other adjustments of approximately $3 million, subject to additional customary purchase price adjustments. DCP Partners may pay up to an additional $15 million to the sellers depending on the earnings of the assets after a three-year period. DCP Partners financed the acquisition by liquidating a portion of its restricted investments. In addition, DCP Partners entered into a separate agreement that provides the seller with available treating capacity on certain Michigan assets. The seller agreed to pay DCP Partners up to approximately $2 million annually for up to nine years if they do not meet certain criteria, including providing additional volumes for treatment. These payments would reduce goodwill as a return of purchase price. This agreement may be terminated earlier if certain performance criteria of Michigan assets are satisfied. Certain of these performance criteria were satisfied and, as a result, the amount the seller will pay DCP Partners has been reduced to approximately $1 million per year as of December 31, 2008. DCP Partners initially held a $25 million letter of credit to secure the seller s contingent future performance under this agreement and to secure the seller s indemnification obligation under the acquisition agreement; however as a result of the satisfaction of certain performance conditions, this amount was reduced to approximately $23 million as of December 31, 2008.

Under the purchase method of accounting, the assets and liabilities of MPP were recorded at their respective fair values as of the date of the acquisition, and we recorded goodwill of approximately $6 million. The goodwill amount recognized relates primarily to projected growth from new customers. The values of certain assets and liabilities are preliminary, and are subject to adjustments as additional information is obtained. When finalized, material adjustments may result. The purchase price allocation is as follows:

	(Millions)
Cash	$ 2
Accounts receivable	2
Property, plant and equipment	116
Goodwill	6
Intangible assets	20
Other long-term assets	4
Non-controlling interest	(2)
Total purchase price allocation	$ 148

In October 2008, we acquired certain pipeline and compressor station assets located in Kansas, Oklahoma and Texas from Northern Natural Gas for $49 million.

On August 29, 2007, we acquired the stock of Momentum Energy Group, Inc., or MEG, for approximately $635 million plus closing adjustments of approximately $11 million. The results of MEG s operations have been included in the consolidated financial statements since that date. As a result of the acquisition, we expanded our operations into the Fort Worth, Piceance and Powder River producing basins, thus diversifying our business into new areas. We funded our portion of this acquisition with a 364-day bridge loan for $450 million, which was paid off in September 2007 with proceeds from the issuance of the $450 million principal amount of 6.75% Senior Notes, as well as cash on hand. See further discussion of this transaction in the *Contributions to DCP Partners* section below.

Under the purchase method of accounting, the assets and liabilities of MEG were recorded at their respective fair values as of the date of the acquisition, and we recorded goodwill of approximately $138 million, F-19

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including purchase price adjustments of $3 million during the first quarter of 2008. The goodwill amount recognized relates primarily to projected growth in the Fort Worth and Piceance producing basins due to significant natural gas reserves and high level of drilling activity.

The purchase price allocation is as follows (in millions):

Cash	$ 42
Receivables	23
Other assets	2
Property, plant and equipment	282
Intangible assets	254
Goodwill	138
Payables	(18)
Other liabilities	(34)
Current debt	(20)
Non-controlling interest	(23)
Total purchase price allocation	$ 646

In May 2007, DCP Partners acquired certain gathering and compression assets located in southern Oklahoma, as well as related commodity purchase contracts, from Anadarko Petroleum Corporation for approximately $181 million.

Acquisition of Additional Equity Interests In December 2006, we acquired an additional one-third interest in Main Pass Oil Gathering Company, or Main Pass, for approximately $30 million. We now own two-thirds of Main Pass with one other partner. Main Pass is a joint venture whose primary operation is a crude oil gathering pipeline system in the Gulf of Mexico. Since Main Pass is not a variable interest entity, and we do not have the ability to exercise control, we continue to account for Main Pass under the equity method of accounting.

In November 2006, we purchased the remaining 16% minority interest in Dauphin Island Gathering Partners, or DIGP, for $7 million. DIGP was owned 84% by us prior to this transaction, and subsequent to this transaction, is owned 100% by us. DIGP owns gathering and transmission assets in the Gulf Coast.

Dispositions

Disposition of Investments in Unconsolidated Affiliates In October 2008, we sold certain interests in unconsolidated affiliates to unrelated third parties for $19 million in cash, subject to purchase price adjustments, and recognized a gain of $11 million, which is reflected in gain on sale of assets in the consolidated statements of operations and comprehensive income.

Disposition of Various Gathering, Transmission and Processing Assets During the first quarter of 2006, we sold assets totaling $57 million, for proceeds of $85 million, and we recognized a gain of $28 million.

Contributions to DCP Partners

MEG Concurrent with our acquisition of the stock of MEG in August 2007, DCP Partners acquired certain subsidiaries of MEG from us for $166 million plus post-closing purchase price adjustments of approximately $9 million. These subsidiaries of MEG own assets in the Piceance Basin, including a 70% operated interest in the

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Collbran Valley Gas Gathering joint venture in western Colorado, and assets in the Powder River Basin, including the Douglas gas gathering system in Wyoming. DCP Partners financed this transaction with $120 million of borrowings under the DCP Partners   Credit Agreement, the issuance of common units through a private placement with certain institutional investors and cash on hand. In August 2007, DCP Partners issued 2,380,952 common limited partner units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100 million in the aggregate. These units were registered with the SEC in January 2008. As a result of this transaction, the omnibus agreement with DCP Partners was amended to increase the annual fee payable to us by DCP Partners by $2 million for incremental general and administrative expenses. We operate these assets and they are included in our financial statements, through the consolidation of DCP Partners.

DCP East Texas Holdings, LLC and Discovery Producer Services LLC In July 2007, we contributed to DCP Partners a 25% limited liability company interest in DCP East Texas Holdings, LLC, or East Texas, our 40% limited liability company interest in Discovery Producer Services LLC, or Discovery, and a derivative instrument, for aggregate consideration of $244 million in cash, including $1 million for net working capital and other adjustments, $27 million in common units and $1 million in general partner equivalent units. We own the remaining 75% limited liability company interest in East Texas, while third parties still own the other 60% limited liability interest in Discovery. DCP Partners financed the cash portion of this transaction with borrowings under its existing credit facility. We will continue to operate East Texas and both of these assets will continue to be included in our financial statements, through the consolidation of DCP Partners. In December of 2008, we announced that we will contribute an additional 25% ownership interest in East Texas to DCP Partners in exchange for 100% DCP Partners   common units. This transaction is expected to close in April 2009.

Wholesale Propane Logistics Business In November 2006, we contributed our wholesale propane logistics business to DCP Partners for consideration of approximately $83 million, including $77 million in cash ($10 million of which was paid in January 2007 upon completion of construction of a new propane terminal), and $6 million in Class C units. DCP Partners financed this transaction with its existing credit facility and the issuance of Class C units, which were subsequently converted into common units on July 2, 2007. As a result of this transaction, the omnibus agreement with DCP Partners was amended to increase the annual fee payable to us by DCP Partners by $2 million for incremental general and administrative expenses. We will continue to operate these assets and these assets will continue to be included in our financial statements, through the consolidation of DCP Partners.

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3. Agreements and Transactions with Affiliates

The following table summarizes our transactions with affiliates:

	Year Ended December 31, 2008	2007	2006
		(millions)	
ConocoPhillips (a):			
Sales of natural gas and petroleum products to affiliates	$ 3,413	$ 2,787	$ 2,677
Transportation, storage and processing	$ 17	$ 17	$ 12
Purchases of natural gas and petroleum products from affiliates	$ 689	$ 489	$ 492
Operating and general and administrative expenses	$ 2	$ 1	$ 5
Spectra Energy:			
Sales of natural gas and petroleum products to affiliates	$	$ 2	$
Transportation, storage and processing	$	$ 4	$
Purchases of natural gas and petroleum products from affiliates	$ 172	$ 123	$
Operating and general and administrative expenses	$ 7	$ 13	$
Unconsolidated affiliates:			
Sales of natural gas and petroleum products to affiliates	$ 94	$ 95	$ 95
Transportation, storage and processing	$ 26	$ 23	$ 20
Purchases of natural gas and petroleum products from affiliates	$ 184	$ 169	$ 160
Duke Energy:			
Sales of natural gas and petroleum products to affiliates	$	$	$ 41
Transportation, storage and processing	$	$	$ 18
Purchases of natural gas and petroleum products from affiliates	$	$	$ 137
Operating and general and administrative expenses	$	$	$ 30

(a) Includes ConocoPhillips 50% owned equity method investment, ChevronPhillips Chemical Company LLC

ConocoPhillips

Long-term NGL Purchases Contract and Transactions We sell a portion of our residue gas and NGLs to ConocoPhillips and its subsidiaries, including ChevronPhillips Chemical Company LLC, or CP Chem, a 50% equity investment of ConocoPhillips. In addition, we purchase natural gas from ConocoPhillips. Under the NGL Output Purchase and Sale Agreements, or the NGL Agreements, with ConocoPhillips and CP Chem, ConocoPhillips and CP Chem have the right to purchase at index-based prices substantially all NGLs produced by our various processing plants located in the Mid-Continent and Permian Basin regions, and the Austin Chalk area, which include approximately 40% of our total NGL production. The NGL Agreements also grant ConocoPhillips and CP Chem the right to purchase at index-based prices certain quantities of NGLs produced at processing plants that are acquired and/or constructed by us in the future in various counties in the Mid-Continent and Permian Basin regions, and the Austin Chalk area. The primary terms of the agreements are effective until January 1, 2015. We anticipate continuing to purchase and sell these commodities and provide these services to ConocoPhillips and CP Chem in the ordinary course of business.

Spectra Energy

Commodity Transactions We sell a portion of our residue gas and NGLs to, purchase natural gas and other petroleum products from, and provide gathering, transportation and other services to Spectra Energy and their subsidiaries. Management anticipates continuing to purchase and sell commodities and provide services to Spectra Energy in the ordinary course of business.

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Included in the consolidated balance sheets in accounts receivable affiliates as of December 31, 2008 and 2007 are insurance recovery receivables of approximately $13 million and other receivables of $2 million, respectively, and included in other long-term assets affiliates as of December 31, 2008 and 2007, are insurance recovery receivables of $0 and $27 million, respectively. Prior to January 2, 2007, the insurance recovery receivables were from an insurance provider that is a subsidiary of Duke Energy. In connection with the Spectra spin, Spectra Energy is responsible for the insurance liabilities. During the years ended December 31, 2008, 2007 and 2006, we recorded hurricane related business interruption insurance recoveries of $0, $4 million and $1 million, respectively, included in the consolidated statements of operations and comprehensive income as transportation, storage and processing.

During the second quarter of 2008, DCP Partners entered into a propane supply agreement with Spectra Energy. This agreement, effective May 1, 2008 and terminating April 30, 2014, provides DCP Partners propane supply at their marine terminal for up to approximately 120 million gallons of propane annually. This contract replaces the supply provided under a contract with a third party that was terminated during the first quarter of 2008.

Transactions with other unconsolidated affiliates

We sell a portion of our residue gas and NGLs to, purchase natural gas and other petroleum products from, and provide gathering and transportation services to, unconsolidated affiliates. We anticipate continuing to purchase and sell commodities and provide services to unconsolidated affiliates in the ordinary course of business.

Duke Energy

In connection with the Spectra spin, Duke Energy is not considered a related party for reporting periods after January 2, 2007.

Commodity Transactions In 2006, we sold a portion of our residue gas and NGLs to, purchased natural gas and other petroleum products from, and provided gathering and transportation services to Duke Energy and their subsidiaries.

Services Agreement Under a services agreement, Duke Energy and certain of its subsidiaries provided us with various staff and support services, including information technology products and services, payroll, employee benefits, property taxes, media relations, printing and records management. Additionally, we used other Duke Energy services subject to hourly rates, including legal, insurance, internal audit, tax planning, human resources and security departments. In connection with the Spectra spin, as of December 31, 2007, our corporate operations, Spectra Energy, or third party service providers had assumed responsibility for all services previously provided to us by Duke Energy.

In the fourth quarter of 2006, an insurance provider that is a subsidiary of Duke Energy agreed to settle an insurance claim, related to a damaged underground storage facility, for approximately $21 million. We had recorded a receivable in 2005 related to this claim for approximately $4 million. Upon receipt of the cash in December 2006, we relieved the receivable and recorded business interruption insurance recoveries of approximately $16 million, included in the consolidated statements of operations and comprehensive income as transportation, storage and processing.

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4. Inventories

Inventories were as follows:

	December 31, 2008	December 31, 2007
	(millions)	
Natural gas held for resale	$ 7	$ 39
NGLs	36	78
Total inventories	$ 43	$ 117

5. Property, Plant and Equipment

Property, plant and equipment by classification was as follows:

	Depreciable Life	December 31, 2008	December 31, 2007
		(millions)	
Gathering	15 - 30 years	$ 3,633	$ 3,233
Processing	25 - 30 years	2,134	2,030
Transportation	25 - 30 years	1,329	1,224
Underground storage	20 - 50 years	141	121
General plant	3 - 5 years	219	153
Construction work in progress		367	347
		7,823	7,108
Accumulated depreciation		(2,987)	(2,665)
Property, plant and equipment, net		$ 4,836	$ 4,443

Depreciation expense for the years ended December 31, 2008, 2007 and 2006 was $344 million, $304 million and $275 million, respectively. Interest capitalized on construction projects in 2008, 2007 and 2006, was approximately $10 million, $4 million and $3 million, respectively. At December 31, 2008, we had non-cancelable purchase obligations of approximately $83 million for capital projects anticipated to be completed in 2009.

DCP Partners leases one of the MPP transmission pipelines to a third party under a long-term contract. The carrying value of the pipeline is approximately $23 million, with accumulated depreciation of less than $1 million. Minimum future non-cancelable rental payments are as follows:

	(millions)
2009	$ 3
2010	3
2011	3
2012	3
2013	2
Thereafter	21
Total	$ 35

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6. Goodwill and Intangible Assets

The changes in carrying amount of goodwill are as follows:

	December 31, 2008 (millions)	December 31, 2007 (millions)
Goodwill, beginning of period	$ 556	$ 421
Acquisitions	9	135
Goodwill, end of period	$ 565	$ 556

Goodwill increased by $6 million during 2008 as a result of the amount that we recognized in connection with our acquisition of MPP, and by $3 million for the final purchase price allocation for the MEG acquisition. In 2007, we recognized $135 million of goodwill in connection with our acquisition of MEG.

We perform an annual goodwill impairment test, and update the test during interim periods if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We use a discounted cash flow analysis supported by market valuation multiples to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, estimated future cash flows and an estimated run rate of general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. Our annual goodwill impairment test, as of August 31, 2008 indicated that our reporting units fair values exceed their carrying or book values. Accordingly, no impairment of goodwill is indicated. During the fourth quarter of 2008, as a result of the decline in the unit price of DCP Partners units on the New York Stock Exchange, we updated our fair value analysis of the DCP Partners reporting unit using current marketplace assumptions and concluded that the carrying value of the goodwill associated with these units is recoverable. However, given the current volatility in the market, as well as volatile commodity prices, we will continue to monitor the recoverability of such amounts. Continued volatility and marketplace activity may alter our conclusion in the future, and could result in the recognition of an impairment charge.

Intangible assets consist primarily of customer contracts and related relationships, including commodity purchase, transportation and processing contracts. The gross carrying amount and accumulated amortization for intangible assets are as follows:

	December 31, 2008 (millions)	December 31, 2007 (millions)
Gross carrying amount	$ 426	$ 398
Accumulated amortization	(107)	(86)
Intangible assets, net	$ 319	$ 312

Intangible assets increased in 2008 and 2007 as a result of the MPP and MEG acquisitions, respectively, through which $20 million and $254 million of intangible assets were acquired. During the years ended December 31, 2008, 2007 and 2006 we recorded amortization expense of $21 million, $12 million and $9 million, respectively. The remaining amortization periods range from less than one year to 25 years, with a weighted average remaining period of approximately 21 years.

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Estimated amortization for these contracts for the next five years and thereafter is as follows as of December 31, 2008:

	Estimated Amortization (millions)
2009	$ 21
2010	21
2011	20
2012	20
2013	20
Thereafter	217
Total	$ 319

7. Investments in Unconsolidated Affiliates

We have investments in the following unconsolidated affiliates accounted for using the equity method:

	2008 Ownership	December 31, 2008	December 31, 2007
		(millions)	
Discovery Producer Services LLC	40.00%	$ 105	$ 118
Main Pass Oil Gathering Company	66.67%	43	43
Mont Belvieu I	20.00%	11	12
Sycamore Gas System General Partnership	48.45%	10	11
Other unconsolidated affiliates	Various	10	20
Total investments in unconsolidated affiliates		$ 179	$ 204

Discovery Producer Services LLC Discovery operates a cryogenic natural gas processing plant near Larose, Louisiana, a natural gas liquids fractionator plant near Paradis, Louisiana with a design capacity of 600 MMcf/d and approximately 280 miles of pipe, and several onshore laterals expanding their presence in the Gulf. The deficit between the carrying amount of the investment and the underlying equity of Discovery of $40 million and $44 million at December 31, 2008 and 2007, respectively, is associated with, and is being depreciated over the life of, the underlying long-lived assets of Discovery.

Main Pass Oil Gathering Company In December 2006, we acquired an additional 33.33% interest in Main Pass, a joint venture whose primary operation is a crude oil gathering pipeline system in the Main Pass East and Viosca Knoll Block areas in the Gulf of Mexico. We now own 66.67% of Main Pass with one other partner. Since Main Pass is not a variable interest entity, and we do not have the ability to exercise control, we continue to account for Main Pass under the equity method. The excess of the carrying amount of the investment over the underlying equity of Main Pass of $11 million and $12 million at both December 31, 2008 and 2007, is associated with, and is being depreciated over the life of, the underlying long-lived assets of Main Pass.

Mont Belvieu I Mont Belvieu I owns a 150 MBbl/d fractionation facility in the Mont Belvieu, Texas Market Center. The deficit between the carrying amount of the investment and the underlying equity of Mont Belvieu I of $9 million and $10 million at December 31, 2008 and 2007, respectively, is associated with, and is being depreciated over the life of, the underlying long-lived assets of Mont Belvieu I.

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Sycamore Gas System General Partnership Sycamore Gas System General Partnership, or Sycamore, is a partnership formed for the purpose of constructing, owning and operating a gas gathering and compression system in Carter County, Oklahoma. The excess of the carrying amount of the investment over the underlying equity of Sycamore of $6 million and $7 million at December 31, 2008 and 2007, respectively, is associated with, and is being depreciated over the life of, the underlying long-lived assets of Sycamore.

Equity in earnings of unconsolidated affiliates amounted to the following:

	Year Ended December 31,		
	2008	2007	2006
		(millions)	
Discovery Producer Services LLC	$ 17	$ 24	$ 17
Main Pass Oil Gathering Company	2	1	3
Mont Belvieu I	(1)	1	(1)
Sycamore Gas System General Partnership		(1)	(1)
Other unconsolidated affiliates	2	4	2
Total equity in earnings of unconsolidated affiliates	$ 20	$ 29	$ 20
Distributions from unconsolidated affiliates	44	32	20
Equity in earnings of unconsolidated affiliates, net of distributions	$ (24)	$ (3)	$

The following summarizes combined financial information of unconsolidated affiliates:

	Year Ended December 31,		
	2008	2007	2006
		(millions)	
Income Statement:			
Operating revenues	$ 336	$ 354	$ 322
Operating expenses	$ 307	$ 297	$ 287
Net income	$ 34	$ 61	$ 42

	December 31,	
	2008	2007
	(millions)	
Balance sheet:		
Current assets	$ 86	$ 123
Long-term assets	542	638
Current liabilities	(60)	(49)
Long-term liabilities	(26)	(19)

Net assets	$ 542	$ 693

8. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities, as well as short term and restricted investments, which are measured at fair value. Fair values are generally based upon quoted market prices, where available. In the event that listed market prices or quotes are not available, we

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determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an exit price methodology, in line with how we believe a marketplace participant would value that asset or liability. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, the time value of money, and/or liquidity of the market.

Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us.

Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability position with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin that we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.

Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in less active markets, for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

We manage our derivative instruments on a portfolio basis and the valuation adjustments described above are calculated on this basis. We believe that the portfolio level approach represents the highest and best use for these assets as there are benefits inherent in naturally offsetting positions within the portfolio at any given time, and this approach is consistent with how a market participant would view and value the assets. Although we take a portfolio approach to managing these assets/liabilities, in order to reflect the fair value of any one individual contract within the portfolio, we allocate all valuation adjustments down to the contract level; to the extent deemed necessary, based upon either the notional contract volume, or the contract value, whichever is more applicable.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other marketplace participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis, taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 12, Risk Management and Hedging Activities, Credit Risk and Financial Instruments.

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Valuation Hierarchy

Our fair value measurements are grouped into a three-level valuation hierarchy. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows.

Level 1 inputs are unadjusted quoted prices for *identical* assets or liabilities in active markets.

Level 2 inputs include quoted prices for *similar* assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

Level 3 inputs are unobservable and considered significant to the fair value measurement.

A financial instrument s categorization within the hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

We enter into a variety of derivative financial instruments, which may include exchange traded instruments (such as New York Mercantile Exchange, or NYMEX, crude oil, or natural gas futures) or over the counter instruments, or OTC, instruments (such as natural gas contracts, crude oil or NGL swaps). The exchange traded instruments are generally executed on the NYMEX exchange with a highly rated broker dealer serving as the clearinghouse for individual transactions.

Our activities expose us to varying degrees of commodity price risk exposure. To mitigate a portion of this risk, and to manage commodity price risk related primarily, to owned natural gas storage and pipeline assets we engage in natural gas asset based trading and marketing, we may enter into natural gas and crude oil derivatives to lock in a specific margin when market conditions are favorable. A portion of this may be accomplished through the use of exchange traded derivative contracts. Such instruments are generally classified as Level 1 since the value is equal to the quoted market price of the exchange traded instrument as of our balance sheet date, and no adjustments are required. Depending upon market conditions and our strategy we may enter into exchange traded derivative positions with a significant time horizon to maturity. Although such instruments are exchange traded, market prices may only be readily observable for a portion of the duration of the instrument. In order to calculate the fair value of these instruments, readily observable market information is utilized to the extent that it is available; however, in the event that readily observable market data is not available, we may interpolate based upon observable data. In instances where we utilize an interpolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 2. In certain limited instances, we may extrapolate based upon the last readily observable data, developing our own expectation of fair value. To the extent that we have utilized extrapolated data, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

We also engage in the business of trading energy related products and services, which expose us to market variables and commodity price risk. We may enter into physical contracts or financial instruments with the objective of realizing a positive margin from the purchase and sale of these commodity-based instruments. We may enter into derivative instruments for NGLs or other energy related products, primarily using the OTC derivative instrument markets, which may not be as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and a market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which

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prices are readily observable in the OTC market, are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, historical and future expected correlation of NGL prices to crude oil, the knowledge of expected supply sources coming on line, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

Each instrument is assigned to a level within the hierarchy at the end of each financial quarter depending upon the extent to which the valuation inputs are observable. Generally, an instrument will move toward a level within the hierarchy that requires a lower degree of judgment as the time to maturity approaches, and as the markets in which the asset trades will likely become more liquid and prices more readily available in the market, thus reducing the need to rely upon our internally developed assumptions. However, the level of a given instrument may change, in either direction, depending upon market conditions and the availability of market observable data.

Interest Rate Derivative Assets and Liabilities

We have interest rate swap agreements as part of our overall capital strategy. These instruments effectively exchange a portion of our floating rate debt for fixed rate debt or our fixed rate debt for floating rate debt, and are held with major financial institutions, which are expected to fully perform under the terms of our agreements. The swaps are generally priced based upon a United States Treasury instrument with similar characteristics, adjusted by the credit spread between our company and the United States Treasury instrument. Given that a significant portion of the swap value is derived from the credit spread, which may be observed by comparing similar assets in the market, these instruments are classified as Level 2. Default risk on either side of the swap transaction is also considered in the valuation. We record counterparty credit, our entity valuation, as well as liquidity reserves in the valuation of our interest rate swaps; however, these reserves are not considered to be a significant input to the overall valuation.

Restricted Investments

We are required to post collateral to secure the term loan portion of DCP Partners credit facility, and may elect to invest a portion of our available cash balances in various financial instruments such as commercial paper, money market instruments and highly rated debt securities that have stated maturities of 20 years or more, which are categorized as available-for-sale securities. The money market instruments are generally priced at acquisition cost, plus accreted interest at the stated rate, which approximates fair value, without any additional adjustments. However, given that there is no observable exchange traded market for identical money market securities, we have classified these instruments within Level 2. Investments in commercial paper and highly rated debt securities are priced using a yield curve for similarly rated instruments, and are classified within Level 2. As of December 31, 2008, nearly all of our restricted investments were held in the form of money market securities. By virtue of our balances in these funds on September 19, 2008, all of these investments are eligible for, and the funds are participating in, the U.S. Treasury Department s Guarantee Program for Money Market Funds.

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The following table presents the financial instruments carried at fair value as of December 31, 2008, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	Quoted Market Prices in Active Markets (Level 1)	Internal Models With Significant Observable Market Inputs (Level 2)	Internal Models With Significant Unobservable Market Inputs (Level 3)	Total Carrying Value
		(millions)		
Current assets:				
Commodity derivative instruments (a)	$ 34	$ 175	$ 210	$ 419
Available-for-sale securities (b)	$	$ 15	$	$ 15
Long-term assets:				
Commodity derivative instruments (c)	$ 61	$ 36	$ 22	$ 119
Restricted investments	$	$ 60	$	$ 60
Current liabilities (d):				
Commodity derivative instruments	$ (79)	$ (145)	$ (155)	$ (379)
Interest rate instruments	$	$ (19)	$	$ (19)
Long-term liabilities (e):				
Commodity derivative instruments	$ (8)	$ (6)	$ (44)	$ (58)
Interest rate instruments	$	$ (23)	$	$ (23)

(a) Included in current unrealized gains on derivative instruments in our consolidated balance sheets.
(b) Included in cash and cash equivalents in our consolidated balance sheets.
(c) Included in long-term unrealized gains on derivative instruments in our consolidated balance sheets.
(d) Included in current unrealized losses on derivative instruments in our consolidated balance sheets.
(e) Included in long-term unrealized losses on derivative instruments in our consolidated balance sheets.

Changes in Level 3 Fair Value Measurements

The table below illustrates a rollforward of the amounts included in our consolidated balance sheets for derivative financial instruments that we have classified within Level 3. The determination to classify a financial instrument within Level 3 is based upon the significance of the unobservable factors used in determining the overall fair value of the instrument. Since financial instruments classified as Level 3 typically include a combination of observable components (that is, components that are actively quoted and can be validated to external sources) and unobservable components, the gains and losses in the table below may include changes in fair value due in part to observable market factors, or changes to our assumptions on the unobservable components. Depending upon the information readily observable in the market, and/or the use of unobservable inputs, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. In the event that there is a movement to/from the classification of an instrument as Level 3, we have reflected such items in the table below within the Transfers In/Out of Level 3 caption.

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We manage our overall risk at the portfolio level, and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. Since Level 1 and Level 2 risk management instruments are not included in the rollforward below, the gains or losses in the table do not reflect the effect of our total risk management activities.

	Balance at December 31, 2007	Net Realized and Unrealized Gains (Losses) Included in Earnings	Transfers In/Out of Level 3 (a)	Purchases, Issuances and Settlements, Net	Balance at December 31, 2008	Net Unrealized Gains (Losses) Still Held Included in Earnings (b)
Commodity derivative instruments:						
Current assets	$ 125	$ 143	$	$ (58)	$ 210	$ 210
Long-term assets	$ 21	$ 2	$ (1)	$	$ 22	$ 1
Current liabilities	$ (112)	$ (101)	$	$ 58	$ (155)	$ (155)
Long-term liabilities	$ (11)	$ (33)	$	$	$ (44)	$ (33)

(a) Amounts transferred in are reflected at fair value as of the end of the period and amounts transferred out are reflected at fair value at the beginning of the period.

(b) Represents the amount of total gains or losses for the period, included in trading and marketing gains or losses, attributable to the change in unrealized gains or losses relating to assets and liabilities classified as Level 3 that are still held at December 31, 2008.

9. Estimated Fair Value of Financial Instruments

We have determined the following fair value amounts using available market information and appropriate valuation methodologies. Considerable judgment is required, however, in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts.

The fair value of short-term investments, restricted investments, accounts receivable, accounts payable and short-term borrowings are not materially different from their carrying amounts because of the short-term nature of these instruments or the stated rates approximating market rates. Unrealized gains and unrealized losses on mark-to-market and hedging instruments are carried at fair value.

The estimated fair values of current debt, including current maturities of long-term debt, and long-term debt, with the exception of DCP Partners long-term debt, are determined by prices obtained from market quotes. The carrying value of DCP Partners long-term debt approximates fair value, as the interest rate is variable and reflects current market conditions. The estimated fair value of long-term debt was $3,286 and $3,030 as of December 31, 2008 and 2007, respectively.

10. Asset Retirement Obligations

Our asset retirement obligations relate primarily to the retirement of various gathering pipelines and processing facilities, obligations related to right-of-way easement agreements, and contractual leases for land use. We recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of

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the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled.

We identified various assets as having an indeterminate life, for which there is no requirement to establish a fair value for future retirement obligations associated with such assets. These assets include certain pipelines, gathering systems and processing facilities. A liability for these asset retirement obligations will be recorded only if and when a future retirement obligation with a determinable life is identified. These assets have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. Additionally, if the portion of an owned plant containing asbestos were to be modified or dismantled, we would be legally required to remove the asbestos. We currently have no plans to take actions that would require the removal of the asbestos in these assets. Accordingly, the fair value of the asset retirement obligation related to this asbestos cannot be estimated and no obligation has been recorded.

The asset retirement obligation is adjusted each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The following table summarizes changes in the asset retirement obligation, included in other long-term liabilities in the consolidated balance sheets:

	December 31,	
	2008	2007
	(millions)	
Balance, beginning of period	$ 59	$ 52
Accretion expense	5	4
Liabilities incurred	5	4
Liabilities settled	(1)	
Other		(1)
Balance, end of period	$ 68	$ 59

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11. Financing

Long-term debt was as follows:

	December 31, 2008	December 31, 2007
	(millions)	
Debt securities:		
Issued August 2000, interest at 7.875% payable semiannually, due August 2010	$ 800	$ 800
Issued January 2001, interest at 6.875% payable semiannually, due February 2011	250	250
Issued November 2008, interest at 9.700% payable semiannually, due December 2013	250	
Issued October 2005, interest at 5.375% payable semiannually, due October 2015	200	200
Issued August 2000, interest at 8.125% payable semiannually, due August 2030 (a)	300	300
Issued October 2006, interest at 6.450% payable semiannually, due November 2036	300	300
Issued September 2007, interest at 6.750% payable semiannually, due September 2037	450	450
DCP Midstream s credit facility revolver, weighted-average interest rate of 2.69%, due April 2012	360	
DCP Partners credit facility revolver, weighted-average interest rate of 2.08% and 5.47%, respectively, due June 2012 (b)	596	530
DCP Partners credit facility term loan, interest rate of 1.54% and 5.05%, respectively, due June 2012 (c)	60	100
Fair value adjustments related to interest rate swap fair value hedges (a)	43	8
Unamortized discount	(7)	(8)
Long-term debt	$ 3,602	$ 2,930

(a) The swaps associated with this debt were terminated in December 2008. The remaining fair value adjustments of $43 million related to the swaps will be amortized as a reduction to interest expense through the maturity date of the debt.

(b) $575 million of debt has been swapped to a fixed rate obligation with effective fixed rates ranging from 2.26% to 5.19%, for a net effective rate of 4.48% on the $596 million of outstanding debt under the DCP Partners revolving credit facility as of December 31, 2008.

(c) The term loan facility is fully secured by restricted investments.

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Approximate future maturities of long-term debt in the year indicated are as follows at December 31, 2008:

	Debt Maturities (millions)
2010	$ 800
2011	250
2012	1,016
2013	250
Thereafter	1,250
	3,566
Unamortized discount	(7)
Fair value adjustments related to interest rate swap fair value hedges	43
Long-term debt	$ 3,602

Debt Securities In November 2008, we issued $250 million principal amount of 9.70% Senior Notes due 2013, or the 9.70% Notes, for proceeds of approximately $248 million, net of related offering costs. The 9.70% Notes mature and become due and payable on December 1, 2013. We will pay interest semiannually on June 1 and December 1 of each year, beginning June 1, 2009. We used $200 million of the proceeds of this offering to pay down our 364-day agreement that we entered into in April 2008 and the remainder was used for general corporate purposes.

In September 2007, we issued $450 million principal amount of 6.75% Senior Notes due 2037, or the 6.75% Notes, for proceeds of approximately $444 million, net of related offering costs. The 6.75% Notes mature and become due and payable on September 15, 2037. We pay interest semiannually on March 15 and September 15 of each year.

The debt securities mature and become payable on the respective due dates, and are not subject to any sinking fund provisions. Interest is payable semiannually. The debt securities are unsecured and are redeemable at our option.

DCP Midstream s Credit Facilities with Financial Institutions We have a $450 million revolving credit facility, or the Facility, which is used to support our commercial paper program, and for working capital and other general corporate purposes. Any outstanding borrowings under the Facility at maturity may, at our option, be converted into an unsecured one-year term loan. The Facility may be used for letters of credit. As of December 31, 2008 and 2007, there were borrowings of $360 million and $0 outstanding under the Facility and available capacity of $82 million and $445 million, respectively. There was no commercial paper outstanding as of December 31, 2008 and 2007. As of December 31, 2008, there were approximately $8 million in letters of credit outstanding, compared to approximately $5 million in letters of credit outstanding as of December 31, 2007. During 2008, total outstanding indebtedness under the Facility, including borrowings and drawn letters of credit issued under the Facility, was not less than $0 and did not exceed $360 million. The weighted average indebtedness outstanding under the Facility was $54 million for 2008.

Indebtedness under the Facility bears interest at a rate equal to, at our option and based on our current debt rating, either: (1) London Interbank Offered Rate, or LIBOR, plus 0.23% per year for the initial 50% usage or LIBOR plus 0.28% per year if usage is greater than 50%; or (2) the higher of (a) the Wachovia Bank prime rate per year and (b) the Federal Funds rate plus 0.5% per year. The Facility incurs an annual facility fee of 0.07% based on our credit rating on the drawn and undrawn portions.

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In November 2008, we entered into a $350 million revolving credit facility agreement, or the $350 Million Facility, which matures in November 2009. The $350 Million Facility may be used to support our commercial paper program, for working capital requirements and for other general corporate purposes. As of December 31, 2008, there were no borrowings under the $350 Million Facility.

Indebtedness under the $350 Million Facility bears interest at a rate equal to, at our option and based on our debt rating at December 31, 2008, (1) the higher of (a) Citibank s prime rate per year, (b) the Federal Funds rate plus 0.5% per year, or (c) LIBOR plus 2.125% per year, with an increase of 0.25% per quarter, up to 3.125% or (2) LIBOR plus 2.125% per year, with an increase of 0.25% per quarter, up to 3.125%. The $350 Million Facility incurs an annual facility fee of 0.625% based on our current debt rating plus (a) 0.0% to 0.75%, escalating 0.25% quarterly, on the undrawn portions; and (b) 0.5% to 1.75 %, escalating quarterly, on the drawn portions.

In April 2008, we entered into a $300 million 364-day credit agreement, which was fully funded in April 2008, matures in April 2009 and is included within short-term borrowings in the consolidated balance sheets. The proceeds were used to partially fund the April 2008 dividend to our parents and the debt bears interest at a rate equal to, at our option and based on our debt rating at December 31, 2008, either (1) LIBOR, plus 0.75% per year or (2) the higher of (a) the Federal Funds Rate in effect on such day plus 0.5% per year or (b) the JPMorgan Chase Bank prime rate per year. As of December 31, 2008 the outstanding balance under the 364-day agreement was $100 million and is classified in short-term borrowings in the accompanying consolidated balance sheets as of December 31, 2008.

The Facility, the $350 Million Facility and the 364-day credit agreement each require that we maintain a consolidated leverage ratio (the ratio of consolidated indebtedness to consolidated EBITDA, in each case as is defined by these agreements) of not more than 5.0 to 1.0 and on a temporary basis for not more than three consecutive quarters following the consummation of qualifying asset acquisitions (as defined by the agreements) of not more than 5.5 to 1.0. Prior to being amended in April 2008, the Facility required that we maintain a debt to total capitalization ratio of less than or equal to 60%.

In August 2007, we entered into a 364-day bridge loan and borrowed $450 million to fund substantially all of the acquisition of the stock of MEG. We repaid the loan in September with proceeds from the issuance of the 6.75% Notes (see discussion of long-term debt above).

DCP Midstream Partners Credit Facilities with Financial Institutions On June 21, 2007, DCP Partners entered into the Amended and Restated Credit Agreement that matures on June 21, 2012, or the DCP Partners Credit Agreement, which replaced the existing credit agreement, and consists of a total credit facility of $850 million, including a $790 million revolving credit facility and a $60 million term loan facility as of December 31, 2008. At both December 31, 2008 and 2007, DCP Partners had less than $1 million of letters of credit outstanding under the DCP Partners Credit Agreement. As of December 31, 2008 and 2007, the available capacity under the revolving credit facility was $172 million and $70 million, respectively. The $172 million available capacity at December 31, 2008 is net of approximately $22 million non-participation by Lehman Brothers as discussed below. Outstanding balances under the term loan facility are fully collateralized by investments in high-grade securities, which are classified as restricted investments in the accompanying consolidated balance sheets as of December 31, 2008 and 2007. During 2008, total outstanding indebtedness under the DCP Partners Credit Agreement ranged from $630 million to $735 million. The weighted average total indebtedness outstanding under the DCP Partners Credit Agreement was approximately $664 million for the year ended December 31, 2008.

Under the DCP Partners Credit Agreement, indebtedness under the revolving credit facility bears interest at either: (1) the higher of Wachovia Bank s prime rate or the federal funds rate plus 0.50%; or (2) LIBOR plus an

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applicable margin, which ranges from 0.23% to 0.575% dependent upon the leverage level or credit rating. The revolving credit facility incurs an annual facility fee of 0.07% to 0.175% depending on the applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility. The term loan facility bears interest at a rate equal to; (1) LIBOR plus 0.10%; or (2) the higher of Wachovia Bank s prime rate or the federal funds rate plus 0.50%.

The DCP Partners Credit Agreement requires DCP Partners to maintain a leverage ratio (the ratio of consolidated indebtedness to consolidated EBITDA, in each case as is defined by the DCP Partners Credit Agreement) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of qualifying asset acquisitions in the midstream energy business of not more than 5.5 to 1.0. The DCP Partners Credit Agreement also requires DCP Partners to maintain an interest coverage ratio (the ratio of consolidated EBITDA to consolidated interest expense, in each case as is defined by the DCP Partners Credit Agreement) of greater than or equal to 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination.

Lehman Brothers Commercial Bank, or Lehman Brothers, is a lender under the DCP Partners Credit Agreement. Lehman Brothers has not funded its portion of DCP Partners borrowing requests since its bankruptcy, and it is uncertain whether it will participate in future borrowing requests. Accordingly, the availability of new borrowings under the DCP Partners Credit Agreement has been reduced by approximately $22 million as of December 31, 2008. If Lehman Brothers elects not to participate in the DCP Partners Credit Agreement, or does not transfer their commitment to another commercial lender under the credit facility, the availability will be reduced by up to an additional $3 million, for a total reduction of up to $25 million.

In May 2007, DCP Partners entered into a two-month bridge loan and borrowed $88 million to partially fund an acquisition of assets. DCP Partners used a portion of the net proceeds of a private placement of limited partner units to extinguish the $88 million outstanding on this loan in June 2007.

Other Agreements As of December 31, 2008, DCP Partners had an outstanding letter of credit with a counterparty to their commodity derivative instruments of $10 million, which reduces the amount of cash DCP Partners may be required to post as collateral. This letter of credit was issued directly by a financial institution and does not reduce the available capacity under the DCP Partners Credit Agreement.

Other Financing In March 2008, DCP Partners issued 4,250,000 common limited partner units at $32.44 per unit, and received proceeds of approximately $132 million, net of offering costs.

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12. Risk Management and Hedging Activities, Credit Risk and Financial Instruments

The impact of our derivative activity on our results of operations and financial position is summarized below:

	2008	Year Ended December 31, 2007 (millions)	2007
Commodity derivative instruments:			
Gains reclassified from AOCI into earnings	$	$ 1	$ 4
Interest rate derivative instruments:			
Losses reclassified from AOCI into earnings	$ 3	$ (1)	$ (1)
Commodity derivative activity:			
Unrealized gains (losses) from derivative activity	$ 194	$ (102)	$ 6
Realized (losses) gains from derivative activity	(93)	59	71
Total trading and marketing gains (losses), net	$ 101	$ (43)	$ 77

	December 31, 2008 (millions)	2007
Commodity derivative instruments:		
Net deferred losses in AOCI	$ (1)	$ (1)
Interest rate derivative instruments:		
Net deferred losses in AOCI	(16)	(10)
AOCI	$ (17)	$ (11)

For the years ended December 31, 2008 and 2007, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

Commodity Price Risk Our principal operations of gathering, processing, compression, transportation and storage of natural gas, and the accompanying operations of fractionation, transportation, gathering, treating, processing, storage and trading and marketing of NGLs create commodity price risk exposure due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. As an owner and operator of natural gas processing and other midstream assets, we have an inherent exposure to market variables and commodity price risk. The amount and type of price risk is dependent on the underlying natural gas contracts entered into to purchase and process natural gas. Risk is also dependent on the types and mechanisms for sales of natural gas and NGLs, and related products produced, processed, transported or stored.

Energy Trading (Market) Risk Certain of our subsidiaries are engaged in the business of trading energy related products and services, including managing purchase and sales portfolios, storage contracts and facilities, and transportation commitments for products. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and we may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments.

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Interest Rate Risk We enter into debt arrangements that have either fixed or floating rates, therefore we are exposed to market risks related to changes in interest rates. We periodically use interest rate swaps to hedge interest rate risk associated with our debt. Our primary goals include (1) maintaining an appropriate ratio of fixed-rate debt to floating-rate debt; (2) reducing volatility of earnings resulting from interest rate fluctuations; and (3) locking in attractive interest rates based on historical rates.

Credit Risk Our principal customers range from large, natural gas marketing services to industrial end-users for our natural gas products and services, as well as large multi-national petrochemical and refining companies, to small regional propane distributors for our NGL products and services. Substantially all of our natural gas and NGL sales are made at market-based prices. Approximately 40% of our NGL production is committed to ConocoPhillips and CP Chem under an existing 15-year contract, which expires in 2015. This concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of these limits on an ongoing basis. We may use various master agreements that include language giving us the right to request collateral to mitigate credit exposure. The collateral language provides for a counterparty to post cash or letters of credit for exposure in excess of the established threshold. The threshold amount represents an open credit limit, determined in accordance with our credit policy. The collateral language also provides that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, our master agreements and our standard gas and NGL sales contracts contain adequate assurance provisions, which allow us to suspend deliveries and cancel agreements, or continue deliveries to the buyer after the buyer provides security for payment in a satisfactory form.

As of December 31, 2008, we held cash deposits of $26 million included in other current liabilities and letters of credit of $163 million from counterparties to secure their future performance under financial or physical contracts. We had cash deposits with counterparties of $42 million, included in other current assets, to secure our obligations to provide future services or to perform under financial contracts. As of December 31, 2008, DCP Partners had no cash collateral posted with counterparties to their commodity derivative instruments. As of December 31, 2008, DCP Partners had an outstanding letter of credit with a counterparty to its commodity derivative instruments of $10 million. This letter of credit was issued directly by a financial institution and does not reduce the available capacity under the DCP Partners Credit Agreement. This letter of credit reduces the amount of cash DCP Partners may be required to post as collateral. Collateral amounts held or posted may be fixed or may vary, depending on the value of the underlying contracts, and could cover normal purchases and sales, trading and hedging contracts. In many cases, we and our counterparties publicly disclose credit ratings, which may impact the amounts of collateral requirements.

Physical forward contracts and financial derivatives are generally cash settled at the expiration of the contract term. These transactions are generally subject to specific credit provisions within the contracts that would allow the seller, at its discretion, to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment satisfactory to the seller.

Commodity Derivative Activity Our operations of gathering, processing, and transporting natural gas, and the related operations of transporting and marketing of NGLs create commodity price risk due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil.

We manage our commodity derivative activities in accordance with our risk management policy, which limits exposure to market risk and requires regular reporting to management of potential financial exposure.

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Commodity Cash Flow Protection Activities DCP Partners uses natural gas and crude oil swaps and option contracts to mitigate the risk of market fluctuations in the price of NGLs, natural gas and condensate. Prior to July 1, 2007, the effective portion of the change in fair value of a derivative designated as a cash flow hedge was accumulated in AOCI. During the period in which the hedged transaction impacted earnings, amounts in AOCI associated with the hedged transaction were reclassified to the consolidated statements of operations and comprehensive income in the same accounts as the item being hedged.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for derivatives associated with managing DCP Partners commodity price risk. As a result, the remaining net loss deferred in AOCI at that time is being reclassified to sales of natural gas and petroleum products through December 2011, as the derivative transactions impact earnings. Subsequent to July 1, 2007, the changes in fair value of these financial derivatives are included in trading and marketing gains and losses in the consolidated statements of operations and comprehensive income. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

As of December 31, 2008, DCP Partners has mitigated a portion of their expected natural gas and condensate commodity price risk associated with the equity volumes from their gathering and processing operations through 2013 with natural gas, NGL and crude oil derivatives.

Commodity Cash Flow Hedges During 2008, we executed a series of derivative financial instruments, which have been designated as cash flow hedges of the price risk associated with forecasted purchases of natural gas in 2010. For the year ended December 31, 2008, amounts recognized as comprehensive income in the consolidated statements of operations and comprehensive income for changes in the fair value of these hedge instruments were not significant. Amounts recognized for the effects of any ineffectiveness were also not significant. No amounts were reclassified to the consolidated statements of operations and comprehensive income as a result of settlements and no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the change in probability of forecasted transactions occurring. The deferred balance in AOCI was a loss of approximately $1 million at December 31, 2008. Amounts expected to be reclassified from AOCI into earnings during the next 12 months are not significant. Due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings.

Commodity Fair Value Hedges Historically, we used fair value hedges to mitigate risk to changes in the fair value of an asset or a liability (or an identified portion thereof) that is attributable to fixed price risk. We may hedge producer price locks (fixed price gas purchases) and market locks (fixed price gas sales) to reduce our cash flow exposure to fixed price risk via swapping the fixed price risk for a floating price position (New York Mercantile Exchange or index based).

Normal Purchases and Normal Sales If a contract qualifies and is designated as a normal purchase or normal sale, no recognition of the contract s fair value in the consolidated financial statements is required until the associated delivery period impacts earnings. We have applied this accounting election for contracts involving the purchase or sale of commodities in future periods, as well as select operating expense contracts.

Commodity Derivatives Trading and Marketing Our trading and marketing program is designed to realize margins related to fluctuations in commodity prices and basis differentials, and to maximize the value of certain storage and transportation assets. Certain of our subsidiaries are engaged in the business of trading energy related products and services including managing purchase and sales portfolios, storage contracts and facilities, and transportation commitments for products. These energy trading operations are exposed to market variables

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and commodity price risk with respect to these products and services, and may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. We manage our trading and marketing portfolio with strict policies, which limit exposure to market risk, and require daily reporting to management of potential financial exposure. These policies include statistical risk tolerance limits using historical price movements to calculate daily value at risk.

Interest Rate Cash Flow Hedges DCP Partners mitigates a portion of their interest rate risk with interest rate swaps, which reduce the exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swaps convert the interest rate associated with an aggregate of $575 million of the variable rate exposure to a fixed rate obligation. All interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the consolidated balance sheets. As of December 31, 2008, $5 million of deferred net losses on derivative instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings however, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 2.26% to 5.19% and receive interest payments based on the three-month LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

Prior to issuing fixed rate debt in August 2000, we entered into, and terminated, treasury locks and interest rate swaps to lock in the interest rate prior to it being fixed at the time of debt issuance. The losses realized on these agreements, which were terminated in 2000, are deferred in AOCI and amortized against interest expense over the life of the respective debt. The amount amortized to interest expense during the years ended December 31, 2008 and 2007, was $1 million for both periods. The deferred balance was a loss of $4 million and $5 million at December 31, 2008 and 2007, respectively. Approximately $1 million of deferred net losses related to these instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the underlying hedged interest expense transaction occurs.

Interest Rate Fair Value Hedges We entered into interest rate swaps to convert $100 million of fixed-rate debt securities issued in August 2000 to floating rate debt. These interest rate fair value hedges were at a floating rate based on six-month LIBOR, which was re-priced semiannually through 2030. The swaps met conditions that permitted the assumption of no ineffectiveness. As such, for the life of the swaps no ineffectiveness was recognized. These swaps were terminated in December 2008 and we received cash of approximately $36 million net of a $7 million transaction fee, which is included in interest expense in the consolidated statements of operations and comprehensive income. The remaining $43 million change in fair value of the underlying debt will be amortized as a reduction to interest expense through 2030.

13. Non-Controlling Interest

Non-controlling interest represents the ownership interests of third-party entities in net assets of various equity method investments in consolidated affiliates, including ownership interest of DCP Partners public unitholders in net assets of DCP Partners through DCP Partners publicly traded common units, and in net assets of DCP East Texas Holdings, LLC, of which DCP Partners acquired a 25% equity interest in July 2007 as well as Collbran Valley Gas Gathering, which was acquired by DCP Partners in conjunction with the MEG acquisition in August 2007 and has a 30% non-controlling interest. Jackson Pipeline Company, LP was acquired by DCP

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Partners in conjunction with the MPP acquisition in October 2008 and has a 25% non-controlling interest. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party and affiliate investors interest in our consolidated balance sheet amounts shown as non-controlling interest. Distributions to and contributions from non-controlling interests represent cash payments and cash contributions, respectively, from such third-party and affiliate investors.

14. Equity-Based Compensation

We recorded equity-based compensation (benefit) expense as follows, the components of which are further described below:

	Year Ended December 31,		
	2008	2007	2006
	(millions)		
DCP Midstream, LLC Long-Term Incentive Plan (2006 Plan)	$	$ 4	$ 1
DCP Partners Long-Term Incentive Plan (DCP Partners Plan)	(1)	2	1
Duke Energy 1998 Plan and Spectra Energy Long-Term Incentive Plan	(1)	1	6
Total	$ (2)	$ 7	$ 8

	Vesting Period (years)	Unrecognized Compensation Expense at December 31, 2008 (millions)	Estimated Forfeiture Rate	Weighted-Average Remaining Vesting (years)
DCP Midstream s 2006 Plan:				
Relative Performance Units (RPUs)	8	$	72%(a)	5
Strategic Performance Units (SPUs)	3	$ 2	22%(a)	1
Phantom Units	5	$ 2	23%(a)	2
DCP Partners Phantom Units	3	$	22%(a)	
DCP Partners Plan:				
Performance Units	3	$	50%	1
Phantom Units	0.5/3	$	0%	
Restricted Phantom Units	3	$	50%	2
Duke Energy s 1998 Plan and Spectra Energy s 2007 LTIP Plan:				
Stock Options (no activity in 2007 or 2008)	0-10	$	NA	
Stock Based Performance Awards	3	$	6%	
Phantom Awards	1-5	$	6%	1
Other Stock Awards	1-5	$	NA	

(a) Weighted-average estimated forfeiture rate

DCP Midstream, LLC Long-Term Incentive Plan, or 2006 Plan Under our 2006 Long Term Incentive Plan, or 2006 Plan, equity instruments may be granted to our key employees. The 2006 Plan provides for the grant of Relative Performance Units, or RPUs, Strategic Performance Units, or SPUs, and Phantom Units. The RPUs, SPUs and Phantom Units consist of a notional unit based on the value of common shares or units of ConocoPhillips, Duke Energy, Spectra Energy and DCP Partners. The weighting varies depending on when the

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units were granted. The DCP Partners Phantom Units constitute a notional unit equal to the fair value of DCP Partners common units. Each award provides for the grant of dividend or distribution equivalent rights, or DERs. The 2006 Plan is administered by the compensation committee of our board of directors. We first granted awards under the 2006 Plan during the second quarter of 2006. All awards are subject to cliff vesting.

Relative Performance Units The number of RPUs that will ultimately vest range from 0% to 200% of the outstanding RPUs, depending on the achievement of specified performance targets over a three year period ending in January 2009 and 2010, respectively, for units granted in 2006 and 2007. The final performance payout is determined by the compensation committee of our board of directors. After the performance period, vesting occurs over five years, at the end of which the value is based on the participant s investment elections during the deferral period. The DERs will be paid in cash at the end of the performance period. The following tables presents information related to RPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2006		$	
Granted	44,080	$ 42.89	
Outstanding at December 31, 2006	44,080	$ 42.89	
Granted	42,340	$ 43.98	
Forfeited	(21,237)	$ 43.55	
Vested or paid in cash	(3,016)	$ 42.86	
Outstanding at December 31, 2007	62,167	$ 43.41	
Forfeited	(5,850)	$ 43.36	
Vested or paid in cash	(3,047)	$ 42.86	
Outstanding at December 31, 2008	53,270	$ 43.44	$ 31.83
Expected to vest	26,892	$ 43.36	$ 32.06

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Strategic Performance Units The number of SPUs that will ultimately vest range from 0% to 200% of the outstanding SPUs, depending on the achievement of specified performance targets over a three year period ending on December 31, 2008, 2009 and 2010, respectively, for units granted in 2006, 2007 and 2008. The final performance payout is determined by the compensation committee of our board of directors. The DERs will be paid in cash at the end of the performance period. The following tables presents information related to SPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2006		$	
Granted	84,960	$ 42.92	
Outstanding at December 31, 2006	84,960	$ 42.92	
Granted	86,380	$ 44.04	
Forfeited	(28,305)	$ 43.51	
Vested or paid in cash	(3,016)	$ 42.86	
Outstanding at December 31, 2007	140,019	$ 43.49	
Granted	112,930	$ 35.49	
Forfeited	(14,617)	$ 41.86	
Vested or paid in cash	(3,047)	$ 42.86	
Outstanding at December 31, 2008	235,285	$ 39.76	$ 26.82
Expected to vest	166,879	$ 39.27	$ 26.46

The estimate of RPUs and SPUs that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate and achievement of performance targets. Therefore the amounts of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations and comprehensive income.

Phantom Units The DERs are paid quarterly in arrears. The following table presents information related to Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2006		$	
Granted	17,460	$ 42.95	

Outstanding at December 31, 2006	17,460	$	42.95			
Granted	19,450	$	44.10			
Forfeited	(2,930)	$	43.42			
Vested or paid in cash	(180)	$	42.86			
Outstanding at December 31, 2007	33,800	$	43.57			
Granted	112,930	$	35.49			
Forfeited	(5,270)	$	39.15			
Outstanding at December 31, 2008	141,460	$	37.39	$	23.56	
Expected to vest	115,334	$	37.44	$	23.80	

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DCP Partners Phantom Units The DERs are paid quarterly in arrears. The following table presents information related to the DCP Partners Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Price Per Unit
Outstanding at January 1, 2006		$	
Granted	47,750	$ 28.60	
Outstanding at December 31, 2006	47,750	$ 28.60	
Granted	13,500	$ 50.57	
Forfeited	(2,000)	$ 28.60	
Vested or paid in cash	(7,500)	$ 28.60	
Outstanding at December 31, 2007	51,750	$ 34.33	
Forfeited	(2,750)	$ 51.10	
Outstanding at December 31, 2008	49,000	$ 33.39	$ 9.40
Expected to vest	48,750	$ 33.33	$ 9.40

DCP Partners Long-Term Incentive Plan, or DCP Partners Plan Under DCP Partners Long Term Incentive Plan, or DCP Partners Plan, which was adopted by DCP Midstream GP, LLC, equity instruments may be granted to key employees, consultants and directors of DCP Midstream GP, LLC and its affiliates who perform services for DCP Partners. The DCP Partners Plan provides for the grant of limited partner units, or LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of dividend equivalent rights, or DERs. Subject to adjustment for certain events, an aggregate of 850,000 common units may be delivered pursuant to awards under the DCP Partners Plan. Awards that are canceled, forfeited or withheld to satisfy DCP Midstream GP, LLC s tax withholding obligations are available for delivery pursuant to other awards. The DCP Partners Plan is administered by the compensation committee of DCP Midstream GP, LLC s board of directors. All awards are subject to cliff vesting, with the exception of the Phantom Units issued to the directors in conjunction with the initial public offering, which are subject to graded vesting provisions.

Awards granted to directors and awards granted to employees in 2008 are accounted for as equity-based awards; all other awards are accounted for as liability awards.

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Performance Units The number of Performance Units that will ultimately vest range from 0% to 200% of the outstanding Performance Units, depending on the achievement of specified performance targets over three year performance periods. The final performance percentage payout is determined by the compensation committee of DCP Partners board of directors. The DERs will be paid in cash at the end of the performance period. The following table presents information related to the Performance Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Price Per Unit
Outstanding at January 1, 2006		$	
Granted	40,560	$ 26.96	
Forfeited	(17,470)	$ 26.96	
Outstanding at December 31, 2006	23,090	$ 26.96	
Granted	29,610	$ 37.29	
Forfeited	(5,740)	$ 31.39	
Outstanding at December 31, 2007	46,960	$ 32.93	
Granted	17,085	$ 33.85	
Forfeited	(12,025)	$ 32.42	
Outstanding at December 31, 2008	52,020	$ 33.35	$ 9.40
Expected to vest (a)	45,350	$ 31.70	$ 9.40

(a) Based on our December 31, 2008 estimated achievement of specified performance targets, the performance target for units that are expected to vest for units granted in 2008 is 100%, for units granted in 2007 is 102% and for units granted in 2006 is 150%. The estimated forfeiture rate for units granted in 2008 and 2007 is 50%, and for units granted in 2006 is 0%.

The estimate of Performance Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate and achievement of performance targets. Therefore the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations and comprehensive income.

Phantom Units In conjunction with their initial public offering, in January 2006 DCP Partners awarded Phantom Units to key employees, and to directors who are not officers or employees of DCP Midstream GP, LLC, or its affiliates who perform services for DCP Partners. The remaining Phantom Units outstanding at December 31, 2008 vested on January 3, 2009.

In 2007, DCP Partners granted 4,500 Phantom Units pursuant to the DCP Partners Plan, to directors who are not officers or employees of affiliates of DCP Midstream as part of their annual director fees for 2007. Of these Phantom Units, 4,000 units vested during 2007 and 500 units vested during 2008.

In 2008, DCP Partners granted 4,000 Phantom Units, pursuant to the LTIP, to directors who are not officers or employees of affiliates of DCP Midstream as part of their annual director fees in 2008. All of these units vested during 2008.

The DERs are paid quarterly in arrears.

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The following table presents information related to the Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Price Per Unit
Outstanding at January 1, 2006		$	
Granted	35,900	$ 24.05	
Forfeited	(11,200)	$ 24.05	
Outstanding at December 31, 2006	24,700	$ 24.05	
Granted	4,500	$ 42.90	
Forfeited	(2,333)	$ 24.05	
Vested or paid in cash	(6,668)	$ 35.23	
Outstanding at December 31, 2007	20,199	$ 24.56	
Granted	4,000	$ 35.88	
Forfeited	(4,000)	$ 24.05	
Vested or paid in cash	(6,501)	$ 32.91	
Outstanding at December 31, 2008	13,698	$ 24.05	$ 9.40
Expected to vest	13,698	$ 24.05	$ 9.40

The estimate of Phantom Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate.

Restricted Phantom Units DCP Midstream Partners General Partner s board of directors awarded restricted phantom LPUs, or RPUs, to key employees under the LTIP. The RPUs are expected to vest on December 31, 2011. The DERs are paid quarterly in arrears. The following table presents information related to the RPUs:

	Units	Grant Date Weighted-Average Price per Unit	Measurement Date Price per Unit
Outstanding at December 31, 2007		$	$
Granted	17,085	$ 33.85	
Forfeited	(2,395)	$ 35.88	

Outstanding at December 31, 2008	14,690	$ 33.52	$ 9.40
Expected to vest	8,544	$ 33.85	$ 9.40

The estimate of RPUs that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate.

All awards issued under the 2006 Plan and the DCP Partners Plan are intended to be settled in cash at each reporting period or units upon vesting. Compensation expense is recognized ratably over each vesting period, and will be remeasured quarterly for all awards outstanding until the units are vested. The fair value of all awards is determined based on the closing price of the relevant underlying securities at each measurement date.

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Duke Energy 1998 Plan and Spectra Energy 2007 Long-Term Incentive Plan Under the Duke Energy 1998 Plan, or the 1998 Plan, Duke Energy granted certain of our key employees stock options, stock-based performance awards, phantom stock awards and other stock awards to be settled in shares of Duke Energy s common stock, or the Stock-Based Awards. Upon execution of the 50-50 Transaction in July 2005, our employees incurred a change in status from Duke Energy employees to non-employees. As a result, we began accounting for these awards using the fair value method. No awards have been and we do not expect to settle any awards granted under the 1998 Plan with cash.

In connection with the Spectra spin, one replacement Duke Energy Stock-Based Award and one-half Spectra Energy Stock-Based Award were distributed to each holder of Duke Energy Stock-Based Awards for each award held at the time of the Spectra spin. Substantially all converted Stock-Based Awards are subject to the terms and conditions applicable to the original Duke Energy Stock-Based Awards. The Spectra Energy Stock-Based Awards resulting from the conversion are considered to have been issued under the Spectra Energy 2007 Long-Term Incentive Plan, or the Spectra Energy 2007 LTIP.

The Spectra Energy 2007 LTIP provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. A maximum of 30 million shares of common stock may be awarded under the Spectra Energy 2007 LTIP. Options granted under the Spectra Energy 2007 LTIP are issued with exercise prices equal to the fair market value of Spectra Energy common stock on the grant date, have ten year terms, and vest immediately or over terms not to exceed five years. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible. Restricted, performance and phantom stock awards granted under the Spectra Energy 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. The fair value of the awards granted is measured based on the fair market value of the shares on the date of grant, and the related compensation expense is recognized over the requisite service period which is the same as the vesting period.

Stock Options Under the 1998 Plan, the exercise price of each option granted could not be less than the market price of Duke Energy s common stock on the date of grant. Effective July 1, 2005, these options were accounted using the fair value method. As a result, compensation expense subsequent to July 1, 2005, is recognized based on the change in the fair value of the stock options at each reporting date until vesting.

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The following table shows information regarding options to purchase Duke Energy s common stock granted to our employees, reflecting shares outstanding as impacted by the conversion.

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Life (years)	Aggregate Intrinsic Value (millions)
Outstanding at January 1, 2006	2,592,567	$ 29.46	5.2	
Exercised	(367,088)	$ 21.15		
Forfeited	(124,417)	$ 29.96		
Effect of conversion	(258,058)			
Outstanding at December 31, 2006	1,843,004	$ 17.85	4.1	
Exercised	(21,960)	$ 13.89		
Forfeited	(5,088)	$ 22.90		
Outstanding at December 31, 2007	1,815,956	$ 17.89	3.2	
Exercised	(151,480)	$ 13.45		
Forfeited	(106,889)	$ 19.77		
Outstanding at December 31, 2008	1,557,587	$ 18.19	2.4	$ 2
Exercisable at December 31, 2008	1,557,587	$ 18.19	2.4	$ 2

The total intrinsic value of options exercised during the years ended December 31, 2008 and 2007, was approximately $1 million and less than $1 million, respectively.

The following table shows information regarding options to purchase Spectra Energy s common stock granted to our employees, reflecting shares outstanding as impacted by the conversion.

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Life (years)	Aggregate Intrinsic Value (millions)
Outstanding at January 1, 2006		$		
Effect of conversion	1,066,595			
Outstanding at December 31, 2006	1,066,595	$ 26.43	4.1	
Exercised	(73,920)	$ 17.84		

Forfeited	(55,427)	$	31.78			
Outstanding at December 31, 2007	937,248	$	26.80	3.2		
Exercised	(68,869)	$	18.91			
Forfeited	(72,400)	$	28.06			
Outstanding at December 31, 2008	795,979	$	27.36	2.4	$	1
Exercisable at December 31, 2008	795,979	$	27.36	2.4	$	1

The total intrinsic value of options exercised during the years ended December 31, 2008 and 2007, was approximately $1 million and less than $1 million, respectively.

Stock-Based Performance Awards There were no stock-based performance awards granted during the years ended December 31, 2008 and 2007.

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The following tables summarize information about stock-based performance awards activity, reflecting shares outstanding as impacted by the conversion:

Duke Energy 1998 Plan	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2006	342,453	$ 23.88	
Forfeited	(40,835)	$ 23.85	
Effect of conversion	(128,213)		
Outstanding at December 31, 2006	173,405	$ 15.58	
Forfeited	(40)	$ 15.38	
Outstanding at December 31, 2007	173,365	$ 15.58	
Vested	(83,762)	$ 15.39	
Forfeited	(59,663)	$ 15.39	
Outstanding at December 31, 2008	29,940	$ 16.50	$ 15.01
Expected to vest	28,200	$ 16.50	$ 15.01

Spectra Energy 2007 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2006		$	
Effect of conversion	184,083		
Outstanding at December 31, 2006	184,083	$ 20.93	
Vested	(83,309)	$ 18.30	
Forfeited	(14,091)	$ 20.42	
Outstanding at December 31, 2007	86,683	$ 23.54	
Vested	(41,884)	$ 23.25	
Forfeited	(29,829)	$ 23.25	
Outstanding at December 31, 2008	14,970	$ 24.94	$ 15.74

Expected to vest	14,009	$	24.94	$	15.74

The total fair value of the performance stock awards that vested during the year ended December 31, 2008 was approximately $2 million for both periods. No awards were granted during the years ended December 31, 2008 and 2007.

Phantom Stock Awards There were no phantom stock awards granted during the years ended December 31, 2008 and 2007.

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DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Year Ended December 31, 2008, 2007 and 2006

The following tables summarize information about phantom stock awards activity, reflecting shares outstanding as impacted by the conversion:

Duke Energy 1998 Plan	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2008	241,216	$ 24.22	
Vested	(54,150)	$ 23.90	
Forfeited	(22,378)	$ 24.29	
Effect of conversion	(52,664)		
Outstanding at December 31, 2006	112,024	$ 15.59	
Vested	(29,190)	$ 15.54	
Forfeited	(5,624)	$ 15.38	
Outstanding at December 31, 2007	77,210	$ 15.62	
Vested	(24,419)	$ 15.57	
Forfeited	(3,287)	$ 15.38	
Outstanding at December 31, 2008	49,504	$ 15.66	$ 15.01
Expected to vest	46,627	$ 15.66	$ 15.01

Spectra Energy 2007 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2006		$	
Effect of conversion	104,171		
Outstanding at December 31, 2006	104,171	$ 21.31	
Vested	(59,258)	$ 19.66	
Forfeited	(6,308)	$ 22.81	
Outstanding at December 31, 2007	38,605	$ 23.60	
Vested	(12,209)	$ 23.53	
Forfeited	(1,644)	$ 23.24	
Outstanding at December 31, 2008	24,752	$ 23.66	$ 15.74

Expected to vest	23,163	$	23.66	$	15.74

The total fair value of the phantom stock awards that vested during the years ended December 31, 2008 and 2007 was approximately $1 million and $2 million, respectively. No awards were granted during the years ended December 31, 2008 and 2007.

15. Benefits

All Company employees who are 18 years old and work at least 20 hours per week are eligible for participation in our 401(k) and retirement plan, to which we contributed 4% of each eligible employee s qualified earnings through December 31, 2006. Effective January 1, 2007, we began contributing a range of 4% to 7% of each eligible employee s qualified earnings to the retirement plan, based on years of service. Additionally, we

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Year Ended December 31, 2008, 2007 and 2006

match employees contributions in the 401(k) plan up to 6% of qualified earnings. During the years ended December 31, 2008, 2007 and 2006 we expensed plan contributions of $19 million, $17 million and $15 million, respectively.

We offer certain eligible executives the opportunity to participate in DCP Midstream LP s Non-Qualified Executive Deferred Compensation Plan. This plan allows participants to defer current compensation on a pre-tax basis and to receive tax deferred earnings on such contributions. The plan also has make-whole provisions for plan participants who may otherwise be limited in the amount that we can contribute to the 401(k) plan on the participant s behalf. All amounts contributed to or earned by the plan s investments are held in a trust account for the benefit of the participants. The trust and the liability to the participants are part of our general assets and liabilities, respectively.

16. Income Taxes

We are structured as a limited liability company, which is a pass-through entity for United States income tax purposes. We own a corporation that files its own federal, foreign and state corporate income tax returns. The income tax (benefit) expense related to this corporation is included in our income tax (benefit) expense, along with state and local taxes of the limited liability company and other subsidiaries.

The State of Texas imposes a margin tax that is assessed at 1% of taxable margin apportioned to Texas. Accordingly, we have recorded current tax expense for the Texas margin tax beginning in 2007. During 2008, we acquired properties in Michigan, which imposes a business tax of 0.8% on gross receipts and 4.95% of Michigan taxable income. The sum of gross receipts and income tax is subject to a tax surcharge of 21.99%. Michigan provides tax credits that may reduce our final income tax liability.

Income tax expense consists of the following:

	Year Ended December 31,		
	2008	2007	2006
		(millions)	
Current:			
Federal	$ (3)	$ 5	$ 5
State	13	11	1
Deferred:			
Federal	(13)	(4)	
State		(1)	17
Total income tax (benefit) expense	$ (3)	$ 11	$ 23

The Company has a net long-term deferred tax asset of approximately $3 million at December 31, 2008, which is included in other long-term assets on the consolidated balance sheets. The deferred tax asset is comprised of differences between the financial statement carrying amount and the tax basis of property, plant and equipment ($18 million liability), investments in consolidated affiliates ($10 million asset), and net operating loss ($11 million asset). The net operating losses begin expiring in 2021, which we expect to fully utilize. Deferred taxes were not material at December 31, 2007.

Our effective tax rate differs from statutory rates primarily due to our being structured as a limited liability company, which is a pass-through entity for United States income tax purposes, while being treated as a taxable

DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Year Ended December 31, 2008, 2007 and 2006

entity in certain states. Additionally, some of our subsidiaries are tax paying entities for United States income tax purposes.

17. Commitments and Contingent Liabilities

Litigation The midstream industry has seen a number of class action lawsuits involving royalty disputes, mismeasurement and mispayment allegations. Although the industry has seen these types of cases before, they were typically brought by a single plaintiff or small group of plaintiffs. A number of these cases are now being brought as class actions. We are currently named as defendants in some of these cases. Management believes we have meritorious defenses to these cases and, therefore, will continue to defend them vigorously. These class actions, however, can be costly and time consuming to defend. We are also a party to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business.

In March 2008, after receiving regulatory approval, we finalized settlement of a lawsuit alleging migration of acid gas from a storage formation into a third-party producing formation. We obtained the land and the rights to the producing formation. This matter did not have a material adverse effect upon our consolidated results of operations, financial position or cash flows.

In December 2006, El Paso E&P Company, L.P., or El Paso, filed a lawsuit against one of our subsidiaries, DCP Assets Holding, LP and an affiliate of DCP Midstream GP, LP, in District Court, in Harris County, Texas. The litigation stems from an ongoing commercial dispute involving DCP Partners Minden processing plant that dates back to August 2000. El Paso claims damages, including interest, in the amount of $6 million in the litigation, the bulk of which stems from audit claims under our commercial contract.

Management currently believes that these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage and other indemnification arrangements, will not have a material adverse effect upon our consolidated results of operations, financial position or cash flows.

General Insurance Midstream s insurance coverage is carried with an affiliate of ConocoPhillips and third-party insurers. Midstream s insurance coverage includes: (1) general liability insurance covering third-party exposures; (2) statutory workers compensation insurance; (3) automobile liability insurance for all owned, non-owned and hired vehicles; (4) excess liability insurance above the established primary limits for general liability and automobile liability insurance; (5) property insurance, which covers the replacement value of all real and personal property and includes business interruption/extra expense; and (6) directors and officers insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

Environmental The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste storage, management, transportation and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of

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DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS Continued

Year Ended December 31, 2008, 2007 and 2006

remedial requirements, the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

On July 20, 2006, the State of New Mexico Environment Department issued Compliance Orders to us that listed air quality violations during the previous five years at three of our owned or operated facilities in New Mexico. The orders alleged a number of violations related to excess emissions beginning January 2001, and further required us to install flares for smokeless operations and to use the flares only for emergency purposes. On April 17, 2008, we signed a settlement agreement with the New Mexico Environment Department that resolved all alleged violations through the date of the settlement agreement. Under the terms of the settlement agreement, we paid approximately $2 million in civil penalties and agreed to fund $59 million in facility upgrades at three of our gas plants through April 2011.

We utilize assets under operating leases in several areas of operations. Consolidated rental expense, including leases with no continuing commitment, amounted to $45 million, $41 million and $37 million in 2008, 2007 and 2006, respectively. Rental expense for leases with escalation clauses is recognized on a straight line basis over the initial lease term.

Minimum rental payments under our various operating leases in the year indicated are as follows:

	Minimum Rental Payments (millions)
2009	$ 28
2010	25
2011	24
2012	22
2013	20
Thereafter	23
Total payments	$ 142

18. Guarantees and Indemnifications

We periodically enter into agreements for the acquisition or divestiture of assets. These agreements contain indemnification provisions that may provide indemnity for environmental, tax, employment, outstanding litigation, breaches of representations, warranties and covenants, or other liabilities related to the assets being acquired or divested. Claims may be made by third parties under these indemnification agreements for various periods of time depending on the nature of the claim. The effective periods on these indemnification provisions generally have terms of one to five years, although some are longer. Our maximum potential exposure under these indemnification agreements can vary depending on the nature of the claim and the particular transaction. We are unable to estimate the total maximum potential amount of future payments under indemnification agreements due to several factors, including uncertainty as to whether claims will be made under these indemnities.

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Year Ended December 31, 2008, 2007 and 2006

19. Supplemental Cash Flow Information

	December 31, 2008	2007 (millions)	2006
Cash paid for interest:			
Cash paid for interest, net of capitalized interest	$ 190	$ 159	$ 141
Cash paid for income taxes	$ 5	$ 11	$ 10
Non-cash investing and financing activities:			
Distributions payable to members	$	$ 123	$ 127
Net increase in property, plant and equipment	$ 7	$ 8	$ 10

During the years ended December 31, 2008 and 2007, we received distributions from DCP Partners of $31 million and $19 million, respectively, which are eliminated in consolidation.

20. Subsequent Events

In February 2009, we announced that our East Texas natural gas processing complex and residue natural gas delivery system, known as the Carthage Hub, have been temporarily shut in following an explosion and fire that occurred when a nearby third party owned pipeline outside of our property line ruptured. We do not expect a material impact on our consolidated results of operations, cash flows or financial position as a result of this event.

In February 2009, the remaining 3,571,429 DCP Partners subordinated units were converted into common units following the completion of the subordination period and satisfactory completion of all subordination period tests contained in the DCP Partners partnership agreement.

On January 27, 2009, the board of directors of the DCP Partners general partner declared a quarterly distribution of $0.60 per unit, payable on February 13, 2009 to unitholders of record on February 6, 2009.

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DCP MIDSTREAM, LLC

SCHEDULE II CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS AND RESERVES FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006

	Balance at Beginning of Period	Charged to Consolidated Statements of Operations	Charged to Other Accounts (b)	Deductions (c)	Balance at End of Period
			(Millions)		
December 31, 2008					
Allowance for doubtful accounts	$ 5	$ 2	$	$ (1)	$ 6
Environmental	12	10		(4)	18
Litigation	15			(11)	4
Other (a)	3				3
	$ 35	$ 12	$	$ (16)	$ 31
December 31, 2007					
Allowance for doubtful accounts	$ 3	$ 2	$ 1	$ (1)	$ 5
Environmental	12	2	2	(4)	12
Litigation	9	9		(3)	15
Other (a)	4			(1)	3
	$ 28	$ 13	$ 3	$ (9)	$ 35
December 31, 2006					
Allowance for doubtful accounts	$ 4	$	$	$ (1)	$ 3
Environmental	13	3		(4)	12
Litigation	5	6		(2)	9
Other (a)	6			(2)	4
	$ 28	$ 9	$	$ (9)	$ 28

(a) Principally consists of other contingency reserves, which are included in current liabilities.
(b) Consists of purchase accounting adjustments for the Momentum Energy Group, Inc. acquisition in 2007.
(c) Principally consists of cash payments, collections, reserve reversals and liabilities settled.

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EXHIBIT INDEX

Exhibit No.	Exhibit Description
2.1	Separation and Distribution Agreement by and between Duke Energy Corporation and Spectra Energy Corp, dated as of December 13, 2006 (filed as Exhibit No. 2.1 to Form 8-K of Spectra Energy Corp on December 15, 2006)
2.2	Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and DCP Midstream, LLC, dated as of May 26, 2005 (filed as Exhibit No. 10.4 to Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2005, File No. 1-4928)
2.2.1	First Amendment to Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and DCP Midstream, LLC, dated as of June 30, 2005 (filed as Exhibit No. 10.4.1 to Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2005)
2.2.2	Second Amendment to Reorganization Agreement by and among ConocoPhillips, Duke Capital LLC and DCP Midstream, LLC, dated as of July 11, 2005 (filed as Exhibit No. 10.4.2 to Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2005)
2.3	Amended and Restated Combination Agreement, dated as of September 20, 2001, among Duke Energy Corporation, 3058368 Nova Scotia Company, 3946509 Canada Inc. and Westcoast Energy Inc. (filed as Exhibit No. 10.7 to Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2001)
2.4	Spectra Energy Support Agreement dated as of January 1, 2007, between Spectra Energy Corp, Duke Energy Canada Call Co. and Duke Energy Canada Exchangeco Inc. (filed as Exhibit No. 2.2 to Form S-3 of Spectra Energy Corp on January 17, 2007)
2.5	Spectra Energy Voting and Exchange Trust Agreement dated as of January 1, 2007, between Spectra Energy Corp, Duke Energy Canada Exchangeco Inc. and Computershare Trust Company, Inc. (filed as Exhibit No. 2.3 to Form S-3 of Spectra Energy Corp on January 17, 2007)
2.6	Plan of Arrangement, as approved by the Supreme Court of British Columbia by final order dated December 15, 2006 (filed as Exhibit No. 2.4 to Form S-3 of Spectra Energy Corp on January 17, 2007)
3.1	Amended and Restated Certificate of Incorporation of Spectra Energy Corp (filed as Exhibit No. 3.1 to Form 8-K of Spectra Energy Corp on December 15, 2006)
3.2	Amended and Restated By-laws of Spectra Energy Corp (filed as Exhibit No. 3.2 to Form 8-K of Spectra Energy Corp on December 15, 2006)
4.1	Senior Indenture between Duke Capital Corporation and the Chase Manhattan Bank, dated as of April 1, 1998 (filed as Exhibit No. 4.1 to Form S-3 of Duke Capital Corporation on April 1, 1998, File No. 333-71297)
4.2	First Supplemental Indenture, dated July 20, 1998, between Duke Capital Corporation and The Chase Manhattan Bank (filed as Exhibit No. 4.2 to Form 10-K of Duke Capital Corporation on March 16, 2004)
4.3	Second Supplemental Indenture, dated September 28, 1999, between Duke Capital Corporation and The Chase Manhattan Bank (filed as Exhibit No. 4.3 to Form 10-K of Duke Capital Corporation on March 16, 2004)
4.4	Fifth Supplemental Indenture, dated February 15, 2002, between Duke Capital Corporation and JPMorgan Chase Bank (filed as Exhibit No. 4.6 to Form 10-K of Duke Capital Corporation on March 16, 2004)
4.5	Ninth Supplemental Indenture, dated February 20, 2004, between Duke Capital Corporation and JPMorgan Chase Bank (filed as Exhibit No. 4.10 to Form 10-K of Duke Capital Corporation on March 16, 2004)
4.6	Eleventh Supplemental Indenture, dated August 19, 2004, between Duke Capital LLC and JPMorgan Chase Bank (filed as Exhibit No. 4.6 to Form S-3 of Spectra Energy Corp and Spectra Energy Capital, LLC on March 26, 2008, File No. 333-141982)

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Exhibit No.	Exhibit Description
4.7	Twelfth Supplemental Indenture, dated December 14, 2007, among Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on December 20, 2007)
4.8	Thirteenth Supplemental Indenture, dated as of April 10, 2008, between Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K on April 10, 2008)
4.9	Fourteenth Supplemental Indenture, dated as September 8, 2008, between Spectra Energy Capital, LLC, Spectra Energy Corp and The Bank of New York Mellon Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K on September 9, 2008)
10.1	Tax Matters Agreement by and among Duke Energy Corporation, Spectra Energy Corp, and The Other Spectra Energy Parties, dated as of December 13, 2006 (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on December 15, 2006)
10.2	Transition Services Agreement by and between Duke Energy Corporation and Spectra Energy Corp, dated as of December 13, 2006 (filed as Exhibit No. 10.2 to Form 8-K of Spectra Energy Corp on December 15, 2006)
10.3	Employee Matters Agreement by and between Duke Energy Corporation and Spectra Energy Corp, dated as of December 13, 2006 (filed as Exhibit No. 10.3 to Form 8-K of Spectra Energy Corp on December 15, 2006)
10.3.1	First Amendment to Employee Matters Agreement, dated as of September 28, 2007, by and between Duke Energy Corporation and Spectra Energy Corp (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended September 30, 2007)
10.4	Purchase and Sale Agreement, dated as of February 24, 2005, by and between Enterprise GP Holdings LP and DCP Midstream, LLC (filed as Exhibit No. 10.25 to Form 10-K of Duke Energy Corporation for the year ended December 31, 2004)
10.5	Term Sheet Regarding the Restructuring of DCP Midstream LLC, dated as of February 23, 2005, between Duke Energy Corporation and ConocoPhillips (filed as Exhibit No. 10.26 to Form 10-K of Duke Energy Corporation for the year ended December 31, 2004)
10.6	Second Amended and Restated Limited Liability Company Agreement of DCP Midstream, LLC by and between ConocoPhillips Gas Company and Duke Energy Enterprises Corporation, dated as of July 5, 2005 (filed as Exhibit No. 10.5 to Form 10-K of Duke Energy Corporation for the year ended December 31, 2005)
10.7	Limited Liability Company Agreement of Gulfstream Management & Operating Services, LLC, dated as of February 1, 2001, between Duke Energy Gas Transmission Corporation and Williams Gas Pipeline Company (filed as Exhibit No. 10.18 to Form 10-K of Duke Energy Corporation for the year ended December 31, 2002)
10.8	Loan Agreement, dated as of February 25, 2005, between DCP Midstream, LLC and Duke Capital LLC (filed as Exhibit No. 10.3 to Form 10-Q of Duke Energy Corporation for the quarter ended March 31, 2005)
+10.9	Spectra Energy Corp Directors Savings Plan (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on December 22, 2006)
+10.10	Spectra Energy Corp Executive Savings Plan (filed as Exhibit No. 10.2 to Form 8-K of Spectra Energy Corp on December 22, 2006)
+10.11	Spectra Energy Corp Executive Cash Balance Plan (filed as Exhibit No. 10.3 to Form 8-K of Spectra Energy Corp on December 22, 2006)
+10.12	Form of Change of Control Severance Agreements (filed as Exhibit No. 10.4 to Form 8-K of Spectra Energy Corp on December 22, 2006)

Exhibit No.	Exhibit Description
+10.13	Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.1 to Amendment No. 3 to Form 10 of Spectra Energy Corp on December 6, 2006)
+10.14	Form of Non-Qualified Stock Option Agreement pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.18 to Form 8-K of Spectra Energy Corp on August 3, 2007)
+10.15	Form of Phantom Stock Award Agreement pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.19 to Form 8-K of Spectra Energy Corp on August 3, 2007)
10.16	$1,500,000,000 Credit Agreement, dated as of May 21, 2007, among Spectra Energy Capital, LLC, the banks listed therein, JPMorgan Chase Bank, N.A., as Administration Agent and Citibank, N.A., as Syndication Agent (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Capital, LLC on May 22, 2007)
10.16.1	Amendment No. 1, dated April 8, 2008, among Spectra Energy Corp, Spectra Energy Capital, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent and the banks listed therein to the Credit Agreement dated May 21, 2007 (filed as Exhibit No. 10.2 to Form 10-Q of Spectra Energy Corp for the quarter ended March 31, 2008)
10.17	Support Agreement among Spectra Energy Midstream Holdco Management Partnership, Spectra Energy Income Fund and Spectra Energy Commercial Trust, dated March 4, 2008 (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended March 31, 2008)
+10.18	Form of Phantom Stock Award Agreement pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit No. 10.1 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2008)
+10.19	Form of Performance Award Agreement pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (filed as Exhibit 10.2 to Form 10-Q of Spectra Energy Corp for the quarter ended June 30, 2008)
+10.20	Transitional Employment and Separation Agreement, dated October 15, 2008, between Spectra Energy Corp and Martha B. Wyrsch (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on October 17, 2008)
+10.21	Transitional Employment and Separation Agreement, dated November 4, 2008, between Spectra Energy Corp and William S. Garner, Jr. (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on November 7, 2008)
*12.1	Computation of Ratio of Earnings to Fixed Charges
*21.1	Subsidiaries of the Registrant
*23.1	Consent of Independent Registered Public Accounting Firm
*23.2	Consent of Independent Auditors
*24.1	Power of Attorney
*31.1	Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31.2	Certification of the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

\+ Denotes management contract or compensatory plan or arrangement.
* Filed herewith.