DEVON ENERGY CORP/DE

FORM 10-Q
(Quarterly Report)

Filed 11/02/11 for the Period Ending 09/30/11

Address	333 W. SHERIDAN AVENUE OKLAHOMA CITY, OK 73102
Telephone	4055528183
CIK	0001090012
Symbol	DVN
SIC Code	1311 - Crude Petroleum and Natural Gas
Fiscal Year	12/31

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2011

or

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

Commission File Number 001-32318

DEVON ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**73-1567067**
(State of other jurisdiction of incorporation or organization)	*(I.R.S. Employer identification No.)*
20 North Broadway, Oklahoma City, Oklahoma	**73102-8260**
(Address of principal executive offices)	*(Zip code)*

Registrant's telephone number, including area code: (405) 235-3611

Former name, former address and former fiscal year, if changed from last report: Not applicable

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 ☑ 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 ☑ 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 the Exchange Act.

Large accelerated filer ☑	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	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 ☑

On October 21, 2011, 403.9 million shares of common stock were outstanding.

DEVON ENERGY CORPORATION

FORM 10-Q
For the Quarterly Period Ended September 30, 2011

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DEFINITIONS

Measurements of Oil, Natural Gas and Natural Gas Liquids

- "NGL" or "NGLs" means natural gas liquids.
- "Oil" includes crude oil and condensate.
- "Bbl" means barrel of oil. One barrel equals 42 U.S. gallons.
  - "MBbls" means thousand barrels.
  - "MMBbls" means million barrels.
  - "MBbls/d" means thousand barrels per day.
- "Mcf" means thousand cubic feet of natural gas.
  - "MMcf" means million cubic feet.
  - "Bcf" means billion cubic feet.
  - "Bcfe" means billion cubic feet equivalent.
  - "MMcf/d" means million cubic feet per day.
- "Boe" means barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas.
  - "MBoe" means thousand Boe.
  - "MMBoe" means million Boe.
  - "MBoe/d" means thousand Boe per day.
- "Btu" means British thermal units, a measure of heating value.
  - "MMBtu" means million Btu.
  - "MMBtu/d" means million Btu per day.

Geographic Areas

- "Canada" means the operations of Devon encompassing oil and gas properties located in Canada.
- "International" means the discontinued operations of Devon that encompass oil and gas properties that lie outside the United States and Canada.
- "North America Onshore" means the operations of Devon encompassing oil and gas properties in the continental United States and Canada.
- "U.S. Offshore" means the divested operations of Devon that encompassed oil and gas properties in the Gulf of Mexico.
- "U.S. Onshore" means the properties of Devon encompassing oil and gas properties in the continental United States.

Other

- "FASB" means the United States Financial Accounting Standards Board.
- "Federal Funds Rate" means the interest rate at which depository institutions lend balances at the Federal Reserve to other depository institutions overnight.
- "Inside FERC" refers to the publication Inside F.E.R.C.'s Gas Market Report.
- "LIBOR" means London Interbank Offered Rate.
- "NYMEX" means New York Mercantile Exchange.

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs and plans and objectives of management for future operations, are forward-looking statements. Such forward-looking statements are based on our examination of historical operating trends, the information used to prepare the December 31, 2010 reserve reports and other data in our possession or available from third parties. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as “may,” “will,” “expect,” “intend,” “project,” “estimate,” “anticipate,” “believe,” or “continue” or similar terminology. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, our assumptions about:

- energy markets, including the supply and demand for oil, gas, NGLs and other products or services, as well as the prices of oil, gas, NGLs and other products or services, including regional pricing differentials;
- production levels, including Canadian production subject to government royalties, which fluctuate with prices and production;
- reserve levels;
- competitive conditions;
- technology;
- the availability of capital resources within the securities or capital markets and related risks such as general credit, liquidity, market and interest-rate risks;
- capital expenditure and other contractual obligations;
- currency exchange rates;
- the weather;
- inflation;
- the availability of goods and services;
- drilling risks;
- future processing volumes and pipeline throughput;
- general economic conditions, whether internationally, nationally or in the jurisdictions in which we or our subsidiaries conduct business;
- public policy and government regulatory changes, including changes in royalty, production tax and income tax regimes, changes in hydraulic fracturing regulation and changes in environmental laws, regulation and liability;
- terrorism;
- occurrence of property acquisitions or divestitures; and
- other factors disclosed in Devon’s 2010 Annual Report on Form 10-K under “Item 1A. Risk Factors, “ “Item 2. Properties,” “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Item 7A. Quantitative and Qualitative Disclosures About Market Risk.”

All subsequent written and oral forward-looking statements attributable to Devon, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements. We assume no duty to update or revise our forward-looking statements based on changes in internal estimates or expectations or otherwise.

PART I. Financial Information

Item 1. ***Consolidated Financial Statements***

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	September 30, 2011 (Unaudited)	December 31, 2010
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5,618	$ 2,866
Short-term investments	1,231	145
Accounts receivable	1,430	1,202
Current assets held for sale	26	563
Other current assets	1,302	779
Total current assets	9,607	5,555
Property and equipment, at cost:		
Oil and gas, based on full cost accounting:		
Subject to amortization	59,331	56,012
Not subject to amortization	4,061	3,434
Total oil and gas	63,392	59,446
Other	4,778	4,429
Total property and equipment, at cost	68,170	63,875
Less accumulated depreciation, depletion and amortization	(45,000)	(44,223)
Property and equipment, net	23,170	19,652
Goodwill	5,951	6,080
Long-term assets held for sale	111	859
Other long-term assets	1,027	781
Total assets	$ 39,866	$ 32,927
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable — trade	$ 1,512	$ 1,411
Revenues and royalties due to others	659	538
Short-term debt	3,288	1,811
Current liabilities associated with assets held for sale	50	305
Other current liabilities	522	518
Total current liabilities	6,031	4,583
Long-term debt	5,969	3,819
Asset retirement obligations	1,460	1,423
Liabilities associated with assets held for sale	2	26
Other long-term liabilities	493	1,067
Deferred income taxes	4,809	2,756
Stockholders' equity:		
Common stock of $0.10 par value. Authorized 1.0 billion shares; issued 408.0 million and 431.9 million shares in 2011 and 2010, respectively	41	43
Additional paid-in capital	3,827	5,601
Retained earnings	15,870	11,882
Accumulated other comprehensive earnings	1,412	1,760
Treasury stock, at cost. 0.8 million and 0.4 million shares in 2011 and 2010, respectively	(48)	(33)
Total stockholders' equity	21,102	19,253
Commitments and contingencies (Note 11)		
Total liabilities and stockholders' equity	$ 39,866	$ 32,927

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(Unaudited) (In millions, except per share amounts)			
Revenues:				
Oil, gas and NGL sales	$ 2,111	$ 1,683	$ 6,171	$ 5,535
Oil, gas and NGL derivatives	738	209	986	874
Marketing and midstream revenues	653	461	1,712	1,396
Total revenues	3,502	2,353	8,869	7,805
Expenses and other, net:				
Lease operating expenses	475	415	1,352	1,271
Taxes other than income taxes	108	95	336	288
Marketing and midstream operating costs and expenses	515	336	1,304	1,013
Depreciation, depletion and amortization of oil and gas properties	504	397	1,431	1,249
Depreciation and amortization of non-oil and gas properties	62	66	191	192
Accretion of asset retirement obligations	23	21	69	71
General and administrative expenses	138	131	403	399
Restructuring costs	(3)	63	(2)	55
Interest expense	104	83	270	280
Interest-rate and other financial instruments	40	56	33	121
Other, net	(2)	(9)	(14)	(34)
Total expenses and other, net	1,964	1,654	5,373	4,905
Earnings from continuing operations before income taxes	1,538	699	3,496	2,900
Income tax expense (benefit):				
Current	(248)	(310)	(301)	696
Deferred	746	580	2,184	349
Total income tax expense	498	270	1,883	1,045
Earnings from continuing operations	1,040	429	1,613	1,855
Discontinued operations:				
Earnings (loss) from discontinued operations before income taxes	(4)	1,710	2,584	2,320
Discontinued operations income tax expense (benefit)	(2)	49	—	187
Earnings (loss) from discontinued operations	(2)	1,661	2,584	2,133
Net earnings	$ 1,038	$ 2,090	$ 4,197	$ 3,988
Basic net earnings per share:				
Basic earnings from continuing operations per share	$ 2.51	$ 0.99	$ 3.83	$ 4.20
Basic earnings from discontinued operations per share	—	3.82	6.14	4.82
Basic net earnings per share	$ 2.51	$ 4.81	$ 9.97	$ 9.02
Diluted net earnings per share:				
Diluted earnings from continuing operations per share	$ 2.50	$ 0.98	$ 3.82	$ 4.18
Diluted earnings from discontinued operations per share	—	3.81	6.11	4.81
Diluted net earnings per share	$ 2.50	$ 4.79	$ 9.93	$ 8.99

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE EARNINGS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(Unaudited) (In millions)			
Net earnings	$ 1,038	$ 2,090	$ 4,197	$ 3,988
Foreign currency translation:				
Change in cumulative translation adjustment	(644)	223	(382)	119
Foreign currency translation income tax benefit (expense)	29	(12)	17	(7)
Foreign currency translation total	(615)	211	(365)	112
Pension and postretirement benefit plans:				
Recognition of net actuarial loss and prior service cost in earnings	9	8	26	24
Pension and postretirement benefit plans income tax expense	(3)	(3)	(9)	(9)
Pension and postretirement benefit plans total	6	5	17	15
Other comprehensive (loss) earnings, net of tax	(609)	216	(348)	127
Comprehensive earnings	$ 429	$ 2,306	$ 3,849	$ 4,115

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Earnings	Treasury Stock	Total Stockholders' Equity
				(Unaudited) (In millions)			
Nine Months Ended September 30, 2011:							
Balance as of December 31, 2010	432	$ 43	$ 5,601	$11,882	$ 1,760	$ (33)	$ 19,253
Net earnings	—	—	—	4,197	—	—	4,197
Other comprehensive (loss) earnings, net of tax	—	—	—	—	(348)	—	(348)
Stock option exercises	2	—	101	—	—	—	101
Common stock repurchased	—	—	—	—	—	(2,008)	(2,008)
Common stock retired	(26)	(2)	(1,991)	—	—	1,993	—
Common stock dividends	—	—	—	(209)	—	—	(209)
Share-based compensation	—	—	105	—	—	—	105
Share-based compensation tax benefits	—	—	11	—	—	—	11
Balance as of September 30, 2011	408	$ 41	$ 3,827	$15,870	$ 1,412	$ (48)	$ 21,102
Nine Months Ended September 30, 2010:							
Balance as of December 31, 2009	447	$ 45	$ 6,527	$ 7,613	$ 1,385	$ —	$ 15,570
Net earnings	—	—	—	3,988	—	—	3,988
Other comprehensive earnings, net of tax	—	—	—	—	127	—	127
Stock option exercises	—	—	18	—	—	—	18
Common stock repurchased	—	—	—	—	—	(950)	(950)
Common stock retired	(15)	(2)	(941)	—	—	943	—
Common stock dividends	—	—	—	(211)	—	—	(211)
Share-based compensation	—	—	103	—	—	—	103
Share-based compensation tax benefits	—	—	7	—	—	—	7
Balance as of September 30, 2010	432	$ 43	$ 5,714	$11,390	$ 1,512	$ (7)	$ 18,652

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(Unaudited) (In millions)	
Cash flows from operating activities:		
Net earnings	$ 4,197	$ 3,988
Earnings from discontinued operations, net of tax	(2,584)	(2,133)
Adjustments to reconcile earnings from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	1,622	1,441
Deferred income tax expense	2,184	349
Unrealized change in fair value of financial instruments	(661)	(136)
Other noncash charges	185	154
Net (increase) decrease in working capital	(308)	164
Decrease in long-term other assets	51	28
(Decrease) increase in long-term other liabilities	(459)	57
Cash from operating activities — continuing operations	4,227	3,912
Cash from operating activities — discontinued operations	(13)	324
Net cash from operating activities	4,214	4,236
Cash flows from investing activities:		
Capital expenditures	(5,515)	(4,793)
Proceeds from property and equipment divestitures	13	4,131
Purchases of short-term investments	(5,751)	—
Redemptions of short-term investments	4,665	—
Redemptions of long-term investments	10	20
Other	(33)	(13)
Cash from investing activities — continuing operations	(6,611)	(655)
Cash from investing activities — discontinued operations	3,162	2,298
Net cash from investing activities	(3,449)	1,643
Cash flows from financing activities:		
Net commercial paper borrowings (repayments)	3,196	(1,432)
Proceeds from borrowings of long-term debt, net of issuance costs	2,221	—
Debt repayments	(1,760)	(350)
Proceeds from stock option exercises	101	18
Repurchases of common stock	(1,987)	(929)
Dividends paid on common stock	(209)	(211)
Excess tax benefits related to share-based compensation	11	7
Net cash from financing activities	1,573	(2,897)
Effect of exchange rate changes on cash	(10)	5
Net increase in cash and cash equivalents	2,328	2,987
Cash and cash equivalents at beginning of period (including cash related to assets held for sale)	3,290	1,011
Cash and cash equivalents at end of period (including cash related to assets held for sale)	$ 5,618	$ 3,998

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Summary of Significant Accounting Policies

The accompanying unaudited consolidated financial statements and notes of Devon Energy Corporation ("Devon") have been prepared pursuant to the rules and regulations of the United States Securities and Exchange Commission. Pursuant to such rules and regulations, certain disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been omitted. The accompanying consolidated financial statements and notes should be read in conjunction with the consolidated financial statements and notes included in Devon's 2010 Annual Report on Form 10-K.

The unaudited interim consolidated financial statements furnished in this report reflect all adjustments that are, in the opinion of management, necessary to a fair statement of Devon's financial position as of September 30, 2011 and Devon's results of operations and cash flows for the three-month and nine-month periods ended September 30, 2011 and 2010.

Recently Issued Accounting Standards Not Yet Adopted

In May 2011, the FASB issued Accounting Standards Update 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS* . This update does not require additional fair value measurements and is not intended to establish valuation standards or affect valuation practices outside of financial reporting. However, beginning in Devon's 2011 Annual Report on Form 10-K, this update will require certain additional disclosures related to Devon's fair value measurements. Devon does not expect the adoption of this update will materially impact its financial statement disclosures.

In June 2011, the FASB issued Accounting Standards Update 2011-05, *Presentation of Comprehensive Income* . Beginning in Devon's 2011 Annual Report on Form 10-K, this update will give Devon the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. Devon has not determined which presentation option it will choose but does not expect its selection to materially impact the presentation of its financial statements.

In September 2011, the FASB issued Accounting Standards Update 2011-08: *Intangibles — Goodwill and Other (Topic 350): Testing Goodwill for Impairment* . This update permits an entity to make a qualitative assessment of whether it is more likely than not that a reporting unit's fair value is less than its carrying amount before applying the two-step goodwill impairment test. An entity is not required to calculate the fair value of a reporting unit unless the entity determines that it is more likely than not that its fair value is less than its carrying amount. Devon will adopt the provisions for this update in its annual impairment test as of October 31, 2011. Devon does not expect the adoption of this update will impact its goodwill value.

2. Short-Term Investments

Devon periodically invests excess cash in U.S. Treasuries, commercial paper and other marketable securities with original maturities exceeding three months. Such securities are presented as short-term investments in the accompanying consolidated balance sheets.

During the first nine months of 2011, Devon invested a portion of the International offshore divestiture proceeds it had received, causing short-term investments to increase. The carrying value of these investments approximates their fair value. As of September 30, 2011, the average remaining maturity of our short-term investments was 97 days, with a weighted average yield of 0.2 percent.

3. Accounts Receivable

The components of accounts receivable include the following:

	September 30, 2011	December 31, 2010
	(In millions)	
Oil, gas and NGL sales	$ 819	$ 786
Joint interest billings	269	204
Marketing and midstream revenues	185	165
Other	166	57
Gross accounts receivable	1,439	1,212
Allowance for doubtful accounts	(9)	(10)
Net accounts receivable	$ 1,430	$ 1,202

4. Derivative Financial Instruments

Objectives and Strategies

Devon periodically enters into derivative financial instruments to manage its exposure to market risks, such as changes in commodity prices, interest rates and currency exchange rates. Devon does not hold or issue derivative financial instruments for speculative trading purposes and has elected not to designate any of its derivative instruments for hedge accounting treatment.

Devon's commodity derivative financial instruments include financial price swaps, basis swaps, costless price collars and call options. Under the terms of the price swaps, Devon receives a fixed price for its production and pays a variable market price to the contract counterparty. For the basis swaps, Devon receives a fixed differential between two regional gas index prices and pays a variable differential on the same two index prices to the contract counterparty. The price collars set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon will cash-settle the difference with the counterparty to the collars. Under the terms of the call options, Devon sold to counterparties the right to purchase production at a predetermined price.

Devon's interest rate swaps include contracts in which Devon receives a fixed rate and pays a variable rate on a total notional amount.

Devon's foreign currency contracts include forward contracts that hedge certain monetary assets denominated in Canadian dollars.

Credit Risk

Through its derivative financial instruments, Devon exposes itself to credit risk, which arises from the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are placed with a number of counterparties whom Devon believes are minimal credit risks. It is Devon's policy to enter into derivative contracts only with investment grade rated counterparties deemed by management to be competent and competitive market makers. Additionally, Devon's derivative contracts generally require cash collateral to be posted if either its or the counterparty's credit rating falls below investment grade. The mark-to-market exposure threshold, above which collateral must be posted, decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $55 million for the majority of Devon's contracts. As of September 30, 2011, the credit ratings of all Devon's counterparties were investment grade.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(Unaudited)

Commodity Derivatives

As of September 30, 2011, Devon had the following open oil derivative positions. Devon's oil derivatives settle against the average of the prompt month NYMEX West Texas Intermediate futures price.

Production Period	Price Swaps		Price Collars			Call Options Sold	
Period	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Q4 2011	—	—	45,000	$ 75.00	$ 108.89	19,500	$ 95.00
Q1-Q4 2012	22,000	$ 107.17	54,000	$ 85.74	$ 126.42	19,500	$ 95.00
Q1-Q4 2013	—	—	7,000	$ 90.00	$ 125.12	—	—

As of September 30, 2011, Devon had the following open natural gas derivative positions. Devon's natural gas derivative swaps, collars and call options settle against the Inside FERC first of the month Henry Hub index.

Production Period	Price Swaps		Price Collars			Call Options Sold	
Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)	Volume (MMBtu/d)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)
Q4 2011	712,500	$ 5.51	287,935	4.66	5.07	—	—
Q1-Q4 2012	325,000	$ 5.09	490,000	4.75	5.57	487,500	$ 6.00

Basis Swaps			
Production Period	Index	Volume (MMBtu/d)	Weighted Average Differential to Henry Hub ($/MMBtu)
Q4 2011	Panhandle Eastern Pipeline	150,000	$(0.33)

As of September 30, 2011, Devon had the following open NGL derivative positions:

Basis Swaps			
Production Period	Pay	Volume (Bbls/d)	Weighted Average Differential to WTI ($/Bbl)
Q4 2011	Natural Gasoline	332	$ (9.75)
Q1-Q4 2012	Natural Gasoline	500	$(10.10)
Q1-Q4 2013	Natural Gasoline	500	$ (6.80)

Interest Rate Derivatives

As of September 30, 2011, Devon had the following open interest rate derivative positions:

Fixed-to-Floating Swaps			
Notional	Fixed Rate Received	Variable Rate Paid	Expiration
(In millions)			
$100	1.90%	Federal funds rate	August 3, 2012
500	3.90%	Federal funds rate	July 18, 2013
250	3.85%	Federal funds rate	July 22, 2013
$850	3.65%		

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(Unaudited)

Foreign Currency Derivative

As of September 30, 2011, Devon had the following open foreign currency derivative position:

		Forward Contract		
Currency	Contract Type	CAD Notional (In millions)	Fixed Rate Received (CAD-USD)	Expiration
Canadian Dollar	Sell	$305	0.9615	December 30, 2011

Financial Statement Presentation

The following table presents the derivative fair values included in the accompanying consolidated balance sheets.

	Balance Sheet Caption	September 30, 2011	December 31, 2010
		(In millions)	
Asset derivatives:			
Commodity derivatives	Other current assets	$ 672	$ 248
Commodity derivatives	Other long-term assets	188	1
Interest rate derivatives	Other current assets	29	100
Interest rate derivatives	Other long-term assets	27	40
Total asset derivatives		$ 916	$ 389
Liability derivatives:			
Commodity derivatives	Other current liabilities	$ 38	$ 50
Commodity derivatives	Other long-term liabilities	20	142
Total liability derivatives		$ 58	$ 192

The following table presents the cash settlements and unrealized gains and losses on fair value changes included in the accompanying consolidated statements of operations associated with these derivative financial instruments. Cash settlements and unrealized gains and losses on fair value changes associated with Devon's commodity derivatives are presented in the "Oil, gas and NGL derivatives" caption in the accompanying consolidated statements of operations. Cash settlements and unrealized gains and losses on fair value changes associated with Devon's interest rate and foreign currency derivatives are presented in the "Interest-rate and other financial instruments" caption in the accompanying consolidated statements of operations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions)			
Cash settlements:				
Commodity derivatives	$ 96	$ 232	$ 241	$ 580
Interest rate derivatives	52	17	73	37
Foreign currency derivatives	22	—	22	—
Total cash settlements	170	249	336	617
Unrealized gains (losses):				
Commodity derivatives	642	(23)	745	294
Interest rate derivatives	(55)	(72)	(84)	(158)
Total unrealized gains (losses)	587	(95)	661	136
Net gain (loss) recognized on statement of operations	$ 757	$ 154	$ 997	$ 753

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(Unaudited)

5. Other Current Assets

The components of other current assets include the following:

	September 30, 2011	December 31, 2010
	(In millions)	
Derivative financial instruments	$ 701	$ 348
Income taxes receivable	420	270
Inventories	98	120
Other	83	41
Other current assets	$ 1,302	$ 779

6. Goodwill

During the first nine months of 2011, Devon’s Canadian goodwill decreased $129 million entirely due to foreign currency translation.

7. Debt

Credit Lines

Devon has a $2.7 billion syndicated, unsecured revolving line of credit (the “Senior Credit Facility”). As of September 30, 2011, Devon had no borrowings under the Senior Credit Facility, but its borrowing capacity was reduced $0.1 billion by outstanding letters of credit.

The Senior Credit Facility contains only one material financial covenant. This covenant requires Devon’s ratio of total funded debt to total capitalization to be less than 65 percent. The credit agreement contains definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in the consolidated financial statements. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling impairments or goodwill impairments. As of September 30, 2011, Devon was in compliance with this covenant. Devon’s debt-to-capitalization ratio at September 30, 2011, as calculated pursuant to the terms of the agreement, was 22 percent.

2.40% Notes Due July 15, 2016, 4.00% Notes Due July 15, 2021 and 5.60% Notes Due July 15, 2041

In July 2011, Devon issued $2.25 billion of senior notes. The $2.22 billion of net proceeds received after discounts and issuance costs, were used to repay outstanding commercial paper balances as of June 30, 2011. These notes are unsecured and unsubordinated obligations of Devon.

Commercial Paper

In March 2011, Devon’s Board of Directors authorized an increase in its commercial paper program from $2.2 billion to $5.0 billion. Commercial paper debt generally has a maturity of between 1 and 90 days, although it can have a maturity of up to 365 days, and bears interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market.

Although Devon ended the third quarter of 2011 with approximately $6.8 billion of cash and short-term investments, the vast majority of this amount consists of proceeds from its International divestitures. Based on Devon’s evaluation of future cash needs across its operations in the United States and Canada, these proceeds remain outside of the United States.

Consequently, subsequent to the commercial paper repayment in July 2011 noted above, Devon utilized additional commercial paper borrowings primarily to fund debt maturities, capital expenditures, common stock repurchases and dividends in excess of cash flow generated by its United States operating activities. As of September 30, 2011, Devon’s average borrowing rate on its $3.2 billion of commercial paper borrowings was 0.27 percent. At December 31, 2010, Devon had no borrowings of commercial paper.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(Unaudited)

8. Asset Retirement Obligations

The schedule below summarizes changes in Devon's asset retirement obligations.

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(In millions)	
Asset retirement obligations as of beginning of period	$ 1,497	$ 1,513
Liabilities incurred	38	36
Liabilities settled	(56)	(94)
Revision of estimated obligation	19	194
Liabilities assumed by others	—	(256)
Accretion expense on discounted obligation	69	71
Foreign currency translation	(41)	10
Asset retirement obligations as of end of period	1,526	1,474
Less current portion	66	80
Asset retirement obligations, long-term	$ 1,460	$ 1,394

During the first nine months of 2010, Devon recognized a revision to its asset retirement obligations totaling $194 million. The increase was primarily due to an overall increase in abandonment cost estimates and a decrease in the discount rate used to calculate the present value of the obligations.

During the first nine months of 2010, Devon reduced its asset retirement obligations by $256 million for those obligations that were assumed by purchasers of Devon's Gulf of Mexico oil and gas properties in 2010.

9. Retirement Plans

Net Periodic Benefit Cost

The following table presents the components of net periodic benefit cost for Devon's pension and other postretirement benefit plans.

	Pension Benefits				Other Postretirement Benefits			
	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010	2011	2010	2011	2010
	(In millions)							
Service cost	$ 10	$ 9	$ 28	$ 25	$ —	$ —	$ 1	$ —
Interest cost	15	15	45	43	—	1	1	3
Expected return on plan assets	(11)	(10)	(32)	(28)	—	—	—	—
Amortization of prior service cost	1	—	3	2	—	1	(1)	1
Net actuarial loss	8	7	24	21	—	—	—	—
Net periodic benefit cost	$ 23	$ 21	$ 68	$ 63	$ —	$ 2	$ 1	$ 4

Pension Plan Assets

Devon previously disclosed in its financial statements for the year ended December 31, 2010, that it expected to contribute $84 million to its qualified pension plans in 2011. During 2011, Devon increased its estimated contribution to $446 million and has fully funded the contribution as of September 30, 2011. The increase in Devon's 2011 contributions is due to increased discretionary funding.

As a result of the discretionary contributions noted above, Devon amended its target allocation for its pension plan assets in the second quarter of 2011. Devon previously disclosed a target allocation of 47.5% for equity securities, 40% for fixed income and 12.5% for other investment types. Devon now expects an allocation of 70% fixed income, 20% equity and 10% for other investment types for its pension assets.

10. Stockholders' Equity

Stock Repurchases

During the first nine months of 2011, Devon repurchased 26.0 million common shares for $2.0 billion, or $76.95 per share, under its $3.5 billion stock repurchase program announced in 2010. As of September 30, 2011, Devon had repurchased 44.3 million common shares for $3.2 billion, or $72.25 per share, under this program, which expires December 31, 2011.

Dividends

Devon paid common stock dividends of $209 million and $211 million in the first nine months of 2011 and 2010, respectively. These amounts reflect quarterly cash dividend rates of $0.16 per share in 2010 and the first quarter of 2011 and $0.17 per share in the second and third quarters of 2011.

11. Commitments and Contingencies

Devon is party to various legal actions arising in the normal course of business. Matters that are probable of unfavorable outcome to Devon and which can be reasonably estimated are accrued. Such accruals are based on information known about the matters, Devon's estimates of the outcomes of such matters and its experience in contesting, litigating and settling similar matters. None of the actions are believed by management to involve future amounts that would be material to Devon's financial position or results of operations after consideration of recorded accruals although actual amounts could differ materially from management's estimate.

Royalty Matters

Numerous natural gas producers and related parties, including Devon, have been named in various lawsuits alleging violation of the federal False Claims Act. The suits allege that the producers and related parties used below-market prices, improper deductions, improper measurement techniques and transactions with affiliates, which resulted in underpayment of royalties in connection with natural gas and NGLs produced and sold from federal and Indian owned or controlled lands. Devon does not currently believe that it is subject to material exposure with respect to such royalty matters.

Environmental Matters

Devon is subject to certain laws and regulations relating to environmental remediation activities associated with past operations, such as the Comprehensive Environmental Response, Compensation, and Liability Act and similar state statutes. In response to liabilities associated with these activities, loss accruals primarily consist of estimated costs associated with remediation. Devon's monetary exposure for environmental matters is not expected to be material.

Chief Redemption Matters

In 2006, Devon acquired Chief Holdings LLC ("Chief") from the owners of Chief, including Trevor Rees-Jones, the majority owner of Chief. In 2008, a former owner of Chief filed a petition against Rees-Jones, as the former majority owner of Chief, and Devon, as Chief's successor pursuant to the 2006 acquisition. The petition claimed, among other things, violations of the Texas Securities Act, fraud and breaches of Rees-Jones' fiduciary responsibility to the former owner in connection with Chief's 2004 redemption of the owner's minority ownership stake in Chief.

On June 20, 2011, a court issued a judgment against Rees-Jones for $196 million, of which $133 million of the judgment was also issued against Devon. Both Rees-Jones and Devon are appealing the judgment. However, if the appeal is unsuccessful, Devon can and will seek full payment of the judgment and any related interest, costs and expenses from Rees-Jones pursuant to an existing indemnification agreement between Rees-Jones, certain other parties and Devon. Devon does not expect to have any net exposure as a result of the judgment. However, because Devon does not have a legal right of set off with respect to the judgment, Devon has recorded in its September 30, 2011 consolidated balance sheet both a $133 million liability relating to the judgment with an offsetting $133 million receivable relating to its right to be indemnified by Rees-Jones and certain other parties pursuant to the indemnification agreement.

Other Matters

Devon is involved in other various routine legal proceedings incidental to its business. However, to Devon's knowledge, there were no other material pending legal proceedings to which Devon is a party or to which any of its property is subject.

Commitments

At the end of 2010, Devon's commitments included approximately $0.6 billion related to lease contracts for a deepwater drilling rig and a floating, production, storage and offloading facility being used in Brazil. Devon's remaining commitments for these leases were assumed by the buyer of its assets upon closing the Brazil divestiture transaction discussed in Note 15.

12. Fair Value Measurements

Certain of Devon's assets and liabilities are reported at fair value in the accompanying consolidated balance sheets. Such assets and liabilities include amounts for both financial and non-financial instruments. The following tables provide carrying value and fair value measurement information for Devon's financial assets and liabilities.

The carrying values of cash, accounts receivable, other current receivables, accounts payable and other payables and accrued expenses included in the accompanying consolidated balance sheets approximated fair value at September 30, 2011 and December 31, 2010. These assets and liabilities are not presented in the following tables.

	Carrying Amount	Total Fair Value	Fair Value Measurements Using: Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
			(In millions)		
September 30, 2011 assets (liabilities):					
Cash equivalents	$ 5,161	$ 5,161	$ 1,262	$ 3,899	$ —
Short-term investments	$ 1,231	$ 1,231	$ 289	$ 942	$ —
Long-term investments	$ 84	$ 84	$ —	$ —	$ 84
Commodity derivatives	$ 860	$ 860	$ —	$ 860	$ —
Commodity derivatives	$ (58)	$ (58)	$ —	$ (58)	$ —
Interest rate derivatives	$ 56	$ 56	$ —	$ 56	$ —
Debt	$ (9,257)	$(10,625)	$ —	$(10,533)	$ (92)

	Carrying Amount	Total Fair Value	Fair Value Measurements Using: Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
			(In millions)		
December 31, 2010 assets (liabilities):					
Cash equivalents	$ 2,335	$ 2,355	$ 2,335	$ —	$ —
Short-term investments	$ 145	$ 145	$ 145	$ —	$ —
Long-term investments	$ 94	$ 94	$ —	$ —	$ 94
Commodity derivatives	$ 249	$ 249	$ —	$ 249	$ —
Commodity derivatives	$ (192)	$ (192)	$ —	$ (192)	$ —
Interest rate derivatives	$ 140	$ 140	$ —	$ 140	$ —
Debt	$ (5,630)	$ (6,629)	$ —	$ (6,485)	$ (144)

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(Unaudited)

Level 1 Fair Value Measurements

Cash equivalents and short-term investments — Amounts consist primarily of United States Treasury bills. The fair value approximates the carrying value.

Level 2 Fair Value Measurements

Cash equivalents and short-term investments — Amounts consist primarily of commercial paper investments. The fair value is based upon quotes from brokers, which generally approximate the carrying value.

Debt — Devon's debt instruments do not actively trade in an established market. The fair values of its fixed-rate debt are estimated by discounting the principal and interest payments at rates available for debt with similar terms and maturity. The fair value of Devon's variable-rate commercial paper borrowings is the carrying value.

Level 3 Fair Value Measurements

Devon's Level 3 fair value measurements included in the table above relate to certain long-term investments and a non-interest bearing promissory note. Included below is a summary of the changes in Devon's Level 3 fair value measurements during the first nine months of 2011 and 2010.

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(In millions)	
Long-term investments balance at beginning of period	$ 94	$ 115
Redemptions of principal	(10)	(20)
Long-term investments balance at end of period	$ 84	$ 95

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(In millions)	
Debt balance at beginning of period	$ (144)	$ —
Issuance of promissory note	—	(139)
Foreign currency translation	3	(4)
Accretion of promissory note	(4)	(1)
Redemptions of principal	53	1
Debt balance at end of period	$ (92)	$ (143)

13. Restructuring Costs

In the fourth quarter of 2009, Devon announced plans to divest its offshore assets. As of September 30, 2011, Devon had divested all of its U.S. Offshore assets and substantially all of its International assets.

Through the end of the third quarter of 2011, Devon had incurred $202 million of restructuring costs associated with these divestitures. This amount is comprised of $120 million of employee severance costs, $78 million associated with abandoned office leases and $4 million of other miscellaneous costs.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(Unaudited)

Financial Statement Presentation

The schedule below summarizes activity and balances associated with Devon's restructuring liabilities.

	Continuing Operations			Discontinued Operations		
	Other Current Liabilities	Other Long-Term Liabilities	Total	Other Current Liabilities	Other Long-Term Liabilities	Total
	(In millions)					
Balance as of December 31, 2010	$ 31	$ 51	$ 82	$ 16	$ —	$ 16
Cash severance settled	(13)	—	(13)	(12)	—	(12)
Cash severance revision	1	—	1	(2)	—	(2)
Lease obligations settled	(1)	(10)	(11)	—	—	—
Lease obligations revision	1	(6)	(5)	—	—	—
Balance as of September 30, 2011	$ 19	$ 35	$ 54	$ 2	$ —	$ 2
Balance as of December 31, 2009.	$ 61	$ —	$ 61	$ 23	$ —	$ 23
Cash severance settled	(17)	—	(17)	(3)	—	(3)
Lease obligations incurred	17	53	70	—	—	—
Cash severance revision	(18)	—	(18)	(5)	—	(5)
Balance as of September 30, 2010	$ 43	$ 53	$ 96	$ 15	$ —	$ 15

The schedule below summarizes the components of restructuring costs in the accompanying 2011 and 2010 consolidated statements of operations.

	Three Months Ended September 30, 2011			Nine Months Ended September 30, 2011		
	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total
	(In millions)					
Lease obligations	$ (3)	$ —	$ (3)	$ (5)	$ —	$ (5)
Share-based awards	—	—	—	(1)	—	(1)
Cash severance	—	—	—	1	(2)	(1)
Asset impairments	—	—	—	2	—	2
Other	—	—	—	1	—	1
Restructuring costs	$ (3)	$ —	$ (3)	$ (2)	$ (2)	$ (4)

	Three Months Ended September 30, 2010			Nine Months Ended September 30, 2010		
	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total
	(In millions)					
Lease obligations	$ 70	$ —	$ 70	$ 70	$ —	$ 70
Asset impairments	11	—	11	11	—	11
Cash severance	(13)	(1)	(14)	(18)	(5)	(23)
Share-based awards	(5)	(2)	(7)	(9)	(3)	(12)
Other	—	—	—	1	—	1
Restructuring costs	$ 63	$ (3)	$ 60	$ 55	$ (8)	$ 47

14. Income Taxes

In the second quarter of 2011, a portion of Devon's foreign earnings were no longer deemed to be permanently reinvested in accordance with accounting principles generally accepted in the United States. Accordingly, Devon recognized $725 million of deferred tax expense and $19 million of current income tax expense during the second quarter of 2011 related to assumed repatriations of such earnings under current U.S. tax law. These earnings were primarily related to the gains generated from Devon's International divestiture transactions. Excluding the $744 million of tax expense, Devon's effective income tax rate was 33% in the first nine months of 2011.

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Also, in the second and third quarters of 2010, Devon recognized $52 million and $23 million, respectively, of deferred income tax expense related to assumed repatriations of earnings in accordance with accounting principles generally accepted in the United States. Excluding these amounts, Devon's effective income tax rate was 34% in the first nine months ended of 2010.

15. Discontinued Operations

In May 2011, Devon completed the divestiture of its operations in Brazil. With the close of the Brazil transaction, Devon has substantially completed its planned offshore divestitures. In aggregate, Devon's U.S. and International offshore sales have generated total proceeds of $10 billion, or approximately $8 billion after-tax, assuming repatriation of a substantial portion of the foreign proceeds under current U.S. tax law.

Revenues related to Devon's discontinued operations totaled $43 million in the first nine months of 2011 and $139 million and $573 million in the third quarter and first nine months of 2010, respectively. Devon did not have revenues related to its discontinued operations in the third quarter of 2011.

Earnings from discontinued operations in 2011 and 2010 were largely impacted by gains on Devon's International divestiture transactions. The following table presents the gains on the divestitures according to the quarters in which the divestitures closed in 2011 and 2010. The after-tax amounts in the table below exclude income tax expense related to assumed repatriations discussed in Note 14.

	Second Quarter 2011		Third Quarter 2010		Second Quarter 2010	
	Gross	After Taxes	Gross	After Taxes	Gross	After Taxes
	(In millions)					
Brazil	$ 2,546	$ 2,546	$ —	$ —	$ —	$ —
Azerbaijan	—	—	1,543	1,524	—	—
China — Panyu	—	—	—	—	308	235
Other	—	—	(8)	(2)	—	—
Total	$ 2,546	$ 2,546	$ 1,535	$ 1,522	$ 308	$ 235

The following table presents the main classes of assets and liabilities associated with Devon's discontinued operations.

	September 30, 2011	December 31, 2010
	(In millions)	
Cash and cash equivalents	$ —	$ 424
Accounts receivable	1	43
Other current assets	25	96
Current assets	$ 26	$ 563
Property and equipment, net	$ 105	$ 848
Other long-term assets	6	11
Long-term assets	$ 111	$ 859
Accounts payable	$ 13	$ 260
Other current liabilities	37	45
Current liabilities	$ 50	$ 305
Long-term liabilities	$ 2	$ 26

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(Unaudited)

16. Earnings Per Share

The following table reconciles earnings from continuing operations and common shares outstanding used in the calculations of basic and diluted earnings per share.

	Earnings	Common Shares	Earnings per Share
	(In millions, except per share amounts)		
Three Months Ended September 30, 2011:			
Earnings from continuing operations	$ 1,040	414	
Attributable to participating securities	(11)	(4)	
Basic earnings per share	1,029	410	$ 2.51
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	1	
Diluted earnings per share	$ 1,029	411	$ 2.50
Three Months Ended September 30, 2010:			
Earnings from continuing operations	$ 429	435	
Attributable to participating securities	(4)	(5)	
Basic earnings per share	425	430	$ 0.99
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	1	
Diluted earnings per share	$ 425	431	$ 0.98
Nine Months Ended September 30, 2011:			
Earnings from continuing operations	$ 1,613	421	
Attributable to participating securities	(16)	(4)	
Basic earnings per share	1,597	417	$ 3.83
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	1	
Diluted earnings per share	$ 1,597	418	$ 3.82
Nine Months Ended September 30, 2010:			
Earnings from continuing operations	$ 1,855	442	
Attributable to participating securities	(21)	(5)	
Basic earnings per share	1,834	437	$ 4.20
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	2	
Diluted earnings per share	$ 1,834	439	$ 4.18

Certain options to purchase shares of Devon’s common stock are excluded from the dilution calculation because the options are antidilutive. During the three-month and nine-month periods ended September 30, 2011, 5.3 million shares and 3.1 million shares, respectively, were excluded from the diluted earnings per share calculations. During the three-month and nine-month periods ended September 30, 2010, 8.6 million shares and 7.9 million shares, respectively, were excluded from the diluted earnings per share calculations.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(Unaudited)

17. Segment Information

Devon manages its North American onshore operations through distinct operating segments, or divisions, which are defined primarily by geographic areas. For financial reporting purposes, Devon aggregates its United States divisions into one reporting segment due to the similar nature of the businesses. However, Devon's Canadian and International divisions are reported as separate reporting segments primarily due to significant differences in the respective regulatory environments.

	U.S.	Canada	International	Total
		(In millions)		
As of September 30, 2011:				
Current assets (1)	$ 2,556	$ 7,025	$ 26	$ 9,607
Property and equipment, net	15,639	7,531	—	23,170
Goodwill	3,046	2,905	—	5,951
Other assets	662	365	111	1,138
Total assets	$21,903	$17,826	$ 137	$39,866
Current liabilities	$ 5,321	$ 660	$ 50	$ 6,031
Long-term debt	4,734	1,235	—	5,969
Asset retirement obligations	593	867	—	1,460
Other liabilities	426	67	2	495
Deferred income taxes	3,486	1,323	—	4,809
Stockholders' equity	7,343	13,674	85	21,102
Total liabilities and stockholders' equity	$21,903	$17,826	$ 137	$39,866

(1) Current assets in the Canadian segment include $6.1 billion of cash, cash equivalents and short-term investments that were generated from Devon's International offshore divestiture program and have not been repatriated to the United States. Accordingly, no current United States income taxes have been recorded or paid on these amounts.

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	U.S.	Canada (In millions)	Total
Three Months Ended September 30, 2011:			
Revenues:			
Oil, gas and NGL sales	$ 1,406	$ 705	$ 2,111
Oil, gas and NGL derivatives	738	—	738
Marketing and midstream revenues	586	67	653
Total revenues	2,730	772	3,502
Expenses and other, net:			
Lease operating expenses	236	239	475
Taxes other than income taxes	96	12	108
Marketing and midstream operating costs and expenses	457	58	515
Depreciation, depletion and amortization of oil and gas properties	302	202	504
Depreciation and amortization of non-oil and gas properties	57	5	62
Accretion of asset retirement obligations	9	14	23
General and administrative expenses	99	39	138
Restructuring costs	(3)	—	(3)
Interest expense	60	44	104
Interest-rate and other financial instruments	38	2	40
Other, net	—	(2)	(2)
Total expenses and other, net	1,351	613	1,964
Earnings from continuing operations before income taxes	1,379	159	1,538
Income tax expense (benefit):			
Current	(240)	(8)	(248)
Deferred	698	48	746
Total income tax expense	458	40	498
Earnings from continuing operations	$ 921	$ 119	$ 1,040
Capital expenditures, continuing operations	$ 1,556	$ 394	$ 1,950

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(Unaudited)

	U.S.	Canada (In millions)	Total
Three Months Ended September 30, 2010:			
Revenues:			
Oil, gas and NGL sales	$ 1,104	$ 579	$ 1,683
Oil, gas and NGL derivatives	214	(5)	209
Marketing and midstream revenues	432	29	461
Total revenues	1,750	603	2,353
Expenses and other, net:			
Lease operating expenses	208	207	415
Taxes other than income taxes	85	10	95
Marketing and midstream operating costs and expenses	314	22	336
Depreciation, depletion and amortization of oil and gas properties	234	163	397
Depreciation and amortization of non-oil and gas properties	60	6	66
Accretion of asset retirement obligations	8	13	21
General and administrative expenses	97	34	131
Restructuring costs	63	—	63
Interest expense	36	47	83
Interest-rate and other financial instruments	55	1	56
Other, net	(7)	(2)	(9)
Total expenses and other, net	1,153	501	1,654
Earnings from continuing operations before income taxes	597	102	699
Income tax expense (benefit):			
Current	(349)	39	(310)
Deferred	590	(10)	580
Total income tax expense	241	29	270
Earnings from continuing operations	$ 356	$ 73	$ 429
Capital expenditures, continuing operations	$ 1,358	$ 308	$ 1,666

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(Unaudited)

	U.S.	Canada (In millions)	Total
Nine Months Ended September 30, 2011:			
Revenues:			
Oil, gas and NGL sales	$ 4,056	$ 2,115	$ 6,171
Oil, gas and NGL derivatives	986	—	986
Marketing and midstream revenues	1,563	149	1,712
Total revenues	6,605	2,264	8,869
Expenses and other, net:			
Lease operating expenses	668	684	1,352
Taxes other than income taxes	297	39	336
Marketing and midstream operating costs and expenses	1,178	126	1,304
Depreciation, depletion and amortization of oil and gas properties	853	578	1,431
Depreciation and amortization of non-oil and gas properties	174	17	191
Accretion of asset retirement obligations	26	43	69
General and administrative expenses	284	119	403
Restructuring costs	(2)	—	(2)
Interest expense	137	133	270
Interest-rate and other financial instruments	31	2	33
Other, net	(6)	(8)	(14)
Total expenses and other, net	3,640	1,733	5,373
Earnings from continuing operations before income taxes	2,965	531	3,496
Income tax expense (benefit):			
Current	(293)	(8)	(301)
Deferred	2,041	143	2,184
Total income tax expense	1,748	135	1,883
Earnings from continuing operations	$ 1,217	$ 396	$ 1,613
Capital expenditures, before revision of future asset retirement obligations	$ 4,305	$ 1,260	$ 5,565
Revision of future asset retirement obligations	5	14	19
Capital expenditures, continuing operations	$ 4,310	$ 1,274	$ 5,584

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(Unaudited)

	U.S.	Canada	Total
		(In millions)	
Nine Months Ended September 30, 2010:			
Revenues:			
Oil, gas and NGL sales	$ 3,618	$ 1,917	$ 5,535
Oil, gas and NGL derivatives	871	3	874
Marketing and midstream revenues	1,300	96	1,396
Total revenues	5,789	2,016	7,805
Expenses and other, net:			
Lease operating expenses	675	596	1,271
Taxes other than income taxes	258	30	288
Marketing and midstream operating costs and expenses	935	78	1,013
Depreciation, depletion and amortization of oil and gas properties	743	506	1,249
Depreciation and amortization of non-oil and gas properties	173	19	192
Accretion of asset retirement obligations	33	38	71
General and administrative expenses	303	96	399
Restructuring costs	55	—	55
Interest expense	121	159	280
Interest-rate and other financial instruments	121	—	121
Other, net	(36)	2	(34)
Total expenses and other, net	3,381	1,524	4,905
Earnings from continuing operations before income taxes	2,408	492	2,900
Income tax expense (benefit):			
Current	496	200	696
Deferred	404	(55)	349
Total income tax expense	900	145	1,045
Earnings from continuing operations	$ 1,508	$ 347	$ 1,855
Capital expenditures, before revision of future asset retirement obligations	$ 3,547	$ 1,452	$ 4,999
Revision of future asset retirement obligations	72	122	194
Capital expenditures, continuing operations	$ 3,619	$ 1,574	$ 5,193

18. Supplemental Information to Statements of Cash Flows

	Nine Months Ended September 30,	
	2011	2010
	(In millions)	
Net (increase) decrease in working capital:		
(Increase) decrease in accounts receivable	$ (118)	$ 185
(Increase) decrease in other current assets	(149)	11
Increase in accounts payable	58	49
Increase in revenues and royalties due to others	121	29
Decrease in other current liabilities	(220)	(110)
Net (increase) decrease in working capital	$ (308)	$ 164
Supplementary cash flow data — total operations:		
Interest paid (net of capitalized interest)	$ 298	$ 338
Income taxes (received) paid	$ (113)	$ 745

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

The following discussion and analysis addresses material changes in our results of operations and capital resources and uses for the three-month and nine-month periods ended September 30, 2011, compared to the three-month and nine-month periods ended September 30, 2010, and in our financial condition and liquidity since December 31, 2010. For information regarding our critical accounting policies and estimates, see our 2010 Annual Report on Form 10-K under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Financial Overview

During the third quarter and first nine months of 2011, we generated net earnings of $1.0 billion, or $2.50 per diluted share, and $4.2 billion, or $9.93 per diluted share, for the respective periods. This compares to net earnings of $2.1 billion, or $4.79 per diluted share, and $4.0 billion, or $8.99 per diluted share, for the third quarter and first nine months of 2010, respectively.

These earnings comparisons are affected by gains associated with divestitures of our International operations. Our financial results for the first nine months of 2011 includes an after-tax gain of $1.8 billion related to International divestitures. Our financial results for the third quarter and first nine months of 2010 include after-tax gains of $1.5 billion and $1.8 billion, respectively, related to International divestitures.

Key financial measures of our operating performance for the third quarter and first nine months of 2011 compared to 2010 are summarized below. Our North America Onshore comparisons exclude amounts related to our Gulf of Mexico assets that were divested in the first half of 2010.

- North America Onshore oil and NGLs production increased 17% to 20 MMBbls and 13% to 59 MMBbls in the third quarter and first nine months of 2011, respectively.
- North America Onshore gas production increased 3% to 240 Bcf and 4% to 708 Bcf in the third quarter and first nine months of 2011, respectively.
- The combined realized price without hedges for oil, gas and NGLs increased 16% to $34.72 per Boe and 7% to $34.78 per Boe in the third quarter and first nine months of 2011, respectively.
- Oil, gas and NGL derivatives generated cash receipts of $96 million and $241 million for the third quarter and first nine months of 2011, respectively, and cash receipts of $232 million and $580 million in the third quarter and first nine months of 2010, respectively.
- Marketing and midstream operating profit increased 11% to $138 million and 7% to $408 million in the third quarter and first nine months of 2011, respectively.
- North America Onshore per unit operating costs increased 6% to $7.81 per Boe and 4% to $7.62 per Boe in the third quarter and first nine months of 2011, respectively.
- Operating cash flow increased 4% to $1.4 billion in the third quarter of 2011 and was flat at $4.2 billion in the first nine months of 2011.
- Capital spending totaled $5.5 billion in the first nine months of 2011.

In the second quarter of 2011, we completed the divestiture of our operations in Brazil. With the close of the Brazil transaction, we have substantially completed our planned offshore divestitures, generating aggregate after-tax proceeds of approximately $8 billion, assuming repatriation of a substantial portion of the foreign proceeds under current U.S. tax law.

As of September 30, 2011, we held approximately $6.8 billion in cash and short-term investments. We also have access to short-term commercial paper borrowings and our $2.7 billion credit facility. With this liquidity, we continue executing our exploration and development programs, with a focus on near-term growth of our liquids production, and repurchasing common shares under our $3.5 billion share repurchase program. Through October 21, 2011, we had repurchased 47.6 million shares for $3.4 billion, or $71.32 per share.

Third-Quarter Operating Highlights

- In the Permian Basin, we increased oil and natural gas liquids production 17 percent compared to the third quarter of 2010. Liquids production accounted for 75 percent of the 50,000 Boe/d produced in the third quarter of 2011.
- At the Bone Spring play in the Permian Basin, we added 11 new wells to production in the third quarter of 2011. Initial daily production from the 11 wells averaged 540 Boe/d per well.
- In Canada, average net production from our 100 percent-owned Jackfish 1 and Jackfish 2 projects reached a record 36,000 Bbls/d during the quarter. Net production from our Jackfish 2 oil sands project continued to ramp-up ahead of schedule.
- Also in Canada, we completed more than 19 exploration wells targeting oil and liquids rich opportunities across our more than 4 million net acres in the Western Canadian Sedimentary Basin. We tied in 10 of these wells to production in the third quarter. This activity was highlighted by results in the Ferrier area where we commenced production on three Cardium wells with initial production averaging 770 Boe/d per well.
- Third-quarter production from the Cana-Woodford Shale increased 71 percent compared to the year-ago quarter. Net production averaged a record 0.2 Bcfe/d in the quarter, including 8,100 Bbls/d of liquids. Our Cana-Woodford gas processing facility remains on schedule to be fully operational in the fourth quarter.
- Our Barnett Shale production totaled 1.3 Bcfe/d, an eight percent increase over the third-quarter 2010. Liquids production in the Barnett Shale averaged 46,000 Bbls/d, a 15 percent year-over-year increase.
- We brought ten operated Granite Wash wells online in the third quarter. Initial production from these wells averaged 1,250 Boe/d, including 180 Bbls/d of oil and 405 Bbls/d of natural gas liquids. We have an average working interest of 86 percent in these wells.

Results of Operations

Revenues

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Change (1)	2011	2010	Change (1)
Oil Volumes (MMBbls)						
U.S. Onshore	4	4	+21%	12	10	+24%
Canada	7	6	+20%	20	19	+6%
North America Onshore	11	10	+21%	32	29	+12%
U.S. Offshore	—	—	N/M	—	2	-100%
Total	11	10	+21%	32	31	+5%
Gas Volumes (Bcf)						
U.S. Onshore	187	179	+4%	548	518	+6%
Canada	53	53	0%	160	161	-1%
North America Onshore	240	232	+3%	708	679	+4%
U.S. Offshore	—	—	N/M	—	17	-100%
Total	240	232	+3%	708	696	+2%
NGLs Volumes (MMBbls)						
U.S. Onshore	8	7	+14%	24	21	+17%
Canada	1	1	+6%	3	3	0%
North America Onshore	9	8	+13%	27	24	+15%
U.S. Offshore	—	—	N/M	—	—	-100%
Total	9	8	+13%	27	24	+13%
Total Volumes (MMBoe)						
U.S. Onshore	44	41	+8%	128	117	+9%
Canada	17	16	+8%	50	49	+2%
North America Onshore	61	57	+8%	178	166	+7%
U.S. Offshore	—	—	N/M	—	5	-100%
Total	61	57	+8%	178	171	+4%

(1) All percentage changes included in this table are based on actual figures rather than the rounded figures presented.

	Three Months Ended September 30, 2011 (1)	2010 (1)	Change	Nine Months Ended September 30, 2011 (1)	2010 (1)	Change
Oil Prices (per Bbl)						
U.S. Onshore	$ 86.30	$ 71.47	+21%	$ 91.18	$ 73.56	+24%
Canada	$ 61.70	$ 56.89	+8%	$ 65.30	$ 57.90	+13%
North America Onshore	$ 70.89	$ 62.31	+14%	$ 75.04	$ 63.22	+19%
U.S. Offshore	$ —	$ —	N/M	$ —	$ 77.81	-100%
Total	$ 70.89	$ 62.31	+14%	$ 75.04	$ 64.12	+17%
Gas Prices (per Mcf)						
U.S. Onshore	$ 3.71	$ 3.65	+2%	$ 3.64	$ 3.91	-7%
Canada	$ 3.93	$ 3.72	+6%	$ 4.01	$ 4.24	-5%
North America Onshore	$ 3.76	$ 3.67	+2%	$ 3.73	$ 3.99	-7%
U.S. Offshore	$ —	$ —	N/M	$ —	$ 5.12	-100%
Total	$ 3.76	$ 3.67	+2%	$ 3.73	$ 4.02	-7%
NGLs Prices (per Bbl)						
U.S. Onshore	$ 40.95	$ 27.21	+50%	$ 39.05	$ 29.92	+31%
Canada	$ 54.85	$ 43.89	+25%	$ 55.92	$ 46.34	+21%
North America Onshore	$ 42.35	$ 29.01	+46%	$ 40.74	$ 31.81	+28%
U.S. Offshore	$ —	$ —	N/M	$ —	$ 38.22	-100%
Total	$ 42.35	$ 29.01	+46%	$ 40.74	$ 31.90	+28%
Combined Prices (per Boe)						
U.S. Onshore	$ 32.11	$ 27.18	+18%	$ 31.73	$ 28.83	+10%
Canada	$ 41.42	$ 36.62	+13%	$ 42.61	$ 39.33	+8%
North America Onshore	$ 34.72	$ 29.82	+16%	$ 34.78	$ 31.92	+9%
U.S. Offshore	$ —	$ —	N/M	$ —	$ 49.06	-100%
Total	$ 34.72	$ 29.82	+16%	$ 34.78	$ 32.42	+7%

(1) The prices presented exclude any effects due to oil, gas and NGL derivatives.

The volume and price changes in the tables above caused the following changes to our oil, gas and NGLs sales between the three months ended September 30, 2011 and 2010.

	Oil	Gas	NGLs	Total
		(In millions)		
2010 sales	$ 593	$ 851	$ 239	$ 1,683
Changes due to volumes	124	29	31	184
Changes due to prices	99	22	123	244
2011 sales	$ 816	$ 902	$ 393	$ 2,111

The volume and price changes in the tables above caused the following changes to our oil, gas and NGLs sales between the nine months ended September 30, 2011 and 2010.

	Oil	Gas	NGLs	Total
		(In millions)		
2010 sales	$ 1,976	$ 2,798	$ 761	$ 5,535
Changes due to volumes	102	48	101	251
Changes due to prices	354	(207)	238	385
2011 sales	$ 2,432	$ 2,639	$ 1,100	$ 6,171

Oil Sales

Oil sales increased $124 million and $102 million in the third quarter and first nine months of 2011, respectively, due to increased production. The increased production in both periods was driven by the continued development of our Permian Basin properties and our Jackfish thermal heavy oil projects in Canada. The production increase in the nine months ended 2011 was partially offset by the divestiture of our U.S. Offshore properties in the second quarter of 2010.

Oil sales increased $99 million and $354 million in the third quarter and first nine months of 2011, respectively, as a result of a 14 percent and 17 percent increase in our realized price without hedges. The largest contributor to the higher realized prices was the increase in the average West Texas Intermediate price over the same time periods.

Gas Sales

Gas sales increased $29 million and $48 million in the third quarter and first nine months of 2011, respectively, due to increased production. The increased production in both periods resulted primarily from continued development activities in the Barnett and Cana-Woodford Shales, partially offset by natural declines in our other operating areas. The production increase in the nine months ended 2011 was partially offset by the divestiture of our U.S. Offshore properties in the second quarter of 2010.

Gas sales increased $22 million and decreased $207 million during the third quarter and first nine months of 2011, respectively, as a result of a 2 percent increase and a 7 percent decrease in our realized price without hedges. The changes in price were largely due to fluctuations of the North American regional index prices upon which our gas sales are based.

NGL Sales

NGL sales increased $31 million and $101 million during the third quarter and first nine months of 2011, respectively, due to increased production. The increased production in both periods was primarily due to increased drilling in our Barnett Shale, Cana-Woodford Shale and Granite Wash locations.

NGL sales increased $123 million and $238 million during the third quarter and first nine months of 2011, respectively, due to a 46 percent and 28 percent increase in our realized price without hedges. The higher prices were largely due to increases in the Mont Belvieu, Texas hub price during the same time periods.

Oil, Gas and NGL Derivatives

The following tables provide financial information associated with our oil, gas and NGL hedges. The first table presents the cash settlements and unrealized gains and losses recognized as components of our revenues. The subsequent tables present our oil, gas and NGL prices with, and without, the effects of the cash settlements. The prices do not include the effects of unrealized gains and losses.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions)			
Cash settlements:				
Gas derivatives	$ 97	$ 232	$ 262	$ 580
Oil derivatives	(2)	—	(23)	—
NGL derivatives	1	—	2	—
Total cash settlements	96	232	241	580
Unrealized gains (losses) on fair value changes:				
Gas derivatives	157	101	149	290
Oil derivatives	482	(125)	592	3
NGL derivatives	3	1	4	1
Total unrealized gains (losses)	642	(23)	745	294
Oil, gas and NGL derivatives	$ 738	$ 209	$ 986	$ 874

	Three Months Ended September 30, 2011			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 70.89	$ 3.76	$ 42.35	$ 34.72
Cash settlements of hedges	(0.13)	0.40	0.09	1.58
Realized price, including cash settlements	$ 70.76	$ 4.16	$ 42.44	$ 36.30

	Three Months Ended September 30, 2010			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 62.31	$ 3.67	$ 29.01	$ 29.82
Cash settlements of hedges	—	1.00	—	4.14
Realized price, including cash settlements	$ 62.31	$ 4.67	$ 29.01	$ 33.96

	Nine Months Ended September 30, 2011			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 75.04	$ 3.73	$ 40.74	$ 34.78
Cash settlements of hedges	(0.70)	0.37	0.07	1.35
Realized price, including cash settlements	$ 74.34	$ 4.10	$ 40.81	$ 36.13

	Nine Months Ended September 30, 2010			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 64.12	$ 4.02	$ 31.90	$ 32.42
Cash settlements of hedges	—	0.83	—	3.40
Realized price, including cash settlements	$ 64.12	$ 4.85	$ 31.90	$ 35.82

Our oil, gas and NGL derivatives include price swaps, costless collars and basis swaps. For the price swaps, we receive a fixed price for our production and pay a variable market price to the contract counterparty. The price collars set a floor and ceiling price. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we cash-settle the difference with the counterparty to the collars. For the basis swaps, we receive a fixed differential between two regional gas index prices and pay a variable differential on the same two index prices to the contract counterparty. Cash settlements as presented in the tables above represent realized gains or losses related to these various instruments.

Additionally, to enhance a portion of our natural gas price swaps, we have sold gas call options for 2012 and oil call options for 2011 and 2012. The call options give counterparties the right to purchase production at a predetermined price.

During the third quarter and first nine months of 2011, we received $97 million, or $0.40 per Mcf, and $262 million, or $0.37 per Mcf, respectively, from counterparties to settle our gas derivatives and paid $2 million, or $0.13 per Bbl, and $23 million, or $0.70 per Bbl, respectively, from counterparties to settle our oil derivatives. During the third quarter and first nine months of 2010, we received $232 million, or $1.00 per Mcf, and $580 million, or $0.83 per Mcf, respectively, from counterparties to settle our gas derivatives.

In addition to recognizing cash settlement effects, we recognize unrealized changes in the fair values of our oil, gas and NGL derivative instruments in each reporting period. We estimate the fair values of these derivatives primarily by using internal discounted cash flow calculations. We periodically validate our valuation techniques by comparing our internally generated fair value estimates with those obtained from contract counterparties or brokers.

The most significant variable to our cash flow calculations is our estimate of future commodity prices. We base our estimate of future prices upon published forward commodity price curves such as the Inside FERC Henry Hub forward curve for gas instruments and the NYMEX West Texas Intermediate forward curve for oil instruments. Another key input to our cash flow calculations is our estimate of volatility for these forward curves, which we base primarily upon implied volatility. Finally, the amount of production subject to oil, gas and NGL derivatives is not a variable in our cash flow calculations, but it does impact the total derivative value.

Counterparty credit risk is also a component of commodity derivative valuations. We have mitigated our exposure to any single counterparty by contracting with fourteen counterparties. Additionally, our derivative contracts generally require cash collateral to be posted if either our or the counterparty's credit rating falls below investment grade. The mark-to-market exposure threshold, above which collateral must be posted, decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $55 million for the majority of our contracts. As of September 30, 2011, the credit ratings of all our counterparties were investment grade.

Including the cash settlements discussed above, our oil, gas and NGL derivatives generated net gains of $738 million and $986 million during the third quarter and first nine months of 2011, respectively, and net gains of $209 million and $874 million during the third quarter and first nine months of 2010, respectively. In addition to the impact of cash settlements, these net gains and losses were also impacted by new positions that occurred during each period, as well as the relationships between contract prices and the associated forward curves. A summary of our outstanding oil, gas and NGL derivative positions as of September 30, 2011 is included in Note 4 of our consolidated financial statements.

Marketing and Midstream Revenues and Operating Costs and Expenses

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Change (1)	2011	2010	Change (1)
			($ in millions)			
Marketing and midstream:						
Revenues	$ 653	$ 461	+42%	$ 1,712	$ 1,396	+23%
Operating costs and expenses	515	336	+53%	1,304	1,013	+29%
Operating profit	$ 138	$ 125	+11%	$ 408	$ 383	+7%

(1) All percentage changes included in this table are based on actual figures rather than the rounded figures presented.

During the third quarter and first nine months of 2011, marketing and midstream operating profit increased $13 million and $25 million, respectively. The increases in each period were primarily due to higher NGL prices and higher natural gas throughput and NGL production.

Lease Operating Expenses ("LOE")

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Change (1)	2011	2010	Change (1)
Lease operating expenses ($ in millions):						
U.S. Onshore	$ 236	$ 208	+13%	$ 668	$ 615	+9%
Canada	239	207	+15%	684	596	+15%
North America Onshore	475	415	+14%	1,352	1,211	+12%
U.S. Offshore	—	—	N/M	—	60	-100%
Total	$ 475	$ 415	+14%	$ 1,352	$ 1,271	+6%
Lease operating expenses per Boe:						
U.S. Onshore	$ 5.38	$ 5.11	+5%	$ 5.23	$ 5.25	0%
Canada	$ 14.06	$ 13.14	+7%	$ 13.78	$ 12.23	+13%
North America Onshore	$ 7.81	$ 7.35	+6%	$ 7.62	$ 7.30	+4%
U.S. Offshore	$ —	$ —	N/M	$ —	$ 12.00	-100%
Total	$ 7.81	$ 7.35	+6%	$ 7.62	$ 7.44	+2%

(1) All percentage changes included in this table are based on actual figures rather than the rounded figures presented.

LOE increased $60 million in the third quarter of 2011. The largest contributor to this increase was our 8 percent growth in North America Onshore production, which caused an increase of $32 million. Additionally, LOE increased $14 million due to changes in the exchange rate between the U.S. and Canadian dollars. The remainder of the increase is primarily due to cost escalation. The higher exchange rate and cost escalation were also the primary contributors to the increases in LOE per Boe.

LOE increased $81 million in the first nine months of 2011. This amount consisted of a $141 million increase related to our North America Onshore operations and a $60 million decrease related to our U.S. Offshore operations that were sold in the second quarter of 2010. The largest contributor to our North America Onshore LOE increase was our 7 percent growth in production, which caused an increase of $86 million. Additionally, North America Onshore LOE increased $38 million due to changes in the exchange rate between the U.S. and Canadian dollars. The higher exchange rate and cost escalation were also the main contributors to the increase in North America Onshore LOE per Boe.

Taxes Other Than Income Taxes

	Three Months Ended September 30, 2011	2010	Change (1)	Nine Months Ended September 30, 2011	2010	Change (1)
			($ in millions)			
Production	$ 63	$ 51	+23%	$ 187	$ 156	+20%
Ad valorem	43	42	+4%	144	128	+13%
Other	2	2	-18%	5	4	+26%
Total	$ 108	$ 95	+14%	$ 336	$ 288	+17%

(1) All percentage changes included in this table are based on actual figures rather than the rounded figures presented.

Production taxes increased in the third quarter of 2011 and first nine months of 2011 primarily due to an increase in our U.S. Onshore revenues, on which such taxes are assessed. Ad valorem taxes increased in the third quarter and first nine months of 2011 primarily due to higher estimated assessed values of our oil and gas property and equipment.

Depreciation, Depletion and Amortization of Oil and Gas Properties ("DD&A")

	Three Months Ended September 30, 2011	2010	Change (1)	Nine Months Ended September 30, 2011	2010	Change (1)
Total production volumes (MMBoe)	61	57	+8%	178	171	+4%
DD&A rate ($ per Boe)	$ 8.29	$ 7.04	+18%	$ 8.07	$ 7.32	+10%
DD&A expense ($ in millions)	$ 504	$ 397	+27%	$ 1,431	$ 1,249	+15%

(1) All percentage changes included in this table are based on actual figures rather than the rounded figures presented.

The following table details the changes in DD&A of oil and gas properties between the three and nine months ended September 30, 2011 and 2010 (in millions).

	Three Months Ended September 30,	Nine Months Ended September 30,
2010 DD&A	$ 397	$ 1,249
Change due to volumes	31	49
Change due to rate	76	133
2011 DD&A	$ 504	$ 1,431

Oil and gas property-related DD&A increased $76 million and $133 million in the third quarter of 2011 and first nine months of 2011, respectively, due to 18 percent and 10 percent increases in the respective DD&A rates. The largest contributors to the higher rates were our drilling and development activities subsequent to the end of the third quarter of 2010 and changes in the exchange rate between the U.S. and Canadian dollars. The increase in the nine months ended 2011 rate was partially offset by the divestiture of our U.S. Offshore properties in the second quarter of 2010.

General and Administrative Expenses ("G&A")

	Three Months Ended September 30, 2011	2010	Change (1)	Nine Months Ended September 30, 2011	2010	Change (1)
			($ in millions)			
Gross G&A	$ 253	$ 235	+7%	$ 736	$ 720	+2%
Capitalized G&A	(85)	(75)	+12%	(247)	(236)	+4%
Reimbursed G&A	(30)	(29)	+6%	(86)	(85)	+2%
Net G&A	$ 138	$ 131	+5%	$ 403	$ 399	+1%

(1) All percentage changes included in this table are based on actual figures rather than the rounded figures presented.

Gross and net G&A increased during the third quarter and first nine months of 2011 primarily due to higher employee compensation and benefits.

Restructuring Costs

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(In millions)			
Lease obligations	$ (3)	$ 70	$ (5)	$ 70
Asset impairments	—	11	2	11
Cash severance	—	(13)	1	(18)
Share-based awards	—	(5)	(1)	(9)
Other	—	—	1	1
Total	$ (3)	$ 63	$ (2)	$ 55

As a result of our offshore divestitures, we ceased using certain office space in the third quarter of 2010 that was subject to non-cancellable operating lease arrangements. Consequently, we recognized $70 million of restructuring costs that represent the present value of our future obligations under the leases, net of anticipated sublease income. Our estimate of lease obligations was based upon certain key estimates that could change over the term of the leases. These estimates include the estimated sublease income that we may receive over the term of the leases, as well as the amount of variable operating costs that we will be required to pay under the leases. Additionally, we recognized $11 million of asset impairment charges for leasehold improvements and furniture associated with the office space we ceased using in the third quarter of 2010.

Interest Expense

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(In millions)			
Interest based on debt outstanding	$ 120	$ 98	$ 318	$ 307
Capitalized interest	(19)	(20)	(56)	(55)
Early retirement of debt	—	—	—	19
Other	3	5	8	9
Total interest expense	$ 104	$ 83	$ 270	$ 280

Interest based on debt outstanding increased during the third quarter and first nine months of 2011 primarily due to the issuance of our $2.25 billion notes in July 2011.

In the second quarter of 2010, we redeemed $350 million of 7.25% senior notes prior to their scheduled maturity of October 1, 2011. The $19 million presented in the table above represents the net of the $28 million make-whole premium and $9 million amortization of the remaining premium.

Interest-Rate and Other Financial Instruments

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(In millions)			
(Gains) losses from:				
Interest rate swaps — cash settlements	$ (52)	$ (17)	$ (73)	$ (37)
Interest rate swaps — unrealized fair value changes	55	72	84	158
Foreign currency swap — cash settlements	(22)	—	(22)	—
Foreign currency	59	1	44	—
Total	$ 40	$ 56	$ 33	$ 121

During the third quarter and first nine months of 2011, we received cash settlements totaling $52 million and $73 million, respectively, from counterparties to settle our interest rate swaps. During the third quarter and first nine months of 2010, we received cash settlements totaling $17 million and $37 million, respectively.

In addition to recognizing cash settlements, we recognize unrealized changes in the fair values of our interest rate swaps each reporting period. We estimate the fair values of our interest rate swap financial instruments primarily by using internal discounted cash flow calculations based upon forward interest-rate yields. The most significant variable to our cash flow calculations for our interest rate swaps is our estimate of future interest rate yields. We base our estimate of future yields upon our own internal model that utilizes forward curves such as the LIBOR or the Federal Funds Rate provided by a third party. We periodically validate our valuation techniques by comparing our internally generated fair value estimates with those obtained from contract counterparties or brokers.

During the third quarter and first nine months of 2011, we incurred unrealized losses of $55 million and $84 million, respectively, resulting primarily from the settlements of our forward starting interest rate swaps in the third quarter of 2011 and changes in interest rates. During the third quarter and first nine months of 2010, we incurred unrealized losses of $72 million and $158 million, respectively as a result of changes in interest rates.

Similar to our commodity derivative contracts, counterparty credit risk is also a component of interest rate and foreign exchange rate derivative valuations. We have mitigated our exposure to any single counterparty by contracting with five separate counterparties. Additionally, our derivative contracts generally require cash collateral to be posted if either our or the counterparty's credit rating falls below investment grade. The mark-to-market exposure threshold, above which collateral must be posted, decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $55 million for the majority of our contracts. The credit ratings of all our counterparties were investment grade as of September 30, 2011.

Income Taxes

The following table presents our total income tax expense and a reconciliation of our effective income tax rate to the U.S. statutory income tax rate.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Total income tax expense (in millions)	$ 498	$ 270	$ 1,883	$ 1,045
U.S. statutory income tax rate	35%	35%	35%	35%
State income taxes	1%	1%	1%	1%
Taxation on Canadian operations	(1%)	(1%)	(2%)	(1%)
Assumed repatriations	—	3%	21%	2%
Other	(3%)	1%	(1%)	(1%)
Effective income tax rate	32%	39%	54%	36%

In the second quarter of 2011, a portion of our foreign earnings were no longer deemed to be permanently reinvested in accordance with accounting principles generally accepted in the United States of America. Accordingly, we recognized $725 million of deferred tax expense and $19 million of current income tax expense during the second quarter of 2011 related to assumed repatriations of such earnings under current U.S. tax law. These earnings were primarily related to the gains generated from our International divestiture transactions. Excluding the $744 million of tax expense, our effective income tax rate was 33% in the first nine months of 2011.

Also, in the second and third quarters of 2010, we recognized $52 million and $23 million, respectively, of deferred income tax expense related to assumed repatriations of earnings in accordance with accounting principles generally accepted in the United States of America. Excluding these amounts, our effective income tax rate was 36% in the third quarter of 2010 and 34% in the first nine months ended of 2010.

Earnings From Discontinued Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Total production (MMBoe)	—	2	1	8
Combined price without hedges (per Boe)	$ —	$ 67.55	$ 81.94	$ 72.01

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions)			
Operating revenues	$ —	$ 139	$ 43	$ 573
Expenses and other, net:				
Operating expenses	—	42	33	176
Gain on sale of oil and gas properties	—	(1,535)	(2,546)	(1,843)
Other, net	4	(78)	(28)	(80)
Total expenses and other, net	4	(1,571)	(2,541)	(1,747)
Earnings (loss) before income taxes	(4)	1,710	2,584	2,320
Income tax (benefit) expense	(2)	49	—	187
Earnings (loss) from discontinued operations	$ (2)	$ 1,661	$ 2,584	$ 2,133

Earnings decreased in the third quarter of 2011 primarily as a result of the $1.5 billion gain ($1.5 billion after-tax) recognized from the divestiture of our Azerbaijan operations in the third quarter of 2010.

Earnings increased in the first nine months of 2011 primarily as a result of the $2.5 billion gain ($2.5 billion after-tax) recognized from the divestiture of our Brazil operations. This increase was partially offset by the Azerbaijan divestiture discussed above and a $308 million gain ($235 million after taxes) recognized from the divestiture of our Panyu operations in China during the second quarter of 2010.

Capital Resources, Uses and Liquidity

The following discussion of capital resources and liquidity should be read in conjunction with the consolidated statements of cash flows included in Part I, Item 1.

Sources and Uses of Cash

	Nine Months Ended September 30,	
	2011	2010
	(In millions)	
Sources of cash and cash equivalents:		
Operating cash flow — continuing operations	$ 4,227	$ 3,912
Net debt activity	3,657	—
Cash reclassified from discontinued operations	3,251	2,824
Stock option exercises	101	18
Divestitures of property and equipment	13	4,131
Other	21	27
Total sources of cash and cash equivalents	**11,270**	**10,912**
Uses of cash and cash equivalents:		
Capital expenditures	(5,515)	(4,793)
Repurchases of common stock	(1,987)	(929)
Net purchases of short-term investments	(1,086)	—
Dividends	(209)	(211)
Net debt activity	—	(1,782)
Other	(33)	(13)
Total uses of cash and cash equivalents	**(8,830)**	**(7,728)**
Increase from continuing operations	2,440	3,184
Decrease from discontinued operations, net of reclassifications to continuing operations	(102)	(202)
Effect of foreign exchange rates	(10)	5
Net increase in cash and cash equivalents	**$ 2,328**	**$ 2,987**
Cash and cash equivalents at end of period	$ 5,618	$ 3,998
Short-term investments at end of period	$ 1,231	$ —

Operating Cash Flow — Continuing Operations

Net cash provided by operating activities ("operating cash flow") continued to be a significant source of capital and liquidity in the first nine months of 2011. Our operating cash flow increased 8 percent during 2011 largely due to higher current income taxes in 2010 associated with taxable gains on our U.S. Offshore divestitures. Higher commodity prices and production in 2011, partially offset by lower realized gains from our commodity derivatives, also contributed to the increase in cash flow.

Other Sources of Cash — Continuing and Discontinued Operations

As needed, we supplement our operating cash flow and available cash by accessing available credit under our credit facilities and commercial paper program. We may also issue long-term debt to supplement our operating cash flow while maintaining adequate liquidity under our credit facilities. Additionally, we may acquire short-term investments to maximize our income on available cash balances. As needed, we reduce such short-term investment balances to further supplement our operating cash flow and available cash. Another source of cash proceeds comes from employee stock option exercises.

During the first nine months of 2011, we increased our commercial paper borrowings by $3.2 billion and received $0.5 billion from new debt issuances, net of debt maturities. Additionally, we completed the divestiture of our operations in Brazil, generating $3.3 billion in net proceeds, and received proceeds of $101 million from shares issued for employee stock option exercises. We used these sources of cash to fund capital expenditures, repurchases of our common stock, purchases of short-term investments and dividends in excess of the cash flow generated by our United States operating activities.

During the first nine months of 2010, we completed the divestiture of our U.S. Offshore, Azerbaijan and China properties, generating $6.6 billion in pre-tax proceeds net of closing adjustments, or $5.6 billion after taxes. We used proceeds from the 2010 divestitures to repay commercial paper borrowings, retire $350 million of other debt and began repurchasing our common shares. In addition, we redeployed $500 million of proceeds into our North America Onshore properties by acquiring a 50% interest in the Pike oil sands in Alberta, Canada.

Capital Expenditures

Our capital expenditures are presented by geographic area and type in the following table. The amounts in the table reflect cash payments for capital expenditures, including cash paid for capital expenditures incurred in prior quarters. Capital expenditures actually incurred during the first nine months of 2011 and 2010 were approximately $5.6 billion and $5.0 billion, respectively.

	Nine Months Ended September 30,	
	2011	2010
	(In millions)	
U.S. Onshore	$ 3,665	$ 2,564
Canada	1,224	1,438
North America Onshore	4,889	4,002
U.S. Offshore	—	365
Total exploration and development	4,889	4,367
Midstream	244	176
Other	382	250
Total continuing operations	$ 5,515	$ 4,793

Our capital expenditures consist of amounts related to our oil and gas exploration and development operations, our midstream operations and other corporate activities. The vast majority of our capital expenditures are for the acquisition, drilling and development of oil and gas properties, which totaled $4.9 billion and $4.4 billion in the first nine months of 2011 and 2010, respectively. Excluding the $500 million Pike oil sands acquisition in 2010, the increase in exploration and development capital spending in the first nine months of 2011 was primarily due to increased drilling and development and new venture acreage acquisitions. With rising oil prices and proceeds from our offshore divestitures, we are increasing our acreage positions and associated exploration and development activities to drive near-term growth of our onshore liquids production.

Capital expenditures for our midstream operations are primarily for the construction and expansion of natural gas processing plants, natural gas pipeline systems and oil pipelines. Our midstream capital expenditures are largely impacted by oil and gas drilling activities. Therefore, the increase in development drilling also increased midstream capital activities.

Capital expenditures related to corporate activities increased in 2011. This increase is largely driven by the construction of our new headquarters in Oklahoma City.

Repurchases of Common Stock

During the first nine months of 2011, we continued repurchasing shares under our $3.5 billion stock repurchase program announced in May 2010. Including unsettled shares, we repurchased 26.0 million common shares for $2.0 billion, or $76.95 per share, in the first nine months of 2011. This program expires on December 31, 2011.

Short-term Investments

During the first nine months of 2011, we had net short-term investment purchases totaling $1.1 billion. These purchases represent our investment of a portion of the International offshore divestiture proceeds into United States Treasury securities and commercial paper. As of September 30, 2011, the average remaining maturity of these short-term investments was 97 days.

Dividends

We paid common stock dividends of $209 million and $211 million in the first nine months of 2011 and 2010, respectively. These amounts reflect quarterly cash dividend rates of $0.16 per share in 2010 and the first quarter of 2011 and $0.17 per share in the second and third quarters of 2011.

Liquidity

Historically, our primary source of capital and liquidity has been operating cash flow and cash on hand. Additionally, we maintain revolving lines of credit and a commercial paper program, which can be accessed as needed to supplement operating cash flow and cash balances. Other available sources of capital and liquidity include equity and debt securities that can be issued pursuant to our automatically effective shelf registration statement filed with the Securities Exchange Commission. We estimate the combination of these sources of capital will be adequate to fund future capital expenditures, share repurchases, debt repayments and our other contractual commitments. The following sections discuss changes to our liquidity subsequent to filing our 2010 Annual Report on Form 10-K.

Operating Cash Flow

We expect operating cash flow to continue to be our primary source of liquidity. Our operating cash flow is sensitive to many variables, the most volatile of which is pricing of the oil, gas and NGLs produced. To mitigate some of the risk inherent in prices, we have utilized various price swap, fixed-price physical delivery and price collar contracts to set minimum and maximum prices on our 2011 production. As of September 30, 2011, approximately 40 percent of our 2011 gas production is associated with financial price swaps, collars and fixed-price physicals. We also have basis swaps associated with 0.2 Bcf per day of our 2011 gas production. Additionally, approximately 36 percent of our 2011 oil production is associated with financial price collars. We also have call options that, if exercised, would relate to an additional 16 percent of our 2011 oil production.

Looking beyond 2011, we have also entered into contracts to manage the price risk relative to our 2012 and 2013 oil, gas and NGL production. A summary of these contracts as of September 30, 2011, is included in Note 4 to our consolidated financial statements under Item 1. “Consolidated Financial Statements” of this Form 10-Q.

Offshore Divestitures

In May 2011, we completed the divestiture of our operations in Brazil. With the close of the Brazil transaction, we have substantially completed our planned offshore divestitures. In aggregate, our U.S. and International offshore sales generated total proceeds of $10 billion, or approximately $8 billion after-tax assuming repatriation of a substantial portion of the foreign proceeds under current U.S. tax law.

Furthermore, in connection with the divestiture of our Brazil assets, our remaining deepwater drilling rig and floating, production storage and offloading facility commitments were assumed by the purchaser of the assets.

Credit Availability

In March 2011, our Board of Directors authorized an increase in our commercial paper program from $2.2 billion to $5.0 billion.

As of October 21, 2011, we had $1.9 billion of available borrowings under our commercial paper program, and had $2.6 billion of available capacity under our syndicated, unsecured Senior Credit Facility.

The Senior Credit Facility contains only one material financial covenant. This covenant requires us to maintain a ratio of total funded debt to total capitalization, as defined in the credit agreement, of no more than 65 percent. The credit agreement defines total funded debt as funds received through the issuance of debt securities such as debentures, bonds, notes payable, credit facility borrowings and short-term commercial paper borrowings. In addition, total funded debt includes all obligations with respect to payments received in consideration for oil, gas and NGL production yet to be acquired or produced at the time of payment. Funded debt excludes our outstanding letters of credit and trade payables. The credit agreement defines total capitalization as the sum of funded debt and stockholders' equity adjusted for noncash financial writedowns, such as full cost ceiling impairments. As of September 30, 2011, we were in compliance with this covenant. Our debt-to-capitalization ratio at September 30, 2011, as calculated pursuant to the terms of the agreement, was 22 percent.

Although we ended the third quarter of 2011 with approximately $6.8 billion of cash and short-term investments, the vast majority of this amount consists of proceeds from our International offshore divestitures that are held by certain of our foreign subsidiaries. Based on our evaluation of future cash needs across our operations in the United States and Canada, these proceeds continue to be held by our foreign subsidiaries. We do not currently expect to repatriate such amounts to the United States. If we were to repatriate a portion or all of the cash and short-term investments held by these foreign subsidiaries, we would be required to accrue and pay current income taxes in accordance with current United States tax law. With these proceeds remaining outside of the United States, we expect to continue using commercial paper borrowings in the United States to supplement our United States based operating cash flow to fund our capital expenditures and common stock repurchase program. Additionally, we do not expect near-term increases in such borrowings will have a material effect on our overall liquidity or financial condition.

Capital Expenditures

We previously disclosed that we expected our 2011 capital expenditures to range from $5.4 billion to $6.0 billion. During 2011, we expanded our Canadian, Permian Basin and new ventures exploration activities, which were all targeted at oil and liquids-rich opportunities. We also increased drilling activity in the liquids-rich portions of the Barnett and Cana shales. Additionally, we are experiencing upward pressure on costs due to industry inflation and a weaker U.S. dollar compared to the Canadian dollar. As a result, we increased our total estimated capital expenditures. We now expect our 2011 capital expenditures to approximate $7.3 billion. We anticipate having adequate capital resources to fund our capital expenditures.

Common Stock Repurchase Program

As of October 21, 2011, we had repurchased 47.6 million common shares for $3.4 billion, or $71.32 per share, under our $3.5 billion repurchase program. This program expires on December 31, 2011.

Pension Funding and Estimates

We previously disclosed in our financial statements for the year ended December 31, 2010, that we expected to contribute $84 million to our qualified pension plans in 2011. During 2011, we increased our estimated contribution to $446 million. As of September 30, 2011, we have fulfilled this commitment. The increase in our 2011 contributions was due to increased discretionary funding.

Recently Issued Accounting Standards Not Yet Adopted

See Note 1 to our consolidated financial statements under Item 1. "Consolidated Financial Statements" of this Form 10-Q.

Item 3. *Quantitative and Qualitative Disclosures About Market Risk*

Commodity Price Risk

We have commodity derivatives that pertain to production for the last three months of 2011, as well as 2012 and 2013. The key terms to all our oil, gas and NGL derivative financial instruments as of September 30, 2011 are presented in Note 4 to the consolidated financial statements under Item 1. “Consolidated Financial Statements” of this Form 10-Q.

The fair values of our commodity derivatives are largely determined by estimates of the forward curves of the relevant price indices. At September 30, 2011, a 10 percent increase in the forward curves associated with our gas derivative instruments would have decreased our net asset position by approximately $153 million and a 10 percent decrease would have increased our net asset position by approximately $153 million. A 10 percent increase in the forward curves associated with our oil derivative instruments would have decreased our net asset position by approximately $208 million and a 10 percent decrease would have increased our net asset by approximately $215 million.

Interest Rate Risk

At September 30, 2011, we had debt outstanding of $9.3 billion. Of this amount, $6.1 billion, or 65 percent, bears fixed interest rates averaging 6.3 percent. Additionally, we had $3.2 billion of outstanding commercial paper, bearing interest at floating rates which averaged 0.27 percent.

As of September 30, 2011, we had open interest rate swap positions that are presented in Note 4 to our consolidated financial statements under Item 1. “Consolidated Financial Statements” of this Form 10-Q.

The fair values of our interest rate swaps are largely determined by estimates of the forward curves of the Federal Funds rate and LIBOR. A 10 percent change in these forward curves would not materially impact our balance sheet at September 30, 2011.

Foreign Currency Risk

Our net assets, net earnings and cash flows from our Canadian subsidiaries are based on the U.S. dollar equivalent of such amounts measured in the Canadian dollar functional currency. Assets and liabilities of the Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period. A 10 percent unfavorable change in the Canadian-to-U.S. dollar exchange rate would not materially impact our September 30, 2011 balance sheet.

Our non-Canadian foreign subsidiaries have a U.S. dollar functional currency. However, one of these foreign subsidiaries holds Canadian-dollar cash and engages in short-term intercompany loans with Canadian subsidiaries that are sometimes based in Canadian dollars. Additionally, at September 30, 2011, we held foreign currency exchange forward contracts to hedge exposures to fluctuations in exchange rates on the Canadian-dollar cash. The increase or decrease in the value of the forward contracts is offset by the increase or decrease to the U.S. dollar equivalent of the Canadian-dollar cash. The value of the intercompany loans increases or decreases from the remeasurement of the loans into the U.S. dollar functional currency. Based on the amount of the intercompany loans, a 10 percent change in the foreign currency exchange rates would not materially impact our September 30, 2011 balance sheet.

Item 4. *Controls and Procedures*

Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that material information relating to Devon, including its consolidated subsidiaries, is made known to the officers who certify Devon’s financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation, Devon’s principal executive and principal financial officers have concluded that Devon’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective as of September 30, 2011, to ensure that the information required to be disclosed by Devon in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms.

Changes in Internal Control Over Financial Reporting

There was no change in Devon's internal control over financial reporting during the third quarter of 2011 that has materially affected, or is reasonably likely to materially affect, Devon's internal control over financial reporting.

PART II. Other Information

Item 1. *Legal Proceedings*

There have been no material changes to the information included in Item 3. "Legal Proceedings" in our 2010 Annual Report on Form 10-K.

Item 1A. *Risk Factors*

There have been no material changes to the information included in Item 1A. "Risk Factors" in our 2010 Annual Report on Form 10-K.

Item 2. *Unregistered Sales of Equity Securities and Use of Proceeds*

2011 Period	Total Number of Shares Purchased [(1)]	Average Price Paid per Share	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs [(1)]
			(In millions)
July 1 — July 31	1,592,190	$ 80.16	$ 889
August 1 — August 31	4,194,031	$ 66.67	$ 610
September 1 — September 30	5,062,500	$ 61.75	$ 297
Total	10,848,721	$ 66.35	

(1) In May 2010, our Board of Directors approved a $3.5 billion share repurchase program. This program expires December 31, 2011. As of September 30, 2011, we had repurchased 44.3 million common shares for $3.2 billion, or $72.25 per share, under this program.

Item 3. *Defaults Upon Senior Securities*

None.

Item 5. *Other Information*

None.

Item 6. *Exhibits*

(a) *Exhibits* required by Item 601 of Regulation S-K are as follows:

Exhibit Number	Description
31.1	Certification of principal executive officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of principal executive officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

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.

DEVON ENERGY CORPORATION

Date: November 2, 2011

/s/ Jeffrey A. Agosta
Jeffrey A. Agosta
Executive Vice President — Chief Financial Officer

INDEX TO EXHIBITS

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101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

CERTIFICATION PURSUANT TO
RULE 13a-14(a)/15d-14(a),
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John Richels, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Devon Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 2, 2011

/s/ John Richels
John Richels
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
RULE 13a-14(a)/15d-14(a),
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Jeffrey A. Agosta, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Devon Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 2, 2011

/s/ Jeffrey A. Agosta
Jeffrey A. Agosta
Executive Vice President — Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Report of Devon Energy Corporation ("Devon") on Form 10-Q for the period ended September 30, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John Richels, President and Chief Executive Officer of Devon, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Devon.

/s/ John Richels
John Richels
President and Chief Executive Officer
November 2, 2011

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Report of Devon Energy Corporation ("Devon") on Form 10-Q for the period ended September 30, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jeffrey A. Agosta, Executive Vice President — Chief Financial Officer of Devon, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Devon.

/s/ Jeffrey A. Agosta
Jeffrey A. Agosta
Executive Vice President — Chief Financial Officer
November 2, 2011