Spectra Energy Corp.
Form 10-Q
November 08, 2010
Table of Contents

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, 2010

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 29, 2010: 648,221,917

Table of Contents

SPECTRA ENERGY CORP

FORM 10-Q FOR THE QUARTER ENDED

September 30, 2010

INDEX

Table of Contents

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, including the risk of a prolonged economic slowdown or decline, or the risk of delay in a recovery, which can affect the long-term demand for natural gas and related services;

potential effects arising from terrorist attacks and any consequential or other hostilities;

changes in environmental, safety and other laws and regulations;

results and costs of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general market and economic conditions;

increases in the cost of goods and services required to complete capital projects;

declines in the market prices of equity and debt securities and resulting funding requirements for defined benefit pension plans;

growth in opportunities, including the timing and success of efforts to develop U.S. and Canadian pipeline, storage, gathering, processing and other 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.

Table of Contents

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, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Operating Revenues				
Transportation, storage and processing of natural gas	$ 707	$ 655	$ 2,113	$ 1,885
Distribution of natural gas	179	167	1,014	1,017
Sales of natural gas liquids	96	73	312	246
Other	37	38	123	106
Total operating revenues	1,019	933	3,562	3,254
Operating Expenses				
Natural gas and petroleum products purchased	119	101	727	759
Operating, maintenance and other	322	265	958	785
Depreciation and amortization	165	149	482	429
Property and other taxes	72	66	220	197
Total operating expenses	678	581	2,387	2,170
Gains on Sales of Other Assets and Other, net		1		11
Operating Income	341	353	1,175	1,095
Other Income and Expenses				
Equity in earnings of unconsolidated affiliates	98	60	297	267
Other income and expenses, net	7	12	17	35
Total other income and expenses	105	72	314	302
Interest Expense	159	160	476	456
Earnings From Continuing Operations Before Income Taxes	287	265	1,013	941
Income Tax Expense From Continuing Operations	69	54	242	260
Income From Continuing Operations	218	211	771	681
Income From Discontinued Operations, net of tax	1	1	17	3

Net Income	219	212	788	684
Net Income Noncontrolling Interests	22	21	59	55
Net Income Controlling Interests	$ 197	$ 191	$ 729	$ 629
Common Stock Data				
Weighted-average shares outstanding				
Basic	648	646	648	640
Diluted	650	647	650	641
Earnings per share from continuing operations				
Basic	$ 0.30	$ 0.30	$ 1.10	$ 0.98
Diluted	$ 0.30	$ 0.30	$ 1.09	$ 0.98
Earnings per share				
Basic	$ 0.30	$ 0.30	$ 1.13	$ 0.98
Diluted	$ 0.30	$ 0.30	$ 1.12	$ 0.98
Dividends per share	$ 0.25	$ 0.25	$ 0.75	$ 0.75

See Notes to Condensed Consolidated Financial Statements.

Table of Contents

SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)

	September 30, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and cash equivalents	$ 156	$ 166
Receivables, net	699	778
Inventory	371	321
Other	196	164
Total current assets	1,422	1,429
Investments and Other Assets		
Investments in and loans to unconsolidated affiliates	2,003	2,001
Goodwill	4,236	3,948
Other	483	407
Total investments and other assets	6,722	6,356
Property, Plant and Equipment		
Cost	21,428	19,960
Less accumulated depreciation and amortization	5,053	4,613
Net property, plant and equipment	16,375	15,347
Regulatory Assets and Deferred Debits	997	947
Total Assets	$ 25,516	$ 24,079

See Notes to Condensed Consolidated Financial Statements.

Table of Contents

SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions, except per-share amounts)

	September 30, 2010	December 31, 2009
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 353	$ 333
Short-term borrowings and commercial paper	982	162
Taxes accrued	50	139
Interest accrued	161	167
Current maturities of long-term debt	740	809
Other	779	885
Total current liabilities	3,065	2,495
Long-term Debt	9,277	8,947
Deferred Credits and Other Liabilities		
Deferred income taxes	3,232	3,113
Regulatory and other	1,655	1,634
Total deferred credits and other liabilities	4,887	4,747
Commitments and Contingencies		
Preferred Stock of Subsidiaries	258	225
Equity		
Preferred stock, $0.001 par, 22 million shares authorized, no shares outstanding		
Common stock, $0.001 par, 1 billion shares authorized, 648 million and 647 million shares outstanding at September 30, 2010 and December 31, 2009, respectively	1	1
Additional paid-in capital	4,701	4,700
Retained earnings	1,338	1,096
Accumulated other comprehensive income	1,430	1,328
Total controlling interests	7,470	7,125
Noncontrolling interests	559	540
Total equity	8,029	7,665
Total Liabilities and Equity	$ 25,516	$ 24,079

See Notes to Condensed Consolidated Financial Statements.

Table of Contents

SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 788	$ 684
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	493	440
Deferred income tax expense	62	125
Equity in earnings of unconsolidated affiliates	(297)	(267)
Distributions received from unconsolidated affiliates	303	107
Other	(342)	178
Net cash provided by operating activities	1,007	1,267
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(881)	(713)
Investments in and loans to unconsolidated affiliates	(6)	(55)
Acquisitions, net of cash acquired	(492)	(295)
Purchases of held-to-maturity securities	(850)	
Proceeds from sales and maturities of held-to-maturity securities	809	
Proceeds from sales and maturities of available-for-sale securities		32
Distributions received from unconsolidated affiliates	12	148
Receipt from affiliate repayment of loan		186
Other	(13)	(43)
Net cash used in investing activities	(1,421)	(740)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from the issuance of long-term debt	2,625	3,405
Payments for the redemption of long-term debt	(2,502)	(2,839)
Net increase (decrease) in short-term borrowings and commercial paper	821	(892)
Distributions to noncontrolling interests	(54)	(153)
Proceeds from the issuance of Spectra Energy common stock		448
Proceeds from the issuance of Spectra Energy Partners, LP common units		208
Dividends paid on common stock	(487)	(471)
Other	3	5
Net cash provided by (used in) financing activities	406	(289)
Effect of exchange rate changes on cash	(2)	(10)
Net increase (decrease) in cash and cash equivalents	(10)	228

Cash and cash equivalents at beginning of period		166		205
Cash and cash equivalents at end of period	$	156	$	433
Supplemental Disclosures				
Property, plant and equipment accruals	$	71	$	49

See Notes to Condensed Consolidated Financial Statements.

SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

(Unaudited)

(In millions)

	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income: Foreign Currency Translation Adjustments	Accumulated Other Comprehensive Income: Other	Noncontrolling Interests	Total
December 31, 2009	$ 1	$ 4,700	$ 1,096	$ 1,686	$ (358)	$ 540	$ 7,665
Net income			729			59	788
Foreign currency translation adjustments				114		13	127
Unrealized mark-to-market net loss on hedges					(31)		(31)
Reclassification of cash flow hedges into earnings					1		1
Pension and benefits impact					18		18
Dividends on common stock			(487)				(487)
Stock-based compensation		23					23
Distributions to noncontrolling interests						(54)	(54)
Other, net		(22)				1	(21)
September 30, 2010	$ 1	$ 4,701	$ 1,338	$ 1,800	$ (370)	$ 559	$ 8,029
December 31, 2008	$ 1	$ 4,104	$ 899	$ 881	$ (345)	$ 470	$ 6,010
Net income			629			55	684
Foreign currency translation adjustments				673		10	683
Unrealized mark-to-market net loss 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	$ (337)	$ 542	$ 7,480

See Notes to Condensed Consolidated Financial Statements.

Table of Contents

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, 2009, 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.

We have corrected the presentation of certain restricted cash balances in the accompanying condensed consolidated balance sheets. Restricted cash, totaling $30 million at December 31, 2009 that was previously classified as Cash and Cash Equivalents, is currently presented within Other Current Assets. Beginning and ending Cash and Cash Equivalents balances on the Condensed Consolidated Statements of Cash Flows for the nine months ended September 30, 2009 were also reduced by $9 million and $17 million, respectively, from amounts previously reported and Cash Used in Investing Activities for the nine-month period was reduced by $8 million. Management has concluded that these corrections are immaterial to our previously issued financial statements.

Use of Estimates. To conform with generally accepted accounting principles 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.

2. Acquisition

Bobcat Gas Storage. On August 30, 2010, we acquired the Bobcat Gas Storage assets and development project (Bobcat) from Haddington Energy Partners III LP and GE Energy Financial Services for a cash purchase price of $540 million, of which approximately $38 million was withheld at closing pending certain outcomes. The withheld amounts are recorded within Deferred Credits and Other Liabilities Regulatory and Other on the Condensed Consolidated Balance Sheet at September 30, 2010.

Table of Contents

Strategically located on the Gulf Coast in southeastern Louisiana near Henry Hub, the Bobcat assets interconnect with five major interstate pipelines, including our Texas Eastern Transmission, LP pipeline, and complement our existing pipeline and storage portfolio in the region. Bobcat is part of the U.S. Transmission segment. Once fully developed and operational, these high-deliverability salt dome storage caverns will have a total working gas storage capacity of 46 billion cubic feet. Storage infrastructure such as Bobcat plays a vital role in meeting customers needs for managing demand swings on a seasonal basis, satisfying the increasing demand for natural gas-fired power generation and providing customers with the advantage and flexibility to access all the major markets in the United States.

The following table summarizes the preliminary fair values of the assets and liabilities acquired as of August 30, 2010. Subsequent adjustments may be recorded upon the completion of the valuation and the final determination of the purchase price allocation.

	Purchase Price Allocation (in millions)
Cash purchase price	$ 540
Working capital and other purchase adjustments	7
Total	547
Cash	17
Other current assets	3
Property, plant and equipment	322
Current liabilities	(8)
Deferred credits and other liabilities	(4)
Total assets acquired/liabilities assumed	330
Goodwill	$ 217

Goodwill related to the acquisition of Bobcat is deductible for income tax purposes.

Pro forma results of operations reflecting the acquisition of Bobcat as if the acquisition had occurred as of the beginning of the periods presented in this report do not materially differ from actual reported results.

Bobcat is a party to certain leases associated with its storage caverns that expire in 2036. Future minimum lease payments under these lease obligations total $47 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 segments in deciding how to allocate resources and evaluate performance. There is no aggregation within our defined business segments.

U.S. Transmission provides transportation and storage of natural gas for customers in various regions of the northeastern and southeastern United States and the Maritime Provinces in Canada. The natural gas transmission and storage operations in the U.S. are primarily subject to the Federal Energy Regulatory Commission s (FERC s) rules and regulations.

Distribution provides retail natural gas distribution service in Ontario, Canada, as well as natural gas transportation and storage services to other utilities and energy market participants. These services are provided by Union Gas 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 Canadian Midstream businesses. BC Pipeline and BC Field Services operations are primarily subject to the rules and regulations of Canada s National Energy Board (NEB).

Field Services gathers and processes natural gas and fractionates, markets and trades NGLs. It conducts operations through DCP Midstream, which is owned 50% by us and 50% by ConocoPhillips. 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 less noncontrolling interests related to those earnings.

On a segment basis, EBIT represents earnings from continuing operations (both operating and non-operating) before interest and taxes, net of noncontrolling interests related to those earnings. 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.

Table of Contents

Business Segment Data

	Unaffiliated Revenues	Intersegment Revenues	Total Operating Revenues (a)	Segment EBIT/ Consolidated Earnings from Continuing Operations before Income Taxes (a)
		(in millions)		
Three Months Ended September 30, 2010				
U.S. Transmission	$ 441	$ 1	$ 442	$ 231
Distribution	261		261	63
Western Canada Transmission & Processing	315		315	90
Field Services				70
Total reportable segments	1,017	1	1,018	454
Other	2	13	15	(23)
Eliminations		(14)	(14)	
Interest expense				159
Interest income and other (b)				15
Total consolidated	$ 1,019	$	$ 1,019	$ 287
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
Nine Months Ended September 30, 2010				
U.S. Transmission	$ 1,337	$ 4	$ 1,341	$ 701
Distribution	1,260		1,260	282
Western Canada Transmission & Processing	959		959	278
Field Services				227
Total reportable segments	3,556	4	3,560	1,488
Other	6	36	42	(53)
Eliminations		(40)	(40)	
Interest expense				476
Interest income and other (b)				54
Total consolidated	$ 3,562	$	$ 3,562	$ 1,013

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

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

(b) Includes foreign currency transaction gains and losses and the add-back of noncontrolling interests related to segment EBIT.

Table of Contents

4. Regulatory Matters

Maritimes & Northeast Pipeline, L.L.C. (M&N LLC). During 2009, M&N LLC filed a rate case with the FERC. The rate case included the impact of the Phase IV expansion facilities that went into service in January 2009 and resulted in lower recourse rates that went into effect in August 2009. In April 2010, the FERC approved a settlement that resolves all issues in the case. Although the settlement results in a reduction to M&N LLC s recourse rates, the settlement will not have a material impact on consolidated results of operations.

Maritimes & Northeast Pipeline Limited Partnership (M&N LP). M&N LP initiated interim rates effective January 1, 2010 which were equal to final approved 2009 rates. Settlement on all 2010 issues, other than compensation for funds held in escrow, was reached in March 2010. Effective April 1, 2010, M&N LP received NEB approval of the interim rates related to the resolved issues. These 2010 interim rates are retroactive back to January 1, 2010. Final 2010 rates with respect to the issue of compensation for funds held in escrow will be determined after a hearing before the NEB. M&N LP filed an application with the NEB on July 26, 2010 seeking compensation for funds held in escrow and finalizing 2010 tolls. The NEB issued an order setting March 1, 2011 as the initial hearing date for the escrow issue.

Union Gas. In September 2010, Union Gas filed an application with the OEB seeking approval of its 2011 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 Union Gas service territory effective January 1, 2011. This increase is primarily attributable to the removal of long-term storage revenues which were historically credited to these delivery rates. The OEB s decision in the Natural Gas Electricity Interface Review required that the long-term storage revenues included in delivery rates be removed over a four-year period, starting in 2008.

5. Income Taxes

Income tax expense from continuing operations for the three months ended September 30, 2010 was $69 million, compared to $54 million for the same period in 2009, increasing primarily as a result of higher earnings from continuing operations and a higher effective tax rate when comparing the quarters. Income tax expense from continuing operations for the nine months ended September 30, 2010 was $242 million, compared to $260 million reported for the same period in 2009, decreasing primarily as a result of favorable tax audit settlements, partially offset by an increase in income tax expense due to higher earnings.

The effective tax rate for income from continuing operations for the three months ended September 30, 2010 was 24.0% compared to 20.4% reported for the same period in 2009. The effective tax rate for income from continuing operations for the nine months ended September 30, 2010 was 23.9% compared to 27.6% reported for the same period in 2009. The lower effective tax rate for the nine months ended September 30, 2010 was primarily due to favorable tax settlements, most notably an administrative change by the Canadian federal government that resulted in cash tax refunds from historical tax years and a reduction to the deferred tax liability.

No material net change in uncertain tax benefits was recognized during the nine months ended September 30, 2010. Although uncertain, no material increases or decreases in uncertain tax benefits are expected to occur prior to September 30, 2011.

6. Discontinued Operations

Discontinued operations includes the net effects of a settlement arrangement related to prior liquefied natural gas contracts and, during the first quarter of 2010, an immaterial income tax adjustment related to previously discontinued operations.

Table of Contents

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

	Revenues	Pre-tax Earnings	Income Tax Expense (Benefit)	Income From Discontinued Operations, Net of Tax
			(in millions)	
Three Months Ended September 30, 2010				
Other	$	$ 2	$ 1	$ 1
Total consolidated	$	$ 2	$ 1	$ 1
Three Months Ended September 30, 2009				
Western Canada Transmission & Processing	$ 1	$ 1	$	$ 1
Other	22			
Total consolidated	$ 23	$ 1	$	$ 1
Nine Months Ended September 30, 2010				
Other	$ 107	$ 6	$ (11)	$ 17
Total consolidated	$ 107	$ 6	$ (11)	$ 17
Nine Months Ended September 30, 2009				
Western Canada Transmission & Processing	$ 1	$ 1	$	$ 1
Other	88	3	1	2
Total consolidated	$ 89	$ 4	$ 1	$ 3

7. Comprehensive Income

Components of comprehensive income are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
		(in millions)		
Net income	$ 219	$ 212	$ 788	$ 684
Other comprehensive income				
Foreign currency translation adjustments	228	468	127	683
Unrealized mark-to-market net loss on hedges	(13)	(14)	(31)	(9)
Reclassification of cash flow hedges into earnings		4	1	
Pension and benefits impact	6	(3)	18	19
Total comprehensive income, net of tax	440	667	903	1,377
Less: comprehensive income noncontrolling interests	25	27	72	65

Comprehensive income controlling interests	$ 415	$ 640	$ 831	$ 1,312

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.

Table of Contents

The following table presents basic and diluted EPS calculations:

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(in millions, except per-share amounts)			
Income from continuing operations, net of tax controlling interests	$ 196	$ 190	$ 712	$ 626
Income from discontinued operations, net of tax controlling interests	1	1	17	3
Net income controlling interests	$ 197	$ 191	$ 729	$ 629
Weighted-average common shares, outstanding				
Basic	648	646	648	640
Diluted	650	647	650	641
Basic earnings per common share (a)				
Continuing operations	$ 0.30	$ 0.30	$ 1.10	$ 0.98
Discontinued operations, net of tax			0.03	
Total basic earnings per common share	$ 0.30	$ 0.30	$ 1.13	$ 0.98
Diluted earnings per common share (a)				
Continuing operations	$ 0.30	$ 0.30	$ 1.09	$ 0.98
Discontinued operations, net of tax			0.03	
Total diluted earnings per common share	$ 0.30	$ 0.30	$ 1.12	$ 0.98

(a) Quarterly earnings-per-share amounts are stand-alone calculations and may not be additive to year-to-date amounts due to rounding.
Weighted-average shares used to calculate diluted EPS includes the effect of certain options and restricted stock awards. Certain other options and stock awards related to approximately 10 million and 11 million shares for the three months ended September 30, 2010 and 2009, respectively, and 10 million and 12 million shares for the nine months ended September 30, 2010 and 2009, respectively, were not included in the calculation of diluted EPS. These options and stock awards were not included 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. Marketable Securities and Restricted Funds

Held-to-Maturity (HTM) Marketable Securities. HTM marketable securities, totaling $168 million at September 30, 2010 and $121 million at December 31, 2009, are classified as Investments and Other Assets Other in the Condensed Consolidated Balance Sheets. These securities, primarily Canadian government securities, are restricted funds pursuant to certain M&N LP debt agreements. These funds, plus future cash from operations that would otherwise be available for distribution to the partners of M&N LP, are placed in escrow until the balance in escrow is sufficient to fund all future debt service on the notes. The notes payable have semi-annual interest and principal payments and are due in 2019.

At September 30, 2010, the contractual maturities of outstanding HTM securities are less than one year. Purchases and sales of HTM marketable securities are presented on a gross basis within Cash Flows From Investing Activities on the Condensed Consolidated Statements of Cash Flows.

Table of Contents

Additional information regarding HTM investments follows:

	September 30, 2010			December 31, 2009		
	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value
			(in millions)			
Canadian government securities	$	$	$ 168	$	$	$ 113
Money market instruments						8
Total held-to-maturity investments	$	$	$ 168	$	$	$ 121

Other Restricted Funds. In addition to the HTM securities held in escrow described above, we had funds totaling $55 million at September 30, 2010, classified as Other Current Assets, that were also considered restricted funds, primarily related to insurance and M&N LP debt service requirements.

10. 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, 2010	December 31, 2009
	(in millions)	
Natural gas	$ 249	$ 219
NGLs	51	21
Materials and supplies	71	81
Total inventory	$ 371	$ 321

11. Investments in and Loans to Unconsolidated Affiliates

Our most significant investment in unconsolidated affiliates is our 50% investment 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,	
	2010	2009	2010	2009
		(in millions)		
Operating revenues	$ 2,604	$ 2,073	$ 8,198	$ 5,806
Operating expenses	2,436	1,928	7,564	5,469
Operating income	168	145	634	337
Net income	108	93	435	158
Net income attributable to members interests	119	89	414	169

In January 2009, DCP Midstream reclassified to equity certain deferred gains on sales of common units in DCP Midstream Partners, LP (DCP Partners). Our proportionate 50% share, totaling $135 million pre-tax, was recorded in Equity in Earnings of Unconsolidated Affiliates in the Condensed Consolidated Statement of Operations in the first quarter of 2009.

Table of Contents

In the first and third quarters of 2010, DCP Midstream recorded to equity gains on additional sales of common units of DCP Partners. Our proportionate shares, totaling $9 million and $11 million pre-tax, were recorded in Equity in Earnings of Unconsolidated Affiliates in the respective periods.

12. Goodwill

We completed our annual goodwill impairment test as of April 1, 2010 and no impairments were identified. We primarily use a discounted cash flow analysis to determine fair value for each reporting unit. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in key markets served by our operations, regulatory stability, the ability to renew contracts, commodity prices (where appropriate), and foreign currency exchange rates, as well as other factors that affect our revenue, expense and capital expenditure projections.

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

	December 31, 2009	Increases (a)	September 30, 2010
		(in millions)	
U.S. Transmission	$ 2,391	$ 255	$ 2,646
Distribution	831	17	848
Western Canada Transmission & Processing	726	16	742
Total consolidated	$ 3,948	$ 288	$ 4,236

(a) Increases consist of foreign currency translation and $217 million of goodwill at U.S. Transmission associated with the August 2010 acquisition of Bobcat. See Note 2 for further discussion.

13. Debt and Credit Facilities

Available Credit Facilities and Restrictive Debt Covenants

	Expiration Date	Total Credit Facilities Capacity	Outstanding at September 30, 2010: Commercial Paper	Revolving Credit	Letters of Credit	Total	Available Credit Facilities Capacity
				(in millions)			
Spectra Energy Capital, LLC (a)							
Multi-year syndicated	2012	$ 1,500	$ 841	$	$ 14	$ 855	$ 645
Westcoast Energy Inc. (b)							
Multi-year syndicated	2011	194	31			31	163
Union Gas (c)							
Multi-year syndicated	2012	486	110			110	376
Spectra Energy Partners, LP							
Multi-year syndicated	2012	500		230		230	270
Total		$ 2,680	$ 982	$ 230	$ 14	$ 1,226	$ 1,454

(a) Credit facility contains a covenant requiring Spectra Energy s debt-to-total capitalization ratio to not exceed 65%.
(b) U.S. dollar equivalent at September 30, 2010. The credit facility totals 200 million Canadian dollars and contains a covenant that requires the Westcoast Energy Inc. non-consolidated debt-to-total capitalization ratio to not exceed 75%.
(c) U.S. dollar equivalent at September 30, 2010. The credit facility totals 500 million Canadian dollars and contains a covenant that requires the Union Gas debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year.

Table of Contents

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

Our credit agreements contain various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of September 30, 2010, we were in compliance with those covenants. In addition, our credit agreements allow for acceleration of payments or termination of the agreements due to nonpayment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. Our debt and credit agreements do not contain provisions that trigger an acceleration of indebtedness based solely on the occurrence of a material adverse change in our financial condition or results of operations.

14. Fair Value Measurements

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

		September 30, 2010 (in millions)			
Description	**Condensed Consolidated Balance Sheet Caption**	**Total**	**Level 1**	**Level 2**	**Level 3**
Corporate debt securities	Cash and cash equivalents	$ 67	$	$ 67	$
Corporate debt securities	Investments and other assets other	19	19		
Derivative assets interest rate swaps	Investments and other assets other	61		61	
Money market funds	Investments and other assets other	17	17		
Total Assets		$ 164	$ 36	$ 128	$
Derivative liabilities natural gas purchase contracts	Deferred credits and other liabilities regulatory and other	$ 10	$	$	$ 10
Derivative liabilities interest rate swaps	Deferred credits and other liabilities regulatory and other	33		33	
Total Liabilities		$ 43	$	$ 33	$ 10

		December 31, 2009 (in millions)			
Description	**Condensed Consolidated Balance Sheet Caption**	**Total**	**Level 1**	**Level 2**	**Level 3**
Money market funds	Cash and cash equivalents	$ 14	$ 14	$	$
Corporate debt securities	Cash and cash equivalents	50		50	
Derivative assets natural gas purchase contracts	Investments and other assets other	15			15
Derivative assets interest rate swaps	Investments and other assets other	18		18	
Money market funds	Investments and other assets other	25	25		
Total Assets		$ 122	$ 39	$ 68	$ 15
Derivative liabilities interest rate swaps	Deferred credits and other liabilities regulatory and other	$ 17	$	$ 17	$
Total Liabilities		$ 17	$	$ 17	$

18

Table of Contents

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

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(in millions)			
Long-term derivative assets (liabilities)				
Fair value, beginning of period	$ 1	$ 24	$ 15	$ 36
Total realized/unrealized gains (losses):				
Included in earnings		(1)	(3)	(5)
Included in Investments and Other Assets Other		2		3
Included in other comprehensive income	(11)	(6)	(22)	(15)
Fair value, end of period	$ (10)	$ 19	$ (10)	$ 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/liabilities held at the end of the period	$	$ (1)	$ (2)	$ (5)

Level 1

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

Level 2 Valuation Techniques

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

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

Level 3 Valuation Techniques

We do not have significant amounts of assets or liabilities measured and reported using level 3 valuation techniques, which include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation.

Financial Instruments

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

	September 30, 2010		December 31, 2009	
	Book Value	Approximate Fair Value	Book Value	Approximate Fair Value
	(in millions)			
Long-term receivables	$ 119	$ 121	$ 116	$ 118
Long-term debt, including current maturities	10,017	11,598	9,756	10,690

The fair values of long-term debt consider the terms of the related debt absent the impacts of derivative/hedging activities. The book values of long-term debt include the impacts of certain pay floating receive fixed interest rate swaps 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 the 2010 and 2009 periods, there were no adjustments to assets and liabilities measured at fair value on a nonrecurring basis.

15. Commitments and Contingencies

Environmental

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

Like others in the energy industry, we and our affiliates are responsible for environmental remediation at various contaminated sites. These include some properties that are part of our ongoing operations, sites formerly owned or used by us, and sites owned by third parties. Remediation typically involves management of contaminated soils and may involve groundwater remediation. Managed in conjunction with relevant 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 $15 million at September 30, 2010 and $16 million as of December 31, 2009. 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. 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 arose out of the conversion of the Duke Power Company Employees Retirement Plan into the Duke Power Company Retirement Cash Balance Plan. The plaintiffs sought to represent present and former participants in the Duke Energy Retirement Cash Balance Plan. Various motions were filed by the parties, and the Court issued a series of rulings in 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 2008 asserting and re-pleading the three remaining claims which the Court allowed to proceed. In 2009, the Court issued an Order granting class certification for two of plaintiffs remaining claims and denying certification of the plaintiffs third breach of fiduciary claim. Both parties filed motions for summary judgment on April 1, 2010 with respect to the two claims that were certified for class action treatment and Duke Energy also filed a motion for summary judgment on the plaintiffs breach of fiduciary claims.

Table of Contents

A mediation between Plaintiffs and Duke Energy occurred on September 21, 2010 and an agreement was reached to resolve all claims remaining in the case. This agreement is subject to Court approval as it includes the resolution of the claims that were certified as class actions. In connection with our spin-off from Duke Energy in 2007, we agreed to share with Duke Energy any liabilities or damages associated with this matter that specifically relate to those Spectra Energy participants who are class members and who share in the described settlement. The amount applicable to us for the planned settlement is not expected to be material and therefore 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 arising in the ordinary course of business, including matters regarding contract and payment claims, some of which involve substantial monetary amounts. We have insurance coverage for certain of these losses should they be incurred. We believe that the final disposition of these proceedings will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Legal costs related to the defense of loss contingencies are expensed as incurred. We had no material reserves recorded as of September 30, 2010 or December 31, 2009 related to litigation.

Other Commitments and Contingencies

See Note 16 for a discussion of guarantees and indemnifications.

16. 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 perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events.

We have issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-wholly owned entities. In connection with our spin-off from Duke Energy, certain guarantees that were previously issued by us were assigned to, or replaced by, Duke Energy as guarantor in 2006. For any remaining guarantees of other Duke Energy obligations, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements. The maximum potential amount of future payments we could have been required to make under these performance guarantees as of September 30, 2010 was approximately $421 million, which has been indemnified by Duke Energy, as discussed above. One of our outstanding performance guarantees expires in 2028. The remaining guarantees have 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.

Table of Contents

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 unconsolidated entities and third-party entities as of September 30, 2010 was $63 million. Of these guarantees, $4 million expire in 2015 and the remaining 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, 2010, 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.

17. Risk Management and Hedging Activities

We are exposed to the impact of market fluctuations in the prices of NGLs and natural gas purchased primarily as a result of our equity investment in DCP Midstream and our 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 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 derivatives, primarily around interest rate exposures.

At September 30, 2010, we had interest rate hedges in place for various purposes. We had pay floating receive fixed interest rate swaps with a total notional principal amount of $1,494 million to hedge against changes in the fair value of our fixed-rate debt that arise as a result of changes in market interest rates. These swaps also allow us to transform a portion of the underlying cash flows related to our long-term fixed-rate debt securities into variable-rate debt in order to achieve our desired mix of fixed and variable-rate debt. We also had forward-starting pay fixed receive floating interest rate swaps with a total notional principal amount of $150 million to effectively lock in a fixed underlying interest rate in anticipation of the refinancing of a scheduled debt maturity. At Spectra Energy Partners, we had third-party pay fixed receive floating interest rate swaps with a total notional principal amount of $40 million to mitigate our exposure to variable interest rates on loans outstanding under its revolving credit facility.

Our equity investment affiliate, DCP Midstream, also has risk exposures primarily associated with market prices of NGLs and natural gas. DCP Midstream manages these risks separate from Spectra Energy, and utilizes various risk management strategies, including the use of commodity derivatives.

Other than interest rate swaps described above, we did not have any significant derivatives outstanding during the nine months ended September 30, 2010.

Table of Contents

18. 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 and non-contributory DB and defined contribution (DC) retirement plans covering substantially all employees of our Canadian operations.

Our policy is to fund our retirement plans on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants or as required by legislation or plan terms. We made discretionary contributions of $30 million to our U.S. retirement plans in the nine-month period ended September 30, 2010 and made no contributions for the same period in 2009. We do not anticipate making any further discretionary contributions to the U.S. plans during 2010. We made total contributions to the Canadian DC and qualified DB plans of $51 million during the nine months ended September 30, 2010 and $44 million during the same period in 2009. We anticipate that we will make total contributions of approximately $70 million to the Canadian plans in 2010.

Qualified Pension Plans Components of Net Periodic Pension Cost

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in millions)			
U.S.				
Service cost benefit earned	$ 2	$ 2	$ 8	$ 7
Interest cost on projected benefit obligation	6	7	19	20
Expected return on plan assets	(7)	(9)	(23)	(25)
Amortization of loss	2	2	6	4
Net periodic pension cost	$ 3	$ 2	$ 10	$ 6
Canada				
Service cost benefit earned	$ 4	$ 3	$ 12	$ 9
Interest cost on projected benefit obligation	11	10	34	28
Expected return on plan assets	(11)	(11)	(34)	(31)
Amortization of loss	5	1	13	2
Amortization of prior service costs			1	1
Net periodic pension cost	$ 9	$ 3	$ 26	$ 9

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(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	4	3
Amortization of net actuarial loss	1		1	
Net periodic pension cost	$ 2	$ 1	$ 6	$ 4

Table of Contents

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,	
	2010	2009	2010	2009
	(in millions)			
U.S.				
Service cost benefit earned	$ 1	$ 1	$ 1	$ 1
Interest cost on accumulated post-retirement benefit obligation	2	3	8	10
Expected return on plan assets	(1)	(1)	(4)	(4)
Amortization of net transition liability	1	1	3	4
Amortization of loss			1	1
Net periodic other post-retirement benefit cost	$ 3	$ 4	$ 9	$ 12
Canada				
Service cost benefit earned	$ 1	$	$ 3	$ 1
Interest cost on accumulated post-retirement benefit obligation	2	2	5	4
Amortization of past service cost	(1)		(1)	
Net periodic other post-retirement benefit cost	$ 2	$ 2	$ 7	$ 5

19. 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 Energy Capital, LLC (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 Spectra Energy Corp and Spectra Capital is presented utilizing the equity method of accounting for investments in subsidiaries, as required. The non-guarantor subsidiaries column represents all wholly owned subsidiaries of Spectra Capital. This information should be read in conjunction with our accompanying condensed consolidated financial statements and notes thereto.

Table of Contents

Spectra Energy Corp

Condensed Consolidating Statement of Operations

Three Months Ended September 30, 2010

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 1,019	$	$ 1,019
Total operating expenses	8		670		678
Operating income (loss)	(8)		349		341
Equity in earnings of unconsolidated affiliates			98		98
Equity in earnings of subsidiaries	202	319		(521)	
Other income and expenses, net		(6)	13		7
Interest expense		51	108		159
Earnings from continuing operations before income taxes	194	262	352	(521)	287
Income tax expense (benefit) from continuing operations	(3)	60	12		69
Income from continuing operations	197	202	340	(521)	218
Income from discontinued operations, net of tax			1		1
Net income	197	202	341	(521)	219
Net income noncontrolling interests			22		22
Net income controlling interests	$ 197	$ 202	$ 319	$ (521)	$ 197

Table of Contents

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

Table of Contents

Spectra Energy Corp

Condensed Consolidating Statement of Operations

Nine Months Ended September 30, 2010

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 3,562	$	$ 3,562
Total operating expenses	13	1	2,373		2,387
Operating income (loss)	(13)	(1)	1,189		1,175
Equity in earnings of unconsolidated affiliates			297		297
Equity in earnings of subsidiaries	737	1,101		(1,838)	
Other income and expenses, net		(4)	21		17
Interest expense		153	323		476
Earnings from continuing operations before income taxes	724	943	1,184	(1,838)	1,013
Income tax expense (benefit) from continuing operations	(5)	206	41		242
Income from continuing operations	729	737	1,143	(1,838)	771
Income from discontinued operations, net of tax			17		17
Net income	729	737	1,160	(1,838)	788
Net income noncontrolling interests			59		59
Net income controlling interests	$ 729	$ 737	$ 1,101	$ (1,838)	$ 729

27

Table of Contents

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

28

Table of Contents

Spectra Energy Corp

Condensed Consolidating Balance Sheet

September 30, 2010

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$	$ 3	$ 153	$	$ 156
Receivables (payables) consolidated subsidiaries	(50)	225	(175)		
Receivables (payables) other	(5)	1	703		699
Other current assets	2	35	530		567
Total current assets	(53)	264	1,211		1,422
Investments in and loans to unconsolidated affiliates		73	1,930		2,003
Investments in consolidated subsidiaries	10,189	13,419		(23,608)	
Advances receivable (payable) consolidated subsidiaries	(2,695)	3,420	(373)	(352)	
Goodwill			4,236		4,236
Other assets	37	64	382		483
Property, plant and equipment, net			16,375		16,375
Regulatory assets and deferred debits	1	14	982		997
Total Assets	$ 7,479	$ 17,254	$ 24,743	$ (23,960)	$ 25,516
Accounts payable other	$	$ 102	$ 251	$	$ 353
Short-term borrowings and commercial paper		1,192	142	(352)	982
Accrued taxes payable (receivable)	(197)	195	52		50
Current maturities of long-term debt		9	731		740
Other current liabilities	61	51	828		940
Total current liabilities	(136)	1,549	2,004	(352)	3,065
Long-term debt		3,320	5,957		9,277
Deferred credits and other liabilities	145	2,196	2,546		4,887
Preferred stock of subsidiaries			258		258
Equity					
Controlling interests	7,470	10,189	13,419	(23,608)	7,470
Noncontrolling interests			559		559
Total equity	7,470	10,189	13,978	(23,608)	8,029
Total Liabilities and Equity	$ 7,479	$ 17,254	$ 24,743	$ (23,960)	$ 25,516

Table of Contents

Spectra Energy Corp

Condensed Consolidating Balance Sheet

December 31, 2009

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$	$	$ 166	$	$ 166
Receivables (payables) consolidated subsidiaries	(28)	248	(220)		
Receivables (payables) other	(4)	2	780		778
Other current assets	6	6	473		485
Total current assets	(26)	256	1,199		1,429
Investments in and loans to unconsolidated affiliates		74	1,927		2,001
Investments in consolidated subsidiaries	9,319	12,538		(21,857)	
Advances receivable (payable) consolidated subsidiaries	(2,063)	2,440	(30)	(347)	
Goodwill			3,948		3,948
Other assets	38	30	339		407
Property, plant and equipment, net			15,347		15,347
Regulatory assets and deferred debits	1	15	931		947
Total Assets	$ 7,269	$ 15,353	$ 23,661	$ (22,204)	$ 24,079
Accounts payable (receivable) consolidated subsidiaries	$	$ 41	$ (41)	$	$
Accounts payable other	1	93	239		333
Short-term borrowings and commercial paper		388	121	(347)	162
Accrued taxes payable (receivable)	(93)	54	178		139
Current maturities of long-term debt		9	800		809
Other current liabilities	64	64	924		1,052
Total current liabilities	(28)	649	2,221	(347)	2,495
Long-term debt		3,282	5,665		8,947
Deferred credits and other liabilities	172	2,103	2,472		4,747
Preferred stock of subsidiaries			225		225
Equity					
Controlling interests	7,125	9,319	12,538	(21,857)	7,125
Noncontrolling interests			540		540
Total equity	7,125	9,319	13,078	(21,857)	7,665
Total Liabilities and Equity	$ 7,269	$ 15,353	$ 23,661	$ (22,204)	$ 24,079

30

Table of Contents

Spectra Energy Corp

Condensed Consolidating Statements of Cash Flows

Nine Months Ended September 30, 2010

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 729	$ 737	$ 1,160	$ (1,838)	$ 788
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization			493		493
Equity in earnings of unconsolidated affiliates			(297)		(297)
Equity in earnings of subsidiaries	(737)	(1,101)		1,838	
Distributions received from unconsolidated affiliates			303		303
Other	(215)	178	(243)		(280)
Net cash provided by (used in) operating activities	(223)	(186)	1,416		1,007
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(881)		(881)
Investments in and loans to unconsolidated affiliates			(6)		(6)
Acquisitions, net of cash acquired			(492)		(492)
Purchases of held-to-maturity securities			(850)		(850)
Proceeds from sales and maturities of held-to-maturity securities			809		809
Distributions received from unconsolidated affiliates			12		12
Other			(13)		(13)
Net cash used in investing activities			(1,421)		(1,421)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt			2,625		2,625
Payments for the redemption of long-term debt			(2,502)		(2,502)
Net increase in short-term borrowings and commercial paper		799	22		821
Distributions to noncontrolling interests			(54)		(54)
Dividends paid on common stock	(487)	(3)		3	(487)
Distributions and advances from (to) affiliates	709	(607)	(99)	(3)	
Other	1		2		3
Net cash provided by (used in) financing activities	223	189	(6)		406
Effect of exchange rate changes on cash			(2)		(2)
Net increase (decrease) in cash and cash equivalents		3	(13)		(10)
Cash and cash equivalents at beginning of period			166		166

Cash and cash equivalents at end of period	$		$	3	$	153	$		$	156

Table of Contents

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)
Acquisitions, net of cash acquired			(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			(43)		(43)
Net cash provided by (used in) investing activities		160	(900)		(740)
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)
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 from (to) affiliates	(38)	940	(893)	(9)	
Other	12	(2)	(5)		5
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	(79)		228
Cash and cash equivalents at beginning of period		60	145		205
Cash and cash equivalents at end of period	$	$ 367	$ 66	$	$ 433

32

20. New Accounting Pronouncements

The following new accounting pronouncement was adopted during the nine months ended September 30, 2010:

In June 2009, the Financial Accounting Standards Board issued an 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. The adoption of the provisions of this standard on January 1, 2010 did not have any impact on our consolidated results of operations, financial position or cash flows.

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.

Executive Overview

During 2010, our fee-based businesses at U.S. Transmission, Distribution and Western Canada Transmission & Processing have performed well by meeting the needs of our customers and generating increased earnings and cash flows from successful expansion projects placed in service. In addition, commodity prices have improved significantly compared to the same period in 2009 and have positively affected our earnings in the first nine months of 2010.

For the three months ended September 30, 2010 and 2009, we reported net income from controlling interests of $197 million and $191 million, respectively. For the nine months ended September 30, 2010 and 2009, we reported net income from controlling interests of $729 million and $629 million, respectively. The increases for the three and nine-month periods primarily reflect the positive impact of NGL prices on earnings from Field Services, a stronger Canadian dollar and expansion projects at U.S. Transmission and Western Canada Transmission & Processing. NGL prices are correlated to higher crude oil prices, which averaged $78 per barrel for the nine months ended September 30, 2010 versus $57 per barrel during the same period in 2009. These increases in earnings were 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.

The highlights for the three months and nine months ended September 30, 2010 include:

- U.S. Transmission s earnings benefited from expansion projects and higher processing revenues, partially offset by a reimbursement of project development costs and the capitalization of previously expensed development costs in 2009,

- Distribution s earnings increased primarily as a result of a stronger Canadian dollar, a second-quarter 2009 charge for an earnings sharing settlement related to 2008 earnings and a decrease in operating fuel costs, partially offset by lower customer usage of natural gas due to warmer weather in the first half of 2010 and higher employee benefit costs,

- Western Canada Transmission & Processing earnings increased primarily as a result of higher gathering and processing earnings from expansions and a stronger Canadian dollar, and

- Field Services earnings benefited from higher commodity prices, partially offset by a gain recognized in 2009 associated with partnership units issued by DCP Partners.

Table of Contents

In the first nine months of 2010, we had $887 million of capital and investment expenditures excluding the $492 million acquisition of the Bobcat assets and development project discussed below. Excluding the acquisition of Bobcat, we currently project approximately $1.4 billion of capital and investment expenditures for the full year, including expansion capital of approximately $0.8 billion. This represents a $200 million reduction of our original estimate of total expenditures for 2010, primarily as a result of the timing of cash capital outlays and cost savings in Western Canada Transmission & Processing and U.S. Transmission projects. There have been no significant planned project deferrals or cancellations.

As of September 30, 2010, we have access to approximately $1.5 billion available under our credit facilities and expect to continue to utilize commercial paper and revolving lines of credit, as needed, to fund liquidity needs through the remainder of 2010 and into 2011. Financing activities over the next six months will also include the refinancing of debt maturities of approximately $460 million. We may also access the capital markets for other long-term financing, as needed.

In August 2010, we acquired the Bobcat assets and development project for a cash purchase price of $540 million, of which approximately $38 million was withheld at closing as contingent purchase price consideration. We expect to invest an additional $400 million to $450 million to fully develop the facility by the end of 2015. See Note 2 of Notes to Condensed Consolidated Financial Statements for further discussion.

RESULTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in millions)			
Operating revenues	$ 1,019	$ 933	$ 3,562	$ 3,254
Operating expenses	678	581	2,387	2,170
Gains on sales of other assets and other, net		1		11
Operating income	341	353	1,175	1,095
Other income and expenses	105	72	314	302
Interest expense	159	160	476	456
Earnings from continuing operations before income taxes	287	265	1,013	941
Income tax expense from continuing operations	69	54	242	260
Income from continuing operations	218	211	771	681
Income from discontinued operations, net of tax	1	1	17	3
Net income	219	212	788	684
Net income noncontrolling interests	22	21	59	55
Net income controlling interests	$ 197	$ 191	$ 729	$ 629

Three and Nine Months Ended September 30, 2010 Compared to Same Periods in 2009

Operating Revenues. Operating revenues for the three and nine months ended September 30, 2010 increased by $86 million, or 9%, and $308 million, or 9%, respectively, compared to the same periods in 2009. The increases were driven primarily by:

the effects of a stronger Canadian dollar on revenues at Western Canada Transmission & Processing and Distribution, higher earnings from acquisitions and expansion projects and increased processing revenues due to higher prices at U.S. Transmission, and

higher gathering and processing revenues due to contracted volumes from expansions and higher NGL revenues due to higher product prices, net of lower sales volumes from the Empress operations at Western Canada Transmission & Processing, partially offset by

lower natural gas prices passed through to customers at Distribution.

Table of Contents

Operating Expenses. Operating expenses for the three and nine months ended September 30, 2010 increased by $97 million, or 17%, and $217 million, or 10%, respectively, compared to the same periods in 2009. The increases were driven primarily by:

- the effects of a stronger Canadian dollar at Western Canada Transmission & Processing and Distribution,
- a reimbursement of project development costs by customers and the capitalization of previously expensed costs on northeast expansions in 2009 and higher operating costs at U.S. Transmission in 2010, and
- higher facilities maintenance costs related to scheduled processing plant turnarounds at Western Canada Transmission & Processing, partially offset by
- lower natural gas prices passed through to customers at Distribution.

Gains on Sales of Other Assets and Other, Net. Gains on sales of other assets and other, net for the nine months ended September 30, 2010 decreased $11 million compared to the same period in 2009. The decrease was due to a 2009 customer settlement resulting from the cancellation of a capital project.

Operating Income. Operating income for the three and nine months ended September 30, 2010 decreased by $12 million, or 3%, and increased $80 million, or 7%, respectively, compared to the same periods in 2009. The decrease for the three months is primarily due to the capitalization of previously expensed costs in 2009 at U.S. Transmission, partially offset by earnings from expansion projects at U.S. Transmission and Western Canada Transmission & Processing, and a stronger Canadian dollar. The increase for the nine months was primarily driven by a stronger Canadian dollar and expansion projects at U.S. Transmission and Western Canada Transmission & Processing, partially offset by a reimbursement of project development costs by customers and the capitalization of previously expensed costs in 2009 at U.S. Transmission, a decrease in customer usage of natural gas due to warmer weather at Distribution and higher facilities maintenance costs at Western Canada Transmission & Processing.

Other Income and Expenses. Other income and expenses for the three and nine months ended September 30, 2010 increased by $33 million, or 46%, and $12 million, or 4%, respectively, compared to the same periods in 2009. The increases were attributable to higher equity earnings from Field Services primarily due to increased commodity prices, substantially offset by a $135 million gain recognized in 2009 associated with partnership units previously issued by DCP Partners.

Interest Expense. Interest expense for the three and nine months ended September 30, 2010 decreased by $1 million, or 1%, and increased by $20 million, or 4%, respectively, compared to the same periods in 2009. The increase for the nine months was primarily due to a stronger Canadian dollar.

Income Tax Expense from Continuing Operations. Income tax expense from continuing operations for the three and nine months ended September 30, 2010 increased by $15 million and decreased by $18 million, respectively, compared to the same periods in 2009. The increase for the three months is primarily due to higher earnings from continuing operations and a higher effective tax rate. The decrease for the nine months is due to favorable tax settlements, partially offset by higher earnings.

For the three months ended September 30, 2010, the effective tax rate was 24.0% compared to 20.4% for the same period in 2009. The higher effective tax rate in third quarter 2010 is primarily the result of a higher proportion of earnings from U.S. sources that are taxed at higher rates. The effective tax rate for the nine months ended September 30, 2010 was 23.9% compared to 27.6% in the same period in 2009. The lower effective tax rate in 2010 was primarily due to favorable tax settlements, including most notably an administrative change by the Canadian federal government that resulted in $24 million of cash tax refunds.

Income from Discontinued Operations, Net of Tax. The $14 million increase for the nine months ended September 30, 2010 was due to an income tax adjustment related to previously discontinued 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 less noncontrolling interests related to those earnings. On a segment basis, EBIT represents earnings from continuing operations (both operating and non-operating) before interest and taxes, net of noncontrolling interests related to those earnings. Cash, cash equivalents and investments are managed centrally, so the gains and losses on foreign currency remeasurement, and interest and dividend income on those balances, are excluded from the segments EBIT. We consider segment EBIT to be a good indicator of each segment s operating performance from its continuing operations, as it represents the results of our ownership interest in operations without regard to financing methods or capital structures.

Our segment EBIT may not be comparable to similarly titled measures of other companies because other companies 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,	
	2010	2009	2010	2009
	(in millions)			
U.S. Transmission	$ 231	$ 239	$ 701	$ 690
Distribution	63	48	282	240
Western Canada Transmission & Processing	90	84	278	223
Field Services	70	45	227	219
Total reportable segment EBIT	454	416	1,488	1,372
Other	(23)	(10)	(53)	(46)
Total reportable segment and other EBIT	431	406	1,435	1,326
Interest expense	159	160	476	456
Interest income and other (a)	15	19	54	71
Earnings from continuing operations before income taxes.	$ 287	$ 265	$ 1,013	$ 941

(a) Includes foreign currency transaction gains and losses and the add-back of the noncontrolling interests related to segment EBIT.

Noncontrolling interests as presented in the following segment-level discussions includes only noncontrolling interests related to EBIT of non-wholly owned subsidiaries. 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.

Table of Contents

U.S. Transmission

	Three Months Ended September 30, 2010	2009	Increase (Decrease)	Nine Months Ended September 30, 2010	2009	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$ 442	$ 427	$ 15	$ 1,341	$ 1,246	$ 95
Operating expenses						
Operating, maintenance and other	165	126	39	482	390	92
Depreciation and amortization	64	61	3	192	182	10
Gains on sales of other assets and other, net	1	1		1	11	(10)
Operating income	214	241	(27)	668	685	(17)
Other income and expenses	38	19	19	93	60	33
Noncontrolling interests	21	21		60	55	5
EBIT	$ 231	$ 239	$ (8)	$ 701	$ 690	$ 11
Proportional throughput, TBtu (a)	624	607	17	2,009	1,894	115

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

Three Months Ended September 30, 2010 Compared to Same Period in 2009

Operating Revenues. The $15 million increase was driven primarily by:

- an $8 million increase from acquisitions and expansion projects, and
- a $6 million increase from recoveries of electric power and other costs passed through to customers.

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

- a $21 million increase due to the capitalization of project development expenses on northeast expansions in 2009,
- a $10 million increase from benefits, ongoing pipeline integrity costs, equipment repairs and software costs, and
- a $7 million increase from higher electric power and other costs passed through to customers.

Other Income and Expenses. The $19 million increase was primarily a result of an $11 million charge in 2009 due to the discontinuance of rate regulated accounting treatment by Southeast Supply Header, LLC (SESH) and a $7 million increase due to higher allowance for funds used during construction-equity (AFUDC-equity) in 2010 as a result of increased capital spending.

EBIT. The $8 million decrease was primarily due to capitalization of project development costs in 2009 and higher operating costs in 2010, partially offset by the discontinuance of rate regulated accounting treatment by SESH in 2009, higher AFUDC-equity and earnings from expansion projects in 2010.

Nine Months Ended September 30, 2010 Compared to Same Period in 2009

Operating Revenues. The $95 million increase was driven primarily by:

- a $54 million increase from acquisitions and expansion projects,
- an $18 million increase in processing revenues associated with pipeline operations resulting from higher prices,

37

Table of Contents

- a $13 million increase from recoveries of electric power and other costs passed through to customers, and
- an $11 million increase resulting from a stronger Canadian dollar at M&N LP.

Operating, Maintenance and Other. The $92 million increase was driven primarily by:

- a $34 million increase in project development costs, primarily resulting from the 2009 reimbursement of project development costs by customers and the capitalization of previously expensed costs on northeast expansions,
- a $22 million increase from higher electric power and other costs passed through to customers,
- a $20 million increase from benefits, ongoing pipeline integrity costs, equipment repairs, software costs and ad valorem taxes, and
- a $15 million increase from acquisitions and expansion projects.

Depreciation and Amortization. The $10 million increase was primarily driven by expansion projects placed in service in 2009 and a stronger Canadian dollar at M&N LP.

Gains on Sales of Other Assets and Other, Net. The $10 million in 2009 represents a customer settlement resulting from the cancellation of a capital project.

Other Income and Expenses. The $33 million increase was primarily a result of a $10 million increase in earnings from expansion projects on Gulfstream Natural Gas System, L.L.C (Gulfstream) and Steckman Ridge, LP that were placed in service in 2009, an $11 million charge in 2009 due to the discontinuance of rate regulated accounting treatment by SESH and a $12 million increase due to higher AFUDC-equity in 2010.

EBIT. The $11 million increase was primarily due to higher earnings from expansion projects and higher processing revenues, partially offset by a reimbursement of project development costs by customers and the capitalization of previously expensed costs in 2009 and higher operating costs.

Distribution

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	**2009**	**Increase (Decrease)**	**2010**	**2009**	**Increase (Decrease)**
	(in millions, except where noted)					
Operating revenues	$ 261	$ 244	$ 17	$ 1,260	$ 1,236	$ 24
Operating expenses						
Natural gas purchased	54	62	(8)	535	617	(82)
Operating, maintenance and other	96	89	7	298	252	46
Depreciation and amortization	48	44	4	145	126	19
Operating income	63	49	14	282	241	41
Other income and expenses		(1)	1		(1)	1
EBIT	$ 63	$ 48	$ 15	$ 282	$ 240	$ 42

Number of customers, thousands				1,334	1,315	19
Heating degree days, Fahrenheit	285	348	(63)	4,288	4,964	(676)
Pipeline throughput, TBtu	180	133	47	665	589	76
Canadian dollar exchange rate, average	1.04	1.10	(0.06)	1.04	1.17	(0.13)

Table of Contents

Three Months Ended September 30, 2010 Compared to Same Period in 2009

Operating Revenues. The $17 million increase was driven primarily by:

- a $13 million increase resulting from a stronger Canadian dollar, and
- a $4 million increase resulting from higher customer usage of natural gas partially due to increased utilization by industrial customers and growth in numbers of residential customers being served, partially offset by
- a $4 million decrease from lower natural gas prices passed through to customers. Prices charged to customers are based on the 12 month New York Mercantile Exchange (NYMEX) forecast.

Natural Gas Purchased. The $8 million decrease was driven primarily by:

- a $6 million decrease in operating fuel costs, and
- a $4 million decrease from lower natural gas prices passed through to customers, partially offset by
- a $3 million increase resulting from a stronger Canadian dollar.

Operating, Maintenance and Other. The $7 million increase was driven primarily by a stronger Canadian dollar.

Depreciation and Amortization. The $4 million increase was driven primarily by a stronger Canadian dollar.

EBIT. The $15 million increase was primarily a result of increased utilization by industrial customers, growth in number of residential customers being served, a decrease in operating fuel costs and a stronger Canadian dollar.

Nine Months Ended September 30, 2010 Compared to Same Period in 2009

Operating Revenues. The $24 million increase was driven primarily by:

- a $162 million increase resulting from a stronger Canadian dollar, and
- an $11 million increase due to a 2009 charge for a settlement on 2008 earnings to be shared with customers, partially offset by
- a $119 million decrease from lower natural gas prices passed through to customers. Prices charged to customers are based on the 12 month NYMEX forecast.

a $38 million decrease in customer usage of natural gas due to weather that was more than 14% warmer than the same period in the prior year.

Natural Gas Purchased. The $82 million decrease was driven primarily by:

a $119 million decrease from lower natural gas prices passed through to customers,

a $24 million decrease due to lower volumes of natural gas sold as a result of weather that was more than 14% warmer than the same period in the prior year, and

a $14 million decrease in operating fuel costs, partially offset by

a $77 million increase resulting from a stronger Canadian dollar.

Operating, Maintenance and Other. The $46 million increase was driven primarily by:

a $33 million increase resulting from a stronger Canadian dollar, and

a $12 million increase related to higher employee benefits costs primarily associated with higher trending amortization of pension plan market value losses that have occurred in recent years.

Depreciation and Amortization. The $19 million increase was driven primarily by a stronger Canadian dollar.

EBIT. The $42 million increase was primarily a result of a stronger Canadian dollar, a 2009 settlement on 2008 earnings sharing and a decrease in operating fuel costs, partially offset by a decrease in customer usage of natural gas due to warmer weather in 2010 and higher employee benefits costs.

Matters Affecting Future Distribution Results

In December 2009, the OEB issued its policy report on the Cost of Capital for Ontario s Regulated Utilities. In that report, the OEB determined that Utility Return on Equity should be increased by approximately 125 basis points. In May 2010, the OEB clarified that it would only apply the conclusions from its policy report during cost-of-service applications. Accordingly, as Union Gas is currently under a five-year incentive regulation framework that began in 2008, it will incorporate the increase in its cost-of-service application for 2013 rates. That application is expected to be made by the end of 2011.

Western Canada Transmission & Processing

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Increase (Decrease)	2010	2009	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$ 315	$ 260	$ 55	$ 959	$ 770	$ 189
Operating expenses						
Natural gas and petroleum products purchased	62	38	24	189	143	46
Operating, maintenance and other	119	103	16	369	299	70
Depreciation and amortization	46	38	8	124	105	19
Loss on sales of other assets and other, net	(1)		(1)	(1)		(1)
Operating income	87	81	6	276	223	53
Other income and expenses	3	3		2		2
EBIT	$ 90	$ 84	$ 6	$ 278	$ 223	$ 55
Pipeline throughput, TBtu	151	148	3	451	446	5
Volumes processed, TBtu	164	163	1	490	494	(4)
Empress inlet volumes, TBtu	163	169	(6)	441	578	(137)
Canadian dollar exchange rate, average	1.04	1.10	(0.06)	1.04	1.17	(0.13)

Three Months Ended September 30, 2010 Compared to Same Period in 2009

Operating Revenues. The $55 million increase was driven primarily by:

- a $19 million increase due to higher NGL product prices associated with the Empress operations,
- a $17 million increase as a result of a stronger Canadian dollar, and
- a $10 million increase resulting primarily from $15 million of higher gathering and processing revenues due to contracted volumes from expansions in non-conventional supply areas, including Fort Nelson, South Peace Pipeline and West Doe, partially offset by a $5 million decline in conventional supply areas.

Natural Gas and Petroleum Products Purchased. The $24 million increase was driven primarily by:

- a $20 million increase as a result of higher prices of natural gas purchased for the Empress facility caused primarily by higher extraction premiums, and
- a $3 million increase caused by a stronger Canadian dollar.

Operating, Maintenance and Other. The $16 million increase was driven primarily by:

- a $10 million increase relating mainly to scheduled plant turnarounds, and
- a $6 million increase caused by a stronger Canadian dollar.

Table of Contents

Depreciation and Amortization. The $8 million increase was driven primarily by expansion projects placed in service and maintenance capital incurred in 2009 and 2010, and a stronger Canadian dollar.

EBIT. The $6 million increase was driven primarily by higher gathering and processing earnings from expansions and a stronger Canadian dollar.

Nine Months Ended September 30, 2010 Compared to Same Period in 2009

Operating Revenues. The $189 million increase was driven primarily by:

- a $109 million increase as a result of a stronger Canadian dollar,
- a $61 million increase due to higher NGL product prices associated with the Empress operations, and
- a $33 million increase resulting primarily from higher gathering and processing revenues due to contracted volumes from expansions in non-conventional supply areas, including Fort Nelson, South Peace Pipeline and West Doe, and
- a $6 million increase from recovery of carbon and other non-income tax expense from customers, partially offset by
- a $29 million decrease due to lower NGL sales volumes, including lower volumes associated with an approximate 25-day scheduled processing plant turnaround in the second quarter of 2010 at the Empress operations.

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

- a $41 million increase as a result of higher prices of natural gas purchased for the Empress facility caused primarily by higher extraction premiums, and
- a $22 million increase caused by a stronger Canadian dollar, partially offset by
- an $18 million decrease due primarily to lower production volumes at the Empress operations, including lower volumes associated with the scheduled plant turnaround in the second quarter of 2010.

Operating, Maintenance and Other. The $70 million increase was driven primarily by:

- a $40 million increase caused by a stronger Canadian dollar, and
- a $15 million increase relating to scheduled processing plant turnarounds at various locations including Empress and Grizzly Valley, and

a $6 million increase in carbon and other non-income tax expense.

Depreciation and Amortization. The $19 million increase was driven primarily by a stronger Canadian dollar, and expansion projects placed in service and maintenance capital incurred in 2009 and 2010.

EBIT. The $55 million increase was driven primarily by a stronger Canadian dollar and higher gathering and processing earnings from expansions.

Field Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	Increase (Decrease)	2010	2009	Increase (Decrease)
	(in millions, except where noted)					
Equity in earnings of unconsolidated affiliates	$ 70	$ 45	$ 25	$ 227	$ 219	$ 8
EBIT	$ 70	$ 45	$ 25	$ 227	$ 219	$ 8
Natural gas gathered and processed/transported, TBtu/d (a,b)	7.1	7.0	0.1	6.9	7.0	(0.1)
NGL production, MBbl/d (a,c)	378	371	7	364	354	10
Average natural gas price per MMBtu (d)	$ 4.38	$ 3.39	$ 0.99	$ 4.59	$ 3.93	$ 0.66
Average NGL price per gallon (e)	$ 0.87	$ 0.69	$ 0.18	$ 0.96	$ 0.63	$ 0.33
Average crude oil price per barrel (f)	$ 76.20	$ 68.30	$ 7.90	$ 77.65	$ 57.00	$ 20.65

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

Three Months Ended September 30, 2010 Compared to Same Period in 2009

EBIT. Higher equity earnings of $25 million were primarily the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

- a $34 million increase from commodity-sensitive processing arrangements due to increased commodity prices, and
- an $11 million increase as a result of a gain associated with the August 2010 issuance of partnership units by DCP Partners, partially offset by
- an $11 million decrease in gathering and processing margins due to lower volumes and efficiencies,
- a $5 million decrease primarily attributable to increased repairs and maintenance costs, and increased benefits costs, and
- a $4 million decrease in earnings from DCP Partners primarily as a result of mark-to-market losses on derivative instruments used to protect distributable cash flows.

Nine Months Ended September 30, 2010 Compared to Same Period in 2009

EBIT. Higher equity earnings of $8 million were primarily the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

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

an $11 million increase in earnings from DCP Partners primarily as a result of mark-to-market gains on derivative instruments used to protect distributable cash flows, partially offset by

a $115 million decrease as a result of a gain of $135 million in 2009 associated with the issuance of partnership units by DCP Partners compared to a gain of $20 million in 2010,

a $19 million decrease in gathering and processing margins due to lower volumes and efficiencies, primarily attributable to the impact of severe weather, curtailments and third party outages in 2010 that affected operations, a $15 million decrease due to lower results from NGL trading and gas marketing,

a $15 million decrease primarily attributable to increased repairs and maintenance costs, the impact of hurricane insurance recoveries in 2009 and increased benefits costs, and

a $10 million decrease due to higher income tax expense primarily reflecting the de-recognition of certain deferred tax assets.

Matters Affecting Future Field Services Results

Overall, drilling and rig counts continue to improve from the drilling levels experienced in 2009, but still remain below peak levels seen in 2008. The drilling levels vary by geographic area, but in general drilling remains robust in areas with a high content of liquids in the gas stream. In other areas, drilling continues to remain relatively modest. Both throughput volumes and NGL production are higher in the third quarter of 2010 as compared to the third quarter of 2009 due to the drilling occurring in the liquids rich areas. Gas prices currently remain modest due to the increased supply, high inventory, reduced demand and the downturn in the economy. Under DCP Midstream s contract structures, which are predominantly percent-of-proceeds contracts, DCP Midstream receives payments in-kind in the form of commodities and, as a result, typically has a long natural gas position. As such, a decrease in natural gas prices can negatively impact DCP Midstream s margin. However, any decline would be partially offset by its keep-whole contracts where gross margin is directly related to the price of NGLs and inversely related to the price of natural gas. DCP Midstream s long-term view is that as economic conditions improve, natural gas prices will return to levels that will support sustainable levels of natural gas-related drilling.

Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	**2009**	**Increase (Decrease)**	**2010**	**2009**	**Increase (Decrease)**
			(in millions)			
Operating revenues	$ 15	$ 12	$ 3	$ 42	$ 36	$ 6
Operating expenses	39	30	9	93	90	3
Operating loss	(24)	(18)	(6)	(51)	(54)	3
Other income and expenses	1	8	(7)	(2)	8	(10)
EBIT	$ (23)	$ (10)	$ (13)	$ (53)	$ (46)	$ (7)

Three Months Ended September 30, 2010 Compared to Same Period in 2009

EBIT. The $13 million decrease in EBIT reflects higher corporate costs primarily due to timing and an expense of $7 million in the 2010 period for resolution of a corporate legal matter, partially offset by lower captive insurance losses in 2010.

Nine Months Ended September 30, 2010 Compared to Same Period in 2009

EBIT. The $7 million decrease in EBIT reflects higher corporate costs primarily due to an expense of $7 million in the 2010 period for resolution of a corporate legal matter, partially offset by lower captive insurance losses in 2010.

Goodwill Impairment Test

We completed our annual goodwill impairment test as of April 1, 2010 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

43

Table of Contents

future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in key markets served by our operations, regulatory stability, the ability to renew contracts, commodity prices (where appropriate), and foreign currency exchange rates, as well as other factors that affect our revenue, expense and capital expenditure projections.

The long-term 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 increasing demand for natural gas transportation capacity on our pipeline systems. We assumed a weighted average long-term growth rate of 3.7% for our 2010 goodwill impairment analysis. Had we assumed a 100 basis point lower growth rate for each of our reporting units, there would have been 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. In evaluating our reporting units for our 2010 goodwill impairment analysis, we assumed weighted-average costs of capital ranging from 7.1% to 9.4% that market participants would use. Had we assumed a 100 basis point increase in the weighted-average cost of capital for each of our reporting units, there would have been no impairment of goodwill. For our regulated businesses in Canada, if an increase in the cost of capital occurred, we assume that the effect on the corresponding reporting unit s fair value would be ultimately offset by a similar increase in the reporting unit s regulated revenues since those rates include a component that is based on the reporting unit s cost of capital.

LIQUIDITY AND CAPITAL RESOURCES

We will rely primarily upon cash flows from operations and various financing transactions to fund our liquidity and capital requirements for the next 12 months, which may include issuances of commercial paper and long-term debt. At Union Gas, we primarily use commercial paper to support our short-term working capital fluctuations. At Spectra Capital and Westcoast, we primarily use commercial paper for temporary funding of our capital expenditures. We also utilize commercial paper, other variable-rate debt and interest rate swaps to achieve our desired mix of fixed and variable-rate debt. See Note 13 of Notes to Condensed Consolidated Financial Statements and Financing Cash Flows and Liquidity for discussions of available credit facilities and effective shelf registrations. Net working capital was negative $1,643 million as of September 30, 2010, which included short-term borrowings and commercial paper totaling $982 million and current maturities of long-term debt of $740 million.

Operating Cash Flows

Net cash provided by operating activities decreased $260 million to $1,007 million for the nine months ended September 30, 2010 compared to the same period in 2009, driven mainly by lower tax payments in 2009, primarily the result of the U.S. Economic Stimulus Plan which deferred significant amounts of tax payments to future periods, and refunds to customers in 2010 of Union Gas gas purchase costs that were collected in 2009. These were partially offset by increased distributions from DCP Midstream.

Investing Cash Flows

Cash flows used in investing activities increased $681 million to $1,421 million in the first nine months of 2010 compared to the same period in 2009. This change was driven primarily by:

- a $119 million increase in capital and investment expenditures in 2010,
- a $492 million cash outlay in 2010 for the acquisition of Bobcat,
- a $186 million receipt from Southeast Supply Header, LLC in 2009 to repay our loan to them, and
- a $148 million distribution from Gulfstream in the second quarter of 2009 from the proceeds of a Gulfstream debt issuance, partially offset by

the $295 million acquisition of Ozark in 2009.

	Nine Months Ended September 30, 2010	2009
	(in millions)	
Capital and Investment Expenditures (a)		
U.S. Transmission	$ 478	$ 340
Distribution	126	171
Western Canada Transmission & Processing	260	236
Other	23	21
Total	$ 887	$ 768

(a) Excludes the acquisitions of Bobcat in 2010 and Ozark in 2009.

Capital and investment expenditures for the nine months ended September 30, 2010 consisted of $493 million for expansion projects and $394 million for maintenance and other projects.

On August 30, 2010, we acquired the Bobcat assets and development project for a cash purchase price of $540 million, of which approximately $38 million was withheld at closing pending certain outcomes. We expect to invest an additional $400 million to $450 million to fully develop the facility by the end of 2015. The acquisition, primarily funded through the issuance of commercial paper, supports our stated plan of approximately $1 billion per year in expansion capital spending through at least 2014. See Note 2 of Notes to Condensed Consolidated Financial Statements for further discussion of the acquisition of Bobcat.

	Bobcat Acquisition (in millions)
Cash purchase price	$ 540
Working capital and other purchase adjustments	7
Total	547
Withheld at closing	(38)
Cash acquired	(17)
Net cash outlay for acquisition	$ 492

Excluding the acquisition of Bobcat discussed above, we project 2010 capital and investment expenditures of approximately $1.4 billion, consisting of approximately $0.7 billion for U.S. Transmission, $0.2 billion for Distribution and $0.5 billion for Western Canada Transmission & Processing. This represents a $200 million reduction of our original estimate of total expenditures for 2010. The reduction is primarily a result of the timing of cash capital outlays and cost savings in Western Canada Transmission & Processing and U.S. Transmission projects. There have been no significant planned project deferrals or cancellations. Total projected 2010 capital and investment expenditures include approximately $0.8 billion of expansion capital expenditures and $0.6 billion for maintenance and upgrades of existing plants, pipelines and infrastructure to serve growth. We continue to assess short and long-term market requirements and will adjust our capital plans as required.

Financing Cash Flows and Liquidity

Net cash provided by financing activities totaled $406 million in the first nine months of 2010 compared to $289 million used in financing activities in the first nine months of 2009. This change was driven primarily by:

an $821 million net increase in short-term borrowings in 2010, which includes funds used for the acquisition of Bobcat, compared to an $892 million net decrease in 2009 as a result of the planned reduction in commercial paper outstanding during 2009 to preserve liquidity during that period of economic downturn and instability, and

$99 million of higher distributions to noncontrolling interests in 2009, mostly from proceeds of a debt issuance at M&N LLC, partially offset by

$566 million of net issuances of long-term debt in 2009, primarily as a result of the pre-funding of an October 2009 debt maturity, compared to $123 million of net issuances in 2010,

proceeds of $448 million in 2009 from the issuance of Spectra Energy common stock, and

proceeds of $208 million in 2009 from the issuance of Spectra Energy Partners common units in connection with the acquisition of Ozark.

Available Credit Facilities and Restrictive Debt Covenants. See Note 13 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, 2010, this ratio was approximately 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.

Credit Ratings

	Standard and Poor s	Moody s Investor Service	Fitch Ratings	DBRS
As of October 29, 2010				
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/A3	n/a	A

(a) Represents senior unsecured credit rating.

(b) Represents senior secured credit rating. The A2 rating applies to M&N LP s 6.9% notes due 2019 and the A3 rating applies to its 4.34% notes due 2019.

n/a Indicates not applicable.

The above credit ratings are dependent upon, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures, our results of operations, market conditions and other factors. Our credit ratings could impact our ability to raise capital in the future, impact the cost of our capital and, as a result, have an impact on our liquidity.

Dividends. We currently anticipate an average dividend payout ratio over time of approximately 60-65% of estimated annual net income from controlling interests per share of common stock. The actual payout ratio, however, may vary from year to year depending on earnings levels. We expect to continue our policy of paying regular cash dividends. The declaration and payment of dividends are subject to the sole discretion of our Board of Directors and will depend upon many factors, including the financial condition, earnings and capital requirements of our operating subsidiaries, covenants associated with certain debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by our Board of Directors. A dividend of $0.25 per common share was declared on October 19, 2010 and will be paid on December 13, 2010.

46

Other Financing Matters. On July 2, 2010, Westcoast issued 250 million Canadian dollars (approximately $235 million) aggregate principal amount of its 4.57% Medium Term Notes due 2020. Net proceeds from the offering were used for general corporate purposes, including refinancing of current maturities of debt and funding of expansion projects.

On July 23, 2010 Union Gas issued 250 million Canadian dollars (approximately $241 million) of 5.20% notes due 2040. Net proceeds from the offering were used for general corporate purposes, including refinancing of current maturities of debt.

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. 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 aggregate. In addition, as of September 30, 2010, certain of our subsidiaries in Canada have 2.0 billion Canadian dollars (approximately $1.9 billion) available for issuance in the Canadian market under debt shelf prospectuses that expire in October 2012.

OTHER ISSUES

New Accounting Pronouncements

See Note 20 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, 2009. We believe the exposure to market risk has not changed materially.

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, 2010, 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, 2010 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Table of Contents

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

For information regarding material legal proceedings, including regulatory and environmental matters, see Notes 4 and 15 of Notes to Condensed Consolidated Financial Statements, which information is incorporated by reference into this Part II.

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, 2009, which could materially affect our financial condition or future results. There have been no material changes to those risk factors.

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:

- were not intended to 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;
- may have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement;
- may apply contract standards of materiality that are different from materiality under the applicable securities laws; 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.

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.

(a) Exhibits

Exhibit Number	
*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.

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 8, 2010

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

Date: November 8, 2010

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