DEVON ENERGY CORP/DE

FORM 10-Q
(Quarterly Report)

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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 June 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 July 22, 2011, 416.5 million shares of common stock were outstanding.

DEVON ENERGY CORPORATION

FORM 10-Q
For the Quarterly Period Ended June 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.
- “SEC” means United States Securities and Exchange Commission.

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.

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PART I. Financial Information

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	June 30, 2011 (Unaudited)	December 31, 2010
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,351	$ 2,866
Short-term investments	3,367	145
Accounts receivable	1,446	1,202
Current assets held for sale	36	563
Other current assets	711	779
Total current assets	8,911	5,555
Property and equipment, at cost:		
Oil and gas, based on full cost accounting:		
Subject to amortization	59,423	56,012
Not subject to amortization	3,915	3,434
Total oil and gas	63,338	59,446
Other	4,732	4,429
Total property and equipment, at cost	68,070	63,875
Less accumulated depreciation, depletion and amortization	(45,643)	(44,223)
Property and equipment, net	22,427	19,652
Goodwill	6,176	6,080
Long-term assets held for sale	94	859
Other long-term assets	929	781
Total assets	$ 38,537	$ 32,927
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable — trade	$ 1,365	$ 1,411
Revenues and royalties due to others	669	538
Short-term debt	1,962	1,811
Current liabilities associated with assets held for sale	43	305
Other current liabilities	445	518
Total current liabilities	4,484	4,583
Long-term debt	5,968	3,819
Asset retirement obligations	1,499	1,423
Liabilities associated with assets held for sale	2	26
Other long-term liabilities	808	1,067
Deferred income taxes	4,348	2,756
Stockholders' equity:		
Common stock of $0.10 par value. Authorized 1.0 billion shares; issued 418.3 million and 431.9 million shares in 2011 and 2010, respectively	42	43
Additional paid-in capital	4,489	5,601
Retained earnings	14,901	11,882
Accumulated other comprehensive earnings	2,021	1,760
Treasury stock, at cost. 0.3 million and 0.4 million shares in 2011 and 2010, respectively	(25)	(33)
Total stockholders' equity	21,428	19,253
Commitments and contingencies (Note 11)		
Total liabilities and stockholders' equity	$ 38,537	$ 32,927

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(Unaudited) (In millions, except per share amounts)			
Revenues:				
Oil, gas and NGL sales	$ 2,200	$ 1,782	$ 4,060	$ 3,852
Oil, gas and NGL derivatives	416	45	248	665
Marketing and midstream revenues	604	405	1,059	935
Total revenues	3,220	2,232	5,367	5,452
Expenses and other, net:				
Lease operating expenses	453	442	877	856
Taxes other than income taxes	120	92	228	193
Marketing and midstream operating costs and expenses	456	280	789	677
Depreciation, depletion and amortization of oil and gas properties	485	426	927	852
Depreciation and amortization of non-oil and gas properties	65	63	129	126
Accretion of asset retirement obligations	23	24	46	50
General and administrative expenses	135	130	265	268
Restructuring costs	6	(8)	1	(8)
Interest expense	85	111	166	197
Interest-rate and other financial instruments	25	81	8	66
Other, net	(11)	(22)	(27)	(26)
Total expenses and other, net	1,842	1,619	3,409	3,251
Earnings from continuing operations before income taxes	1,378	613	1,958	2,201
Income tax expense (benefit):				
Current	36	707	(53)	1,006
Deferred	1,158	(446)	1,438	(231)
Total income tax expense	1,194	261	1,385	775
Earnings from continuing operations	184	352	573	1,426
Discontinued operations:				
Earnings from discontinued operations before income taxes	2,558	473	2,588	610
Discontinued operations income tax (benefit) expense	(1)	119	2	138
Earnings from discontinued operations	2,559	354	2,586	472
Net earnings	$ 2,743	$ 706	$ 3,159	$ 1,898
Basic net earnings per share:				
Basic earnings from continuing operations per share	$ 0.44	$ 0.79	$ 1.35	$ 3.20
Basic earnings from discontinued operations per share	6.06	0.80	6.09	1.06
Basic net earnings per share	$ 6.50	$ 1.59	$ 7.44	$ 4.26
Diluted net earnings per share:				
Diluted earnings from continuing operations per share	$ 0.43	$ 0.79	$ 1.34	$ 3.19
Diluted earnings from discontinued operations per share	6.05	0.79	6.07	1.05
Diluted net earnings per share	$ 6.48	$ 1.58	$ 7.41	$ 4.24

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE EARNINGS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(Unaudited) (In millions)			
Net earnings	$ 2,743	$ 706	$ 3,159	$ 1,898
Foreign currency translation:				
Change in cumulative translation adjustment	67	(326)	262	(104)
Foreign currency translation income tax (expense) benefit	(2)	17	(12)	5
Foreign currency translation total	65	(309)	250	(99)
Pension and postretirement benefit plans:				
Recognition of net actuarial loss and prior service cost in earnings	8	8	17	16
Pension and postretirement benefit plans income tax expense	(3)	(3)	(6)	(6)
Pension and postretirement benefit plans total	5	5	11	10
Other comprehensive earnings (loss), net of tax	70	(304)	261	(89)
Comprehensive earnings	$ 2,813	$ 402	$ 3,420	$ 1,809

See accompanying notes to consolidated financial statements.

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)			
Six Months Ended June 30, 2011:							
Balance as of December 31, 2010	432	$ 43	$ 5,601	$11,882	$ 1,760	$ (33)	$ 19,253
Net earnings	—	—	—	3,159	—	—	3,159
Other comprehensive earnings (loss), net of tax	—	—	—	—	261	—	261
Stock option exercises	2	—	96	—	—	—	96
Common stock repurchased	—	—	—	—	—	(1,285)	(1,285)
Common stock retired	(16)	(1)	(1,292)	—	—	1,293	—
Common stock dividends	—	—	—	(140)	—	—	(140)
Share-based compensation	—	—	72	—	—	—	72
Share-based compensation tax benefits	—	—	12	—	—	—	12
Balance as of June 30, 2011	418	$ 42	$ 4,489	$14,901	$ 2,021	$ (25)	$ 21,428
Six Months Ended June 30, 2010:							
Balance as of December 31, 2009	447	$ 45	$ 6,527	$ 7,613	$ 1,385	$ —	$ 15,570
Net earnings	—	—	—	1,898	—	—	1,898
Other comprehensive earnings (loss), net of tax	—	—	—	—	(89)	—	(89)
Stock option exercises	—	—	15	—	—	—	15
Common stock repurchased	—	—	—	—	—	(503)	(503)
Common stock retired	(7)	(1)	(437)	—	—	438	—
Common stock dividends	—	—	—	(142)	—	—	(142)
Share-based compensation	—	—	75	—	—	—	75
Share-based compensation tax benefits	—	—	6	—	—	—	6
Balance as of June 30, 2010	440	$ 44	$ 6,186	$ 9,369	$ 1,296	$ (65)	$ 16,830

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2011	2010
	(Unaudited) (In millions)	
Cash flows from operating activities:		
Net earnings	$ 3,159	$ 1,898
Earnings from discontinued operations, net of tax	(2,586)	(472)
Adjustments to reconcile earnings from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	1,056	978
Deferred income tax expense (benefit)	1,438	(231)
Unrealized change in fair value of financial instruments	(74)	(231)
Other noncash charges	82	81
Net (increase) decrease in working capital	(89)	581
Decrease in long-term other assets	45	14
(Decrease) increase in long-term other liabilities	(201)	1
Cash from operating activities — continuing operations	2,830	2,619
Cash from operating activities — discontinued operations	(20)	273
Net cash from operating activities	2,810	2,892
Cash flows from investing activities:		
Capital expenditures	(3,720)	(3,221)
Proceeds from property and equipment divestitures	5	4,129
Purchases of short-term investments	(4,520)	—
Redemptions of short-term investments	1,298	—
Redemptions of long-term investments	1	18
Other	(33)	—
Cash from investing activities — continuing operations	(6,969)	926
Cash from investing activities — discontinued operations	3,170	429
Net cash from investing activities	(3,799)	1,355
Cash flows from financing activities:		
Net commercial paper borrowings (repayments)	2,340	(1,432)
Debt repayments	—	(350)
Proceeds from stock option exercises	96	15
Repurchases of common stock	(1,290)	(430)
Dividends paid on common stock	(140)	(142)
Excess tax benefits related to share-based compensation	12	6
Net cash from financing activities	1,018	(2,333)
Effect of exchange rate changes on cash	32	(9)
Net increase in cash and cash equivalents	61	1,905
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)	$ 3,351	$ 2,916

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 June 30, 2011 and Devon's results of operations and cash flows for the three-month and six-month periods ended June 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.

2. Short-Term Investments

Devon periodically invests excess cash in U.S. Treasury and other marketable securities that are presented as short-term investments in the accompanying June 30, 2011 consolidated balance sheet. During the first half of 2011, Devon invested a portion of the International offshore divestiture proceeds it had received into United States Treasury securities, causing short-term investments to increase. The carrying value of these investments approximates their fair value. As of June 30, 2011, the average remaining maturity of these investments was 67 days, with a weighted average yield of 0.06 percent.

3. Accounts Receivable

The components of accounts receivable include the following:

	June 30, 2011	December 31, 2010
	(In millions)	
Oil, gas and NGL sales	$ 879	$ 786
Joint interest billings	245	204
Marketing and midstream revenues	136	165
Other	195	57
Gross accounts receivable	1,455	1,212
Allowance for doubtful accounts	(9)	(10)
Net accounts receivable	$ 1,446	$ 1,202

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(Unaudited)

4. Derivative Financial Instruments

Objectives and Strategies

Devon periodically enters into commodity and interest rate derivative financial instruments. These instruments are used to manage the inherent uncertainty of future revenues due to oil, gas and NGL price volatility and to manage exposure to interest rate volatility. 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 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 periodically enters into interest rate swaps to manage its exposure to interest rate volatility. 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 also had forward starting swaps and U.S. Treasury locks. In conjunction with Devon's debt issuance discussed in Note 7, Devon received $35 million from the net settlement of its forward starting swaps and U.S. Treasury locks in July 2011.

Counterparty Risk

By using derivative financial instruments to manage exposures to changes in commodity prices and interest rates, Devon exposes itself to credit risk and market risk. Credit risk is 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 June 30, 2011, the credit ratings of all Devon's counterparties were investment grade.

Commodity Derivatives

As of June 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)
Q3-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	—	—

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

As of June 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)
Q3-Q4 2011	712,500	$5.51	215,000	4.75	5.17	—	—
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)
Q3-Q4 2011	Panhandle Eastern Pipeline	150,000	$ (0.33)

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

NGL Basis Swaps

Production Period	Pay	Volume (Bbls/d)	Weighted Average Differential to WTI ($/Bbl)
Q3-Q4 2011	Natural Gasoline	416	$ (9.75)
Q1-Q4 2012	Natural Gasoline	500	$(10.10)
Q1-Q4 2013	Natural Gasoline	500	$ (6.80)

Interest Rate Derivatives

As of June 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)			
$300	4.30%	Six month LIBOR	July 18, 2011
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
$1,150	3.82%		

Forward Starting Swaps

Notional	Fixed Rate Paid	Variable Rate Received	Expiration
(In millions)			
$950	3.92%	Three month LIBOR	July 7, 2011

U.S. Treasury Locks

Notional	Fixed Rate Paid	Variable Rate Received	Expiration
(In millions)			
$350	1.56%	Five year U.S. Treasury	July 6, 2011
300	2.96%	Ten year U.S. Treasury	July 6, 2011
$650	2.21%		

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Unaudited)

Financial Statement Presentation

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

	Balance Sheet Caption	June 30, 2011	December 31, 2010
		(In millions)	
Asset derivatives:			
Commodity derivatives	Other current assets	$ 240	$ 248
Commodity derivatives	Other long-term assets	81	1
Interest rate derivatives	Other current assets	78	100
Interest rate derivatives	Other long-term assets	33	40
Total asset derivatives		$ 432	$ 389
Liability derivatives:			
Commodity derivatives	Other current liabilities	$ 83	$ 50
Commodity derivatives	Other long-term liabilities	78	142
Total liability derivatives		$ 161	$ 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 derivatives are presented in the "Interest-rate and other financial instruments" caption in the accompanying consolidated statements of operations.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions)			
Cash settlements:				
Commodity derivatives	$ 59	$ 252	$ 145	$ 348
Interest rate derivatives	5	4	21	20
Total cash settlements	64	256	166	368
Unrealized gains (losses):				
Commodity derivatives	357	(207)	103	317
Interest rate derivatives	(30)	(85)	(29)	(86)
Total unrealized gains (losses)	327	(292)	74	231
Net gain (loss) recognized on statement of operations	$ 391	$ (36)	$ 240	$ 599

5. Other Current Assets

The components of other current assets include the following:

	June 30, 2011	December 31, 2010
	(In millions)	
Derivative financial instruments	$ 318	$ 348
Income taxes receivable	206	270
Inventories	137	120
Other	50	41
Other current assets	$ 711	$ 779

6. Goodwill

During the first six months of 2011, Devon's Canadian goodwill increased $96 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 June 30, 2011, Devon had no borrowings under the Senior Credit Facility.

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 June 30, 2011, Devon was in compliance with this covenant. Devon's debt-to-capitalization ratio at June 30, 2011, as calculated pursuant to the terms of the agreement, was 19.3 percent.

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 second quarter of 2011 with approximately $6.7 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, during the first six months of 2011, Devon borrowed $2.3 billion of commercial paper in the United States primarily to fund capital expenditures, common stock repurchases and dividends in excess of cash flow generated by its United States operating activities. As of June 30, 2011, Devon's average borrowing rate on its $2.3 billion of commercial paper borrowings was 0.27 percent.

In July 2011, Devon received net proceeds totaling $2,224 million from the issuance of $500 million of 2.40% senior notes due July 15, 2016, $500 million of 4.00% senior notes due July 15, 2021 and $1,250 million of 5.60% senior notes due July 15, 2041. The net proceeds from issuance of this long-term debt is being used to repay substantially all of Devon's outstanding commercial paper as of June 30, 2011 as it matures. Therefore, $2,224 million of Devon's outstanding commercial paper is classified as long-term debt in the accompanying June 30, 2011 consolidated balance sheet.

8. Asset Retirement Obligations

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

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In millions)	
Asset retirement obligations as of beginning of period	$ 1,497	$ 1,513
Liabilities incurred	23	25
Liabilities settled	(39)	(71)
Revision of estimated obligation	16	194
Liabilities assumed by others	—	(256)
Accretion expense on discounted obligation	46	50
Foreign currency translation adjustment	28	(14)
Asset retirement obligations as of end of period	1,571	1,441
Less current portion	72	95
Asset retirement obligations, long-term	$ 1,499	$ 1,346

During the first six 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 six 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 June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010	2011	2010	2011	2010
	(In millions)							
Service cost	$ 9	$ 8	$ 18	$ 16	$ 1	$ —	$ 1	$ —
Interest cost	15	14	30	28	—	1	1	2
Expected return on plan assets	(11)	(9)	(21)	(18)	—	—	—	—
Amortization of prior service cost	1	1	2	2	(1)	—	(1)	—
Net actuarial loss	8	7	16	14	—	—	—	—
Net periodic benefit cost	$ 22	$ 21	$ 45	$ 42	$ —	$ 1	$ 1	$ 2

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. Devon now expects to contribute $346 million to its qualified pension plans in 2011, including $246 million that was contributed in the first six months of 2011 and $100 million that was contributed in July 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 six months of 2011, Devon repurchased 15.2 million common shares under its $3.5 billion stock repurchase program announced in 2010 for $1.3 billion, or $84.52 per share. As of June 30, 2011, Devon had repurchased 33.5 million common shares for $2.5 billion, or $74.16 per share, under this program, which expires December 31, 2011.

Dividends

Devon paid common stock dividends of $140 million and $142 million in the first six months of 2011 and 2010, respectively. The quarterly cash dividend was $0.16 per share in the first and second quarter of 2010 and the first quarter of 2011. In the second quarter of 2011, Devon increased the dividend rate to $0.17 per share.

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

			Fair Value Measurements Using :		
	Carrying Amount	Total Fair Value	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
			(In millions)		
June 30, 2011 assets (liabilities):					
Short-term investments	$ 3,367	$ 3,367	$ 3,367	$ —	$ —
Long-term investments	$ 93	$ 93	$ —	$ —	$ 93
Commodity derivatives	$ 321	$ 321	$ —	$ 321	$ —
Commodity derivatives	$ (161)	$ (161)	$ —	$ (161)	$ —
Interest rate derivatives	$ 111	$ 111	$ —	$ 111	$ —
Debt	$(7,930)	$(8,867)	$(2,340)	$(6,423)	$(104)

			Fair Value Measurements Using :		
	Carrying Amount	Total Fair Value	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
			(In millions)		
December 31, 2010 assets (liabilities):					
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)

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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 six months of 2011 and 2010.

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In millions)	
Long-term investments balance at beginning of period	$ 94	$ 115
Redemptions of principal	(1)	(18)
Long-term investments balance at end of period	$ 93	$ 97

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In millions)	
Debt balance at beginning of period	$ (144)	$ —
Issuance of promissory note	—	(139)
Foreign exchange translation adjustment	(4)	—
Accretion of promissory note	(2)	—
Redemptions of principal	46	—
Debt balance at end of period	$ (104)	$ (139)

13. Restructuring Costs

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

Through the end of the second quarter of 2011, Devon had incurred $204 million of restructuring costs associated with these divestitures. This amount is comprised of $120 million of employee severance costs, $81 million associated with abandoned office leases and $3 million of other miscellaneous costs.

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	(16)	—	(16)	(4)	—	(4)
Lease obligations settled	(1)	(7)	(8)	—	—	—
Lease obligations revision	(1)	(1)	(2)	—	—	—
Cash severance revision	1	—	1	(2)	—	(2)
Balance as of June 30, 2011	$ 14	$ 43	$ 57	$ 10	$ —	$ 10
Balance as of December 31, 2009	$ 61	$ —	$ 61	$ 23	$ —	$ 23
Cash severance settled	(5)	—	(5)	(1)	—	(1)
Cash severance revision	(5)	—	(5)	(3)	—	(3)
Balance as of June 30, 2010	$ 51	$ —	$ 51	$ 19	$ —	$ 19

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

	Three Months Ended June 30, 2011			Six Months Ended June 30, 2011		
	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total
	(In millions)					
Cash severance	$ 1	$ (8)	$ (7)	$ 1	$ (2)	$ (1)
Asset impairments	2	—	2	2	—	2
Lease obligations	2	—	2	(2)	—	(2)
Share-based awards	—	—	—	(1)	—	(1)
Other	1	—	1	1	—	1
Restructuring costs	$ 6	$ (8)	$ (2)	$ 1	$ (2)	$ (1)

	Three Months Ended June 30, 2010			Six Months Ended June 30, 2010		
	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total
	(In millions)					
Cash severance	$ (5)	$ (3)	$ (8)	$ (5)	$ (3)	$ (8)
Share-based awards	(4)	(2)	(6)	(4)	(2)	(6)
Other	1	—	1	1	—	1
Restructuring costs	$ (8)	$ (5)	$ (13)	$ (8)	$ (5)	$ (13)

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 of America. 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 both the second quarter and first six months of 2011, respectively.

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 portion of the foreign proceeds under current U.S. tax law.

Revenues related to Devon’s discontinued operations totaled $43 million in the first six months of 2011 and $222 million and $434 million in the second quarter and first six months of 2010, respectively. Devon did not have revenues related to its discontinued operations in the second quarter of 2011.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Earnings from discontinued operations in the second quarter and first six months of 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 $744 million of 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.

	June 30, 2011	December 31, 2010
	(In millions)	
Cash and cash equivalents	$ —	$ 424
Accounts receivable	2	43
Other current assets	34	96
Current assets	$ 36	$ 563
Property and equipment, net	$ 92	$ 848
Other long-term assets	2	11
Total long-term assets	$ 94	$ 859
Accounts payable	$ 4	$ 260
Other current liabilities	39	45
Current liabilities	$ 43	$ 305
Long-term liabilities	$ 2	$ 26

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 June 30, 2011:			
Earnings from continuing operations	$ 184	422	
Attributable to participating securities	(2)	(5)	
Basic earnings per share	182	417	$ 0.44
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	2	
Diluted earnings per share	$ 182	419	$ 0.43

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	Earnings	Common Shares	Earnings per Share
	(In millions, except per share amounts)		
Three Months Ended June 30, 2010:			
Earnings from continuing operations	$ 352	445	
Attributable to participating securities	(4)	(5)	
Basic earnings per share	348	440	$ 0.79
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	1	
Diluted earnings per share	$ 348	441	$ 0.79
Six Months Ended June 30, 2011:			
Earnings from continuing operations	$ 573	425	
Attributable to participating securities	(6)	(5)	
Basic earnings per share	567	420	$ 1.35
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	2	
Diluted earnings per share	$ 567	422	$ 1.34
Six Months Ended June 30, 2010:			
Earnings from continuing operations	$ 1,426	446	
Attributable to participating securities	(17)	(5)	
Basic earnings per share	1,409	441	$ 3.20
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	1	
Diluted earnings per share	$ 1,409	442	$ 3.19

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 six-month periods ended June 30, 2011, 3.1 million shares were excluded from the diluted earnings per share calculations. During the three-month and six-month periods ended June 30, 2010, 7.9 million shares and 6.4 million shares, respectively, were excluded from the diluted earnings per share calculations.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
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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 June 30, 2011:				
Current assets (1)	$ 1,916	$ 6,959	$ 36	$ 8,911
Property and equipment, net	14,472	7,955	—	22,427
Goodwill	3,046	3,130	—	6,176
Other assets	538	391	94	1,023
Total assets	$19,972	$18,435	$ 130	$38,537
Current liabilities	$ 1,995	$ 2,446	$ 43	$ 4,484
Long-term debt	4,725	1,243	—	5,968
Asset retirement obligations	578	921	—	1,499
Other liabilities	742	66	2	810
Deferred income taxes	2,939	1,409	—	4,348
Stockholders' equity	8,993	12,350	85	21,428
Total liabilities and stockholders' equity	$19,972	$18,435	$ 130	$38,537

(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.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(Unaudited)

	U.S.	Canada (In millions)	Total
Three Months Ended June 30, 2011:			
Revenues:			
Oil, gas and NGL sales	$ 1,438	$ 762	$ 2,200
Oil, gas and NGL derivatives	416	—	416
Marketing and midstream revenues	554	50	604
Total revenues	2,408	812	3,220
Expenses and other, net:			
Lease operating expenses	224	229	453
Taxes other than income taxes	107	13	120
Marketing and midstream operating costs and expenses	413	43	456
Depreciation, depletion and amortization of oil and gas properties	291	194	485
Depreciation and amortization of non-oil and gas properties	59	6	65
Accretion of asset retirement obligations	8	15	23
General and administrative expenses	94	41	135
Restructuring costs	6	—	6
Interest expense	40	45	85
Interest-rate and other financial instruments	25	—	25
Other, net	(7)	(4)	(11)
Total expenses and other, net	1,260	582	1,842
Earnings from continuing operations before income taxes	1,148	230	1,378
Income tax expense:			
Current	35	1	36
Deferred	1,100	58	1,158
Total income tax expense	1,135	59	1,194
Earnings from continuing operations	$ 13	$ 171	$ 184
Capital expenditures, continuing operations	$ 1,499	$ 334	$ 1,833

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(Unaudited)

	U.S.	Canada (In millions)	Total
Three Months Ended June 30, 2010:			
Revenues:			
Oil, gas and NGL sales	$ 1,144	$ 638	$ 1,782
Oil, gas and NGL derivatives	32	13	45
Marketing and midstream revenues	372	33	405
Total revenues	1,548	684	2,232
Expenses and other, net:			
Lease operating expenses	243	199	442
Taxes other than income taxes	83	9	92
Marketing and midstream operating costs and expenses	252	28	280
Depreciation, depletion and amortization of oil and gas properties	248	178	426
Depreciation and amortization of non-oil and gas properties	57	6	63
Accretion of asset retirement obligations	12	12	24
General and administrative expenses	98	32	130
Restructuring costs	(8)	—	(8)
Interest expense	55	56	111
Interest-rate and other financial instruments	81	—	81
Other, net	(26)	4	(22)
Total expenses and other, net	1,095	524	1,619
Earnings from continuing operations before income taxes	453	160	613
Income tax expense (benefit):			
Current	631	76	707
Deferred	(421)	(25)	(446)
Total income tax expense	210	51	261
Earnings from continuing operations	$ 243	$ 109	$ 352
Capital expenditures, continuing operations	$ 1,145	$ 774	$ 1,919

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(Unaudited)

	U.S.	Canada (In millions)	Total
Six Months Ended June 30, 2011:			
Revenues:			
Oil, gas and NGL sales	$ 2,650	$ 1,410	$ 4,060
Oil, gas and NGL derivatives	248	—	248
Marketing and midstream revenues	977	82	1,059
Total revenues	3,875	1,492	5,367
Expenses and other, net:			
Lease operating expenses	432	445	877
Taxes other than income taxes	201	27	228
Marketing and midstream operating costs and expenses	721	68	789
Depreciation, depletion and amortization of oil and gas properties	551	376	927
Depreciation and amortization of non-oil and gas properties	117	12	129
Accretion of asset retirement obligations	17	29	46
General and administrative expenses	185	80	265
Restructuring costs	1	—	1
Interest expense	77	89	166
Interest-rate and other financial instruments	8	—	8
Other, net	(21)	(6)	(27)
Total expenses and other, net	2,289	1,120	3,409
Earnings from continuing operations before income taxes	1,586	372	1,958
Income tax (benefit) expense:			
Current	(53)	—	(53)
Deferred	1,343	95	1,438
Total income tax expense	1,290	95	1,385
Earnings from continuing operations	$ 296	$ 277	$ 573
Capital expenditures, before revision of future asset retirement obligations	$ 2,749	$ 866	$ 3,615
Revision of future asset retirement obligations	2	14	16
Capital expenditures, continuing operations	$ 2,751	$ 880	$ 3,631

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(Unaudited)

	U.S.	Canada (In millions)	Total
Six Months Ended June 30, 2010:			
Revenues:			
Oil, gas and NGL sales	$ 2,514	$ 1,338	$ 3,852
Oil, gas and NGL derivatives	657	8	665
Marketing and midstream revenues	868	67	935
Total revenues	4,039	1,413	5,452
Expenses and other, net:			
Lease operating expenses	467	389	856
Taxes other than income taxes	173	20	193
Marketing and midstream operating costs and expenses	621	56	677
Depreciation, depletion and amortization of oil and gas properties	509	343	852
Depreciation and amortization of non-oil and gas properties	113	13	126
Accretion of asset retirement obligations	25	25	50
General and administrative expenses	206	62	268
Restructuring costs	(8)	—	(8)
Interest expense	85	112	197
Interest-rate and other financial instruments	66	—	66
Other, net	(29)	3	(26)
Total expenses and other, net	2,228	1,023	3,251
Earnings from continuing operations before income taxes	1,811	390	2,201
Income tax expense (benefit):			
Current	845	161	1,006
Deferred	(186)	(45)	(231)
Total income tax expense	659	116	775
Earnings from continuing operations	$ 1,152	$ 274	$ 1,426
Capital expenditures, before revision of future asset retirement obligations	$ 2,189	$ 1,144	$ 3,333
Revision of future asset retirement obligations	72	122	194
Capital expenditures, continuing operations	$ 2,261	$ 1,266	$ 3,527

18. Supplemental Information to Statements of Cash Flows

	Six Months Ended June 30, 2011	2010
	(In millions)	
Net (increase) decrease in working capital:		
Increase in accounts receivable	$ (100)	$ (1)
(Increase) decrease in other current assets	(41)	44
Increase (decrease) in accounts payable	9	(21)
Increase (decrease) in revenues and royalties due to others	130	(21)
(Decrease) increase in other current liabilities	(87)	580
Net (increase) decrease in working capital	$ (89)	$ 581
Supplementary cash flow data — total operations:		
Interest paid (net of capitalized interest)	$ 160	$ 202
Income taxes (received) paid	$ (125)	$ 306

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 six-month periods ended June 30, 2011, compared to the three-month and six-month periods ended June 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 second quarter and first six months of 2011, we generated net earnings of $2.7 billion, or $6.48 per diluted share, and $3.2 billion, or $7.41 per diluted share, for the respective periods. This compares to net earnings of $706 million, or $1.58 per diluted share, and $1.9 billion, or $4.24 per diluted share for the second quarter and first six months of 2010, respectively. Our financial results for the second quarter and first six months of 2011 include an after-tax gain of $1.8 billion related to International divestitures.

Key measures of our financial performance for the second quarter and first six 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 NGL production increased 7% to 20 MMBbls and 5% to 39 MMBbls in the second quarter and first six months of 2011, respectively.
- North America Onshore gas production increased 4% to 240 Bcf and 5% to 468 Bcf in the second quarter and first six months of 2011, respectively.
- The combined realized price without hedges for oil, gas and NGLs increased 20% to $36.63 per Boe and 3% to $34.80 per Boe in the second quarter and first six months of 2011, respectively.
- Oil, gas and NGL derivatives generated cash receipts of $59 million and $145 million for the second quarter and first six months of 2011, respectively, and cash receipts of $252 million and $348 million in the second quarter and first six months of 2010, respectively.
- Marketing and midstream operating profit increased 19% to $148 million and 5% to $270 million in the second quarter and first six months of 2011, respectively.
- North America Onshore per unit operating costs increased 3% to $7.55 per Boe and 3% to $7.52 per Boe in the second quarter and first six months of 2011, respectively.
- Operating cash flow increased 11% to $1.6 billion in the second quarter of 2011 and decreased 3% to $2.8 billion in the first six months of 2011, respectively.
- Capital spending totaled approximately $3.7 billion in the first six 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 portion of the foreign proceeds under current U.S. tax law.

In July 2011, we issued $500 million of 2.40% senior notes due July 15, 2016, $500 million of 4.00% senior notes due July 15, 2021 and $1,250 million of 5.60% senior notes due July 15, 2041. The net proceeds from issuance of this debt is being used to repay our outstanding commercial paper as it matures.

Our performance and the proceeds from our previous offshore divestitures have allowed us to maintain a robust level of liquidity. As of June 30, 2011, we held approximately $6.7 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 July 22, 2011, we had repurchased 35.1 million shares for $2.6 billion, or $74.44 per share.

Second-Quarter Operating Highlights

- In the Permian Basin, we increased production 17 percent over the second quarter of 2010, to 49 MBoe/d. Oil and natural gas liquids accounted for 75 percent of the Permian Basin's second quarter production.
- We completed nine operated Bone Spring wells within the Permian Basin in the second quarter. Initial daily production from the nine wells averaged more than 700 Boe/d per well. We have an average working interest of 77 percent in these wells.
- In Canada, we commenced steam injection and achieved first production from our Jackfish 2 oil sands project in the second quarter. Production from the 100 percent-owned project is expected to ramp-up to 35 MBbls/d before royalties over the next 18 months.
- Production from our Cana-Woodford Shale play averaged a record 189 MMcfe/d in the second quarter, including nearly 9 MBbls/d of liquids. This represents an 80 percent increase in total production compared to the year-ago quarter.
- Our Barnett Shale production increased 13 percent over the second-quarter 2010 to a record 1.3 Bcfe/d, including 46 MBbls/d of liquids production.
- We brought 8 operated Granite Wash wells online in the second quarter. Initial production from these wells averaged 2 MBoe/d, including 200 Bbls/d of oil and 730 Bbls/d of natural gas liquids. We have an average working interest of 71 percent in these wells.
- We have assembled 1.1 million net acres targeting new oil and liquids-rich gas opportunities across multiple basins in the U.S. In 2011, we plan to drill more than 30 wells targeting the Tuscaloosa Marine Shale, Niobrara Shale, Mississippian Lime, Ohio Utica Shale and the A1 Carbonate and Utica Shale in Michigan.

Results of Operations

Revenues

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	Change (1)	2011	2010	Change (1)
Oil Volumes (MMBbls)						
U.S. Onshore	5	3	+27%	8	6	+26%
Canada	6	6	-3%	13	13	-1%
North America Onshore	11	9	+7%	21	19	+8%
U.S. Offshore	—	1	-100%	—	2	-100%
Total	11	10	0%	21	21	-2%
Gas Volumes (Bcf)						
U.S. Onshore	184	173	+6%	361	339	+7%
Canada	56	58	-3%	107	108	-1%
North America Onshore	240	231	+4%	468	447	+5%
U.S. Offshore	—	7	-100%	—	17	-100%
Total	240	238	+1%	468	464	+1%
NGLs Volumes (MMBbls)						
U.S. Onshore	8	7	+20%	16	14	+18%
Canada	1	1	-5%	2	2	-2%
North America Onshore	9	8	+17%	18	16	+16%
U.S. Offshore	—	—	-100%	—	—	-100%
Total	9	8	+15%	18	16	+13%
Total Volumes (MMBoe)						
U.S. Onshore	43	39	+11%	84	76	+10%
Canada	17	17	-3%	33	33	-1%
North America Onshore	60	56	+6%	117	109	+7%
U.S. Offshore	—	2	-100%	—	5	-100%
Total	60	58	+3%	117	114	+2%

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

	Three Months Ended June 30, 2011 (1)	Three Months Ended June 30, 2010 (1)	Change	Six Months Ended June 30, 2011 (1)	Six Months Ended June 30, 2010 (1)	Change
Oil Prices (per Bbl)						
U.S. Onshore	$98.28	$74.65	+32%	$93.84	$74.73	+26%
Canada	$73.65	$54.43	+35%	$67.29	$58.36	+15%
North America Onshore	$83.31	$61.11	+36%	$77.32	$63.67	+21%
U.S. Offshore	$ —	$79.09	N/M	$ —	$77.81	N/M
Total	$83.31	$62.35	+34%	$77.32	$64.93	+19%
Gas Prices (per Mcf)						
U.S. Onshore	$ 3.72	$ 3.47	+7%	$ 3.61	$ 4.05	-11%
Canada	$ 4.08	$ 3.99	+2%	$ 4.05	$ 4.50	-10%
North America Onshore	$ 3.80	$ 3.60	+6%	$ 3.71	$ 4.16	-11%
U.S. Offshore	$ —	$ 4.39	N/M	$ —	$ 5.12	N/M
Total	$ 3.80	$ 3.62	+5%	$ 3.71	$ 4.19	-12%
NGLs Prices (per Bbl)						
U.S. Onshore	$40.43	$28.73	+41%	$38.04	$31.39	+21%
Canada	$58.80	$46.18	+27%	$56.49	$47.52	+19%
North America Onshore	$42.20	$30.81	+37%	$39.90	$33.31	+20%
U.S. Offshore	$ —	$35.59	N/M	$ —	$38.22	N/M
Total	$42.20	$30.90	+37%	$39.90	$33.41	+19%
Combined Prices (per Boe)						
U.S. Onshore	$33.19	$26.77	+24%	$31.53	$29.71	+6%
Canada	$45.55	$37.08	+23%	$43.23	$40.62	+6%
North America Onshore	$36.63	$29.92	+22%	$34.80	$33.00	+5%
U.S. Offshore	$ —	$46.17	N/M	$ —	$49.06	N/M
Total	$36.63	$30.49	+20%	$34.80	$33.70	+3%

(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 NGL sales between the three months ended June 30, 2011 and 2010.

	Oil	Gas (In millions)	NGLs	Total
2010 sales	$ 673	$ 861	$ 248	$ 1,782
Changes due to volumes	(1)	9	37	45
Changes due to prices	225	43	105	373
2011 sales	$ 897	$ 913	$ 390	$ 2,200

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

	Oil	Gas (In millions)	NGLs	Total
2010 sales	$ 1,383	$ 1,947	$ 522	$ 3,852
Changes due to volumes	(26)	17	70	61
Changes due to prices	259	(227)	115	147
2011 sales	$ 1,616	$ 1,737	$ 707	$ 4,060

Oil Sales

Oil sales decreased $1 million and $26 million in the second quarter and first six months of 2011, respectively, due to a decrease in production. The decreases were primarily due to the divestiture of our U.S. Offshore properties in the second quarter of 2010, partially offset by increased North America Onshore production of 7 percent and 8 percent, respectively. The increased North America Onshore production in both periods resulted primarily from continued development of our Permian Basin properties and increased production from our Jackfish thermal heavy oil project in Canada.

Oil sales increased $225 million and $259 million in the second quarter and first six months of 2011, respectively, as a result of a 34 percent and 19 percent increase in our realized price without hedges. The largest contributor to the increase in our realized prices was the increase in the average West Texas Intermediate price over the same time period.

Gas Sales

A 1 percent increase in production during the second quarter and first six months of 2011 caused gas sales to increase by $9 million and $17 million, respectively. The increases were comprised of the net effect of a 4 percent and 5 percent increase, respectively, in our North America Onshore production, partially offset by the divestiture of our U.S. Offshore properties in the second quarter of 2010. The increased North America Onshore 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.

Gas sales increased $43 million and decreased $227 million during the second quarter and first six months of 2011, respectively, as a result of a 5 percent increase and a 12 percent decrease, respectively, in our realized price without hedges. The changes in price were largely due to the volatility of the North American regional index prices upon which our gas sales are based.

NGL Sales

NGL sales increased $37 million and $70 million during the second quarter and first six months of 2011, respectively, due to a 15 percent increase and 13 percent increase in 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 $105 million and $115 million during the second quarter and first six months of 2011, respectively, due to a 37 percent and 19 percent increase in our realized price without hedges. The increases 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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions)			
Cash receipts (payments):				
Gas derivatives	$ 74	$ 252	$ 165	$ 348
Oil derivatives	(16)	—	(21)	—
NGL derivatives	1	—	1	—
Total cash settlements	59	252	145	348
Unrealized gains (losses) on fair value changes:				
Gas derivatives	49	(331)	(8)	189
Oil derivatives	308	124	110	128
NGL derivatives	—	—	1	—
Total unrealized gains (losses)	357	(207)	103	317
Oil, gas and NGL derivatives	$ 416	$ 45	$ 248	$ 665

	Three Months Ended June 30, 2011			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 83.31	$ 3.80	$ 42.20	$ 36.63
Cash settlements of hedges	(1.49)	0.31	0.05	0.99
Realized price, including cash settlements	$ 81.82	$ 4.11	$ 42.25	$ 37.62

	Three Months Ended June 30, 2010			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 62.35	$ 3.62	$ 30.90	$ 30.49
Cash settlements of hedges	—	1.06	—	4.31
Realized price, including cash settlements	$ 62.35	$ 4.68	$ 30.90	$ 34.80

	Six Months Ended June 30, 2011			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 77.32	$ 3.71	$ 39.90	$ 34.80
Cash settlements of hedges	(1.00)	0.35	0.06	1.25
Realized price, including cash settlements	$ 76.32	$ 4.06	$ 39.96	$ 36.05

	Six Months Ended June 30, 2010			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 64.93	$ 4.19	$ 33.41	$ 33.70
Cash settlements of hedges	—	0.75	—	3.04
Realized price, including cash settlements	$ 64.93	$ 4.94	$ 33.41	$ 36.74

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 second quarter and first six months of 2011, we received $74 million, or $0.31 per Mcf, and $165 million, or $0.35 per Mcf, respectively, from counterparties to settle our gas derivatives and paid $16 million, or $1.49 per Bbl, and $21 million, or $1.00 per Bbl, respectively, from counterparties to settle our oil derivatives. During the second quarter and first six months of 2010, we received $252 million, or $1.06 per Mcf, and $348 million, or $0.75 per Mcf, respectively, from counterparties to settle our gas derivatives.

In addition to recognizing these cash settlement effects, we also 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. Based on the amount of volumes subject to our gas derivative financial instruments at June 30, 2011, a 10 percent increase in these forward curves would have increased our unrealized losses by approximately $224 million. A 10 percent increase in the forward curves associated with our oil derivatives would have decreased our unrealized gains by approximately $300 million. 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 June 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 $416 million and $248 million during the second quarter and first six months of 2011, respectively. Including the cash settlements discussed above, our oil, gas and NGL derivatives generated net gains of $45 million and $665 million during the second quarter and first six 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 June 30, 2011 is included in Item 3. "Quantitative and Qualitative Disclosures About Market Risk" of this report.

Marketing and Midstream Revenues and Operating Costs and Expenses

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	Change (1)	2011	2010	Change (1)
			($ in millions)			
Marketing and midstream:						
Revenues	$ 604	$ 405	+49%	$ 1,059	$ 935	+13%
Operating costs and expenses	456	280	+63%	789	677	+16%
Operating profit	$ 148	$ 125	+19%	$ 270	$ 258	+5%

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

During the second quarter of 2011, marketing and midstream revenues increased $199 million and operating costs and expenses increased $176 million, causing operating profit to increase $23 million. During the first six months of 2011, marketing and midstream revenues increased $124 million and operating costs and expenses increased $112 million, causing operating profit to increase $12 million. 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 June 30,			Six Months Ended June 30,		
	2011	2010	Change (1)	2011	2010	Change (1)
Lease operating expenses ($ in millions):						
U.S. Onshore	$ 224	$ 216	+4%	$ 432	$ 407	+6%
Canada	229	199	+15%	445	389	+14%
North America Onshore	453	415	+9%	877	796	+10%
U.S. Offshore	—	27	-100%	—	60	-100%
Total	$ 453	$ 442	+3%	$ 877	$ 856	+3%
Lease operating expenses per Boe:						
U.S. Onshore	$ 5.18	$ 5.52	-6%	$ 5.15	$ 5.33	-3%
Canada	$ 13.71	$ 11.53	+19%	$ 13.63	$ 11.80	+16%
North America Onshore	$ 7.55	$ 7.36	+3%	$ 7.52	$ 7.28	+3%
U.S. Offshore	$ —	$ 13.18	N/M	$ —	$ 12.00	N/M
Total	$ 7.55	$ 7.56	0%	$ 7.52	$ 7.49	0%

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

LOE increased $11 million in the second quarter of 2011. This amount consisted of a $38 million increase related to our North America Onshore operations and a $27 million decrease related to our U.S. Offshore operations that were sold in the second quarter of 2010. Our 6 percent increase in North America Onshore production increased LOE by $27 million. Additionally, North America Onshore LOE increased $14 million due to changes in the exchange rate between the U.S. and Canadian dollars. The higher exchange rate was also the main contributor to the increases in North America Onshore and total LOE per Boe.

LOE increased $21 million in the first six months of 2011. This amount consisted of an $81 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. Our 7 percent increase in North America Onshore production increased LOE by $54 million. Additionally, North America Onshore LOE increased $25 million due to changes in the exchange rate between the U.S. and Canadian dollars. The higher exchange rate was also the main contributor to the increases in North America Onshore and total LOE per Boe.

Taxes Other Than Income Taxes

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	Change (1)	2011	2010	Change (1)
			($ in millions)			
Production	$ 68	$ 46	+48%	$ 124	$ 105	+18%
Ad valorem	51	46	+10%	101	86	+17%
Other	1	—	+175%	3	2	+62%
Total	$ 120	$ 92	+30%	$ 228	$ 193	+18%

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

Production taxes increased $22 million and $19 million in the second quarter of 2011 and first six months of 2011, respectively, primarily due to an increase in our U.S. Onshore revenues. Ad valorem taxes increased $5 million and $15 million in the second quarter and first six months of 2011, respectively, 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 June 30,			Six Months Ended June 30,		
	2011	2010	Change (1)	2011	2010	Change (1)
Total production volumes (MMBoe)	60	58	+3%	117	114	+2%
DD&A rate ($ per Boe)	$ 8.08	$ 7.28	+11%	$ 7.95	$ 7.45	+7%
DD&A expense ($ in millions)	$ 485	$ 426	+14%	$ 927	$ 852	+9%

(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 six months ended June 30, 2011 and 2010 (in millions).

	Three Months Ended June 30,	Six Months Ended June 30,
2010 DD&A	$ 426	$ 852
Change due to rate	48	58
Change due to volumes	11	17
2011 DD&A	$ 485	$ 927

Oil and gas property-related DD&A increased $48 million and $58 million in the second quarter of 2011 and first six months of 2011, respectively, due to 11 percent and 7 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 second quarter of 2010 and changes in the exchange rate between the U.S. and Canadian dollars. These increases were partially offset by a decrease in the rate due to our 2010 U.S. offshore property divestitures.

General and Administrative Expenses ("G&A")

	Three Months Ended June 30, 2011	2010	Change (1)	Six Months Ended June 30, 2011	2010	Change (1)
	($ in millions)					
Gross G&A	$ 245	$ 240	+3%	$ 483	$ 485	0%
Capitalized G&A	(81)	(81)	+1%	(162)	(161)	+1%
Reimbursed G&A	(29)	(29)	0%	(56)	(56)	0%
Net G&A	$ 135	$ 130	+4%	$ 265	$ 268	-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 second quarter of 2011 primarily due to changes in the exchange rate between the U.S. and Canadian dollars. Gross and net G&A decreased during the first six months of 2011 primarily due to lower employee compensation and benefits resulting from our 2010 offshore divestitures.

Interest Expense

	Three Months Ended June 30, 2011	2010	Six Months Ended June 30, 2011	2010
	(In millions)			
Interest based on debt outstanding	$ 100	$ 104	$ 198	$ 209
Capitalized interest	(17)	(14)	(37)	(35)
Early retirement of debt	—	19	—	19
Other	2	2	5	4
Total interest expense	$ 85	$ 111	$ 166	$ 197

Interest expense decreased during the second quarter and first six months of 2011 primarily due to the early redemption of our 7.25 percent $350 million senior notes in the second quarter of 2010. When we redeemed these notes prior to their scheduled maturity, we recognized $19 million of additional interest expense related to the early retirement of the debt.

Interest-Rate and Other Financial Instruments

	Three Months Ended June 30, 2011	2010	Six Months Ended June 30, 2011	2010
	(In millions)			
(Gains) losses from interest rate swaps:				
Cash settlements	$ (5)	$ (4)	$ (21)	$ (20)
Unrealized fair value changes	30	85	29	86
Total	$ 25	$ 81	$ 8	$ 66

During the second quarter and first six months of 2011, we received cash settlements totaling $5 million and $21 million, respectively, from counterparties to settle our interest rate swaps. During the second quarter and first six months of 2010, we received cash settlements totaling $4 million and $20 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. We periodically validate our valuation techniques by comparing our internally generated fair value estimates with those obtained from contract counterparties or brokers. During the second quarter and first six months of 2011, we incurred unrealized losses of $30 million and $29 million, respectively, as a result of changes in interest rates. During the second quarter and first six months of 2010, we incurred unrealized losses of $85 million and $86 million, respectively.

The most significant variable to our cash flow calculations 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. Based on the notional amount subject to the interest rate swaps at June 30, 2011, a 10% increase in these forward curves would have decreased our unrealized losses for our interest rate swaps by approximately $79 million.

Similar to our commodity derivative contracts, counterparty credit risk is also a component of interest rate derivative valuations. We have mitigated our exposure to any single counterparty by contracting with seven 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 June 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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Total income tax expense (in millions)	$ 1,194	$ 261	$ 1,385	$ 775
U.S. statutory income tax rate	35%	35%	35%	35%
State income taxes	1%	3%	1%	1%
Taxation on Canadian operations	(2%)	(1%)	(2%)	(1%)
Assumed repatriations	54%	8%	38%	2%
Other	(1%)	(2%)	(1%)	(2%)
Effective income tax rate	87%	43%	71%	35%

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 both the second quarter and first six months of 2011.

In the second quarter of 2010, we recognized $52 million of deferred income tax expense related to assumed repatriations of earnings from certain of our foreign subsidiaries. Excluding the $52 million of deferred tax expense, our effective income tax rate was 35% and 33% in the second quarter and first six months of 2010.

Earnings From Discontinued Operations

The following table presents the components of our earnings from discontinued operations.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Total production (MMBoe)	—	3	1	6
Combined price without hedges (per Boe)	$ —	$ 74.45	$ 81.94	$ 73.56
		(In millions)		
Operating revenues	$ —	$ 222	$ 43	$ 434
Expenses and other, net:				
Operating expenses	7	56	33	133
Gain on sale of oil and gas properties	(2,546)	(308)	(2,546)	(308)
Other, net	(19)	1	(32)	(1)
Total expenses and other, net	(2,558)	(251)	(2,545)	(176)
Earnings before income taxes	2,558	473	2,588	610
Income tax (benefit) expense	(1)	119	2	138
Earnings from discontinued operations	$ 2,559	$ 354	$ 2,586	$ 472

Earnings increased in the second quarter and first six 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 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

	Six Months Ended June 30,	
	2011	2010
	(In millions)	
Sources of cash and cash equivalents:		
Operating cash flow — continuing operations	$ 2,830	$ 2,619
Cash reclassified from discontinued operations	3,251	450
Commercial paper borrowings	2,340	—
Stock option exercises	96	15
Divestitures of property and equipment	5	4,129
Other	13	24
Total sources of cash and cash equivalents	**8,535**	**7,237**
Uses of cash and cash equivalents:		
Capital expenditures	(3,720)	(3,221)
Net purchases of short-term investments	(3,222)	—
Repurchases of common stock	(1,290)	(430)
Dividends	(140)	(142)
Commercial paper repayments	—	(1,432)
Debt repayments	—	(350)
Other	(33)	—
Total uses of cash and cash equivalents	**(8,405)**	**(5,575)**
Increase from continuing operations	130	1,662
(Decrease) increase from discontinued operations, net of reclassifications to continuing operations	(101)	252
Effect of foreign exchange rates	32	(9)
Net increase in cash and cash equivalents	**$ 61**	**$ 1,905**
Cash and cash equivalents at end of period	$ 3,351	$ 2,916
Short-term investments at end of period	$ 3,367	$ —

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 six months of 2011. Our operating cash flow increased approximately 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, 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 second quarter of 2011, we completed the divestiture of our operations in Brazil, generating $3.3 billion in net proceeds.

During the first six months of 2011, we utilized commercial paper borrowings of $2.3 billion to fund capital expenditures, common share repurchases and dividends in excess of our operating cash flow.

During the first six months of 2011, we received proceeds of $96 million from shares issued for employee stock option exercises.

During the first six months of 2010, we completed the divestiture of all our U.S. Offshore properties and our Panyu operations in China, generating $4.6 billion in pre-tax proceeds ($3.6 billion after taxes). We used proceeds from these divestitures to repay commercial paper borrowings, retire $350 million of other debt and repurchase 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 six months of 2011 and 2010 were approximately $3.6 billion and $3.3 billion, respectively.

	Six Months Ended June 30,	
	2011	2010
	(In millions)	
U.S. Onshore	$ 2,375	$ 1,468
Canada	936	1,202
North America Onshore	3,311	2,670
U.S. Offshore	—	287
Total exploration and development	3,311	2,957
Midstream	151	108
Other	258	156
Total continuing operations	$ 3,720	$ 3,221

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 $3.3 billion and $3.0 billion in the first six 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 six 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.

Short-term Investments

During the first six months of 2011, we had net short-term investment purchases totaling $3.2 billion. These purchases represent our investment of a portion of the International offshore divestiture proceeds into United States Treasury securities. As of June 30, 2011, the average remaining maturity of these short-term investments was 67 days.

Repurchases of Common Stock

During the first six months of 2011, we continued repurchasing shares under our $3.5 billion stock repurchase program announced in May 2010. Including unsettled shares, we repurchased 15.2 million common shares for $1.3 billion, or $84.52 per share, in the first six months of 2011. This program expires on December 31, 2011.

Dividends

We paid common stock dividends of $140 million and $142 million in the first six months of 2011 and 2010, respectively. The quarterly cash dividend was $0.16 per share in the first and second quarter of 2010 and the first quarter of 2011. In the second quarter of 2011, we increased the dividend rate to $0.17 per share.

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 SEC. We estimate the combination of these sources of capital will be adequate to fund future capital expenditures, share repurchases, debt repayments and 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 June 30, 2011, approximately 38 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 June 30, 2011, is included in Item 3. "Quantitative and Qualitative Disclosures About Market Risk" of this report.

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 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.

In July 2011, we issued $500 million of 2.40% senior notes due July 15, 2016, $500 million of 4.00% senior notes due July 15, 2021 and $1,250 million of 5.60% senior notes due July 15, 2041. The net proceeds from this issuance are being used to repay our outstanding commercial paper as it matures. As of July 22, we had repaid $1.9 billion of commercial paper borrowings, 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 June 30, 2011, we were in compliance with this covenant. Our debt-to-capitalization ratio at June 30, 2011, as calculated pursuant to the terms of the agreement, was 19.3 percent.

Although we ended the second quarter of 2011 with $6.7 billion of cash and short-term investments, the vast majority of this amount consists of proceeds from our International offshore divestitures. Based on our evaluation of future cash needs across our operations in the United States and Canada, these proceeds remain outside of the United States. With these proceeds remaining outside of the United States, we expect to continue to increase our commercial paper borrowings in the United States to supplement our United States based operating cash flow to fund our capital expenditures, common stock repurchase program and repay long-term debt.

Capital Expenditures

We previously disclosed that we expected our 2011 capital expenditures to range from $5.4 billion to $6.0 billion. In the first half of 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 range from $6.7 billion to $7.3 billion. We anticipate having adequate capital resources to fund our capital expenditures.

Common Stock Repurchase Program

As of July 22, 2011, we had repurchased $2.6 billion, or 35.1 million common shares at an average price of $74.44 under our $3.5 billion repurchase program. This program expires on December 31, 2011.

Pension Funding and Estimates

We previously disclosed that we expected to contribute approximately $84 million to our qualified pension plans during 2011. We now expect to contribute $346 million to our qualified pension plans in 2011, including $246 million that was contributed in the first six months of 2011 and $100 million that was contributed in July 2011. The increase in our 2011 estimated contribution is due to discretionary funding.

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 our 2011 Annual Report on Form 10-K, this update will require certain additional disclosures related to our fair value measurements. We do not expect the adoption of this update will materially impact our financial statement disclosures.

In June 2011, the FASB issued Accounting Standards Update 2011-05, *Presentation of Comprehensive Income* . Beginning in our 2011 Annual Report on Form 10-K, this update will give us 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. We have not determined which presentation option we will choose but do not expect our selection to materially impact the presentation of our financial statements.

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

Commodity Price Risk

We have commodity derivatives that pertain to production for the last six months of 2011, as well as 2012 and 2013. The key terms to all our oil, gas and NGL derivative financial instruments as of June 30, 2011 are presented in the following tables.

We had the following open oil derivative positions. Our 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)
Q3-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	—	—

We had the following open natural gas derivative positions. Our 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)
Q3-Q4 2011	712,500	$5.51	215,000	4.75	5.17	—	—
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)
Q3-Q4 2011	Panhandle Eastern Pipeline	150,000	$(0.33)

We had the following open NGL derivative positions:

NGL Basis Swaps			
Production Period	Pay	Volume (Bbls/d)	Weighted Average Differential to WTI ($/Bbl)
Q3-Q4 2011	Natural Gasoline	416	$ (9.75)
Q1-Q4 2012	Natural Gasoline	500	$(10.10)
Q1-Q4 2013	Natural Gasoline	500	$ (6.80)

The fair values of our commodity derivatives presented in the tables above are largely determined by estimates of the forward curves of the relevant price indices. At June 30, 2011, a 10 percent increase in the forward curves associated with our gas derivative instruments would have increased our unrealized losses by approximately $224 million. A 10 percent increase in the forward curves associated with our oil derivative instruments would have decreased our unrealized gains by approximately $300 million.

Interest Rate Risk

At June 30, 2011, we had debt outstanding of $7.9 billion. Of this amount, $5.6 billion, or 70 percent bears fixed interest rates averaging 7.2 percent. Additionally, we had $2.3 billion of outstanding commercial paper, bearing interest at floating rates which averaged 0.27 percent.

As of June 30, 2011, we had the open interest rate swap positions listed in the following table. As of June 30, 2011, we also had forward starting swaps and U.S. Treasury locks that were net settled in July 2011 in conjunction with our $2.25 billion debt issuance. We received $35 million to settle these derivatives.

Fixed-to-Floating Swaps			
Notional (In millions)	Fixed Rate Received	Variable Rate Paid	Expiration
$ 300	4.30%	Six month LIBOR	July 18, 2011
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
$ 1,150	3.82%		

The fair values of our interest rate swaps are largely determined by estimates of the forward curves of the Federal Funds rate and LIBOR. At June 30, 2011, a 10 percent increase in these forward curves would have decreased our unrealized losses for our interest rate swaps by approximately $79 million.

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 June 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 June 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 second 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)
April 1 — April 30	1,907,538	$88.81	$1,433
May 1 — May 31	2,217,710	$82.83	$1,250
June 1 — June 30	2,942,530	$79.08	$1,017
Total	7,067,778	$82.88	

(1) In May 2010, our Board of Directors approved a $3.5 billion share repurchase program. This program expires December 31, 2011. As of June 30, 2011, we had repurchased 33.5 million common shares for $2.5 billion, or $74.16 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: August 3, 2011	*/s/ Jeffrey A. Agosta*
	Jeffrey A. Agosta
	Executive Vice President — Chief Financial Officer

INDEX TO EXHIBITS

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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: August 3, 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: August 3, 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 June 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
August 3, 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 June 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
August 3, 2011