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, 2012

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 September 30, 2012: 653,019,303

Table of Contents

SPECTRA ENERGY CORP

FORM 10-Q FOR THE QUARTER ENDED

September 30, 2012

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;

the development of alternative energy resources;

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

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

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

growth in opportunities, including the timing and success of efforts to develop U.S. and Canadian pipeline, storage, gathering, processing and other related 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 these 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,		Nine Months Ended September 30,	
	2012	**2011**	**2012**	**2011**
Operating Revenues				
Transportation, storage and processing of natural gas	$ 791	$ 778	$ 2,406	$ 2,342
Distribution of natural gas	180	193	925	1,086
Sales of natural gas liquids	74	114	279	384
Other	27	38	118	111
Total operating revenues	1,072	1,123	3,728	3,923
Operating Expenses				
Natural gas and petroleum products purchased	125	130	704	795
Operating, maintenance and other	348	373	1,003	1,034
Depreciation and amortization	188	182	557	534
Property and other taxes	83	80	252	247
Total operating expenses	744	765	2,516	2,610
Gains on Sales of Other Assets and Other, net		3	2	7
Operating Income	328	361	1,214	1,320
Other Income and Expenses				
Equity in earnings of unconsolidated affiliates	88	160	297	428
Other income and expenses, net	19	18	53	42
Total other income and expenses	107	178	350	470
Interest Expense	159	157	471	471
Earnings From Continuing Operations Before Income Taxes	276	382	1,093	1,319
Income Tax Expense From Continuing Operations	72	108	289	372
Income From Continuing Operations	204	274	804	947
Income From Discontinued Operations, net of tax		7	2	23
Net Income	204	281	806	970
Net Income Noncontrolling Interests	25	27	79	75

Net Income Controlling Interests	$	179	$	254	$	727	$	895
Common Stock Data								
Weighted-average shares outstanding								
Basic		653		650		653		650
Diluted		655		652		655		652
Earnings per share from continuing operations								
Basic and Diluted	$	0.27	$	0.38	$	1.11	$	1.34
Earnings per share								
Basic	$	0.27	$	0.39	$	1.11	$	1.38
Diluted	$	0.27	$	0.39	$	1.11	$	1.37
Dividends per share	$	0.28	$	0.26	$	0.84	$	0.78

See Notes to Condensed Consolidated Financial Statements.

Table of Contents

SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

(In millions)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Net Income	$ 204	$ 281	$ 806	$ 970
Other comprehensive income				
Foreign currency translation adjustments	252	(614)	281	(366)
Unrealized mark-to-market net gain on hedges	2	1	5	1
Reclassification of cash flow hedges into earnings	3	2	7	7
Pension and benefits impact	8	8	31	23
Other				8
Total other comprehensive income (loss)	265	(603)	324	(327)
Total Comprehensive Income (Loss), net of tax	469	(322)	1,130	643
Less: Comprehensive Income Noncontrolling Interests	29	17	83	69
Comprehensive Income (Loss) Controlling Interests	$ 440	$ (339)	$ 1,047	$ 574

See Notes to Condensed Consolidated Financial Statements.

Table of Contents

SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)

	September 30, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and cash equivalents	$ 146	$ 174
Receivables, net	775	962
Inventory	404	393
Other	296	235
Total current assets	1,621	1,764
Investments and Other Assets		
Investments in and loans to unconsolidated affiliates	2,118	2,064
Goodwill	4,541	4,420
Other	468	530
Total investments and other assets	7,127	7,014
Property, Plant and Equipment		
Cost	25,875	23,932
Less accumulated depreciation and amortization	6,268	5,674
Net property, plant and equipment	19,607	18,258
Regulatory Assets and Deferred Debits	1,227	1,102
Total Assets	$ 29,582	$ 28,138

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, 2012	December 31, 2011
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 451	$ 498
Commercial paper	1,317	1,052
Taxes accrued	52	82
Interest accrued	168	178
Current maturities of long-term debt	1,281	525
Other	754	766
Total current liabilities	4,023	3,101
Long-term Debt	9,892	10,146
Deferred Credits and Other Liabilities		
Deferred income taxes	4,252	3,940
Regulatory and other	1,739	1,797
Total deferred credits and other liabilities	5,991	5,737
Commitments and Contingencies		
Preferred Stock of Subsidiaries	258	258
Equity		
Preferred stock, $0.001 par, 22 million shares authorized, no shares outstanding		
Common stock, $0.001 par, 1 billion shares authorized, 653 million and 651 million shares outstanding at September 30, 2012 and December 31, 2011, respectively	1	1
Additional paid-in capital	4,844	4,814
Retained earnings	2,152	1,977
Accumulated other comprehensive income	1,593	1,273
Total controlling interests	8,590	8,065
Noncontrolling interests	828	831
Total equity	9,418	8,896
Total Liabilities and Equity	$ 29,582	$ 28,138

See Notes to Condensed Consolidated Financial Statements.

7

Table of Contents

SPECTRA ENERGY CORP

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)

	Nine Months Ended September 30, 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 806	$ 970
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	566	543
Deferred income tax expense	174	240
Equity in earnings of unconsolidated affiliates	(297)	(428)
Distributions received from unconsolidated affiliates	252	351
Other	(47)	11
Net cash provided by operating activities	1,454	1,687
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(1,418)	(1,299)
Investments in and loans to unconsolidated affiliates		(6)
Acquisitions, net of cash acquired	(30)	(390)
Purchases of held-to-maturity securities	(2,276)	(1,199)
Proceeds from sales and maturities of held-to-maturity securities	2,173	1,206
Purchases of available-for-sale securities	(15)	(938)
Proceeds from sales and maturities of available-for-sale securities	21	1,128
Distributions received from unconsolidated affiliates	11	6
Other changes in restricted funds	77	(57)
Other	7	3
Net cash used in investing activities	(1,450)	(1,546)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from the issuance of long-term debt	350	806
Payments for the redemption of long-term debt	(28)	(494)
Net increase in commercial paper	256	147
Net decrease in revolving credit facilities borrowings		(289)
Distributions to noncontrolling interests	(86)	(74)
Proceeds from the issuance of Spectra Energy Partners, LP common units		213
Dividends paid on common stock	(555)	(511)
Other	28	14
Net cash used in financing activities	(35)	(188)
Effect of exchange rate changes on cash	3	(9)
Net decrease in cash and cash equivalents	(28)	(56)
Cash and cash equivalents at beginning of period	174	130

Cash and cash equivalents at end of period	$ 146	$ 74
Supplemental Disclosures		
Property, plant and equipment non-cash accruals	$ 192	$ 176

See Notes to Condensed Consolidated Financial Statements.

Table of Contents

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, 2011	$ 1	$ 4,814	$ 1,977	$ 1,832	$ (559)	$ 831	$ 8,896
Net income			727			79	806
Other comprehensive income				277	43	4	324
Dividends on common stock			(552)				(552)
Stock-based compensation		17					17
Distributions to noncontrolling interests						(86)	(86)
Spectra Energy common stock issued		13					13
September 30, 2012	$ 1	$ 4,844	$ 2,152	$ 2,109	$ (516)	$ 828	$ 9,418
December 31, 2010	$ 1	$ 4,726	$ 1,487	$ 2,010	$ (415)	$ 678	$ 8,487
Net income			895			75	970
Other comprehensive income (loss)				(360)	39	(6)	(327)
Dividends on common stock			(511)				(511)
Stock-based compensation		29					29
Distributions to noncontrolling interests						(74)	(74)
Spectra Energy Partners, LP common units issued		38				154	192
September 30, 2011	$ 1	$ 4,793	$ 1,871	$ 1,650	$ (376)	$ 827	$ 8,766

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 and the accounts of our majority-owned subsidiaries, after eliminating intercompany transactions and balances. 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, 2011, and reflect all normal recurring adjustments that are, in our opinion, necessary to fairly present our results of operations and financial position. Amounts reported in the Condensed Consolidated Statements of Operations are not necessarily indicative of amounts expected for the respective annual periods due to the effects of seasonal temperature variations on energy consumption, primarily in our gas distribution operations, as well as changing commodity prices on certain of our processing operations and other factors.

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

2. 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, 100%-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 of segments within our reportable business segments.

U.S. Transmission provides transportation and storage of natural gas for customers in various regions of the northeastern and southeastern United States and the Maritime Provinces in Canada. The natural gas transmission and storage operations in the U.S. are primarily subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC). Spectra Energy Partners, LP (Spectra Energy Partners), a master limited partnership, is part of the U.S. Transmission segment.

Table of Contents

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 mostly 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, processes, treats, compresses, transports and stores natural gas. In addition, this segment also fractionates, transports, gathers, treats, processes, stores, markets and trades NGLs. It conducts operations through DCP Midstream, which is owned 50% by us and 50% by Phillips 66. DCP Midstream gathers raw natural gas through gathering systems located in nine major conventional and non-conventional natural gas producing regions: Mid-Continent, Rocky Mountain, East Texas-North Louisiana, Barnett Shale, Gulf Coast, South Texas, Central Texas, Antrim Shale and Permian Basin. DCP Midstream has a 26% ownership interest in DCP Midstream Partners, LP (DCP Partners), a master limited partnership.

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), which represents earnings from continuing operations (both operating and non-operating) before interest and taxes, net of noncontrolling interests related to those earnings. Our 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, 2012				
U.S. Transmission	$ 458	$ 2	$ 460	$ 238
Distribution	269		269	55
Western Canada Transmission & Processing	343	5	348	83
Field Services				62
Total reportable segments	1,070	7	1,077	438
Other	2	17	19	(29)
Eliminations		(24)	(24)	
Interest expense				159
Interest income and other (b)				26
Total consolidated	$ 1,072	$	$ 1,072	$ 276
Three Months Ended September 30, 2011				
U.S. Transmission	$ 469	$ 2	$ 471	$ 235
Distribution	276		276	50
Western Canada Transmission & Processing	376	16	392	119
Field Services				134
Total reportable segments	1,121	18	1,139	538
Other	2	18	20	(23)
Eliminations		(36)	(36)	
Interest expense				157
Interest income and other (b)				24
Total consolidated	$ 1,123	$	$ 1,123	$ 382
Nine Months Ended September 30, 2012				
U.S. Transmission	$ 1,413	$ 6	$ 1,419	$ 746
Distribution	1,188		1,188	281
Western Canada Transmission & Processing	1,121	22	1,143	315
Field Services				221
Total reportable segments	3,722	28	3,750	1,563
Other	6	53	59	(83)
Eliminations		(81)	(81)	
Interest expense				471
Interest income and other (b)				84
Total consolidated	$ 3,728	$	$ 3,728	$ 1,093
Nine Months Ended September 30, 2011				
U.S. Transmission	$ 1,404	$ 7	$ 1,411	$ 757

Distribution	1,347		1,347	305
Western Canada Transmission & Processing	1,166	36	1,202	373
Field Services				353
Total reportable segments	3,917	43	3,960	1,788
Other	6	47	53	(76)
Eliminations		(90)	(90)	
Interest expense				471
Interest income and other (b)				78
Total consolidated	$ 3,923	$	$ 3,923	$ 1,319

(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

3. Regulatory Matters

Union Gas. As 2012 is the final year in Union Gas current multi-year incentive regulation framework, Union Gas filed an application with the OEB in November 2011 to set their distribution rates effective January 1, 2013. As part of the 2013 rates hearing process, Union Gas conducted settlement negotiations with its intervening parties. A settlement agreement was reached on most capital and rate base issues, and on all operating costs. That settlement agreement was accepted by the OEB on July 10, 2012. The unsettled issues, including operating revenue, cost of capital and rate design, were the subjects of a hearing. On October 25, 2012, the OEB issued its decision on the unsettled issues. Union Gas is in the process of determining the effect of the decision on customer rates for 2013. The draft rate order for OEB approval will be filed early December 2012. Union Gas expects approval of rates in January 2013 to be implemented in the first quarter of 2013. Union Gas is also revisiting the timing of its application for a new multi-year incentive regulation framework.

In August 2012, the OEB determined it would review the treatment of 2011 revenues derived from the optimization of Union Gas upstream transportation contracts as part of the application to dispose of 2011 year-end deferral account and other balances. Union Gas has historically and continues to record the optimization of upstream transportation contracts as revenues. The OEB s decision on this issue is expected in mid to late November 2012. The OEB decision on Union Gas 2013 rates application issued October 25, 2012 found that, among other things, the optimization of upstream transportation contracts effective 2013 are to be considered a reduction of natural gas supply costs, the majority of which are to be passed through to customers. If the OEB were to find retroactively that the optimization for 2011 should have been treated in a similar manner to the 2013 rate case, this could result in a payable to Union Gas ratepayers of up to approximately $30 million for the period January 1, 2011 through September 30, 2012. No provisions for this are reflected in our Condensed Consolidated Financial Statements.

Southeast Supply Header, LLC (SESH). SESH operates under rates approved by the FERC in 2008. That order required SESH to file a Cost and Revenue Study at the end of three years of operations. SESH filed the Cost and Revenue Study and the FERC accepted the filing on July 26, 2012. There was no change to the currently effective rates.

Gulfstream Natural Gas System, LLC (Gulfstream). Gulfstream operates under rates approved by the FERC in 2007. In 2007, the FERC issued an order approving Gulfstream s Phase III expansion project. That order also required Gulfstream to file a Cost and Revenue Study three years after the Phase III facilities went into service. Gulfstream filed the Cost and Revenue Study and the FERC accepted the filing on August 6, 2012. There were no changes to the currently effective rates.

4. Income Taxes

Income tax expense from continuing operations for the three months ended September 30, 2012 was $72 million, compared to $108 million for the same period in 2011. Income tax expense from continuing operations for the nine months ended September 30, 2012 was $289 million, compared to $372 million reported for the same period in 2011. The lower income tax expense for each of the 2012 periods resulted from lower earnings from continuing operations and a lower Canadian effective tax rate, partially offset by favorable tax adjustments in 2011.

The effective tax rate for income from continuing operations for both the three and nine-month periods ended September 30, 2012 was 26%, compared to 28% for both prior-year periods. The lower effective tax rates in 2012 were primarily due to a lower Canadian effective tax rate.

We recognized a $7 million increase in uncertain tax positions during the nine-month period ended September 30, 2012. Although uncertain, no material increases or decreases in uncertain tax positions are expected to occur prior to September 30, 2013.

Table of Contents

5. Discontinued Operations

Discontinued operations is mostly comprised of the net effects of a settlement arrangement related to prior liquefied natural gas (LNG) contracts. See Note 8 for further discussion.

The following table summarizes results classified as Income from Discontinued Operations, Net of Tax in the accompanying Condensed Consolidated Statements of Operations:

	Revenues	Pre-tax Earnings	Income Tax Expense	Income From Discontinued Operations, Net of Tax
		(in millions)		
Three Months Ended September 30, 2012				
Other	$	$	$	$
Total consolidated	$	$	$	$
Three Months Ended September 30, 2011				
Other	$ 50	$ 11	$ 4	$ 7
Total consolidated	$ 50	$ 11	$ 4	$ 7
Nine Months Ended September 30, 2012				
Other	$ 99	$ 3	$ 1	$ 2
Total consolidated	$ 99	$ 3	$ 1	$ 2
Nine Months Ended September 30, 2011				
Other	$ 182	$ 36	$ 13	$ 23
Total consolidated	$ 182	$ 36	$ 13	$ 23

6. 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.

Weighted-average shares used to calculate diluted EPS include the effect of certain options and restricted stock awards. Certain other options related to approximately five million shares for both the three and nine-month periods ended September 30, 2011 were not included in the calculation of diluted EPS because the option exercise prices were greater than the average market price of the shares during these periods.

Table of Contents

The following table presents our basic and diluted EPS calculations:

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(in millions, except per-share amounts)			
Income from continuing operations, net of tax controlling interests	$ 179	$ 247	$ 725	$ 872
Income from discontinued operations, net of tax controlling interests		7	2	23
Net income controlling interests	$ 179	$ 254	$ 727	$ 895
Weighted-average common shares outstanding				
Basic	653	650	653	650
Diluted	655	652	655	652
Basic earnings per common share (a)				
Continuing operations	$ 0.27	$ 0.38	$ 1.11	$ 1.34
Discontinued operations, net of tax		0.01		0.04
Total basic earnings per common share	$ 0.27	$ 0.39	$ 1.11	$ 1.38
Diluted earnings per common share (a)				
Continuing operations	$ 0.27	$ 0.38	$ 1.11	$ 1.34
Discontinued operations, net of tax		0.01		0.03
Total diluted earnings per common share	$ 0.27	$ 0.39	$ 1.11	$ 1.37

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

7. Inventory

Inventory consists 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, 2012	December 31, 2011
	(in millions)	
Natural gas	$ 245	$ 263
NGLs	81	58
Materials and supplies	78	72
Total inventory	$ 404	$ 393

Non-cash charges totaling $2 million in the third quarter of 2012 and $10 million in the nine months ended September 30, 2012 were recorded to Natural Gas and Petroleum Products Purchased on the Condensed Consolidated Statements of Operations ($8 million after tax for the nine-month period) to reduce propane inventory at our Empress operations at Western Canada Transmission & Processing to estimated net realizable value.

Table of Contents

8. 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,	
	2012	2011	2012	2011
	(in millions)			
Operating revenues	$ 2,355	$ 3,482	$ 7,476	$ 9,715
Operating expenses	2,233	3,124	6,925	8,836
Operating income	122	358	551	879
Net income	89	312	429	740
Net income attributable to members interests	95	266	371	676

DCP Midstream recorded gains on sales of common units of DCP Partners to equity in 2012 and 2011. Our proportionate 50% share, totaling $14 million and $1 million in the third quarters of 2012 and 2011, respectively, and $36 million and $15 million during the nine-month periods ended September 30, 2012 and 2011, respectively, was recorded in Equity in Earnings of Unconsolidated Affiliates in the Condensed Consolidated Statements of Operations.

Related Party Transactions. In 2008, we entered into a settlement agreement related to certain liquefied natural gas transportation contracts under which one of our subsidiaries claims were satisfied pursuant to commercial transactions involving the purchase of propane from certain parties. We subsequently entered into associated agreements with affiliates of DCP Midstream for the sale of these propane volumes. Net purchases and sales of propane under these arrangements are reflected as discontinued operations. Purchases of propane under the settlement agreement, and subsequent sales to affiliates of DCP Midstream, ended during the second quarter of 2012.

Sales of propane to affiliates of DCP Midstream are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Sales of propane	$	$ 50	$ 99	$ 182

9. Marketable Securities and Restricted Funds

We routinely invest excess cash and various restricted balances in securities such as commercial paper, banker s acceptances, corporate debt securities, treasury bills and money market funds in the United States and Canada. We do not purchase marketable securities for speculative purposes, nor do we routinely sell marketable securities prior to their scheduled maturity dates. Therefore, we do not have any securities classified as trading securities. A portion of our investments of restricted funds, primarily insurance-related funds, are classified as available-for-sale marketable securities as they may occasionally be sold prior to their scheduled maturity dates due to unexpected cash needs. Initial investments in securities are classified as purchases of the respective type of securities (available-for-sale (AFS) marketable securities or held-to-maturity (HTM) marketable securities). Maturities of securities are classified within proceeds from sales and maturities of securities in the Condensed Consolidated Statements of Cash Flows.

16

Table of Contents

AFS Securities. Estimated fair values of AFS securities follow:

	Estimated Fair Value	
	September 30, 2012	December 31, 2011
	(in millions)	
Corporate debt securities	$ 23	$ 18
Canadian government securities		14
Money market funds	1	3
Total available-for-sale investments	$ 24	$ 35

We had $14 million of restricted AFS securities classified as Current Assets Other as of December 31, 2011, and $1 million as of September 30, 2012 and $3 million as of December 31, 2011 classified as Investments and Other Assets Other. These funds are related to insurance.

At September 30, 2012, the weighted-average contractual maturity of outstanding AFS securities was one year.

There were no material gross unrealized holding gains or losses associated with investments in AFS securities at September 30, 2012 or December 31, 2011.

During 2010, we invested a portion of the proceeds from Spectra Energy Partners issuance of common units to the public in AFS marketable securities. These investments were pledged as collateral against Spectra Energy Partners term loan. Spectra Energy Partners term loan was repaid in June 2011 and the related investments were liquidated.

HTM Securities. Estimated fair values of HTM securities follow:

	Estimated Fair Value	
	September 30, 2012	December 31, 2011
	(in millions)	
Canadian government securities	$ 154	$ 107
Banker s acceptances	121	55
Total held-to-maturity investments	$ 275	$ 162

Restricted HTM marketable securities of $67 million as of September 30, 2012 are classified as Current Assets Other, and $208 million as of September 30, 2012 and $162 million as of December 31, 2011 are classified as Investments and Other Assets Other. These securities are restricted funds pursuant to certain Maritimes & Northeast Pipeline Limited Partnership (M&N LP) debt agreements. These funds, plus future cash from operations that would have otherwise been available for distribution to the partners of M&N LP, were required to be placed in escrow until the balance in escrow was sufficient to fund all future debt service on the M&N LP notes. As of September 30, 2012, there were sufficient funds held in escrow to fund all future debt service on the M&N LP notes.

At September 30, 2012, the weighted-average contractual maturity of outstanding HTM securities was less than one year.

There were no material gross unrecognized holding gains or losses associated with investments in HTM securities at September 30, 2012 or December 31, 2011.

Other Restricted Funds. In addition to the portions of the AFS and HTM securities that were restricted funds as described above, we had restricted funds totaling $37 million at September 30, 2012 and $35 million at December 31, 2011 classified as Current Assets Other, and $79 million at December 31, 2011 classified as Investments and Other Assets Other. These restricted funds are related to additional amounts for the M&N LP debt service requirements and insurance.

Changes in restricted balances are presented within Cash Flows from Investing Activities on our Condensed Consolidated Statements of Cash Flows.

10. Goodwill

We perform our goodwill impairment test annually and evaluate goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. We completed our annual goodwill impairment test as of April 1, 2012 and no impairments were identified.

We perform our annual review for goodwill impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete financial information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar. We determined that our reporting units are equivalent to our reportable segments, except for the reporting units of our Western Canada Transmission & Processing reportable segment, which are one level below.

As permitted under new accounting guidance on testing goodwill for impairment, we performed either a qualitative assessment or a quantitative assessment of each of our reporting units based on management s judgment. With respect to our qualitative assessments, we considered events and circumstances specific to us, such as macroeconomic conditions, industry and market considerations, cost factors and overall financial performance, when evaluating whether it was more likely than not that the fair values of our reporting units were less than their respective carrying amounts.

In connection with our quantitative assessments, we primarily used a discounted cash flow analysis to determine the fair values of those reporting units. Key assumptions in the determination of fair value included the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporated 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 reporting units revenue, expense and capital expenditure projections.

The increase in goodwill at September 30, 2012 compared to December 31, 2011 is the result of a change in the Canadian dollar exchange rate.

Table of Contents

11. Debt and Credit Facilities

Available Credit Facilities and Restrictive Debt Covenants

	Expiration Date	Total Credit Facilities Capacity	Outstanding at September 30, 2012 Commercial Paper	Letters of Credit (in millions)	Total	Available Credit Facilities Capacity
Spectra Energy Capital, LLC (a)						
Multi-year syndicated	2016	$ 1,500	$ 873	$ 5	$ 878	$ 622
Westcoast Energy Inc. (b)						
Multi-year syndicated	2016	305	165		165	140
Union Gas (c)						
Multi-year syndicated	2016	407	238		238	169
Spectra Energy Partners (d)						
Multi-year syndicated	2016	700	41		41	659
Total		$ 2,912	$ 1,317	$ 5	$ 1,322	$ 1,590

(a) Credit facility contains a covenant requiring the Spectra Energy Corp consolidated debt-to-total capitalization ratio, as defined in the agreement, to not exceed 65%. This ratio was 59% at September 30, 2012.

(b) U.S. dollar equivalent at September 30, 2012. The credit facility is 300 million Canadian dollars and contains a covenant that requires the Westcoast Energy Inc. non-consolidated debt-to-total capitalization ratio to not exceed 75%. The ratio was 45% at September 30, 2012.

(c) U.S. dollar equivalent at September 30, 2012. The credit facility is 400 million Canadian dollars and contains a covenant that requires the Union Gas debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 65% at September 30, 2012.

(d) Credit facility contains a covenant that requires Spectra Energy Partners to maintain a ratio of total Debt-to-Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA), as defined in the credit agreement, of 5.0 or less. As of September 30, 2012, this ratio was 2.6. Adjusted EBITDA is a non-GAAP measure. Because Adjusted EBITDA excludes some, but not all, items that affect net income and is defined differently by companies in our industry, Spectra Energy Partners definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies. Adjusted EBITDA should not be considered an alternative to net income, operating income, cash from operations or any other measure of financial performance or liquidity presented in accordance with GAAP.

The issuances of commercial paper, letters of credit and revolving borrowings reduce the amounts available under the credit facilities. As of September 30, 2012, there were no revolving borrowings outstanding.

Our credit agreements contain various covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of September 30, 2012, we were in compliance with those covenants. In addition, our credit agreements allow for acceleration of payments or termination of the agreements due to nonpayment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. Our debt and credit agreements do not contain provisions that trigger an acceleration of indebtedness based solely on the occurrence of a material adverse change in our financial condition or results of operations.

As noted above, the terms of the Spectra Energy Capital, LLC (Spectra Capital) credit agreement require our consolidated debt-to-total capitalization ratio, as defined in the agreement, to be 65% or lower. Per the terms of the agreement, collateralized debt and Spectra Energy Partners debt and equity are excluded in the calculation of the ratio. This ratio was 59% at September 30, 2012.

Table of Contents

12. 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:

Description	Condensed Consolidated Balance Sheet Caption	Total	Level 1	Level 2	Level 3
		September 30, 2012 (in millions)			
Corporate debt securities	Cash and cash equivalents	$ 76	$	$ 76	$
Corporate debt securities	Current assets other	7		7	
Derivative assets interest rate swaps	Current assets other	11		11	
Corporate debt securities	Investments and other assets other	16		16	
Derivative assets interest rate swaps	Investments and other assets other	53		53	
Money market funds	Investments and other assets other	1	1		
Total Assets		$ 164	$ 1	$ 163	$
Derivative liabilities natural gas purchase contracts	Deferred credits and other liabilities regulatory and other	$ 8	$	$	$ 8
Derivative liabilities interest rate swaps	Deferred credits and other liabilities regulatory and other	12		12	
Total Liabilities		$ 20	$	$ 12	$ 8

Description	Condensed Consolidated Balance Sheet Caption	Total	Level 1	Level 2	Level 3
		December 31, 2011 (in millions)			
Corporate debt securities	Cash and cash equivalents	$ 49	$	$ 49	$
Canadian government securities	Current assets other	14	14		
Corporate debt securities	Current assets other	2		2	
Corporate debt securities	Investments and other assets other	16		16	
Derivative assets interest rate swaps	Investments and other assets other	66		66	
Money market funds	Investments and other assets other	3	3		
Total Assets		$ 150	$ 17	$ 133	$
Derivative liabilities natural gas purchase contracts	Current liabilities other	$ 1	$	$	$ 1
Derivative liabilities natural gas purchase contracts	Deferred credits and other liabilities regulatory and other	13			13
Derivative liabilities interest rate swaps	Deferred credits and other liabilities regulatory and other	16		16	
Total Liabilities		$ 30	$	$ 16	$ 14

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Long-term derivative liabilities				
Fair value, beginning of period	$ 10	$ 8	$ 14	$ 6
Total realized/unrealized losses (gains):				
Included in earnings	1	1	1	2
Included in other comprehensive income	(3)	(2)	(6)	(1)
Settlements			(1)	
Fair value, end of period	$ 8	$ 7	$ 8	$ 7
Total losses (gains) 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	$ (3)	$ 1	$ 2

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, including our long-term debt, 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 a third-party source 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.

Table of Contents

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, 2012		December 31, 2011	
	Book Value	Approximate Fair Value	Book Value	Approximate Fair Value
		(in millions)		
Note receivable noncurrent (a)	$ 71	$ 71	$ 71	$ 71
Long-term debt, including current maturities (b)	11,106	13,180	10,600	12,398

(a) Included within Investments in and Loans to Unconsolidated Affiliates.
(b) Excludes unamortized items and a fair value hedge carrying value adjustment.

The fair value of our long-term debt, including current maturities, is determined based on market-based prices as described in the Level 2 valuation technique described above.

The fair values of cash and cash equivalents, restricted cash, short-term investments, accounts receivable, note receivable-noncurrent, 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 2012 and 2011 periods, there were no material adjustments to assets and liabilities measured at fair value on a nonrecurring basis.

13. Risk Management and Hedging Activities

We are exposed to the impact of market fluctuations in the prices of NGLs and natural gas purchased as a result of our investment in DCP Midstream, and the ownership of NGL processing and marketing operations in western Canada and the processing plants associated with our U.S. pipeline assets. 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 derivatives, primarily around interest rate exposures.

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

At September 30, 2012, we had pay floating receive fixed interest rate swaps outstanding with a total notional principal amount of $2,104 million to hedge against changes in the fair value of our fixed-rate debt that arise as a result of changes in market interest rates. These swaps also allow us to transform a portion of the underlying interest payments related to our long-term fixed-rate debt securities into variable-rate interest payments in order to achieve our desired mix of fixed and variable-rate debt.

Other than interest rate swaps described above, we did not have any significant derivatives outstanding during the nine months ended September 30, 2012.

Table of Contents

14. 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 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 undiscounted liabilities related to extended environmental-related activities totaling $14 million as of September 30, 2012 and $16 million as of December 31, 2011. These liabilities represent provisions for costs associated with remediation activities at some of our current and former sites, as well as other environmental contingent liabilities.

Litigation

Litigation and Legal Proceedings. We are involved in 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 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, 2012 or December 31, 2011 related to litigation.

Other Commitments and Contingencies

See Note 15 for a discussion of guarantees and indemnifications.

15. Guarantees and Indemnifications

We have various financial guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. We enter into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included on the Condensed Consolidated Balance Sheets. The possibility of having to 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-100%-owned entities. In connection with our spin-off from

Duke Energy Corporation (Duke Energy) in 2007, 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, 2012 was approximately $406 million, which has been indemnified by Duke Energy as discussed above. One of these outstanding performance guarantees, which has a maximum potential amount of future payment of $201 million, expires in 2028. The remaining guarantees have no contractual expirations.

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 in place at the time of our spin-off from Duke Energy. D/FD is one of the entities transferred to Duke Energy in connection with our spin-off. 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.

Westcoast Energy Inc. (Westcoast), a 100%-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 agreements, 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.

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.

As of September 30, 2012, the amounts recorded for the guarantees and indemnifications, described above, including the indemnifications by Duke Energy to us, are not material, both individually and in the aggregate.

16. Employee Benefit Plans

Retirement Plans. We have a qualified non-contributory defined benefit (DB) retirement plan for most U.S. employees and non-qualified, non-contributory, unfunded defined benefit plans which cover certain current and former U.S. executives. 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, where applicable, 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 contributions of $21 million to our U.S. retirement plans in the nine months ended September 30, 2012 and $15 million in the same period in 2011. We made total contributions to the Canadian DC and qualified DB plans of $52 million during the nine months ended September 30, 2012 and $54 million in the same period in 2011. We anticipate that we will make total contributions of approximately $25 million to the U.S. plans and approximately $90 million to the Canadian plans in 2012.

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
U.S.				
Service cost benefit earned	$ 4	$ 3	$ 11	$ 10
Interest cost on projected benefit obligation	5	6	17	19
Expected return on plan assets	(8)	(8)	(23)	(24)
Amortization of loss	4	3	11	8
Net periodic pension cost	$ 5	$ 4	$ 16	$ 13
Canada				
Service cost benefit earned	$ 7	$ 5	$ 20	$ 16
Interest cost on projected benefit obligation	13	12	38	39
Expected return on plan assets	(15)	(12)	(44)	(37)
Amortization of loss	10	7	28	21
Amortization of prior service costs			1	1
Net periodic pension cost	$ 15	$ 12	$ 43	$ 40

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,	
	2012	2011	2012	2011
	(in millions)			
U.S.				
Service cost benefit earned	$ 1	$ 1	$ 1	$ 1
Interest cost on accumulated post-retirement benefit obligation	2	2	6	7
Expected return on plan assets	(1)	(1)	(3)	(3)
Amortization of loss			1	1
Net periodic other post-retirement benefit cost	$ 2	$ 2	$ 5	$ 6
Canada				
Service cost benefit earned	$ 2	$ 2	$ 6	$ 4
Interest cost on accumulated post-retirement benefit obligation	2	1	5	5
Amortization of loss		1	1	1
Amortization of prior service credit	(1)	(1)	(1)	(1)
Net periodic other post-retirement benefit cost	$ 3	$ 3	$ 11	$ 9

25

Table of Contents

Retirement/Savings Plan

We have employee savings plans available to both U.S. and Canadian employees. Employees may participate in a matching contribution where we match a certain percentage of before tax employee contributions, of up to 6% of eligible pay per pay period for U.S. employees and up to 5% of eligible pay per pay period for Canadian employees. We expensed pre-tax employer matching contributions of $2 million in both the three-month periods ended September 30, 2012 and 2011 and $9 million in both the nine-month periods ended September 30, 2012 and 2011 for U.S. employees, and $3 million in both the three-month periods ended September 30, 2012 and 2011 and $9 million in both the nine-month periods ended September 30, 2012 and 2011 for Canadian employees.

17. Consolidating Financial Information

Spectra Energy Corp has agreed to fully and unconditionally guarantee the payment of principal and interest under all series of notes outstanding under the Senior Indenture of Spectra Capital, a 100%-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 consolidated 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 Statements of Operations

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Three Months Ended September 30, 2012					
Total operating revenues	$	$	$ 1,073	$ (1)	$ 1,072
Total operating expenses	3		742	(1)	744
Operating income (loss)	(3)		331		328
Equity in earnings of unconsolidated affiliates			88		88
Equity in earnings of subsidiaries	181	290		(471)	
Other income and expenses, net	(2)		21		19
Interest expense		48	111		159
Earnings before income taxes	176	242	329	(471)	276
Income tax expense (benefit)	(3)	61	14		72
Net income	179	181	315	(471)	204
Net income noncontrolling interests			25		25
Net income controlling interests	$ 179	$ 181	$ 290	$ (471)	$ 179
Three Months Ended September 30, 2011					
Total operating revenues	$	$	$ 1,125	$ (2)	$ 1,123
Total operating expenses			767	(2)	765
Gains on sales of other assets and other, net			3		3
Operating income			361		361
Equity in earnings of unconsolidated affiliates			160		160
Equity in earnings of subsidiaries	254	368		(622)	
Other income and expenses, net		(1)	19		18
Interest expense		48	109		157
Earnings from continuing operations before income taxes	254	319	431	(622)	382
Income tax expense from continuing operations		65	43		108
Income from continuing operations	254	254	388	(622)	274
Income from discontinued operations, net of tax			7		7
Net income	254	254	395	(622)	281
Net income noncontrolling interests			27		27
Net income controlling interests	$ 254	$ 254	$ 368	$ (622)	$ 254

Table of Contents

Spectra Energy Corp

Condensed Consolidating Statements of Operations

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Nine Months Ended September 30, 2012					
Total operating revenues	$	$	$ 3,730	$ (2)	$ 3,728
Total operating expenses	11		2,507	(2)	2,516
Gains on sales of other assets and other, net			2		2
Operating income (loss)	(11)		1,225		1,214
Equity in earnings of unconsolidated affiliates			297		297
Equity in earnings of subsidiaries	726	1,118		(1,844)	
Other income and expenses, net	(3)	1	55		53
Interest expense		144	327		471
Earnings from continuing operations before income taxes	712	975	1,250	(1,844)	1,093
Income tax expense (benefit) from continuing operations	(16)	249	56		289
Income from continuing operations	728	726	1,194	(1,844)	804
Income (loss) from discontinued operations, net of tax	(1)		3		2
Net income	727	726	1,197	(1,844)	806
Net income noncontrolling interests			79		79
Net income controlling interests	$ 727	$ 726	$ 1,118	$ (1,844)	$ 727
Nine Months Ended September 30, 2011					
Total operating revenues	$	$	$ 3,925	$ (2)	$ 3,923
Total operating expenses			2,612	(2)	2,610
Gains on sales of other assets and other, net			7		7
Operating income			1,320		1,320
Equity in earnings of unconsolidated affiliates			428		428
Equity in earnings of subsidiaries	895	1,303		(2,198)	
Other income and expenses, net		5	37		42
Interest expense		147	324		471
Earnings from continuing operations before income taxes	895	1,161	1,461	(2,198)	1,319
Income tax expense from continuing operations		266	106		372
Income from continuing operations	895	895	1,355	(2,198)	947
Income from discontinued operations, net of tax			23		23

Net income	895	895	1,378	(2,198)	970
Net income noncontrolling interests			75		75
Net income controlling interests	$ 895	$ 895	$ 1,303	$ (2,198)	$ 895

Table of Contents

Spectra Energy Corp

Condensed Consolidating Statements of Comprehensive Income

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Three Months Ended September 30, 2012					
Net income	$ 179	$ 181	$ 315	$ (471)	$ 204
Other comprehensive income	2	1	262		265
Total comprehensive income, net of tax	181	182	577	(471)	469
Less: comprehensive income noncontrolling interests			29		29
Comprehensive income controlling interests	$ 181	$ 182	$ 548	$ (471)	$ 440
Three Months Ended September 30, 2011					
Net income	$ 254	$ 254	$ 395	$ (622)	$ 281
Other comprehensive income (loss)	3		(606)		(603)
Total comprehensive income (loss), net of tax	257	254	(211)	(622)	(322)
Less: comprehensive income noncontrolling interests			17		17
Comprehensive income (loss) controlling interests	$ 257	$ 254	$ (228)	$ (622)	$ (339)
Nine Months Ended September 30, 2012					
Net income	$ 727	$ 726	$ 1,197	$ (1,844)	$ 806
Other comprehensive income	9	2	313		324
Total comprehensive income, net of tax	736	728	1,510	(1,844)	1,130
Less: comprehensive income noncontrolling interests			83		83
Comprehensive income controlling interests	$ 736	$ 728	$ 1,427	$ (1,844)	$ 1,047
Nine Months Ended September 30, 2011					
Net income	$ 895	$ 895	$ 1,378	$ (2,198)	$ 970
Other comprehensive income (loss)	7		(334)		(327)
Total comprehensive income, net of tax	902	895	1,044	(2,198)	643
Less: comprehensive income noncontrolling interests			69		69
Comprehensive income controlling interests	$ 902	$ 895	$ 975	$ (2,198)	$ 574

Table of Contents

Spectra Energy Corp

Condensed Consolidating Balance Sheet

September 30, 2012

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$	$ 1	$ 145	$	$ 146
Receivables (payables) consolidated subsidiaries	108	(108)			
Receivables other	3	21	751		775
Other current assets	19	13	668		700
Total current assets	130	(73)	1,564		1,621
Investments in and loans to unconsolidated affiliates		70	2,048		2,118
Investments in consolidated subsidiaries	12,784	16,125		(28,909)	
Advances receivable (payable) consolidated subsidiaries	(4,131)	4,297	394	(560)	
Goodwill			4,541		4,541
Other assets	39	72	357		468
Property, plant and equipment, net			19,607		19,607
Regulatory assets and deferred debits	1	13	1,213		1,227
Total Assets	$ 8,823	$ 20,504	$ 29,724	$ (29,469)	$ 29,582
Accounts payable other	$ 1	$ 75	$ 375	$	$ 451
Commercial paper		1,433	444	(560)	1,317
Accrued taxes payable	2		50		52
Current maturities of long-term debt		744	537		1,281
Other current liabilities	49	96	777		922
Total current liabilities	52	2,348	2,183	(560)	4,023
Long-term debt		2,560	7,332		9,892
Deferred credits and other liabilities	181	2,812	2,998		5,991
Preferred stock of subsidiaries			258		258
Equity					
Controlling interests	8,590	12,784	16,125	(28,909)	8,590
Noncontrolling interests			828		828
Total equity	8,590	12,784	16,953	(28,909)	9,418
Total Liabilities and Equity	$ 8,823	$ 20,504	$ 29,724	$ (29,469)	$ 29,582

Table of Contents

Spectra Energy Corp

Condensed Consolidating Balance Sheet

December 31, 2011

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$	$ 2	$ 172	$	$ 174
Receivables (payables) consolidated subsidiaries		(1)	1		
Receivables other			962		962
Other current assets	57	5	566		628
Total current assets	57	6	1,701		1,764
Investments in and loans to unconsolidated affiliates		70	1,994		2,064
Investments in consolidated subsidiaries	11,720	14,884		(26,604)	
Advances receivable (payable) consolidated subsidiaries	(3,534)	4,116	10	(592)	
Goodwill			4,420		4,420
Other assets	42	105	383		530
Property, plant and equipment, net			18,258		18,258
Regulatory assets and deferred debits	1	15	1,086		1,102
Total Assets	$ 8,286	$ 19,196	$ 27,852	$ (27,196)	$ 28,138
Accounts payable other	$ 3	$ 62	$ 433	$	$ 498
Commercial paper		1,343	301	(592)	1,052
Accrued taxes payable (receivable)	(46)	2	126		82
Current maturities of long-term debt			525		525
Other current liabilities	76	75	793		944
Total current liabilities	33	1,482	2,178	(592)	3,101
Long-term debt		3,311	6,835		10,146
Deferred credits and other liabilities	188	2,683	2,866		5,737
Preferred stock of subsidiaries			258		258
Equity					
Controlling interests	8,065	11,720	14,884	(26,604)	8,065
Noncontrolling interests			831		831
Total equity	8,065	11,720	15,715	(26,604)	8,896
Total Liabilities and Equity	$ 8,286	$ 19,196	$ 27,852	$ (27,196)	$ 28,138

Table of Contents

Spectra Energy Corp

Condensed Consolidating Statement of Cash Flows

Nine Months Ended September 30, 2012

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 727	$ 726	$ 1,197	$ (1,844)	$ 806
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization			566		566
Equity in earnings of unconsolidated affiliates			(297)		(297)
Equity in earnings of subsidiaries	(726)	(1,118)		1,844	
Distributions received from unconsolidated affiliates			252		252
Other	41	212	(126)		127
Net cash provided by (used in) operating activities	42	(180)	1,592		1,454
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(1,418)		(1,418)
Acquisitions			(30)		(30)
Purchases of held-to-maturity securities			(2,276)		(2,276)
Proceeds from sales and maturities of held-to- maturity securities			2,173		2,173
Purchases of available-for-sale securities			(15)		(15)
Proceeds from sales and maturities of available-for-sale securities			21		21
Distributions received from unconsolidated affiliates			11		11
Other changes in restricted funds			77		77
Other			7		7
Net cash used in investing activities			(1,450)		(1,450)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt			350		350
Payments for the redemption of long-term debt			(28)		(28)
Net increase in commercial paper		122	134		256
Distributions to noncontrolling interests			(86)		(86)
Dividends paid on common stock	(555)				(555)
Distributions and advances from (to) affiliates	484	57	(541)		
Other	29		(1)		28
Net cash provided by (used in) financing activities	(42)	179	(172)		(35)
Effect of exchange rate changes on cash			3		3

Net decrease in cash and cash equivalents		(1)	(27)		(28)
Cash and cash equivalents at beginning of period		2	172		174
Cash and cash equivalents at end of period	$	$ 1	$ 145	$	$ 146

Table of Contents

Spectra Energy Corp

Condensed Consolidating Statement of Cash Flows

Nine Months Ended September 30, 2011

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 895	$ 895	$ 1,378	$ (2,198)	$ 970
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization			543		543
Equity in earnings of unconsolidated affiliates			(428)		(428)
Equity in earnings of subsidiaries	(895)	(1,303)		2,198	
Distributions received from unconsolidated affiliates			351		351
Other	(26)	240	37		251
Net cash provided by (used in) operating activities	(26)	(168)	1,881		1,687
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(1,299)		(1,299)
Investments in and loans to unconsolidated affiliates			(6)		(6)
Acquisitions, net of cash acquired			(390)		(390)
Purchases of held-to-maturity securities			(1,199)		(1,199)
Proceeds from sales and maturities of held-to-maturity securities			1,206		1,206
Purchases of available-for-sale securities			(938)		(938)
Proceeds from sales and maturities of available-for-sale securities			1,128		1,128
Distributions received from unconsolidated affiliates			6		6
Other changes in restricted funds			(57)		(57)
Other			3		3
Net cash used in investing activities			(1,546)		(1,546)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt			806		806
Payments for the redemption of long-term debt			(494)		(494)
Net increase (decrease) in commercial paper		(46)	193		147
Net decrease in revolving credit facilities borrowings			(289)		(289)

Distributions to noncontrolling interests			(74)		(74)
Proceeds from the issuance of Spectra Energy Partners common units			213		213
Dividends paid on common stock	(511)				(511)
Distributions and advances from (to) affiliates	517	218	(735)		
Other	20		(6)		14
Net cash provided by (used in) financing activities	26	172	(386)		(188)
Effect of exchange rate changes on cash			(9)		(9)
Net increase (decrease) in cash and cash equivalents		4	(60)		(56)
Cash and cash equivalents at beginning of period			130		130
Cash and cash equivalents at end of period	$	$ 4	$ 70	$	$ 74

Table of Contents

18. New Accounting Pronouncements

There were no significant accounting pronouncements adopted during the nine months ended September 30, 2012 that had a material impact on our consolidated results of operations, financial position or cash flows.

19. Subsequent Events

On October 24, 2012, Texas Eastern Transmission, LP (Texas Eastern) issued $500 million aggregate principal amount of 2.80% notes due in 2022. We primarily used the proceeds from the offering to repay outstanding commercial paper.

On October 31, 2012, a subsidiary of Spectra Energy Corp transferred a 38.76% interest in Maritimes & Northeast Pipeline, L.L.C. (M&N LLC) to Spectra Energy Partners for approximately $319 million in cash and $56 million in newly issued Spectra Energy Partners partnership units. M&N LLC has debt outstanding of $439 million, 38.76% of which is $170 million. M&N LLC remains a consolidated subsidiary of Spectra Energy Corp after the transaction and our effective ownership of M&N LLC decreased from approximately 78% to approximately 64%.

On October 31, 2012, we announced that pursuant to an agreement in principle with Phillips 66 and DCP Midstream, we expect to acquire a one-third interest in both the Sand Hills and Southern Hills NGL pipeline projects, which currently are under construction by DCP Midstream. The transaction is expected to close in the fourth quarter of 2012. Upon closing, Spectra Energy, Phillips 66 and DCP Midstream each will own a one-third interest in the two pipeline projects. Upon completion of the pipelines, our direct investment is expected to total between $700 million to $800 million.

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

Consistent with our near-term objective of increasing dividends, we increased our quarterly cash dividend from $0.28 per common share to $0.305 per share, or $1.22 per share annually, effective the fourth quarter of 2012. The new dividend level represents a nearly 9% increase over the previous level.

During 2012, our earnings decreased compared to the same period in 2011 as a result of lower commodity prices at Field Services, extraordinarily warmer weather at Distribution, and lower NGL sales prices related to the Empress operations at Western Canada Transmission & Processing. However, our gathering and processing businesses at Field Services generated higher earnings and our fee-based businesses at U.S. Transmission and Western Canada Transmission & Processing continued to perform well by meeting the needs of our customers and generating strong earnings and operating cash flows from expansion projects.

For the three months ended September 30, 2012 and 2011, we reported net income from controlling interests of $179 million and $254 million, respectively. For the nine months ended September 30, 2012 and 2011, we reported net income from controlling interests of $727 million and $895 million, respectively.

The highlights for the nine months ended September 30, 2012 include the following:

- U.S. Transmission experienced anticipated lower storage revenues and lower processing revenues, partially offset by higher earnings from expansion projects and lower operating costs, Distribution s earnings reflected lower customer usage as a result of warmer weather and expected lower storage revenues, partially offset by higher short-term transportation service revenues and lower operating fuel costs,

Table of Contents

Western Canada Transmission & Processing s earnings decreased mostly as a result of lower earnings at the Empress NGL business due primarily to lower NGL sales prices, partially offset by higher gathering and processing earnings from expansions, and

Field Services earnings decreased mostly due to lower commodity prices, partially offset by higher gathering and processing volumes from asset growth and the absence of severe weather which restricted volumes in 2011, and a reduction in depreciation expense attributable to an increase in the remaining useful lives of gathering, transmission, processing, storage and other assets.

In the first nine months of 2012, we had $1,418 million of capital and investment expenditures excluding the payment of $30 million of the purchase price previously withheld for the acquisition of Bobcat Gas Storage (Bobcat) in 2010, which we have classified as acquisition expenditures. Excluding any expenditures related to the recently announced pending Sand Hills and Southern Hills transaction, we project approximately $2.1 billion of capital and investment expenditures for the full year, including expansion capital of approximately $1.4 billion. Expansion projects for 2012 are on track and we expect that our capital spending will be significantly higher in the fourth quarter of 2012.

We are committed to an investment-grade balance sheet and continued prudent financial management of our capitalization structure. Therefore, financing these growth activities will continue to be based on our strong and growing fee-based earnings and cash flows as well as the issuance of long-term debt. We have access to $1.6 billion available under our credit facilities as of September 30, 2012, to be utilized as needed for effective working capital management.

RESULTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in millions)			
Operating revenues	$ 1,072	$ 1,123	$ 3,728	$ 3,923
Operating expenses	744	765	2,516	2,610
Gains on sales of other assets and other, net		3	2	7
Operating income	328	361	1,214	1,320
Other income and expenses	107	178	350	470
Interest expense	159	157	471	471
Earnings from continuing operations before income taxes	276	382	1,093	1,319
Income tax expense from continuing operations	72	108	289	372
Income from continuing operations	204	274	804	947
Income from discontinued operations, net of tax		7	2	23
Net income	204	281	806	970
Net income noncontrolling interests	25	27	79	75
Net income controlling interests	$ 179	$ 254	$ 727	$ 895

Three and Nine Months Ended September 30, 2012 Compared to Same Periods in 2011

Operating Revenues. Operating revenues for the three and nine months ended September 30, 2012 decreased by $51 million, or 5%, and $195 million, or 5%, respectively, compared to the same periods in 2011. The decreases were driven by:

a decrease in customer usage of natural gas largely due to warmer weather in the first six months of 2012 and lower natural gas prices passed through to customers, net of increased short-term transportation service at Distribution,

Table of Contents

- lower NGL sales prices at the Empress operations and a decrease in contracted volumes in the core gathering and processing business at Western Canada Transmission & Processing, and

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

- higher revenues from expansion projects at Western Canada Transmission & Processing and U.S. Transmission.

Operating Expenses. Operating expenses for the three and nine months ended September 30, 2012 decreased by $21 million, or 3%, and $94 million, or 4%, respectively, compared to the same periods in 2011. The decreases were driven by:

- a decrease in volumes of natural gas sold largely due to warmer weather in the first six months of 2012 and lower natural gas prices passed through to customers at Distribution,

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

- 2011 plant turnaround costs that did not recur in the 2012 period at Western Canada Transmission & Processing, partially offset by

- higher natural gas purchases for extraction due to increased volumes with the exception of the third quarter 2012 at Empress operations in 2012 at Western Canada Transmission & Processing.

Operating Income. Operating income for the three and nine months ended September 30, 2012 decreased by $33 million, or 9%, and $106 million, or 8%, respectively, compared to the same periods in 2011. The decreases were attributable to lower NGL earnings primarily due to lower NGL sales prices related to the Empress operations at Western Canada Transmission & Processing, and lower customer usage of natural gas as a result of warmer weather at Distribution, partially offset by higher earnings from expansion projects at Western Canada Transmission & Processing and U.S. Transmission.

Other Income and Expenses. Other income and expenses for the three and nine months ended September 30, 2012 decreased by $71 million, or 40%, and $120 million, or 26%, respectively, compared to the same periods in 2011. The decreases were attributable to lower equity earnings from Field Services mostly due to lower commodity prices, partially offset by an increase in gathering and processing margins as a result of higher volumes due to asset growth in 2012 and the impact of severe weather in the first quarter of 2011, and a reduction in depreciation expense attributable to an increase of the remaining useful lives of DCP Midstream s gathering, transmission, processing, storage and other assets in 2012. In addition, the lower equity earnings from Field Services were slightly offset by higher allowance for funds used during construction (AFUDC) due to increased capital spending on expansion projects at Western Canada Transmission & Processing.

Income Tax Expense from Continuing Operations. Income tax expense from continuing operations for the three and nine months ended September 30, 2012 decreased by $36 million and $83 million, respectively, compared to the same periods in 2011. The decreases in each of the 2012 periods were attributable to lower earnings from continuing operations and a lower Canadian effective tax rate, partially offset by favorable tax adjustments in 2011.

The effective tax rate for income from continuing operations for both the three and nine-month periods ended September 30, 2012 was 26%, compared to 28% for both prior-year periods. The lower effective tax rates in 2012 were primarily due to a lower Canadian effective tax rate.

Income from Discontinued Operations, Net of Tax. Income from discontinued operations, net of tax for the three and nine months ended September 30, 2012 decreased by $7 million and $21 million, respectively, compared to the same periods in 2011. The decreases were primarily attributable to lower income from propane deliveries in 2012 as a result of a final settlement of these activities in the second quarter of 2012.

Table of Contents

Net Income Noncontrolling Interests. Net income from noncontrolling interests for the nine months ended September 30, 2012 increased by $4 million compared to the same periods in 2011. The increase for nine months ended September 30, 2012 was driven by an increase in noncontrolling ownership interests resulting from the Spectra Energy Partners public sales of additional partner units in June 2011, and higher earnings from Spectra Energy Partners, primarily as a result of the timing of the acquisition of Big Sandy Pipeline, LLC (Big Sandy) in July 2011.

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

Segment Results

Management evaluates segment performance based on EBIT, which 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,	
	2012	2011	2012	2011
	(in millions)			
U.S. Transmission	$ 238	$ 235	$ 746	$ 757
Distribution	55	50	281	305
Western Canada Transmission & Processing	83	119	315	373
Field Services	62	134	221	353
Total reportable segment EBIT	438	538	1,563	1,788
Other	(29)	(23)	(83)	(76)
Total reportable segment and other EBIT	409	515	1,480	1,712
Interest expense	159	157	471	471
Interest income and other (a)	26	24	84	78
Earnings from continuing operations before income taxes.	$ 276	$ 382	$ 1,093	$ 1,319

(a) Includes foreign currency transaction gains and losses and the add-back of 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-100%-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, 2012	Three Months Ended September 30, 2011	Increase (Decrease)	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$ 460	$ 471	$ (11)	$ 1,419	$ 1,411	$ 8
Operating expenses						
Operating, maintenance and other	165	184	(19)	484	486	(2)
Depreciation and amortization	70	69	1	211	203	8
Gains on sales of other assets and other, net		4	(4)	3	8	(5)
Operating income	225	222	3	727	730	(3)
Other income and expenses	40	40		103	103	
Noncontrolling interests	27	27		84	76	8
EBIT	$ 238	$ 235	$ 3	$ 746	$ 757	$ (11)
Proportional throughput, TBtu (a)	650	659	(9)	2,025	2,085	(60)

(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, 2012 Compared to Same Period in 2011

Operating Revenues. The $11 million decrease was driven by:

- a $10 million decrease in processing revenues associated with pipeline operations primarily due to lower prices, and
- a $6 million decrease from anticipated lower storage revenues due to lower storage prices, partially offset by
- a $5 million increase from expansion projects.

Operating, Maintenance and Other. The $19 million decrease was driven by:

- a $12 million decrease in employee benefit costs and lower maintenance costs, and
- a $6 million decrease from project development costs expensed in 2011.

Gain on sale of other assets and other, net. The $4 million decrease was driven by a 2011 customer settlement.

EBIT. The $3 million increase was mainly driven by increased earnings from expansions and lower operating costs, partially offset by lower processing revenues and anticipated lower storage revenues.

Nine Months Ended September 30, 2012 Compared to Same Period in 2011

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

- a $42 million increase from expansion projects and the timing of the acquisition of Big Sandy in July 2011, and
- a $12 million increase in recoveries of electric power and other costs passed through to customers, partially offset by
- a $24 million decrease from anticipated lower storage revenues, lower rates on M&N LP, and contract reductions at Ozark Gas Transmission L.L.C. (Ozark Gas Transmission), and
- a $19 million decrease in processing revenues associated with pipeline operations caused by lower volumes and prices.

Table of Contents

Operating, Maintenance and Other. The $2 million decrease was driven by:

a $7 million decrease due to employee benefit costs and lower maintenance costs, partially offset by accelerated software amortization and other costs, and

a $6 million decrease from project development costs expensed in 2011, partially offset by

an $11 million increase in electric power and other costs passed through to customers.

Depreciation and Amortization. The $8 million increase was driven by expansion projects and the timing of the acquisition of Big Sandy in July 2011.

Gain on sale of other assets and other, net. The $5 million decrease was driven by 2011 customer settlements.

Noncontrolling Interests. The $8 million increase was driven by an increase in noncontrolling ownership interests resulting from the Spectra Energy Partners public sales of additional partner units in June 2011, and higher earnings from Spectra Energy Partners, primarily as a result of the timing of the acquisition of Big Sandy in July 2011.

EBIT. The $11 million decrease was driven by anticipated lower storage revenues, lower rates at M&N LP, contract reductions at Ozark Gas Transmission and lower processing revenues, partially offset by increased earnings from expansions and lower operating costs.

Distribution

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Increase (Decrease)	2012	2011	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$ 269	$ 276	$ (7)	$ 1,188	$ 1,347	$ (159)
Operating expenses						
Natural gas purchased	50	60	(10)	425	556	(131)
Operating, maintenance and other	110	112	(2)	323	326	(3)
Depreciation and amortization	54	54		159	160	(1)
EBIT	$ 55	$ 50	$ 5	$ 281	$ 305	$ (24)
Number of customers, thousands				1,370	1,352	18
Heating degree days, Fahrenheit	295	246	49	3,994	4,948	(954)
Pipeline throughput, TBtu	158	139	19	584	626	(42)
Canadian dollar exchange rate, average	1.00	0.98	0.02	1.00	0.98	0.02

Three Months Ended September 30, 2012 Compared to Same Period in 2011

Operating Revenues. The $7 million decrease was driven by:

a $16 million decrease from lower natural gas prices passed through to customers. Prices charged to customers are adjusted quarterly based on the 12 month New York Mercantile Exchange (NYMEX) forecast, partially offset by

a $6 million increase in short-term transportation service revenues, and a $4 million increase primarily due to industrial market usage of natural gas and growth in the number of customers.

Table of Contents

Natural Gas Purchased. The $10 million decrease was driven by:

- a $16 million decrease from lower natural gas prices passed through to customers, partially offset by
- a $2 million increase primarily due to industrial market usage of natural gas and growth in the number of customers.

EBIT. The $5 million increase was mostly the result of higher short-term transportation service revenues.

Nine Months Ended September 30, 2012 Compared to Same Period in 2011

Operating Revenues. The $159 million decrease was driven by:

- a $96 million decrease in customer usage of natural gas primarily due to weather that was more than 19% warmer than in 2011,
- a $58 million decrease from lower natural gas prices passed through to customers. Prices charged to customers are adjusted quarterly based on the 12 month NYMEX forecast,
- a $27 million decrease resulting from a weaker Canadian dollar, and
- a $7 million decrease primarily due to lower short-term storage revenues as a result of an unfavorable regulatory decision affecting 2010 and 2011 storage revenues, partially offset by
- a $17 million increase in short-term transportation service revenues, and
- a $10 million increase from growth in the number of customers.

Natural Gas Purchased. The $131 million decrease was driven by:

- a $67 million decrease due to lower volumes of natural gas sold primarily due to warmer weather,
- a $58 million decrease from lower natural gas prices passed through to customers,
- a $9 million decrease resulting from a weaker Canadian dollar, and
- an $8 million decrease in operating fuel costs, partially offset by
- a $5 million increase from growth in the number of customers.

Operating, maintenance and other. The $3 million decrease was driven primarily by a weaker Canadian dollar.

EBIT. The $24 million decrease was largely the result of lower customer usage due to warmer weather, a weaker Canadian dollar and lower short-term storage revenues, partially offset by higher short-term transportation service revenues and lower operating fuel costs.

Table of Contents

Western Canada Transmission & Processing

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Increase (Decrease)	2012	2011	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$ 348	$ 392	$ (44)	$ 1,143	$ 1,202	$ (59)
Operating expenses						
Natural gas and petroleum products purchased	81	86	(5)	304	275	29
Operating, maintenance and other	142	148	(6)	406	428	(22)
Depreciation and amortization	50	46	4	145	140	5
Operating income	75	112	(37)	288	359	(71)
Other income and expenses	8	7	1	27	14	13
EBIT	$ 83	$ 119	$ (36)	$ 315	$ 373	$ (58)
Pipeline throughput, TBtu	158	180	(22)	490	529	(39)
Volumes processed, TBtu	162	187	(25)	501	537	(36)
Empress inlet volumes, TBtu	121	145	(24)	401	455	(54)
Canadian dollar exchange rate, average	1.00	0.98	0.02	1.00	0.98	0.02

Three Months Ended September 30, 2012 Compared to Same Period in 2011

Operating Revenues. The $44 million decrease was driven by:

- a $47 million decrease due to lower NGL sales prices associated with the Empress operations,
- a $12 million anticipated decrease in contracted volumes in the core gathering and processing business, and
- a $10 million decrease due primarily to lower sales volumes of residual natural gas at the Empress operations, partially offset by
- a $16 million increase in gathering and processing revenues due to contracted volumes from expansions associated with non-conventional supply discoveries in the Horn River and Montney areas of British Columbia, and
- a $9 million increase due to higher NGL sales volumes associated with short-term sales of propane inventory in the Empress operations.

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

- a $10 million decrease in natural gas purchases for extraction at Empress primarily due to decreased volumes, and
- a $6 million decrease due to lower prices of natural gas purchased for the Empress facility, partially offset by

a $10 million increase due primarily to higher volumes of make-up gas purchases at Empress as a result of higher NGL production.

Operating, Maintenance and Other. The $6 million decrease was driven primarily by plant turnaround costs in the third quarter of 2011 that did not recur in the 2012 period.

Depreciation and Amortization. The $4 million increase was driven mainly by expansion projects placed in service and maintenance capital incurred.

EBIT. The $36 million decrease was driven by lower earnings at the Empress NGL business due mainly to lower NGL sales prices. This was partially offset by improved results in the gathering and processing business, reflecting higher contracted volumes from expansions in the Horn River and Montney areas of British Columbia.

Table of Contents

Nine Months Ended September 30, 2012 Compared to Same Period in 2011

Operating Revenues. The $59 million decrease was driven by:

- an $82 million decrease due to lower NGL sales prices associated with the Empress operations,
- a $26 million decrease as a result of a weaker Canadian dollar,
- a $22 million anticipated decrease in contracted volumes in the core gathering and processing business, and
- an $18 million decrease due to lower NGL sales volumes associated with the Empress operations primarily as a result of warmer weather, partially offset by
- a $53 million increase in gathering and processing revenues due to contracted volumes from expansions associated with non-conventional supply discoveries in the Horn River and Montney areas of British Columbia,
- a $14 million increase due primarily to higher sales volumes of residual natural gas at the Empress operations,
- a $13 million increase in transmission revenues, and
- a $9 million increase from recovery of British Columbia carbon tax and other non-income tax expense from customers.

Natural Gas and Petroleum Products Purchased. The $29 million increase was driven by:

- a $21 million increase in natural gas purchases for extraction at Empress primarily due to increased volumes,
- a $10 million non-cash charge to reduce the book value of propane inventory at our Empress operations to estimated net realizable value, and
- a $7 million increase as a result of higher costs of natural gas purchased for the Empress facility caused primarily by higher extraction premiums, partially offset by
- a $6 million decrease due to a weaker Canadian dollar, and
- a $3 million decrease due primarily to lower volumes of make-up gas purchases at Empress as a result of lower NGL production.

Operating, Maintenance and Other. The $22 million decrease was driven by:

- a $21 million decrease due primarily to plant turnaround costs in 2011 that did not recur in the 2012 period,
- a $10 million decrease due to a weaker Canadian dollar, and
- a $9 million decrease due primarily to lower plant fuel and electricity costs at the Empress NGL business, partially offset by
- a $9 million increase in British Columbia carbon tax and other non-income tax expense, and
- a $6 million increase in project development costs due primarily to LNG pipeline project development.

Depreciation and Amortization. The $5 million increase was driven mainly by expansion projects placed in service and maintenance capital incurred, partially offset by a weaker Canadian dollar.

Other Income and Expenses. The $13 million increase was driven primarily by higher AFUDC resulting from increased capital spending on expansion projects.

Table of Contents

EBIT. The $58 million decrease was driven by lower earnings at the Empress NGL business, including an adjustment to reduce the book value of propane inventory and lower contracted volumes in the core gathering and processing business, partially offset by higher gathering and processing earnings from expansions and 2011 plant turnaround costs that did not recur in 2012.

Matters Affecting Future Western Canada Transmission & Processing Results

Non-cash charges of $10 million ($8 million after tax) were recorded in 2012 to reduce the book value of propane inventory at our Empress operations to estimated net realizable value. If estimated future prices for propane increase by December 31, 2012, write-downs previously recorded, in part or in full, may be reversed. Conversely, if estimated future prices were to decline further, additional write-downs could be required on volumes held at September 30, 2012 or increased during the remainder of 2012.

Field Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Increase (Decrease)	2012	2011	Increase (Decrease)
	(in millions, except where noted)					
Equity in earnings of unconsolidated affiliates	$ 62	$ 134	$ (72)	$ 221	$ 353	$ (132)
EBIT	$ 62	$ 134	$ (72)	$ 221	$ 353	$ (132)
Natural gas gathered and processed/transported, TBtu/d (a,b)	7.2	7.1	0.1	7.1	6.9	0.2
NGL production, MBbl/d (a,c)	398	392	6	401	375	26
Average natural gas price per MMBtu (d)	$ 2.81	$ 4.19	$ (1.38)	$ 2.59	$ 4.21	$ (1.62)
Average NGL price per gallon (e)	$ 0.72	$ 1.24	$ (0.52)	$ 0.83	$ 1.21	$ (0.38)
Average crude oil price per barrel (f)	$ 92.22	$ 89.76	$ 2.46	$ 96.17	$ 95.48	$ 0.69

(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, 2012 Compared to Same Period in 2011

EBIT. Lower equity earnings of $72 million were mainly the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

- an $89 million decrease from commodity-sensitive processing arrangements due to decreased NGL and natural gas prices, net of increased crude oil prices,

- a $17 million decrease primarily attributable to higher operating costs, largely resulting from a planned increase in repairs and maintenance activities due to asset growth, and

- an $8 million decrease in earnings from DCP Partners as a result of mark-to-market losses on derivative instruments used to protect distributable cash flows and lower commodity prices, which were partially offset by decreased depreciation expense as a result of an adjustment to the remaining useful lives of DCP Partners gathering, transmission, processing, storage and other assets during the second quarter of 2012, as described below, partially offset by

Table of Contents

a $19 million increase due to decreased depreciation expense as a result of changes to the remaining useful lives of DCP Midstream s gathering, transmission, processing, storage and other assets during the second quarter of 2012. The key contributing factor to the change is an increase in estimated remaining economically recoverable commodity reserves, resulting from advances in extraction processes as well as improved technology used to locate commodity reserves,

a $13 million increase in gains associated with the issuance of partnership units by DCP Partners,

a $6 million increase attributable to lower interest expense due to higher capitalized interest in 2012 as a result of growth, and

a $4 million increase in gathering and processing volumes, attributable to asset growth across certain geographic regions.

Nine Months Ended September 30, 2012 Compared to Same Period in 2011

EBIT. Lower equity earnings of $132 million were mainly the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

a $205 million decrease from commodity-sensitive processing arrangements due to decreased NGL and natural gas prices, net of increased crude oil prices,

a $23 million decrease primarily attributable to higher operating costs, largely resulting from a planned increase in repairs and maintenance activities due to asset growth, and

a $16 million decrease attributable to unfavorable results from gas and NGL marketing, partially offset by

a $41 million increase in gathering and processing volumes, as a result of asset growth across certain geographic regions and the absence of severe weather which caused wellhead freeze-offs which shut in gas wells and reduced recoveries in 2011,

a $41 million increase due to decreased depreciation expense as a result of changes to the remaining useful lives of DCP Midstream s gathering, transmission, processing, storage and other assets during the second quarter of 2012 as described above,

a $20 million increase in gains associated with the issuance of partnership units by DCP Partners, and

a $7 million increase attributable to lower interest expense due to higher capitalized interest in 2012 as a result of growth.

Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Increase (Decrease)	2012	2011	Increase (Decrease)
	(in millions)					
Operating revenues	$ 19	$ 20	$ (1)	$ 59	$ 53	$ 6

Operating expenses	46	42	4	139	125	14
Operating loss	(27)	(22)	(5)	(80)	(72)	(8)
Other income and expenses	(2)	(1)	(1)	(3)	(4)	1
EBIT	$ (29)	$ (23)	$ (6)	$ (83)	$ (76)	$ (7)

Three Months and Nine Months Ended September 30, 2012 Compared to Same Periods in 2011

EBIT. The $6 million and $7 million decreases in EBIT for three months and nine months in 2012, respectively, reflect higher corporate costs, including employee benefit costs.

Table of Contents

Impairment of Goodwill

We performed either a qualitative assessment or a quantitative assessment of each of our reporting units based on management s judgment. With respect to our qualitative assessments, we considered events and circumstances specific to us, such as macroeconomic conditions, industry and market considerations, cost factors and overall financial performance, when evaluating whether it was more likely than not that the fair values of our reporting units were less than their respective carrying amounts.

In connection with our quantitative assessments, we primarily used a discounted cash flow analysis to determine fair values of those reporting units. The long-term growth rates used for the reporting units that we quantitatively assessed reflect continued expansion of our assets, driven by new natural gas supplies such as shale gas in North America and increasing demand for natural gas transportation capacity on our pipeline systems primarily as a result of forecasted growth in natural gas-fired power plants. We assumed a weighted average long-term growth rate of 2.9% for our 2012 quantitative goodwill impairment analysis. Had we assumed a 100 basis point lower growth rate for each of the reporting units that we quantitatively assessed, there would have been no impairment of goodwill. We continue to monitor the effects of the global economic downturn with respect to the long-term cost of capital utilized to calculate our reporting units fair values. For our 2012 quantitative goodwill impairment analysis, we assumed weighted-average costs of capital ranging from 5.5% to 6.3% that market participants would use. Had we assumed a 100 basis point increase in the weighted-average cost of capital for each of the reporting units that we quantitatively assessed, there would have been no impairment of goodwill. For our regulated businesses in Canada, if an increase in the cost of capital occurred, we assumed that the effect on the corresponding reporting unit s fair value would be ultimately offset by a similar increase in the reporting unit s regulated revenues since those rates include a component that is based on the reporting unit s cost of capital.

Based on the results of our annual goodwill impairment testing, no indicators of impairment were noted and the fair values of the reporting units that we quantitatively assessed at April 1, 2012 (our testing date) were substantially in excess of their respective carrying values. No triggering events or changes in circumstances occurred during the period April 1, 2012 through September 30, 2012 that would warrant re-testing for goodwill impairment.

LIQUIDITY AND CAPITAL RESOURCES

As of September 30, 2012, we had negative working capital of $2,402 million. This balance includes commercial paper totaling $1,317 million and current maturities of long-term debt of $1,281 million. We will rely upon cash flows from operations and various financing transactions, which may include issuances of short-term and long-term debt, to fund our liquidity and capital requirements for the next 12 months. We have access to four revolving credit facilities, with total combined capital commitments of $2,912 million, with $1,590 million available at September 30, 2012. These facilities are used principally as back-stops for commercial paper programs or for the issuance of letters of credit. At Union Gas, we primarily use commercial paper to support short-term working capital fluctuations. At Spectra Capital, Spectra Energy Partners and Westcoast, we primarily use commercial paper for temporary funding of 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 11 of Notes to Condensed Consolidated Financial Statements for a discussion of available credit facilities and Financing Cash Flows and Liquidity for a discussion of effective shelf registrations.

Operating Cash Flows

Net cash provided by operating activities decreased $233 million to $1,454 million for the nine months ended September 30, 2012 compared to the same period in 2011, driven mostly by lower distributions received from DCP Midstream, higher tax payments in 2012 and lower overall earnings.

Table of Contents

Investing Cash Flows

Net cash used in investing activities decreased $96 million to $1,450 million in the first nine months of 2012 compared to the same period in 2011. This change was driven by the acquisition of Big Sandy in 2011, partially offset by net sales of Spectra Energy Partners AFS marketable securities in 2011 and increased capital expenditures in 2012.

	Nine Months Ended September 30, 2012	2011
	(in millions)	
Capital and Investment Expenditures		
U.S. Transmission (a)	$ 651	$ 534
Distribution	172	200
Western Canada Transmission & Processing	548	515
Other	47	56
Total	$ 1,418	$ 1,305

(a) Excludes $30 million paid in 2012 for amounts previously withheld from the purchase price consideration of the acquisition of Bobcat in 2010 and the $390 million acquisition of Big Sandy in 2011.

Capital and investment expenditures for the nine months ended September 30, 2012 consisted of $952 million for expansion projects and $466 million for maintenance and other projects.

Excluding any expenditures related to the recently announced pending Sand Hills and Southern Hills transaction, we project 2012 capital and investment expenditures of approximately $2.1 billion, consisting of approximately $0.9 billion for U.S. Transmission, $0.3 billion for Distribution, $0.8 billion for Western Canada Transmission & Processing and $ 0.1 billion for Other. Total projected 2012 capital and investment expenditures include approximately $1.4 billion of expansion capital expenditures and $0.7 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 adjust our capital plans as required.

Financing Cash Flows and Liquidity

Net cash used in financing activities decreased $153 million to $35 million in the first nine months of 2012 compared to the same period of 2011. This change was driven by:

- a $289 million decrease in 2011 of Spectra Energy Partners revolving credit facility borrowings outstanding, and
- a $109 million increase in 2012 in net proceeds from commercial paper issued, partially offset by
- proceeds of $213 million in 2011 from the issuance of Spectra Energy Partners common units used to fund a portion of the acquisition of Big Sandy, and
- a $44 million increase in 2012 in dividends paid on common stock, driven primarily by higher per-share dividend rates.

On July 17, 2012, Algonquin issued $350 million aggregate principal amount of 3.51% notes due in 2024. Net proceeds from the offering were used for general corporate purposes.

Available Credit Facilities and Restrictive Debt Covenants. See Note 11 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 require our consolidated debt-to-total-capitalization ratio, as defined in the agreement, to be 65% or lower. Per the terms of the agreement, collateralized debt and Spectra Energy Partners debt and equity are excluded in the calculation of the ratio. As of September 30, 2012, this ratio was 59%. 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. Based on the strength of our total capitalization as of September 30, 2012, it is unlikely that a material adverse effect would occur as a result of a weakened Canadian dollar.

Credit Ratings

	Standard & Poor s	Moody s Investors Service	Fitch Ratings	DBRS
As of September 30, 2012				
Spectra Capital (a)	BBB	Baa2	BBB	n/a
Texas Eastern (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-	Ba1	n/a	n/a
M&N LP (b)	A	A2/A3	n/a	A
Spectra Energy Partners (a)	BBB	Baa3	BBB	n/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. Our near-term objective is to increase our dividend by at least $0.08 per year and to continue paying cash dividends in the future. In the long-term, we anticipate paying dividends at an average payout ratio level of between 60%-65% of our 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. We declared a quarterly cash dividend of $0.305 per common share on October 31, 2012 payable on December 10, 2012 to shareholders of record at the close of business on November 12, 2012. The new dividend level represents a nearly 9% increase over the previous level.

Other Financing Matters. On October 24, 2012, Texas Eastern issued $500 million aggregate principal amount of 2.80% notes due in 2022. We primarily used the proceeds from the offering to repay outstanding commercial paper.

Spectra Energy Corp and Spectra Capital have an effective shelf registration statement on file with the SEC to register the issuance of unspecified amounts of various equity and debt securities, and Spectra Energy Partners has an effective shelf registration statement on file with the SEC to register the issuance of unspecified amounts of limited partner common units and various debt securities. In addition, Westcoast and Union Gas have debt base shelf prospectuses on file with Canadian securities regulators, which were filed in October 2012 to replace expiring prospectuses, to register the issuance of an aggregate 1.6 billion Canadian dollars (approximately $1.6 billion) of debt securities in the Canadian market.

Table of Contents

OTHER ISSUES

New Accounting Pronouncements. There were no significant accounting pronouncements adopted during the nine months ended September 30, 2012 that had a material impact on our consolidated results of operations, financial position or cash flows.

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, 2011. We believe our exposure to market risk has not changed materially since then.

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, 2012, and, based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective at the reasonable assurance level.

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, 2012 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

We have no material pending legal proceedings that are required to be disclosed hereunder. For information regarding other legal proceedings, including regulatory and environmental matters, see Notes 3 and 14 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, 2011, which could materially affect our financial condition or future results. There have been no material changes to those risk factors.

Table of Contents

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.

Table of Contents

(a) Exhibits

Exhibit Number	
*31.1	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification 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, 2012

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

Date: November 8, 2012

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