Spectra Energy Corp.
Form 10-Q
November 06, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2009

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-33007

SPECTRA ENERGY CORP

(Exact Name of Registrant as Specified in its Charter)

Delaware	**20-5413139**
(State or other jurisdiction of incorporation)	**(IRS Employer Identification No.)**

5400 Westheimer Court

Houston, Texas 77056

(Address of principal executive offices, including zip code)

713-627-5400

(Registrant s telephone number, including area code)

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

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

Indicate by check mark 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 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 Exchange Act). Yes ¨ No x

Number of shares of Common Stock, $0.001 par value, outstanding as of October 30, 2009: 646,755,342

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SPECTRA ENERGY CORP

FORM 10-Q FOR THE QUARTER ENDED

September 30, 2009

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

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(In millions, except per-share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Operating Revenues				
Transportation, storage and processing of natural gas	$ 655	$ 586	$ 1,885	$ 1,764
Distribution of natural gas	167	213	1,017	1,239
Sales of natural gas liquids	73	219	246	623
Other	38	62	106	187
Total operating revenues	933	1,080	3,254	3,813
Operating Expenses				
Natural gas and petroleum products purchased	101	231	759	1,127
Operating, maintenance and other	265	304	785	919
Depreciation and amortization	149	144	429	437
Property and other taxes	66	61	197	186
Total operating expenses	581	740	2,170	2,669
Gains on Sales of Other Assets and Other, net	1		11	32
Operating Income	353	340	1,095	1,176
Other Income and Expenses				
Equity in earnings of unconsolidated affiliates	60	273	267	725
Other income and expenses, net	12	9	35	30
Total other income and expenses	72	282	302	755
Interest Expense	160	163	456	470
Earnings From Continuing Operations Before Income Taxes	265	459	941	1,461
Income Tax Expense From Continuing Operations	54	145	260	453
Income From Continuing Operations	211	314	681	1,008
Income (Loss) From Discontinued Operations, net of tax	1	(2)	3	(1)
Net Income	212	312	684	1,007
Net Income Noncontrolling Interests	21	16	55	49

Net Income Controlling Interests	$ 191	$ 296	$ 629	$ 958
Common Stock Data				
Weighted-average shares outstanding				
Basic	646	615	640	626
Diluted	647	617	641	629
Earnings per share from continuing operations				
Basic	$ 0.30	$ 0.49	$ 0.98	$ 1.54
Diluted	$ 0.30	$ 0.48	$ 0.98	$ 1.53
Earnings per share				
Basic	$ 0.30	$ 0.48	$ 0.98	$ 1.53
Diluted	$ 0.30	$ 0.48	$ 0.98	$ 1.52
Dividends per share	$ 0.25	$ 0.25	$ 0.75	$ 0.71

See Notes to Condensed Consolidated Financial Statements.

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SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)

	September 30, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	$ 450	$ 214
Receivables, net	569	795
Inventory	350	279
Other	158	162
Total current assets	1,527	1,450
Investments and Other Assets		
Investments in and loans to unconsolidated affiliates	1,997	2,152
Goodwill	3,901	3,381
Other	408	417
Total investments and other assets	6,306	5,950
Property, Plant and Equipment		
Cost	19,608	17,569
Less accumulated depreciation and amortization	4,499	3,930
Net property, plant and equipment	15,109	13,639
Regulatory Assets and Deferred Debits	996	885
Total Assets	$ 23,938	$ 21,924

See Notes to Condensed Consolidated Financial Statements.

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SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions, except per-share amounts)

	September 30, 2009	December 31, 2008
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 192	$ 285
Short-term borrowings and commercial paper	44	936
Taxes accrued	172	105
Interest accrued	183	158
Current maturities of long-term debt	813	821
Other	853	739
Total current liabilities	2,257	3,044
Long-term Debt	9,347	8,290
Deferred Credits and Other Liabilities		
Deferred income taxes	3,039	2,789
Regulatory and other	1,590	1,566
Total deferred credits and other liabilities	4,629	4,355
Commitments and Contingencies		
Preferred Stock of Subsidiaries	225	225
Stockholders Equity		
Preferred stock, $0.001 par, 22 million shares authorized, no shares outstanding		
Common stock, $0.001 par, 1 billion shares authorized, 647 million and 611 million shares outstanding at September 30, 2009 and December 31, 2008, respectively	1	1
Additional paid-in capital	4,679	4,104
Retained earnings	1,041	899
Accumulated other comprehensive income	1,217	536
Total controlling interests	6,938	5,540
Noncontrolling interests	542	470
Total stockholders equity	7,480	6,010
Total Liabilities and Stockholders Equity	$ 23,938	$ 21,924

See Notes to Condensed Consolidated Financial Statements.

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SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 684	$ 1,007
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	440	445
Deferred income tax expense	125	61
Equity in earnings of unconsolidated affiliates	(267)	(725)
Distributions received from unconsolidated affiliates	107	691
Other	178	(83)
Net cash provided by operating activities	1,267	1,396
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(713)	(1,038)
Investments in and loans to unconsolidated affiliates	(55)	(497)
Acquisitions, net of cash acquired	(295)	(274)
Purchases of available-for-sale securities		(1,289)
Proceeds from sales and maturities of available-for-sale securities	32	1,354
Distributions received from unconsolidated affiliates	148	180
Receipt from affiliate repayment of loan	186	
Other	(35)	
Net cash used in investing activities	(732)	(1,564)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from the issuance of long-term debt	3,405	2,972
Payments for the redemption of long-term debt	(2,839)	(1,801)
Net increase (decrease) in short-term borrowings and commercial paper	(892)	204
Distributions to noncontrolling interests	(153)	(50)
Contributions from noncontrolling interests	2	112
Proceeds from the issuance of Spectra Energy common stock	448	
Proceeds from the issuance of Spectra Energy Partners, LP common units	208	
Repurchases of Spectra Energy common stock		(600)
Dividends paid on common stock	(471)	(444)
Other	3	(39)
Net cash provided by (used in) financing activities	(289)	354
Effect of exchange rate changes on cash	(10)	1
Net increase in cash and cash equivalents	236	187
Cash and cash equivalents at beginning of period	214	94

Cash and cash equivalents at end of period	$ 450	$ 281

See Notes to Condensed Consolidated Financial Statements.

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SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(Unaudited)

(In millions)

				Accumulated Other Comprehensive Income				
	Common Stock	Additional Paid-in Capital	Retained Earnings	Foreign Currency Translation Adjustments	Net Gains (Losses) on Cash Flow Hedges	Other	Noncontrolling Interests	Total
December 31, 2008	$ 1	$ 4,104	$ 899	$ 881	$ (17)	$ (328)	$ 470	$ 6,010
Net income			629				55	684
Foreign currency translation adjustments				673			10	683
Unrealized mark-to-market net gain on hedges					(9)			(9)
Pension and benefits impact						19		19
Spectra Energy common stock issuance		448						448
Spectra Energy Partners, LP common unit issuance		25					168	193
Reclassification of deferred gain on sale of units of Spectra Energy Partners, LP		59						59
Dividends on common stock			(487)					(487)
Stock-based compensation		1						1
Distributions to noncontrolling interests							(157)	(157)
Contributions from noncontrolling interests							2	2
Other, net		42				(2)	(6)	34
September 30, 2009	$ 1	$ 4,679	$ 1,041	$ 1,554	$ (26)	$ (311)	$ 542	$ 7,480
December 31, 2007	$ 1	$ 4,658	$ 368	$ 2,033	$ (8)	$ (195)	$ 581	$ 7,438
Net income			958				49	1,007
Foreign currency translation adjustments				(411)			(9)	(420)
Reclassification of cash flow hedges into earnings					1			1
Unrealized mark-to-market net loss on hedges					(9)			(9)
Pension and benefits impact						29		29
Common stock repurchases		(600)						(600)
Dividends on common stock			(444)					(444)
Stock-based compensation		32						32
Acquisition of Spectra Energy Income Fund							(209)	(209)
Distributions to noncontrolling interests							(53)	(53)
Contributions from noncontrolling interests							112	112
Other, net		8					5	13

September 30, 2008	$ 1	$ 4,098	$ 882	$ 1,622	$ (16)	$ (166)	$ 476	$ 6,897

See Notes to Condensed Consolidated Financial Statements.

SPECTRA ENERGY CORP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. General

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.

Basis of Presentation. The accompanying Condensed 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. These interim financial statements should be read in conjunction with the consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2008, and reflect all normal recurring adjustments that are, in our opinion, necessary to fairly present our results of operations and financial position. Amounts reported in the Condensed Consolidated Statements of Operations are not necessarily indicative of amounts expected for the respective annual periods due to the effects of seasonal temperature variations on energy consumption, primarily in our gas distribution operations, as well as changing commodity prices on certain of our processing operations and other factors.

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 Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements. Although these estimates are based on our best available knowledge at the time, actual results could differ.

Change in Accounting Policy. We perform our goodwill impairment test annually and evaluate goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. Prior to 2009, we performed the annual impairment testing of goodwill using August 31 as the measurement date. Our financial and strategic planning process, including the preparation of long-term cash flow projections, commences in October and typically concludes in January of the following year. These long-term cash flow projections are a key component in performing our annual impairment test of goodwill. This planning cycle has created significant constraints in the availability of both information and human resources needed to provide the appropriate projections to be used in the goodwill impairment test using the August 31 test date. Accordingly, effective with our 2009 annual impairment test, we changed our goodwill impairment test date from August 31 to April 1. We believe that using the April 1 date will alleviate the information and resource constraints that historically existed during the third quarter and will better coincide with the completion of our long-term financial projections. We believe that this accounting change is to an alternative accounting principle that is preferable under the circumstances and does not result in the delay, acceleration or avoidance of an impairment charge. We have determined that this change in accounting principle does not result in adjustments to our financial statements when applied retrospectively as our base assumptions used in the August 31, 2008 measurement date would not have changed significantly had we used April 1, 2008 as the measurement date.

We completed our goodwill impairment test as of April 1, 2009 and no impairments were identified. See Note 11 for further discussion.

Recasts and Reclassifications. We adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 160, Noncontrolling Interests in Consolidated Financial Statements, (now Accounting Standards Codification (ASC) 810-10-65), effective January 1, 2009. When adopting the presentation and disclosure items, retrospective application to conform previously reported financial statements to the new presentation requirements is required. Accordingly, the 2008 data contained in the Condensed Consolidated Financial Statements and the related information contained in this report have been recast to reflect the reporting requirements of this accounting standard. See Note 21 for further discussion of ASC 810-10-65.

Prior to the adoption of this accounting standard, 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. Effective upon the adoption of ASC 810-10-65, 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 ASC 810-10-65, a $59 million deferred gain associated with the formation of Spectra Energy Partners, LP (Spectra Energy Partners), a majority-owned subsidiary, was reclassified from Deferred Credits and Other Liabilities Regulatory and Other to Additional Paid-in Capital on the Condensed Consolidated Balance Sheet as of January 1, 2009.

2. Acquisitions

Ozark Gas Transmission and Ozark Gas Gathering Systems. On May 4, 2009, Spectra Energy Partners acquired all of the ownership interests of NOARK Pipeline System, Limited Partnership (NOARK) from Atlas Pipeline Partners, L.P. (Atlas) for approximately $295 million in cash. NOARK s assets consisted of 100% ownership interests in Ozark Gas Transmission, L.L.C., a 565-mile Federal Energy Regulatory Commission (FERC) regulated interstate natural gas transmission system, and Ozark Gas Gathering, L.L.C., a 365-mile, fee-based, state-regulated natural gas gathering system. The transaction was initially funded by Spectra Energy Partners with $218 million drawn on its bank credit facility, $70 million borrowed under a credit facility with Spectra Energy that was created for the sole purpose of funding a portion of this acquisition, and $7 million of cash on hand. This transaction was partially refinanced by Spectra Energy Partners in the second quarter of 2009 through the issuance of 9.8 million common units to the public, representing limited partner interests, and 0.2 million general partner units to Spectra Energy, resulting in net proceeds of $212 million and a reduction of our ownership interest in Spectra Energy Partners from 84% to 74%. The net proceeds were comprised of $208 million for the common units and $4 million for the general partner units. Funds from the sale of the partner units were used by Spectra Energy Partners to repay the $70 million owed to Spectra Energy and $142 million of the amount drawn on the Spectra Energy Partners bank credit facility. Effective with the repayment to Spectra Energy, the credit facility with Spectra Energy was terminated.

The following table summarizes the fair values of the assets acquired and liabilities assumed as of May 4, 2009.

	Purchase Price Allocation (in millions)
Purchase price	$ 295
Current assets	7
Property, plant and equipment, net	139
Regulatory assets and deferred debits	5
Current liabilities	(5)
Deferred credits and other liabilities	(1)
Total assets acquired/liabilities assumed	145
Goodwill	$ 150

Pro forma results of operations reflecting the acquisition of NOARK, part of the U.S. Transmission segment, as if it had occurred as of the beginning of the periods presented in this report do not materially differ from actual reported results.

Spectra Energy Income Fund. In May 2008, we acquired the 24.4 million units of the Spectra Energy 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).

3. 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 ASC 280, Segment Reporting. 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 rules and regulations of the FERC.

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 Limited (Union Gas), and are primarily subject to the rules and regulations of the Ontario Energy Board (OEB).

Western Canada Transmission & Processing provides transportation of natural gas, natural gas gathering and processing services, and natural gas liquids (NGLs) 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, and the NGL marketing and Midstream businesses. BC Pipeline s 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. 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.

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 noncontrolling interests 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 noncontrolling interests 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)
		(in millions)		
Three Months Ended September 30, 2009				
U.S. Transmission	$ 425	$ 2	$ 427	$ 239
Distribution	244		244	48
Western Canada Transmission & Processing	260		260	84
Field Services				45
Total reportable segments	929	2	931	416
Other	2	10	12	(10)
Eliminations	2	(12)	(10)	
Interest expense				(160)
Interest income and other (b)				19
Total consolidated	$ 933	$	$ 933	$ 265
Three Months Ended September 30, 2008				
U.S. Transmission	$ 401	$ 1	$ 402	$ 213
Distribution	280		280	44
Western Canada Transmission & Processing	397		397	113
Field Services				239
Total reportable segments	1,078	1	1,079	609
Other	2	9	11	(9)
Eliminations		(10)	(10)	
Interest expense				(163)
Interest income and other (b)				22
Total consolidated	$ 1,080	$	$ 1,080	$ 459
Nine Months Ended September 30, 2009				
U.S. Transmission	$ 1,241	$ 5	$ 1,246	$ 690
Distribution	1,236		1,236	240
Western Canada Transmission & Processing	770		770	223
Field Services				219
Total reportable segments	3,247	5	3,252	1,372
Other	5	31	36	(46)
Eliminations	2	(36)	(34)	
Interest expense				(456)
Interest income and other (b)				71
Total consolidated	$ 3,254	$	$ 3,254	$ 941

Nine Months Ended September 30, 2008				
U.S. Transmission	$ 1,202	$ 3	$ 1,205	$ 683
Distribution	1,433		1,433	263
Western Canada Transmission & Processing	1,174		1,174	333
Field Services				647
Total reportable segments	3,809	3	3,812	1,926
Other	4	28	32	(57)
Eliminations		(31)	(31)	
Interest expense				(470)
Interest income and other (b)				62
Total consolidated	$ 3,813	$	$ 3,813	$ 1,461

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

(b) Includes foreign currency transaction gains and losses and the elimination of noncontrolling interests related to EBIT.

4. Regulatory Matters

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

In the second quarter of 2009, we recorded an $11 million charge to Operating Revenues Distribution of Natural Gas on the Condensed Consolidated Statement of Operations as a result of a settlement with Union Gas stakeholders in June 2009 that was subsequently approved by the OEB. The settlement preserves the incentive regulation framework and replaces the provision for a review of the framework with a 90/10 sharing mechanism, in favor of customers, for any utility earnings of 300 basis points or more above the benchmark utility return on equity (ROE) for the year and is retroactive to 2008. The $11 million charge represents the adjustment to credit customers with 90% of Union Gas 2008 utility earnings that exceeded the 2008 benchmark utility ROE by 300 basis points.

In September 2009, we filed an application with the OEB seeking approval of 2010 regulated distribution, storage and transmission rates, determined pursuant to the incentive regulation framework. The application proposes a delivery rate increase of less than 1% for a typical residential customer in our service territory. A decision by the OEB is expected before the end of the year.

Maritimes & Northeast Pipeline Limited Partnership (M&N LP). During 2008, M&N LP operated under an NEB-approved toll settlement that expired December 31, 2008. M&N LP obtained approval to operate under interim rates, effective January 1, 2009, that were set to equal the 2008 rates. The final 2009 toll settlement rates were approved by the NEB in April 2009. M&N LP implemented the new rates on a prospective basis effective May 1, 2009 such that the total tolls charged during 2009 will result in revenues equal to those had the new 2009 rates been in effect for the entire year.

Maritimes & Northeast Pipeline, L.L.C. (M&N LLC). On July 1, 2009, M&N LLC filed a rate case with the FERC. The rate case includes the impact of the Phase IV expansion facilities that went into service January 15, 2009 and results in lower recourse rates. The lower recourse rates did not impact the rates negotiated with customers for service, which are charged to customers for over 90% of M&N LLC s capacity, including its Phase IV expansion facilities.

5. Income Taxes

Income tax expense from continuing operations for the three and nine-month periods ended September 30, 2009 was $54 million and $260 million, respectively, compared to $145 million and $453 million in the same periods in 2008, decreasing primarily as a result of lower earnings in 2009.

The effective tax rate for income from continuing operations for the three months ended September 30, 2009 was 20.4% as compared to 31.6% for the same period in 2008. The lower effective tax rate in 2009 was due to proportionally higher income generated from our Canadian operations, which are subject to lower tax rates as compared to our U.S. operations, and favorable tax settlements in 2009.

The effective tax rate for income from continuing operations for the nine months ended September 30, 2009 was 27.6% as compared to 31.0% for the same period in 2008. The lower effective tax rate in 2009 was primarily due to proportionally higher income generated from our Canadian operations.

We recognized a $10 million decrease in unrecognized tax benefits during the nine-month period ended September 30, 2009. Although uncertain, we believe it is reasonably possible that the total amount of unrecognized tax benefits could decrease by approximately $16 million prior to September 30, 2010. The anticipated changes in unrecognized tax benefits relate to expiration of statutes of limitations and expected audit settlements focused primarily on classification of certain tax attributes, transfer pricing and income allocation.

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6. Discontinued Operations

In December 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. Results of operations of these assets are reflected as discontinued operations in the Condensed Consolidated Statements of Operations for the 2008 periods presented.

In June 2008, we entered into a settlement agreement related to certain liquefied natural gas transportation contracts under which our Spectra Energy LNG Sales Inc. subsidiary s claims were satisfied pursuant to commercial transactions involving the purchase of propane from certain parties. We subsequently 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.

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

	Operating Revenues	Pre-tax Earnings (Loss)	Income Tax Expense (Benefit)	Income (Loss) From Discontinued Operations, Net of Tax
		(in millions)		
Three Months Ended September 30, 2009				
Western Canada Transmission & Processing	$ 1	$ 1	$	$ 1
Other	22			
Total consolidated	$ 23	$ 1	$	$ 1
Three Months Ended September 30, 2008				
Western Canada Transmission & Processing	$ 7	$ (3)	$ (1)	$ (2)
Other	29			
Total consolidated	$ 36	$ (3)	$ (1)	$ (2)
Nine Months Ended September 30, 2009				
Western Canada Transmission & Processing	$ 1	$ 1	$	$ 1
Other	88	3	1	2
Total consolidated	$ 89	$ 4	$ 1	$ 3
Nine Months Ended September 30, 2008				
Western Canada Transmission & Processing	$ 23	$ (2)	$ (1)	$ (1)
Other	59	1	1	
Total consolidated	$ 82	$ (1)	$	$ (1)

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7. Comprehensive Income

Components of comprehensive income are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Net income	$ 212	$ 312	$ 684	$ 1,007
Other comprehensive income (loss)				
Foreign currency translation adjustments	468	(272)	683	(420)
Reclassification of cash flow hedges into earnings (a)	4	1		1
Unrealized mark-to-market net gain (loss) on hedges (b)	(14)	(23)	(9)	(9)
Pension and benefits impact (c)	(3)	3	19	29
Total comprehensive income, net of tax	667	21	1,377	608
Less: comprehensive income noncontrolling interests	27	10	65	40
Comprehensive income controlling interests	$ 640	$ 11	$ 1,312	$ 568

(a) Net of $4 million and $1 million of tax expense for the three months ended September 30, 2009 and 2008, respectively, and $1 million of tax expense for the nine months ended September 30, 2008.

(b) Net of $4 million and $9 million of tax benefit for the three months ended September 30, 2009 and 2008, respectively, and $1 million and $6 million of tax benefit for the nine months ended September 30, 2009 and 2008, respectively. See Note 16 for further details of these amounts.

(c) Net of $6 million and $1 million of tax expense for the three months ended September 30, 2009 and 2008, respectively, and $15 million of tax expense and $14 million of tax benefit for the nine months ended September 30, 2009 and 2008, respectively.

8. Earnings per Common Share

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

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The following table presents our basic and diluted EPS calculations:

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in millions, except per-share amounts)			
Income from continuing operations, net of tax controlling interests	$ 190	$ 299	$ 626	$ 962
Income (loss) from discontinued operations, net of tax controlling interests	1	(3)	3	(4)
Net income controlling interests	$ 191	$ 296	$ 629	$ 958
Weighted-average common shares, outstanding				
Basic	646	615	640	626
Diluted	647	617	641	629
Basic earnings per common share				
Continuing operations	$ 0.30	$ 0.49	$ 0.98	$ 1.54
Discontinued operations, net of tax		(0.01)		(0.01)
Total basic earnings per common share	$ 0.30	$ 0.48	$ 0.98	$ 1.53
Diluted earnings per common share				
Continuing operations	$ 0.30	$ 0.48	$ 0.98	$ 1.53
Discontinued operations, net of tax				(0.01)
Total diluted earnings per common share	$ 0.30	$ 0.48	$ 0.98	$ 1.52

Weighted-average shares used to calculate diluted EPS include the effect of certain options and restricted stock awards. Certain other options and stock awards related to approximately 11 million and six million shares for the three months ended September 30, 2009 and 2008, respectively, and 12 million and seven million shares for the nine months ended September 30, 2009 and 2008, 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 common shares during these periods or performance measures related to the awards had not yet been met.

9. Inventory

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

	September 30, 2009	December 31, 2008
	(in millions)	
Natural gas	$ 222	$ 180
NGLs	36	16
Materials and supplies	92	83
Total inventory	$ 350	$ 279

10. Investments in and Loans to Unconsolidated Affiliates

Our most significant investment in unconsolidated affiliates is our 50% interest in DCP Midstream, which is accounted for under the equity method of accounting. The following represents summary financial information for DCP Midstream, presented at 100%.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Operating revenues	$ 2,073	$ 4,892	$ 5,806	$ 13,769
Operating expenses	1,928	4,261	5,469	12,370
Operating income	145	631	337	1,399
Net income	93	586	158	1,284
Net income attributable to members interests	89	477	169	1,293

As a result of the adoption of SFAS No. 160 (now ASC 810-10-65) on January 1, 2009, DCP Midstream reclassified to equity certain deferred gains on sales of common units in its master limited partnership, DCP Midstream Partners, LP (DCP Partners). Our proportionate 50% share, totaling $135 million, was recorded in Equity in Earnings of Unconsolidated Affiliates on the Condensed Consolidated Statement of Operations in the first quarter of 2009.

As further discussed in Note 6, we entered into a propane sales agreement with an affiliate of DCP Midstream in the second quarter of 2008. We recorded revenues of $21 million and $22 million in the three months ended September 30, 2009 and 2008, respectively, and $65 million and $36 million in the nine months ended September 30, 2009 and 2008, respectively, associated with this agreement, classified within Income (Loss) from Discontinued Operations, Net of Tax.

We and the co-owner of Southeast Supply Header, LLC (SESH), an equity affiliate, previously entered into a loan agreement with SESH whereby each member agreed to loan funds to SESH in connection with the construction of its pipeline facilities. In August 2009, $137 million of the outstanding loan from us was re-characterized as a capital infusion to SESH. In addition, we received $186 million from SESH, recorded as Receipt From Affiliate Repayment of Loan on the Condensed Consolidated Statement of Cash Flows, representing full repayment of the remaining balance of the outstanding loan receivable. A portion of these funds were from the proceeds of a debt issuance by SESH. The loan receivable from SESH, including accrued interest, totaled $327 million at December 31, 2008.

In May 2009, we received a $148 million special distribution from Gulfstream Natural Gas System, L.L.C. (Gulfstream), a 50% owned equity affiliate, from the proceeds of a debt issuance by Gulfstream, of which $144 million was classified as Cash Flows from Investing Activities Distributions Received From Unconsolidated Affiliates on the Condensed Consolidated Statement of Cash Flows.

We have also made loans to Steckman Ridge, LP, an equity affiliate, in connection with the construction of its storage facilities. The loan receivable from Steckman Ridge, LP, including accrued interest, totaled $68 million at September 30, 2009 and $45 million at December 31, 2008.

11. Goodwill

We completed our annual goodwill impairment test as of April 1, 2009 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.

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The long-term growth rates used for our reporting units reflect continued expansion of our assets, driven by new natural gas supplies such as shale gas in North America and, notwithstanding the current economic downturn, increasing demand for capacity on our pipeline systems. However, even if we assumed a zero growth rate for any reporting unit, there would be no impairment of goodwill.

We continue to monitor the effects of the economic downturn that global economies are currently facing on the long-term cost of capital utilized to calculate our reporting unit fair values. However, a 1% increase in the weighted-average cost of capital assumption for any of our reporting units would not result in an impairment of goodwill. Additionally, for our regulated businesses in Canada, if an increase in the cost of capital occurred, the effect on the corresponding reporting unit s fair value would be ultimately offset by a similar increase in the reporting unit s regulated revenues since those rates include a component that is based on the reporting unit s cost of capital.

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

	December 31, 2008	Increases (a)	September 30, 2009
		(in millions)	
U.S. Transmission	$ 2,019	$ 347	$ 2,366
Distribution	727	92	819
Western Canada Transmission & Processing	635	81	716
Total consolidated	$ 3,381	$ 520	$ 3,901

(a) Increases consist of foreign currency translation and $150 million of goodwill at U.S. Transmission associated with the May 2009 acquisition of NOARK. See Note 2 for further discussion.

12. Debt and Credit Facilities

Available Credit Facilities and Restrictive Debt Covenants

	Expiration Date	Credit Facilities Capacity	Outstanding at September 30, 2009 Commercial Paper	Revolving Loan	Letters of Credit	Total
			(in millions)			
Spectra Energy Capital, LLC	2012	$ 1,500(a)	$	$	$ 21	$ 21
Westcoast Energy, Inc.	2011	187(b)	44			44
Union Gas	2012	468(c)				
Spectra Energy Partners	2012	500		240		240
Total		$ 2,655	$ 44	$ 240	$ 21	$ 305

(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 Condensed Consolidated Balance Sheets.

(b) U.S. dollar equivalent at September 30, 2009. 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 September 30, 2009. 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.

The issuance of commercial paper, letters of credit and other borrowings reduces the amounts 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 September 30, 2009, we were in compliance with those covenants. In addition, our credit agreements allow for acceleration of payments or termination of the agreements due to nonpayment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the debt or credit agreements contain material adverse change clauses.

Debt Issuances

On August 28, 2009, Spectra Energy Capital, LLC (Spectra Capital), a wholly owned consolidated subsidiary, issued $300 million of its 5.65% Senior Notes due 2020. The net proceeds of the offering were used to fund capital expenditures and for other general corporate purposes, including the repayment of Spectra Capital s 7.5% senior notes that matured on October 1, 2009.

On August 24, 2009, M&N LP, a 78%-owned consolidated subsidiary, issued 180 million Canadian dollars (approximately $167 million as of the issuance date) of aggregate principal amount of its 4.34% Senior Secured Notes due 2019. The net proceeds of the offering were used to repay existing indebtedness and fund certain collateral accounts of M&N LP.

On May 14, 2009, M&N LLC, a 78%-owned consolidated subsidiary, issued $500 million aggregate principal amount of its 7.5% Senior Notes due 2014. Net proceeds from the offering were used to fund cash distributions to its members. Spectra Energy s share of those cash distributions were used for general corporate purposes.

13. 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:

			September 30, 2009		
Description	**Condensed Consolidated Balance Sheet Caption**	**Total**	**Level 1**	**Level 2**	**Level 3**
			(in millions)		
Corporate debt securities	Cash and cash equivalents	$ 64	$	$ 64	$
Money market funds	Cash and cash equivalents	365	365		
Long-term derivative assets	Investments and other assets other	35		16	19
Money market funds	Investments and other assets other	29	29		
Total Assets		$ 493	$ 394	$ 80	$ 19
Long-term derivative liabilities	Deferred credits and other liabilities regulatory and other	$ 18	$	$ 18	$
Total Liabilities		$ 18	$	$ 18	$

Description	Condensed Consolidated Balance Sheet Caption	December 31, 2008 Total	Level 1	Level 2	Level 3
		(in millions)			
Money market funds	Cash and cash equivalents	$ 60	$ 60	$	$
Debt securities issued by foreign governments	Cash and cash equivalents	6	6		
Corporate debt securities	Cash and cash equivalents	105		105	
Money market funds	Current assets other	13	13		
Short-term derivative assets	Current assets other	13		13	
Money market funds	Investments and other assets other	51	51		
Corporate debt securities	Investments and other assets other	25		25	
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 Assets	Short-Term Derivative Liabilities	Long-Term Derivative Assets	Long-Term Derivative Liabilities
	(in millions)			
Three Months Ended September 30, 2009				
Fair value at June 30, 2009	$	$	$ 24	$
Total gains or losses (realized/unrealized):				
Included in earnings			(1)	
Included in Investments and Other Assets Other			2	
Included in other comprehensive income			(6)	
Fair value at September 30, 2009	$	$	$ 19	$
Total gains (losses) for the period included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets held at September 30, 2009	$	$	$ (1)	$
Three Months Ended September 30, 2008				
Fair value at June 30, 2008	$ 108	$	$ 79	$
Total gains or losses (realized/unrealized):				
Included in earnings			(7)	2
Included in regulatory assets	(105)			
Included in other comprehensive income			(30)	
Normal purchases and sales elections				(2)
Purchases, issuances and settlements	(3)			
Fair value at September 30, 2008	$	$	$ 42	$
Total gains (losses) for the period included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets held at September 30, 2008	$	$	$ (7)	$ 2

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	Short-Term Derivative Assets		Short-Term Derivative Liabilities		Long-Term Derivative Assets (in millions)		Long-Term Derivative Liabilities	
Nine Months Ended September 30, 2009								
Fair value at December 31, 2008	$		$		$	36	$	
Total gains or losses (realized/unrealized):								
Included in earnings						(5)		
Included in Investments and Other Assets Other						3		
Included in other comprehensive income						(15)		
Fair value at September 30, 2009	$		$		$	19	$	
Total gains (losses) for the period included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets held at September 30, 2009	$		$		$	(5)	$	
Nine Months Ended September 30, 2008								
Fair value at December 31, 2007	$		$		$	47	$	(21)
Total gains or losses (realized/unrealized):								
Included in earnings						4		(11)
Included in other comprehensive income				(5)		(9)		
Normal purchases and sales elections								32
Purchases, issuances and settlements				5				
Fair value at September 30, 2008	$		$		$	42	$	
Total gains (losses) for the period included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets held at September 30, 2008	$		$		$	4	$	(11)

Level 2 Valuation Techniques

Fair values of our financial instruments, primarily corporate debt securities 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.

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. Long-term derivative assets and liabilities are 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. Short-term derivative assets are valued based upon interest rates, natural gas options pricing for current and future months including volatility, foreign exchange fluctuations and swap values.

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Financial Instruments. The fair value of financial instruments, excluding derivatives included elsewhere in this Note and in Note 16, 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 September 30, 2009 and December 31, 2008 are not necessarily indicative of the amounts we could have realized in current markets.

	September 30, 2009		December 31, 2008	
	Book Value	Approximate Fair Value	Book Value	Approximate Fair Value
	(in millions)			
Long-term debt (a)	$ 10,160	$ 10,860	$ 9,111	$ 8,996
Corporate debt securities and money market funds	11	11	46	46
Other long-term assets	112	115	430	427

(a) Includes current maturities.

The fair values reflected above consider the terms of the related debt absent the impacts of derivative/hedging activities. The book value of long-term debt referenced above includes certain fixed-to-floating interest rate swaps entered into in 2009 that are designated as fair value hedges.

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.

During 2009, there were no adjustments to assets and liabilities measured at fair value on a nonrecurring basis.

14. Commitments and Contingencies

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 us, 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 affiliated operations.

Included in Deferred Credits and Other Liabilities Regulatory and Other on the Condensed Consolidated Balance Sheets are accruals related to extended environmental-related activities totaling $17 million at both September 30, 2009 and December 31, 2008. 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 Corporation (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. The Court issued an Order on March 31, 2009 denying Duke Energy s motion to dismiss plaintiffs breach of fiduciary claims. A hearing on the issue of class certification of plaintiffs remaining claims was held on April 29, 2009. On September 4, 2009, the Court issued an Order granting class certification for plaintiffs remaining claims and denying certification of the plaintiffs breach of fiduciary claims.

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 upon our current estimate of the number of our employees that could be included in the 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.

Other Litigation and Legal Proceedings. We are involved in other legal, tax and regulatory proceedings in various forums including matters regarding contract, royalty, measurement and payment claims, arising in the ordinary course of business, 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 September 30, 2009 or December 31, 2008 related to litigation matters in accordance with our best estimate of probable loss as defined by ASC 450, Contingencies.

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

Other Commitments and Contingencies

See Note 15 for a discussion of guarantees and indemnifications.

15. 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 Condensed 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 have been 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 September 30, 2009 was approximately $431 million, which has been indemnified by Duke Energy, as discussed above. Approximately $5 million of the performance guarantees expire in 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.

Westcoast Energy Inc. (Westcoast), a wholly owned subsidiary, has issued performance guarantees to third parties guaranteeing the performance of unconsolidated entities, such as equity method investments, and of entities previously sold by Westcoast to third parties. Those guarantees require Westcoast to make payment to the guaranteed third party upon the failure of such unconsolidated or sold entity to make payment under some of its contractual obligations, such as debt, 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 September 30, 2009 was $50 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 September 30, 2009, 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.

16. 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 our 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 our Canadian operations. We employ

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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.

Derivative Portfolio Carrying Value as of September 30, 2009

Asset/(Liability)	Maturity in 2009	Maturity in 2010	Maturity in 2011	Maturity in 2012 and Thereafter	Total Carrying Value
			(in millions)		
Hedging	$	$ 4	$ (4)	$ 35	$ 35
Undesignated				(18)	(18)
Total	$	$ 4	$ (4)	$ 17	$ 17

These amounts represent the combination of amounts presented as assets (liabilities) for unrealized gains and losses on mark-to-market and hedging transactions on our Condensed Consolidated Balance Sheet and do not include any derivative positions of DCP Midstream.

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 is reported in Other Income and Expenses, net in the Condensed Consolidated Statements of Operations. For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings. We are party to natural gas purchase contracts to hedge forecasted purchases. These contracts are for notional amounts of 38 million British thermal units as of September 30, 2009.

As of September 30, 2009, $1 million of pre-tax deferred net losses on derivative instruments related to commodity cash flow hedges were accumulated in Accumulated Other Comprehensive Income (AOCI) on the Condensed Consolidated Balance Sheet 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 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.

For interest rate derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk is recognized in the Condensed Consolidated Statements of Operations. Gains and losses recognized were as follows:

	Three Months Ended September 30,			
	2009		2008	
	(in millions)			
Condensed Consolidated Statements of Operations Caption	**Gain (Loss) on Swaps**	**Gain (Loss) on Borrowings**	**Gain (Loss) on Swaps**	**Gain (Loss) on Borrowings**
Interest expense	$ 10	$ (10)	$ (4)	$ 4

	Nine Months Ended September 30,			
	2009		2008	
	(in millions)			
Condensed Consolidated Statements of Operations Caption	**Gain (Loss) on Swaps**	**Gain (Loss) on Borrowings**	**Gain (Loss) on Swaps**	**Gain (Loss) on Borrowings**
Interest expense	$ 10	$ (10)	$ (7)	$ 7

In the first quarter of 2009, as a result of low interest rates, we settled all existing fixed-to-floating interest rate swaps on $848 million of long-term debt. Gains on the settlements, totaling $67 million, were recorded as follows in the Condensed Consolidated Balance Sheet: $5 million as a reduction to Interest Accrued, $21 million as a reduction to Current Maturities of Long-term Debt and $41 million as a reduction to Long-term Debt. The gains recorded as reductions of debt will be amortized in Interest Expense over the lives of the associated debt. In the first nine months of 2009, we entered into $940 million notional amount of new interest rate swap agreements to mitigate our exposure to variable interest rates on loans outstanding under certain revolving loan facilities and to hedge against declines in the fair value of fixed-rate debt that arise as a result of changes in market interest rates.

Foreign Currency Hedges. We are exposed to foreign currency risk from investments and operations in international affiliate businesses, which is limited to Canada. To mitigate risks associated with foreign currency fluctuations, contracts may be denominated in or indexed to the U.S. dollar and/or local inflation rates, or investments may be naturally hedged through debt denominated or issued in the foreign currency. We may also use foreign currency derivatives, where possible, to manage risk related to foreign currency fluctuations. There were no significant foreign currency derivative transactions during the nine-month periods ended September 30, 2009 or 2008. To monitor our currency exchange rate risks, we use sensitivity analysis, which measures the effect of devaluation of the Canadian dollar.

Asset and Liability Derivatives. The locations and amounts of derivative instruments, recorded at fair value, in the Condensed Consolidated Balance Sheets follow:

Derivatives Designated as Hedging Instruments	**Condensed Consolidated Balance Sheets Caption**	**September 30, 2009**	**December 31, 2008**
		(in millions)	
Asset Derivatives			
Natural gas purchase contract	Investments and other assets other	$ 19	$ 36
Interest rate swaps	Investments and other assets other	16	53
Total		$ 35	$ 89

Derivatives Not Designated as Hedging Instruments	**Condensed Consolidated Balance Sheets Caption**	**September 30, 2009**	**December 31, 2008**
		(in millions)	
Liability Derivatives			
Interest rate swaps	Deferred credits and other liabilities regulatory and other	$ 18	$ 23

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The effective portions of gains (losses), net of tax, recognized in Other Comprehensive Income on derivatives follow:

Cash Flow Hedging Derivatives	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in millions)			
Natural gas purchase contract	$ (13)	$ (26)	$ (12)	$ (5)
Interest rate swaps	(1)	3	3	(4)
Total	$ (14)	$ (23)	$ (9)	$ (9)

The ineffective portion of gains (losses), net of tax, recognized in income on derivatives follows:

Cash Flow Hedging Derivatives	Condensed Consolidated Statements of Operations Caption	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
		(in millions)			
Natural gas purchase contracts	Other income and expenses, net	$ (5)	$ (4)	$ (3)	$ (4)

The reclassifications from Other Comprehensive Income into income, net of tax, on our derivative assets and liabilities follow:

Cash Flow Hedging Derivatives	Condensed Consolidated Statements of Operations Caption	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
		(in millions)			
Natural gas purchase contract	Other income and expenses, net	$ 4	$ (2)	$ (1)	$ (2)
Interest rate swaps	Interest expense		3	1	3
Total		$ 4	$ 1	$	$ 1

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.

Included in Other Current Liabilities and Deferred Credits and Other Liabilities Regulatory and Other are collateral liabilities of $89 million at September 30, 2009 and $121 million at December 31, 2008, which represent cash collateral posted by third parties with us.

17. Sales of Common Stock

On February 13, 2009, we issued 32.2 million shares of Spectra Energy common stock and received net proceeds of $448 million. We used the net proceeds to repay commercial paper as it matured. Borrowings from the commercial paper were used primarily for capital expenditures and for other general corporate purposes.

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18. Sale of Spectra Energy Partners Common Units

As previously discussed, in the second quarter of 2009, Spectra Energy Partners issued 9.8 million common units to the public, representing limited partner interests, and 0.2 million general partner units to Spectra Energy in connection with the refinancing of the purchase of NOARK, resulting in net proceeds of $212 million and a reduction of our ownership interest in Spectra Energy Partners from 84% to 74%. The net proceeds were comprised of $208 million for the common units and $4 million for the general partner units. See Note 2 for further discussion.

In connection with the sale of the partner units, a $40 million gain ($25 million net of tax) resulting from the dilution of our ownership interest in Spectra Energy Partners was recorded in the second quarter of 2009 to Additional Paid-in Capital on the Condensed Consolidated Balance Sheet.

The following table reflects Net Income Controlling Interests and transfers from Noncontrolling Interests related to the sale of the partner units.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Net Income Controlling Interests	$ 191	$ 296	$ 629	$ 958
Increase in Additional Paid-in Capital			25	
Total change from Net Income Controlling Interests and transfers from Noncontrolling Interests	$ 191	$ 296	$ 654	$ 958

19. Employee Benefit Plans

Retirement Plans. We have a qualified non-contributory defined benefit (DB) retirement plan for U.S. employees and non-qualified plans for various executive retirement and savings plans. Our Westcoast subsidiary maintains qualified and non-qualified contributory DB and defined contribution (DC) retirement plans covering substantially all employees of our Canadian operations.

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 contributions to our U.S. retirement plans in the nine-month periods ended September 30, 2009 and 2008, and do not currently anticipate making contributions to these plans during the remainder of 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 retirement plan are determined in accordance with the terms of the plan. We made contributions to the Canadian qualified DB plans of $40 million and $28 million during the nine-month periods ended September 30, 2009 and 2008, respectively. We anticipate that we will make total contributions of approximately $58 million to the Canadian DB plans in 2009. We also made contributions to the Canadian DC plan of $4 million during each of the nine-month periods ended September 30, 2009 and 2008. We anticipate that we will make total contributions of approximately $5 million to the Canadian DC plan in 2009.

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Qualified Pension Plans Components of Net Periodic Pension Cost

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
U.S.				
Service cost benefit earned	$ 2	$ 2	$ 7	$ 7
Interest cost on projected benefit obligation	7	6	20	20
Expected return on plan assets	(9)	(9)	(25)	(27)
Amortization of loss	2	1	4	2
Net periodic pension cost	$ 2	$	$ 6	$ 2
Canada				
Service cost benefit earned	$ 3	$ 4	$ 9	$ 12
Interest cost on projected benefit obligation	10	10	28	30
Expected return on plan assets	(11)	(12)	(31)	(36)
Amortization of loss	1	1	2	4
Amortization of prior service costs			1	
Net periodic pension cost	$ 3	$ 3	$ 9	$ 10

Non-Qualified Pension Benefits Plans Components of Net Periodic Pension Cost

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
U.S.				
Interest cost on projected benefit obligation	$	$	$ 1	$ 1
Net periodic pension cost	$	$	$ 1	$ 1
Canada				
Service cost benefit earned	$	$	$ 1	$ 1
Interest cost on projected benefit obligation	1	1	3	4
Net periodic pension cost	$ 1	$ 1	$ 4	$ 5

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Other Post-Retirement Benefit Plans. 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.

Other Post-Retirement Benefit Plans Components of Net Periodic Benefit Cost

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
U.S.				
Service cost benefit earned	$ 1	$	$ 1	$
Interest cost on accumulated post-retirement benefit obligation	3	4	10	11
Expected return on plan assets	(1)	(1)	(4)	(4)
Amortization of net transition liability	1	1	4	4
Amortization of loss			1	1
Net periodic other post-retirement benefit cost	$ 4	$ 4	$ 12	$ 12
Canada				
Service cost benefit earned	$	$ 1	$ 1	$ 2
Interest cost on accumulated post-retirement benefit obligation	2	1	4	4
Net periodic other post-retirement benefit cost	$ 2	$ 2	$ 5	$ 6

20. Consolidating Financial Information

Spectra Energy Corp has agreed to fully and unconditionally guarantee the payment of principal and interest under all series of notes outstanding under the Senior Indenture of Spectra Capital, a 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 condensed consolidated financial statements and notes thereto.

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Spectra Energy Corp

Condensed Consolidating Statement of Operations

Three Months Ended September 30, 2009

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 933	$	$ 933
Total operating expenses	2		579		581
Gains on sales of other assets and other, net			1		1
Operating income (loss)	(2)		355		353
Equity in earnings of unconsolidated affiliates			60		60
Equity in earnings of subsidiaries	192	272		(464)	
Other income and expenses, net	1		11		12
Interest expense		52	108		160
Earnings from continuing operations before income taxes	191	220	318	(464)	265
Income tax expense from continuing operations		28	26		54
Income from continuing operations	191	192	292	(464)	211
Income from discontinued operations, net of tax			1		1
Net income	191	192	293	(464)	212
Net income noncontrolling interests			21		21
Net income controlling interests	$ 191	$ 192	$ 272	$ (464)	$ 191

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Spectra Energy Corp

Condensed Consolidating Statement of Operations

Three Months Ended September 30, 2008

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 1,080	$	$ 1,080
Total operating expenses	(9)		749		740
Operating income	9		331		340
Equity in earnings of unconsolidated affiliates			273		273
Equity in earnings of subsidiaries	288	440		(728)	
Other income and expenses, net	3	5	1		9
Interest expense		63	100		163
Earnings from continuing operations before income taxes	300	382	505	(728)	459
Income tax expense from continuing operations	4	94	47		145
Income from continuing operations	296	288	458	(728)	314
Loss from discontinued operations, net of tax			(2)		(2)
Net income	296	288	456	(728)	312
Net income noncontrolling interests			16		16
Net income controlling interests	$ 296	$ 288	$ 440	$ (728)	$ 296

Spectra Energy Corp

Condensed Consolidating Statement of Operations

Nine Months Ended September 30, 2009

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 3,254	$	$ 3,254
Total operating expenses	7	1	2,162		2,170
Gains on sales of other assets and other, net			11		11
Operating income (loss)	(7)	(1)	1,103		1,095
Equity in earnings of unconsolidated affiliates			267		267
Equity in earnings of subsidiaries	633	953		(1,586)	
Other income and expenses, net	1	23	11		35
Interest expense		161	295		456
Earnings from continuing operations before income taxes	627	814	1,086	(1,586)	941
Income tax expense (benefit) from continuing operations	(2)	181	81		260
Income from continuing operations	629	633	1,005	(1,586)	681
Income from discontinued operations, net of tax			3		3
Net income	629	633	1,008	(1,586)	684
Net income noncontrolling interests			55		55
Net income controlling interests	$ 629	$ 633	$ 953	$ (1,586)	$ 629

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Spectra Energy Corp

Condensed Consolidating Statement of Operations

Nine Months Ended September 30, 2008

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 3,813	$	$ 3,813
Total operating expenses	1	1	2,667		2,669
Gains on sales of other assets and other, net			32		32
Operating income (loss)	(1)	(1)	1,178		1,176
Equity in earnings of unconsolidated affiliates			725		725
Equity in earnings of subsidiaries	958	1,467		(2,425)	
Other income and expenses, net	1	11	18		30
Interest expense		172	298		470
Earnings from continuing operations before income taxes	958	1,305	1,623	(2,425)	1,461
Income tax expense from continuing operations		347	106		453
Income from continuing operations	958	958	1,517	(2,425)	1,008
Loss from discontinued operations, net of tax			(1)		(1)
Net income	958	958	1, 516	(2,425)	1,007
Net income noncontrolling interests			49		49
Net income controlling interests	$ 958	$ 958	$ 1,467	$ (2,425)	$ 958

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Spectra Energy Corp

Condensed Consolidating Balance Sheet

September 30, 2009

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$	$ 367	$ 83	$	$ 450
Receivables (payables) consolidated subsidiaries	(58)	278	(220)		
Receivables other		2	570	(3)	569
Other current assets	5	23	480		508
Total current assets	(53)	670	913	(3)	1,527
Investments in and loans to unconsolidated affiliates		71	1,926		1,997
Investments in consolidated subsidiaries	9,030	12,260		(21,290)	
Advances receivable (payable) consolidated subsidiaries	(1,894)	2,443	(200)	(349)	
Goodwill			3,901		3,901
Other assets	35	29	344		408
Property, plant and equipment, net			15,109		15,109
Regulatory assets and deferred debits	1	15	980		996
Total Assets	$ 7,119	$ 15,488	$ 22,973	$ (21,642)	$ 23,938
Accounts payable (receivable) consolidated subsidiaries	$	$ 41	$ (41)	$	$
Accounts payable other	4	92	99	(3)	192
Short-term borrowings and commercial paper		349	44	(349)	44
Accrued taxes payable (receivable)	(93)	99	166		172
Current maturities of long-term debt		459	354		813
Other current liabilities	51	76	909		1,036
Total current liabilities	(38)	1,116	1,531	(352)	2,257
Long-term debt		3,287	6,060		9,347
Deferred credits and other liabilities	219	2,055	2,355		4,629
Preferred stock of subsidiaries			225		225
Total stockholders equity	6,938	9,030	12,802	(21,290)	7,480
Total Liabilities and Stockholders Equity	$ 7,119	$ 15,488	$ 22,973	$ (21,642)	$ 23,938

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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	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
Preferred stock of subsidiaries			225		225
Total stockholders equity	5,540	7,375	10,952	(17,857)	6,010
Total Liabilities and Stockholders Equity	$ 5,494	$ 14,585	$ 20,076	$ (18,231)	$ 21,924

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Spectra Energy Corp

Condensed Consolidating Statements of Cash Flows

Nine Months Ended September 30, 2009

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 629	$ 633	$ 1,008	$ (1,586)	$ 684
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization			440		440
Equity in earnings of unconsolidated affiliates			(267)		(267)
Equity in earnings of subsidiaries	(633)	(953)		1,586	
Distributions received from unconsolidated affiliates			107		107
Other	53	203	47		303
Net cash provided by (used in) operating activities	49	(117)	1,335		1,267
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(713)		(713)
Investments in and loans to unconsolidated affiliates		(26)	(29)		(55)
Acquisition of NOARK			(295)		(295)
Proceeds from sales and maturities of available-for-sale securities			32		32
Distributions received from unconsolidated affiliates			148		148
Receipt from affiliate repayment of loan		186			186
Other			(35)		(35)
Net cash used in investing activities		160	(892)		(732)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt		300	3,105		3,405
Payments for the redemption of long-term debt		(197)	(2,642)		(2,839)
Net decrease in short-term borrowings and commercial paper		(768)	(124)		(892)
Distributions to noncontrolling interests			(153)		(153)
Contributions from noncontrolling interests			2		2
Proceeds from the issuance of Spectra Energy common stock	448				448
Proceeds from the issuance of Spectra Energy Partners, LP common units			208		208
Dividends paid on common stock	(471)	(9)		9	(471)
Distributions and advances to parent	(38)	940	(893)	(9)	
Other	12	(2)	(7)		3
Net cash provided by (used in) financing activities	(49)	264	(504)		(289)
Effect of exchange rate changes on cash			(10)		(10)
Net increase (decrease) in cash and cash equivalents		307	(71)		236
Cash and cash equivalents at beginning of period		60	154		214

Cash and cash equivalents at end of period	$	$ 367	$ 83	$	$ 450

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Spectra Energy Corp

Condensed Consolidating Statements of Cash Flows

Nine Months Ended September 30, 2008

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 958	$ 958	$ 1,516	$ (2,425)	$ 1,007
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization			445		445
Deferred income tax expense		10	51		61
Equity in earnings of unconsolidated affiliates			(725)		(725)
Equity in earnings of subsidiaries	(958)	(1,467)		2,425	
Distributions received from unconsolidated affiliates			691		691
Other	(5)	172	(250)		(83)
Net cash provided by (used in) operating activities	(5)	(327)	1,728		1,396
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(1,038)		(1,038)
Investments in and loans to unconsolidated affiliates		(190)	(307)		(497)
Acquisition of Spectra Energy Income Fund			(274)		(274)
Purchases of available-for-sale securities			(1,289)		(1,289)
Proceeds from sales and maturities of available-for-sale securities			1,354		1,354
Distributions received from unconsolidated affiliates			180		180
Net cash used in investing activities		(190)	(1,374)		(1,564)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt		1,000	1,972		2,972
Payments for the redemption of long-term debt			(1,801)		(1,801)
Net increase (decrease) in short-term borrowings and commercial paper		304	(100)		204
Distributions to noncontrolling interests			(50)		(50)
Contributions from noncontrolling interests			112		112
Repurchases of Spectra Energy common stock	(600)				(600)
Dividends paid on common stock	(444)	(10)		10	(444)
Distributions and advances to parent	1,035	(678)	(347)	(10)	
Other	14		(53)		(39)
Net cash provided by (used in) financing activities	5	616	(267)		354
Effect of exchange rate changes on cash			1		1
Net increase in cash and cash equivalents		99	88		187
Cash and cash equivalents at beginning of period			94		94

Cash and cash equivalents at end of period	$		$	99	$	182	$		$	281

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21. New Accounting Pronouncements

The following new accounting pronouncements were adopted during the nine months ended September 30, 2009:

ASC 105, Generally Accepted Accounting Principles (previously SFAS No. 168, The FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles A Replacement of FASB Statement No. 162). This accounting standard results in the Financial Accounting Standards Board (FASB) Accounting Standards Codification (the Codification) becoming the source of authoritative U.S. GAAP recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC are also considered sources of authoritative GAAP for SEC registrants. The Codification supersedes all then-existing non-SEC accounting and reporting standards. All other nongrandfathered, non-SEC accounting literature not included in the Codification is nonauthoritative. The adoption of the provisions of this accounting standard effective with our September 30, 2009 financial statements did not change the application of existing GAAP for us, and as a result, did not have any impact on our consolidated results of operations, financial position or cash flows. Beginning with our financial statements included in this report, accounting references will be made to the Codification references and certain historical references to accounting standards will also be included during this initial transition.

ASC 820, Fair Value Measurement and Disclosures (previously SFAS No. 157, Fair Value Measurements). This accounting standard defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. The FASB issued an amendment to this accounting standard which delayed its effective date 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 the provisions of this amended accounting standard on January 1, 2009 for the measurement of our asset retirement obligations and for our goodwill impairment test did not have any impact on our consolidated results of operations, financial position or cash flows.

ASC 805, Business Combinations (previously SFAS 141R, Business Combinations). This accounting standard requires an 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. This accounting standard 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. The adoption of the provisions of this accounting standard on January 1, 2009 did not have a material impact on our consolidated results of operations, financial position or cash flows.

ASC 810-10-65, Consolidations Overall Transition and Open Effective Date Information (previously SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements). This accounting standard requires all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. This accounting standard eliminates the diversity that existed in accounting for transactions between an entity and noncontrolling interests by requiring that they be treated as equity transactions. We adopted the provisions of this accounting standard 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. This accounting standard 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.

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As discussed in Note 1, a deferred gain associated with the formation of Spectra Energy Partners totaling $59 million was reclassified from Deferred Credits and Other Liabilities Regulatory and Other to Additional Paid-in Capital on the Consolidated Balance Sheet upon adoption of this accounting standard on January 1, 2009.

In November 2008, the FASB ratified Emerging Issues Task Force (EITF) 08-06 (ASC 323-10-35, Investments Equity Method and Joint Ventures Subsequent Measure), which addresses certain aspects of accounting for business combinations and noncontrolling interests on an entity s accounting for equity-method investments. The consensus indicates, among other things, that transaction costs for an investment should be included in the cost of the equity-method investment (and not expensed) and shares subsequently issued by the equity-method investee that reduce the investor s ownership percentage should be accounted for as if the investor had sold a proportionate share of its investment, with gains or losses recorded through earnings. For us, these amendments were effective for transactions occurring after December 31, 2008.

As discussed in Note 10, a $135 million increase to Equity in Earnings of Unconsolidated Affiliates was recorded in the first quarter of 2009 related to DCP Midstream s reclassification of certain deferred gains on sales of common units in its master limited partnership to equity as a result of their adoption of these amendments.

ASC 815-10, Derivatives and Hedging Overall (previously SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133). This accounting standard expands the disclosure requirements related to derivative instruments and hedging activities 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 and how they affect an entity s financial position, financial performance and cash flows. We adopted the amended provisions of this accounting standard effective January 1, 2009 as required. See Note 16 for the disclosures required by this accounting standard.

ASC 275-10, Risks and Uncertainties Overall and ASC 350-30, Intangibles Goodwill and Other General Intangible Other than Goodwill (previously FASB Staff Position (FSP) No. FAS 142-3, Determination of the Useful Life of Intangible Assets). These accounting standards amend the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The adoption of the provisions of this accounting standard on January 1, 2009 had no impact on our consolidated results of operations, financial position or cash flows.

ASC 808-10, Collaborative Arrangements Overall (previously EITF 07-01, Accounting for Collaborative Arrangements). This accounting standard defines collaborative arrangements and establishes 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 this accounting standard 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 this accounting standard on January 1, 2009 had no impact on our consolidated results of operations, financial position or cash flows.

ASC 260-10, Earnings per Share Overall (previously EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities). This accounting standard addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing EPS under the two-class method. The adoption of this accounting standard on January 1, 2009 had no material effect on our computation of EPS.

ASC 855-10, Subsequent Events Overall (previously SFAS No. 165, Subsequent Events). This accounting standard establishes general standards for the accounting for and disclosure of events that occur subsequent to the balance sheet date but before the financial statements of an entity are issued or are available to be issued. The adoption of the provisions of this accounting standard effective June 30, 2009 did not have any impact on our consolidated results of operations, financial position or cash flows.

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The following new accounting pronouncements have been issued, but not yet adopted as of September 30, 2009:

ASC 715-20, Compensation Retirement Benefits Defined Benefit Plans General (previously FSP No. FAS 132(R)-1, Employers Disclosures about Postretirement Benefit Plan Assets). In December 2008, the FASB issued this accounting standard, which requires additional disclosures about plan assets for sponsors of defined benefit pension and postretirement plans including expanded information regarding investment strategies, major categories of plan assets and concentrations of risk within plan assets. Additionally, this accounting standard requires certain disclosures about the fair value of plan assets, such as the inputs and valuation techniques used to measure fair value and information with respect to classification of plan assets in terms of the hierarchy of the source of information used to determine their value. The disclosures under this accounting standard are required for annual periods ending after December 15, 2009. We are currently evaluating the requirements of these additional disclosures.

SFAS No. 167, Amendments to FASB Interpretation No. 46(R). In June 2009, the FASB issued this accounting standard which is intended to address (1) the effects on certain consolidation provisions as a result of the elimination of the concept of qualifying special-purpose entities and (2) constituent concerns about the application of certain consolidation provisions including those in which the accounting and disclosures do not always provide timely and useful information about an enterprise s involvement in a variable interest entity. For us, this accounting standard must be applied as of January 1, 2010. We do not expect the adoption of the provisions of this accounting standard to have any impact on our consolidated results of operations, financial position or cash flows.

22. Subsequent Events

We have evaluated significant events and transactions that occurred from October 1, 2009 through the date of this report and have determined that there were no events or transactions other than those disclosed in this report, if any, that would require recognition or disclosure in our Condensed Consolidated Financial Statements for the quarterly period ended September 30, 2009.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations.
INTRODUCTION

Management s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the accompanying Condensed Consolidated Financial Statements. As previously discussed, the 2008 data contained in the Condensed Consolidated Financial Statements and the related information presented in this report have been recast to reflect the reporting requirements of a new accounting standard related to noncontrolling interests that was adopted on January 1, 2009. See Note 21 of Notes to Condensed Consolidated Financial Statements for further discussion.

Executive Overview

During 2009, our fee-based businesses at U.S. Transmission, Distribution and Western Canada Transmission & Processing have continued to perform well by meeting the needs of our customers and generating increased earnings and cash flows as a result of successful expansion projects placed into service. Commodity prices have continued to negatively affect the comparison to 2008 for our Field Services segment and the Empress operations at Western Canada Transmission & Processing.

For the three months ended September 30, 2009 and 2008, we reported net income from controlling interests of $191 million and $296 million, respectively. For the nine months ended September 30, 2009 and 2008, we reported net income from controlling interests of $629 million and $958 million, respectively. The decreases for the three and nine-month periods primarily reflect lower earnings from Field Services and Western Canada Transmission & Processing, as a result of lower NGL prices associated with lower crude oil prices in 2009. Crude oil averaged $57 per barrel for the nine months ended September 30, 2009 versus $113 per barrel during the same period in 2008. The decrease in earnings for the nine-month period in 2009 was partially offset by the recognition of a $135 million deferred gain ($85 million after-tax) in the first quarter of 2009 associated with partnership units previously issued by DCP Partners, as well as third-quarter and year-to-date earnings from growth projects.

Highlights for the three months and nine months ended September 30, 2009 include:

- U.S. Transmission s earnings benefited from expansion projects placed into service late in 2008 and in 2009 and lower project development costs, partially offset by lower gas processing revenues in 2009 and a customer bankruptcy settlement in the second quarter of 2008,

- Distribution results reflect a weaker Canadian dollar and an earnings sharing settlement in the second quarter of 2009 related to prior year earnings, partially offset by higher storage and transportation revenues,

- Western Canada Transmission & Processing earnings decreased primarily as a result of lower NGL prices related to the Empress processing plant and a weaker Canadian dollar, partially offset by higher gathering and processing revenues,

- Field Services earnings reflect lower NGL and natural gas prices in 2009, partially offset by the recognition of a deferred gain associated with partnership units previously issued by DCP Partners, and

- Other reported lower expenses in the nine months ended September 30, 2009.

In the first nine months of 2009, we reported $768 million of capital and investment expenditures, excluding the $295 million acquisition of NOARK. As of November 1, 2009, we have successfully completed substantially all of our 2009 capital projects. We project approximately $1.1 billion of capital and investment expenditures for the full year, including approximately $600 million of expansion capital expenditures and excluding the acquisition of NOARK. Our 2010 capital budget is expected to be reviewed by our Board of Directors in December 2009. Subject to their approval, we expect to increase our expansion capital spending to approximately $1 billion in 2010 as we continue to pursue opportunities around new natural gas supply volumes.

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Through September 30, 2009, Spectra Energy has issued approximately $1.0 billion of new long-term debt, completing the new issuances expected for 2009. We have approximately $2.4 billion available under our credit facilities and expect to continue to utilize commercial paper and revolving lines of credit, as needed, to fund our liquidity needs through 2010. We currently have no debt issuances planned for 2010 other than refinancings of debt maturities, but may access the markets if conditions are favorable.

In May 2009, Spectra Energy Partners acquired all of the ownership interests of NOARK from Atlas for approximately $295 million in cash. In the second quarter of 2009, Spectra Energy Partners issued 9.8 million common units to the public, representing limited partner interests, and 0.2 million general partner units to Spectra Energy, resulting in net proceeds of $212 million and a reduction of our ownership interest in Spectra Energy Partners from 84% to 74%. The proceeds were used to partially repay the funds borrowed in connection with the acquisition. See Note 2 of Notes to Condensed Consolidated Financial Statements for further discussion.

In February 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.

RESULTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Operating revenues	$ 933	$ 1,080	$ 3,254	$ 3,813
Operating expenses	581	740	2,170	2,669
Gains on sales of other assets and other, net	1		11	32
Operating income	353	340	1,095	1,176
Other income and expenses	72	282	302	755
Interest expense	160	163	456	470
Earnings from continuing operations before income taxes	265	459	941	1,461
Income tax expense from continuing operations	54	145	260	453
Income from continuing operations	211	314	681	1,008
Income (loss) from discontinued operations, net of tax	1	(2)	3	(1)
Net income	212	312	684	1,007
Net income noncontrolling interests	21	16	55	49
Net income controlling interests	$ 191	$ 296	$ 629	$ 958

Three and Nine Months Ended September 30, 2009 Compared to Same Periods in 2008

Operating Revenues. Operating revenues for the three and nine months ended September 30, 2009 decreased by $147 million, or 14%, and $559 million, or 15%, respectively, compared to the same periods in 2008. The decreases were driven primarily by:

- the effects of a weaker Canadian dollar on revenues at Western Canada Transmission & Processing and Distribution, and

- lower NGL prices associated with the Empress operations at Western Canada Transmission & Processing, partially offset by

higher earnings from expansion projects placed into service late in 2008 and in 2009 at U.S. Transmission.

Operating Expenses. Operating expenses for the three and nine months ended September 30, 2009 decreased by $159 million, or 21%, and $499 million, or 19%, respectively, compared to the same periods in 2008. The decreases were driven primarily by:

- the effects of a weaker Canadian dollar at Western Canada Transmission & Processing and Distribution,
- lower prices of natural gas purchased for the Empress facility at Western Canada Transmission & Processing, and
- lower project development costs at U.S. Transmission.

Gains on Sales of Other Assets and Other, net. Gains on sales of other assets and other, net for the three and nine months ended September 30, 2009 increased $1 million and decreased by $21 million, respectively, compared to the same periods in 2008. The decrease for the nine-month period was primarily due to a 2008 second quarter customer bankruptcy settlement, partially offset by a favorable customer settlement in 2009 resulting from the cancellation of a capital project.

Operating Income. Operating income for the three and nine months ended September 30, 2009 increased by $13 million, or 4%, and decreased $81 million, or 7%, respectively, compared to the same periods in 2008. The decrease for the nine-month period was primarily due to lower NGL product prices associated with the Empress operations at Western Canada Transmission & Processing, a weaker Canadian dollar and a 2008 customer bankruptcy settlement at U.S. Transmission, partially offset by higher earnings from expansion projects placed into service late in 2008 and in 2009 at U.S. Transmission.

Other Income and Expenses. Other income and expenses for the three and nine months ended September 30, 2009 decreased by $210 million, or 74%, and $453 million, or 60%, respectively, compared to the same periods in 2008. The decreases were attributable to lower equity in earnings from Field Services, primarily reflecting lower commodity prices, partially offset by a gain recognized in the first quarter of 2009 associated with partnership units previously issued by DCP Partners.

Income Tax Expense from Continuing Operations. Income tax expense from continuing operations for the three and nine months ended September 30, 2009 decreased by $91 million and $193 million, respectively, compared to the same periods in 2008 as a result of lower earnings from continuing operations in 2009.

For the three months ended September 30, 2009, the effective tax rate was 20.4% compared to 31.6% for the same period in 2008. The lower effective tax rate in 2009 was due to proportionally higher income generated from our Canadian operations, which are subject to lower tax rates as compared to our U.S. operations, and favorable tax settlements in 2009.

The effective tax rate for the nine months ended September 30, 2009 was 27.6% compared to 31.0% in the same period in 2008. The lower effective tax rate in 2009 was primarily due to proportionally higher income generated from our Canadian operations.

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

Segment Results

We evaluate segment performance based on EBIT from continuing operations, after deducting noncontrolling interests 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 noncontrolling interests 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 interests in operations without regard to financing methods or capital structures.

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Our segment EBIT may not be comparable to similarly titled measures 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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
U.S. Transmission	$ 239	$ 213	$ 690	$ 683
Distribution	48	44	240	263
Western Canada Transmission & Processing	84	113	223	333
Field Services	45	239	219	647
Total reportable segment EBIT	416	609	1,372	1,926
Other	(10)	(9)	(46)	(57)
Total reportable segment and other EBIT	406	600	1,326	1,869
Interest expense	160	163	456	470
Interest income and other (a)	19	22	71	62
Earnings from continuing operations before income taxes.	$ 265	$ 459	$ 941	$ 1,461

(a) Includes foreign currency transaction gains and losses and the elimination of the noncontrolling interests related to EBIT.
Noncontrolling interests as presented in the following segment-level discussions include only noncontrolling interests related to EBIT of non-wholly owned entities. It does not include noncontrolling interests related to interest and taxes of those operations. The amounts discussed below include intercompany transactions that are eliminated in the Condensed Consolidated Financial Statements.

U.S. Transmission

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2009	2008	Increase (Decrease)	2009	2008	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$ 427	$ 402	$ 25	$ 1,246	$ 1,205	$ 41
Operating expenses						
Operating, maintenance and other	126	156	(30)	390	433	(43)
Depreciation and amortization	61	58	3	182	174	8
Gains on sales of other assets and other, net	1		1	11	32	(21)
Operating income	241	188	53	685	630	55
Other income and expenses	19	39	(20)	60	94	(34)
Noncontrolling interests	21	14	7	55	41	14
EBIT	$ 239	$ 213	$ 26	$ 690	$ 683	$ 7
Proportional throughput, TBtu (a)	607	479	128	1,894	1,596	298

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

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Three Months Ended September 30, 2009 Compared to Same Period in 2008

Operating Revenues. The $25 million increase was driven primarily by:

- a $41 million increase from expansion projects placed into service late in 2008 and 2009, and
- a $17 million increase in transportation and other revenues primarily from the acquisition of Ozark Gas Transmission, L.L.C. (Ozark Gas Transmission) in May 2009, partially offset by
- a $26 million decrease in processing revenues associated with pipeline operations, caused by lower prices and volumes.

Operating, Maintenance and Other. The $30 million decrease was driven primarily by:

- a $33 million decrease in project development costs, reflecting a net benefit of $21 million in the 2009 third quarter due to the capitalization of project development expenses on northeast expansions compared to expensed project development costs of $12 million in the 2008 period. In accordance with our policy, project development costs are initially expensed until it is determined that recovery of such costs through regulated revenues of the completed project is probable, at which time inception-to-date costs of the project are capitalized and operating expenses are reduced.
- a $5 million decrease in operating and administrative costs, including lower insurance costs and ad valorem taxes as a result of favorable property valuations, partially offset by
- a $4 million increase from expansion projects placed into service late in 2008 and 2009.

Depreciation and Amortization. The $3 million increase was primarily driven by expansion projects placed into service late in 2008 and 2009.

Other Income and Expenses. The $20 million decrease was primarily a result of lower capitalization of interest on construction projects and the discontinuance of rate regulated accounting treatment by SESH, an equity investee. These decreases were partially offset by earnings from expansion projects on Gulfstream and SESH placed into service in late 2008.

Noncontrolling Interests. The $7 million increase was driven by an increase in the noncontrolling interests ownership percentage resulting from the Spectra Energy Partners public sale of additional partner units in the second quarter of 2009 and higher earnings from Spectra Energy Partners and M&N LLC.

EBIT. The $26 million increase was primarily due to higher earnings from expansion projects and lower project development costs. These increases were partially offset by lower processing revenues.

Nine Months Ended September 30, 2009 Compared to Same Period in 2008

Operating Revenues. The $41 million increase was driven primarily by:

- a $106 million increase from expansion projects placed into service late in 2008 and 2009,
- a $26 million increase in transportation and other revenues primarily from Ozark Gas Transmission acquired in May 2009, and

an $11 million increase primarily in transportation and storage revenues from recoveries of fuel, electric power and other costs passed through to customers, partially offset by

an $84 million decrease in processing revenues associated with pipeline operations, caused by lower prices and volumes,

a $14 million decrease resulting from a weaker Canadian dollar at M&N LP, and

a $6 million decrease in interruptible transportation revenue due to weather and other market conditions.

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Operating, Maintenance and Other. The $43 million decrease was driven primarily by:

- a $67 million decrease in project development costs, reflecting a net benefit of $39 million in 2009 primarily due to a reimbursement of project development costs by customers and the capitalization of previously expensed costs on northeast expansions compared to expensed project development costs of $28 million in 2008, and

- a $6 million decrease in operating and administrative costs from lower insurance costs and pipeline integrity costs, partially offset by

- a $14 million increase in operating costs from higher fuel, electric power and other costs passed through to customers,

- a $12 million increase from expansion projects placed in service late in 2008 and in 2009, and

- a $7 million increase from Ozark Gas Transmission.

Depreciation and Amortization. The $8 million increase was primarily driven by expansion projects placed into service late in 2008 and in 2009.

Gains on Sales of Other Assets and Other, net. The $21 million decrease was driven by a customer bankruptcy settlement of $31 million in June 2008, partially offset by a customer settlement of $10 million in 2009 resulting from the cancellation of a capital project.

Other Income and Expenses. The $34 million decrease was primarily a result of lower capitalization of interest on construction projects and from the discontinuance of rate regulated accounting treatment by SESH. These decreases were partially offset by earnings from expansion projects on Gulfstream and SESH placed into service in late 2008.

Noncontrolling Interests. The $14 million increase was driven by an increase in the noncontrolling interests ownership percentage resulting from the Spectra Energy Partners public sale of additional partner units in the second quarter of 2009 and higher earnings from Spectra Energy Partners and M&N LLC.

EBIT. The $7 million increase was primarily due to higher earnings from expansion projects and lower project development costs. These increases were partially offset by lower processing revenues and a customer bankruptcy settlement in 2008.

Distribution

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2009	**2008**	**Increase (Decrease)**	**2009**	**2008**	**Increase (Decrease)**
	(in millions, except where noted)					
Operating revenues	$ 244	$ 280	$ (36)	$ 1,236	$ 1,433	$ (197)
Operating expenses						
Natural gas purchased	62	97	(35)	617	747	(130)
Operating, maintenance and other	89	93	(4)	252	284	(32)
Depreciation and amortization	44	45	(1)	126	138	(12)
Operating income	49	45	4	241	264	(23)
Other income and expenses	(1)	(1)		(1)	(1)	
EBIT	$ 48	$ 44	$ 4	$ 240	$ 263	$ (23)

Number of customers, thousands				1,315	1,300	15
Heating degree days, Fahrenheit	348	264	84	4,964	4,815	149
Pipeline throughput, TBtu	133	153	(20)	589	631	(42)

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Three Months Ended September 30, 2009 Compared to Same Period in 2008

Operating Revenues. The $36 million decrease was driven primarily by:

- a $40 million decrease from lower natural gas prices passed through to customers without a mark-up,
- a $13 million decrease resulting from a weaker Canadian dollar, and
- a $6 million decrease in customer usage of natural gas due to conservation efforts and the impacts of the economic recession, partially offset by
- a $10 million increase in storage and transportation revenues attributable to growth of the storage system and an increase in short-term transportation services provided to customers, and
- an $8 million increase due to growth in the number of customers.

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

- a $40 million decrease from lower natural gas prices passed through to customers without a mark-up, and
- a $5 million decrease in customer usage of natural gas due to conservation efforts and the impacts of the economic recession, partially offset by
- a $6 million increase due to growth in the number of customers, and
- a $3 million increase related to fuel used in operations.

Operating, Maintenance and Other. The $4 million decrease was driven primarily by a weaker Canadian dollar.

EBIT. The $4 million increase was primarily a result of higher storage and transportation revenues, partially offset by the effect of a weaker Canadian dollar.

Nine Months Ended September 30, 2009 Compared to Same Period in 2008

Operating Revenues. The $197 million decrease was driven primarily by:

- a $227 million decrease resulting from a weaker Canadian dollar,
- a $34 million decrease in customer usage of natural gas due to conservation efforts and the impacts of the economic recession,

- a $13 million decrease from lower natural gas prices passed through to customers without a mark-up, and

- an $11 million decrease due to a 2009 settlement on 2008 earnings to be shared with customers, partially offset by

- a $39 million increase due to growth in the number of customers,

- a $38 million increase in storage and transportation revenues attributable to growth of the storage system and an increase in short-term transportation services provided to customers, and

- a $15 million increase resulting from a charge in 2008 due to an unfavorable decision from the OEB related to unregulated storage revenues.

Natural Gas Purchased. The $130 million decrease was driven primarily by:

- a $126 million decrease resulting from a weaker Canadian dollar,

- a $31 million decrease in customer usage of natural gas due to conservation efforts and the impacts of the economic recession, and

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a $13 million decrease from lower natural gas prices passed through to customers without a mark-up, partially offset by

a $33 million increase due to growth in the number of customers, and

a $5 million increase in fuel used in operations.

Operating, Maintenance and Other. The $32 million decrease was driven primarily by a weaker Canadian dollar.

Depreciation and Amortization. The $12 million decrease was driven primarily by a weaker Canadian dollar.

EBIT. The $23 million decrease was primarily a result of a weaker Canadian dollar and the 2008 earnings sharing settlement reached in June 2009. These decreases were partially offset by higher storage and transportation revenues.

Western Canada Transmission & Processing

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2009	2008	Increase (Decrease)	2009	2008	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$ 260	$ 397	$ (137)	$ 770	$ 1,174	$ (404)
Operating expenses						
Natural gas and petroleum products purchased	38	136	(98)	143	384	(241)
Operating, maintenance and other	103	110	(7)	299	342	(43)
Depreciation and amortization	38	37	1	105	114	(9)
Operating income	81	114	(33)	223	334	(111)
Other income and expenses	3	(1)	4			
Noncontrolling interests					1	(1)
EBIT	$ 84	$ 113	$ (29)	$ 223	$ 333	$ (110)
Pipeline throughput, TBtu	148	150	(2)	446	454	(8)
Volumes processed, TBtu	163	183	(20)	494	526	(32)
Empress inlet volumes, TBtu	169	218	(49)	578	644	(66)

Three Months Ended September 30, 2009 Compared to Same Period in 2008

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

a $144 million decrease due to lower NGL product prices associated with the Empress operations, and

a $14 million decrease as a result of a weaker Canadian dollar, partially offset by

a $14 million increase resulting primarily from higher gathering and processing revenues due to higher firm contract revenue.

Natural Gas and Petroleum Products Purchased. The $98 million decrease was driven primarily by lower prices of natural gas purchased for the Empress facility.

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

- an $8 million decrease in plant fuel and electricity costs at the Empress facility, and
- a $5 million decrease caused by a weaker Canadian dollar.

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EBIT. The $29 million decrease was driven primarily by lower NGL product prices that negatively impacted the Empress operations, as well as a weaker Canadian dollar, partially offset by lower prices of natural gas purchased for the Empress facility and higher gathering and processing revenues.

Nine Months Ended September 30, 2009 Compared to Same Period in 2008

Operating Revenues. The $404 million decrease was driven primarily by:

- a $339 million decrease due mainly to lower NGL product prices associated with the Empress operations, and
- a $115 million decrease as a result of a weaker Canadian dollar, partially offset by
- a $41 million increase resulting primarily from higher gathering and processing revenues due to higher firm contract revenue, and
- a $12 million increase in revenue to recover carbon tax expense from customers (offset in Operating, Maintenance and Other).

Natural Gas and Petroleum Products Purchased. The $241 million decrease was driven primarily by:

- a $217 million decrease arising from lower prices of natural gas purchased for the Empress facility, and
- a $24 million decrease caused by a weaker Canadian dollar.

Operating, Maintenance and Other. The $43 million decrease was driven primarily by:

- a $46 million decrease caused by a weaker Canadian dollar, and
- a $25 million decrease in plant fuel and electricity costs at the Empress facility, partially offset by
- a $16 million increase in maintenance and other project costs, and
- a $12 million increase in the carbon tax expense (offset in Operating Revenues).

Depreciation and Amortization. The $9 million decrease was driven primarily by a weaker Canadian dollar.

EBIT. The $110 million decrease was driven primarily by lower NGL product prices that negatively impacted the Empress operations, as well as a weaker Canadian dollar, partially offset by lower prices of natural gas purchased for the Empress facility and higher gathering and processing revenues.

Field Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2009	2008	Increase (Decrease)	2009	2008	Increase (Decrease)
	(in millions, except where noted)					
Equity in earnings of unconsolidated affiliates	$ 45	$ 239	$ (194)	$ 219	$ 647	$ (428)
EBIT	$ 45	$ 239	$ (194)	$ 219	$ 647	$ (428)
Natural gas gathered and processed/transported, TBtu/d (a,b)	7.0	6.6	0.4	7.0	7.1	(0.1)
NGL production, MBbl/d (a,c)	371	340	31	354	365	(11)
Average natural gas price per MMBtu (d)	$ 3.39	$ 10.24	$ (6.85)	$ 3.93	$ 9.73	$ (5.80)
Average NGL price per gallon (e)	$ 0.69	$ 1.44	$ (0.75)	$ 0.63	$ 1.42	$ (0.79)

(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.

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Three Months Ended September 30, 2009 Compared to Same Period in 2008

EBIT. Lower equity earnings of $194 million were primarily the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

- a $164 million decrease from commodity-sensitive processing arrangements, due to decreased commodity prices,
- a $21 million decrease in earnings from DCP Partners primarily as a result of decreased mark-to-market gains on hedges used to protect distributable cash flows,
- a $17 million decrease in marketing margins due to lower derivatives gains in 2009, and
- an $8 million decrease due to higher net interest expense resulting from the increased debt associated with growth, acquisitions and a special distribution paid in 2008, partially offset by
- an $8 million increase in gathering and processing margins primarily attributable to the impact of hurricanes in 2008 and other operational impacts, and
- a $5 million increase primarily as a result of lower operating and maintenance expenses due to a cost reduction initiative, partially offset by higher depreciation expense as a result of capital spending and acquisitions in 2008.

Nine Months Ended September 30, 2009 Compared to Same Period in 2008

EBIT. Lower equity earnings of $428 million were primarily the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

- a $547 million decrease from commodity-sensitive processing arrangements, due to decreased commodity prices,
- a $36 million decrease in gathering and processing margins primarily attributable to lower volumes due primarily to reduced drilling and lower recoveries and efficiencies, partially offset by the impact of hurricanes in 2008 and other operational impacts, and
- a $29 million decrease due to higher net interest expense resulting from the increased debt associated with growth, acquisitions and a special distribution paid in 2008, partially offset by
- a $135 million gain associated with partnership units previously issued by DCP Partners,
- a $30 million increase in marketing margins related to higher NGL trading results and favorable derivatives timing, and

a $15 million increase primarily as a result of lower operating and maintenance expenses due to hurricane insurance recoveries and cost reduction initiatives, partially offset by higher depreciation expense as a result of capital spending and acquisitions in 2008.

Matters Affecting Future Field Services Results

In the near term, softening of natural gas prices, potential reduction in available capital and the recent downturn in the economy are having an effect on levels of drilling activity. The impact of these factors will vary across Field Services broad geographic locations. Generally, we have seen a decrease in drilling levels in the first nine months of 2009. Although we have not seen a significant impact on Field Services throughput volumes for the first nine months of 2009 due to reduced drilling levels, throughput volumes could decline further in the remainder of 2009 and beyond should natural gas prices and reduced drilling levels remain at current levels or decline further.

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Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2009	2008	Increase (Decrease)	2009	2008	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$ 12	$ 11	$ 1	$ 36	$ 32	$ 4
Operating expenses	30	19	11	90	85	5
Operating loss	(18)	(8)	(10)	(54)	(53)	(1)
Other income and expenses	8	(1)	9	8	(4)	12
EBIT	$ (10)	$ (9)	$ (1)	$ (46)	$ (57)	$ 11

Three Months Ended September 30, 2009 Compared to Same Period in 2008

EBIT. The $1 million decrease in EBIT reflects primarily a benefit from the favorable resolution of an insurance contingency in 2008, mostly offset by lower corporate costs and benefits received from company-owned life insurance in 2009.

Nine Months Ended September 30, 2009 Compared to Same Period in 2008

EBIT. The $11 million increase in EBIT reflects lower corporate costs in 2009. Results in 2008 included a benefit from the favorable resolution of an insurance contingency.

CRITICAL ACCOUNTING POLICIES

Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2008 contained discussions of our critical accounting policies and estimates that require the use of significant estimates and judgment. See also Note 11 of Notes to Condensed Consolidated Financial Statements contained in this Report on Form 10-Q for the quarterly period ended September 30, 2009 for further discussion regarding significant estimates and judgments used in our annual goodwill impairment test as of April 1, 2009.

LIQUIDITY AND CAPITAL RESOURCES

Net working capital was negative $730 million as of September 30, 2009, which included current maturities of long-term debt of $813 million. We will rely primarily upon cash flows from operations and additional financing transactions to fund our liquidity and capital requirements for the next 12 months, including issuances of short-term and long-term debt. See Financing Cash Flows and Liquidity for discussions of effective shelf registrations and available credit facilities.

Operating Cash Flows

Net cash provided by operating activities decreased $129 million to $1,267 million for the nine months ended September 30, 2009 compared to the same period in 2008, driven by a $584 million decrease in distributions received from unconsolidated affiliates in 2009, primarily from the lower commodity prices at DCP Midstream, partially offset by $255 million of net working capital changes at Union Gas primarily resulting from higher approved gas cost collections from customers in 2009 compared to 2008, and proceeds of $62 million from the termination of fair value hedges in 2009. The gas cost collections have been deferred and will be refunded to customers in future periods.

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Investing Cash Flows

Cash flows used in investing activities decreased $832 million to $732 million in the first nine months of 2009 compared to the same period in 2008. This change was driven primarily by:

- a $767 million decrease in capital and investment expenditures in 2009 as a result of the planned reduction in capital expansion levels for 2009 compared to 2008,
- a $186 million receipt from SESH in 2009 to repay our loan to them, and
- the $274 million acquisition of Spectra Energy Income Fund in 2008, partially offset by
- the $295 million acquisition of NOARK Pipeline System, LP in 2009.

	Nine Months Ended September 30,	
	2009	2008
	(in millions)	
Capital and Investment Expenditures (a)		
U.S. Transmission	$ 340	$ 1,098
Distribution	171	274
Western Canada Transmission & Processing	236	139
Other	21	24
Total	$ 768	$ 1,535

(a) Excludes the acquisition of NOARK.

Capital and investment expenditures for the nine months ended September 30, 2009 consisted of $418 million for expansion projects and $350 million for maintenance and other projects.

As previously discussed, on May 4, 2009, Spectra Energy Partners acquired all of the ownership interests of NOARK from Atlas for approximately $295 million in cash. See Note 2 of Notes to Condensed Consolidated Financial Statements for further discussion.

We continue to project 2009 capital and investment expenditures of approximately $1.1 billion, excluding the acquisition of NOARK, consisting of approximately $500 million for U.S. Transmission, $200 million for Distribution and $400 million for Western Canada Transmission & Processing. Total projected 2009 capital and investment expenditures include approximately $600 million of expansion capital expenditures and $500 million for maintenance and upgrades of existing plants, pipelines and infrastructure to serve growth. We anticipate placing a total of approximately $650 million of capital expansion projects into service in 2009.

Our 2010 capital budget is expected to be reviewed by our Board of Directors in December 2009. Subject to their approval, we expect to increase our expansion capital spending to approximately $1 billion in 2010 as we continue to pursue opportunities around new natural gas supply volumes.

In the second quarter of 2009, we received a $148 million special distribution from Gulfstream, a 50% owned equity affiliate, from the proceeds of a debt issuance by Gulfstream, of which $144 million was classified as Cash Flows from Investing Activities Distributions Received From Unconsolidated Affiliates on the Condensed Consolidated Statement of Cash Flows.

Financing Cash Flows and Liquidity

Our consolidated capital structure includes long-term debt, short-term borrowings, commercial paper and preferred stock of subsidiaries. As of September 30, 2009, our capital structure was 57% debt, 39% common equity of controlling interests and 4% noncontrolling interests and preferred stock of subsidiaries.

Net cash used in financing activities totaled $289 million in the first nine months of 2009 compared to $354 million net cash provided by financing activities in the first nine months of 2008. This change was driven primarily by:

- an $892 million decrease in short-term borrowings in 2009 compared to a $204 million increase in the 2008 period,
- a $110 million decrease in contributions from noncontrolling interests in 2009 compared to the same period in 2008,
- a $103 million increase in distributions to noncontrolling interests in 2009 compared to the same period in 2008, primarily from proceeds of the new debt issuance at M&N, LLC, and
- $566 million of net proceeds from the issuance of long-term debt in 2009 compared to $1,171 million in 2008, partially offset by
- proceeds of $448 million in 2009 from the issuance of Spectra Energy common stock,
- proceeds of $208 million in 2009 from the issuance of Spectra Energy Partners common units, and
- repurchases of Spectra Energy common stock in 2008 of $600 million.

Long-term Debt Issuances. See Note 12 of Notes to Condensed Consolidated Financial Statements for a discussion of significant long-term debt issuances.

Funding of NOARK Acquisition. On May 4, 2009, Spectra Energy Partners acquired all of the ownership interests of NOARK from Atlas for approximately $295 million in cash. The transaction was initially funded by Spectra Energy Partners with $218 million drawn on its bank credit facility, $70 million borrowed under a credit facility with Spectra Energy that was created for the sole purpose of funding a portion of the acquisition, and $7 million of cash on hand. This transaction was partially refinanced by Spectra Energy Partners in the second quarter of 2009 through the issuance of 9.8 million common units to the public, representing limited partner interests, and 0.2 million general partner units to Spectra Energy, resulting in net proceeds of $212 million and a reduction of our ownership interest in Spectra Energy Partners from 84% to 74%. Funds from the sale of the partner units were used by Spectra Energy Partners to repay the $70 million owed to Spectra Energy and $142 million of the amount initially drawn on the Spectra Energy Partners bank credit facility. Effective with the repayment to Spectra Energy, the credit facility with Spectra Energy was terminated.

Common Stock Issuance. 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. We used the net proceeds to repay commercial paper as it matured. Borrowings from the commercial paper were used primarily for capital expenditures and for other general corporate purposes.

Available Credit Facilities and Restrictive Debt Covenants. See Note 12 of Notes to Condensed Consolidated Financial Statements for a discussion of available credit facilities and related financial and other covenants.

The terms of our Spectra Capital credit agreement requires our consolidated debt-to-total-capitalization ratio to be 65% or lower. As of September 30, 2009, this ratio was 57%. Our equity and, as a result, this ratio, are sensitive to significant movements of the Canadian dollar relative to the U.S. dollar due to the significance of our Canadian operations.

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Credit Ratings.

	Standard and Poor s	Moody s Investor Service	Fitch Ratings	DBRS
As of October 30, 2009				
Spectra Capital (a)	BBB	Baa2	BBB	n/a
Texas Eastern Transmission, LP (a)	BBB+	Baa1	BBB+	n/a
Westcoast (a)	BBB+	n/a	n/a	A(low)
Union Gas (a)	BBB+	n/a	n/a	A
Maritimes & Northeast Pipeline, L.L.C. (a)	BBB	Baa3	n/a	n/a
Maritimes & Northeast Pipeline Limited Partnership (b)	A	A2	n/a	A

(a) Represents senior unsecured credit rating.
(b) Represents senior secured credit rating.
n/a Indicates not applicable.

The above credit ratings depend 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.

On April 28, 2009, Standard & Poor s affirmed Spectra Energy Corp s long-term credit rating at BBB+ (investment grade) and lowered its outlook from stable to negative, citing concerns over the impact of low commodity prices. Spectra Capital s and Texas Eastern Transmission, LP s (Texas Eastern s) outlooks were also lowered to negative at that time.

On July 15, 2009, Moody s Investor Service downgraded Spectra Capital s senior unsecured debt rating from Baa1 to Baa2 and Texas Eastern s senior unsecured debt from A3 to Baa1, citing concerns primarily over the impact of low commodity prices and borrowings for capital expansion. Moody s also affirmed Spectra Capital s outlook as stable. This downgrade, which resulted in ratings that are still investment grade, did not trigger any debt acceleration clauses in our debt and credit agreements.

Dividends. We currently anticipate an average dividend payout ratio over time of approximately 60% of estimated annual net income from controlling interests per share of common stock and expect to continue our policy of paying regular cash dividends. 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 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 October 20, 2009 and will be paid on December 14, 2009.

Other Financing Matters. Spectra Energy Corp and Spectra Capital have an automatic shelf registration statement on file with the SEC to register the issuance of unspecified amounts of various equity and debt securities, respectively. This registration statement expires in April 2010. Spectra Energy Partners has an effective shelf registration statement on file with the SEC to register the issuance of limited partner common units and various debt securities up to $1.3 billion in the aggregate. In addition, as of the date of this filing, certain of our subsidiaries have 800 million Canadian dollars (approximately $748 million at September 30, 2009) 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.

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OTHER ISSUES

New Accounting Pronouncements

See Note 21 of Notes to Condensed Consolidated Financial Statements for discussion.

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Our exposure to market risk is described in Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2008. We believe the exposure to market risk has not changed materially at September 30, 2009.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

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

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of September 30, 2009, 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

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 September 30, 2009 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

For information regarding material legal proceedings, see Note 14 of Notes to Condensed Consolidated Financial Statements.

Item 1A. Risk Factors.

In addition to the other information set forth in this report, careful consideration should be given to the factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2008, which could materially affect our financial condition or future results. There were no changes to those risk factors at September 30, 2009.

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

None.

Item 6. Exhibits.

Any agreements included as exhibits to this Form 10-Q may contain representations and warranties by each of the parties to the applicable agreement. These representations and warranties have been made solely for the benefit of the other parties to the applicable agreement and:

- should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;
- have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
- may apply standards of materiality in a way that is different from what may be viewed as material to you or other investors; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

Accordingly, these representations and warranties may not describe the actual state of affairs as of the date they were made or at any other time. We acknowledge that, notwithstanding the inclusion of the foregoing cautionary statements, we are responsible for considering whether additional specific disclosures of material information regarding material contractual provisions are required to make the statements in this Form 10-Q not misleading.

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(a) Exhibits

Exhibit Number	
4.1	Fifteenth Supplemental Indenture, dated as of August 28, 2009, between Spectra Capital, Spectra Energy and the Bank of New York Mellon Trust Company, N.A. (filed as Exhibit No. 4.1 to Form 8-K of Spectra Energy Corp on August 28, 2009).
*10.1	Amendment No. 2, dated September 28, 2009, 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.
*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.
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Taxonomy Extension Schema.
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
*101.DEF	XBRL Taxonomy Extension Definition Linkbase.
*101.LAB	XBRL Taxonomy Extension Label Linkbase.
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

* Filed herewith.

The total amount of securities of the registrant or its subsidiaries authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrant and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the Securities and Exchange Commission, to furnish copies of any or all of such instruments to it.

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SIGNATURES

Pursuant to the requirements 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.

SPECTRA ENERGY CORP

Date: November 6, 2009

/s/ GREGORY L. EBEL
Gregory L. Ebel
President and Chief Executive Officer

Date: November 6, 2009

/s/ J. PATRICK REDDY
J. Patrick Reddy
Chief Financial Officer