DEVON ENERGY CORP/DE
Form 10-Q
May 06, 2010

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2010

or

o **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 þ No o

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 þ No o

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. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

On April 30, 2010, 446.9 million shares of common stock were outstanding.

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For the Quarterly Period Ended March 31, 2010
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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.
- 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 American Onshore means the operations of Devon encompassing oil and gas properties in the continental United States and Canada.

U.S. Offshore means the operations of Devon encompassing 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

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.

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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, 2009 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 beli 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, and the prices of oil, gas, NGLs, including regional pricing differentials, and other products or services;
- production levels, including Canadian production subject to government royalties, which fluctuate with prices and production, and International production governed by payout agreements, which affect reported 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;
- legislative or regulatory changes, including retroactive royalty or production tax regimes, changes in environmental regulation, environmental risks and liability under federal, state and foreign environmental laws and regulations;

terrorism;

occurrence of property acquisitions or divestitures; and

other factors disclosed in Devon s 2009 Annual Report on Form 10-K under Item 2. Properties Preparation of Reserves Estimates and Reserve Audits, 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

	March 31, 2010 (Unaudited)	December 31, 2009
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 724	$ 646
Accounts receivable	1,296	1,208
Derivative financial instruments	733	211
Current assets held for sale	731	657
Other current assets	264	270
Total current assets	3,748	2,992
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($3,266 million and $4,078 million excluded from amortization in 2010 and 2009, respectively)	61,392	60,475
Less accumulated depreciation, depletion and amortization	42,580	41,708
Property and equipment, net	18,812	18,767
Goodwill	6,018	5,930
Long-term assets held for sale	1,409	1,250
Other long-term assets	690	747
Total assets	$ 30,677	$ 29,686
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable trade	$ 1,199	$ 1,137
Revenues and royalties due to others	546	486
Short-term debt	240	1,432
Current portion of asset retirement obligations	90	95
Current liabilities associated with assets held for sale	303	234
Other current liabilities	730	418
Total current liabilities	3,108	3,802
Long-term debt	5,845	5,847
Asset retirement obligations	1,637	1,418
Liabilities associated with assets held for sale	208	213
Other long-term liabilities	921	937

Deferred income taxes	2,003	1,899
Stockholders equity:		
Common stock of $0.10 par value. Authorized 1.0 billion shares; issued 446.8 million and 446.7 million shares in 2010 and 2009, respectively	45	45
Additional paid-in capital	6,577	6,527
Retained earnings	8,733	7,613
Accumulated other comprehensive earnings	1,600	1,385
Total stockholders equity	16,955	15,570
Commitments and contingencies (Note 12)		
Total liabilities and stockholders equity	$ 30,677	$ 29,686

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended March 31, 2010	2009
	(Unaudited) (In millions, except per share amounts)	
Revenues:		
Oil, gas and NGL sales	$ 2,070	$ 1,375
Net gain on oil and gas derivative financial instruments	620	154
Marketing and midstream revenues	530	371
Total revenues	3,220	1,900
Expenses and other income, net:		
Lease operating expenses	414	440
Taxes other than income taxes	101	89
Marketing and midstream operating costs and expenses	397	224
Depreciation, depletion and amortization of oil and gas properties	426	560
Depreciation and amortization of non-oil and gas properties	63	70
Accretion of asset retirement obligations	26	23
General and administrative expenses	138	163
Interest expense	86	83
Change in fair value of other financial instruments	(15)	(5)
Reduction of carrying value of oil and gas properties		6,408
Other (income) expense, net	(4)	7
Total expenses and other income, net	1,632	8,062
Earnings (loss) from continuing operations before income taxes	1,588	(6,162)
Income tax expense (benefit):		
Current	299	(8)
Deferred	215	(2,272)
Total income tax expense (benefit)	514	(2,280)
Earnings (loss) from continuing operations	1,074	(3,882)
Discontinued operations:		
Earnings (loss) from discontinued operations before income taxes	137	(66)
Discontinued operations income tax expense	19	11
Earnings (loss) from discontinued operations	118	(77)
Net earnings (loss)	$ 1,192	$ (3,959)

Basic earnings (loss) from continuing operations per share	$ 2.40	$ (8.74)
Basic earnings (loss) from discontinued operations per share	0.27	(0.18)
Basic net earnings (loss) per share	$ 2.67	$ (8.92)
Diluted earnings (loss) from continuing operations per share	$ 2.39	$ (8.74)
Diluted earnings (loss) from discontinued operations per share	0.27	(0.18)
Diluted net earnings (loss) per share	$ 2.66	$ (8.92)

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE EARNINGS (LOSS)

	Three Months Ended March 31,	
	2010	2009
	(Unaudited) (In millions)	
Net earnings (loss)	$ 1,192	$ (3,959)
Foreign currency translation:		
Change in cumulative translation adjustment	222	(161)
Foreign currency translation income tax (expense) benefit	(12)	11
Foreign currency translation total	210	(150)
Pension and postretirement benefit plans:		
Recognition of net actuarial loss and prior service cost in earnings	8	12
Pension and postretirement benefit plans income tax expense	(3)	(4)
Pension and postretirement benefit plans total	5	8
Other comprehensive earnings (loss), net of tax	215	(142)
Comprehensive earnings (loss)	$ 1,407	$ (4,101)

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Earnings	Treasury Stock	Total Stockholders Equity
				(Unaudited) (In millions)			
Three Months Ended March 31, 2010:							
Balance as of December 31, 2009	447	$ 45	$ 6,527	$ 7,613	$ 1,385	$	$ 15,570
Net earnings (loss)				1,192			1,192
Other comprehensive earnings (loss), net of tax					215		215
Stock option exercises			8				8
Common stock repurchased						(2)	(2)
Common stock retired			(2)			2	
Common stock dividends				(72)			(72)
Share-based compensation			41				41
Share-based compensation tax benefits			3				3
Balance as of March 31, 2010	447	$ 45	$ 6,577	$ 8,733	$ 1,600	$	$ 16,955
Three Months Ended March 31, 2009:							
Balance as of December 31, 2008	444	$ 44	$ 6,257	$ 10,376	$ 383	$	$ 17,060
Net earnings (loss)				(3,959)			(3,959)
Other comprehensive earnings (loss), net of tax					(142)		(142)
Stock option exercises			4				4
Common stock repurchased						(2)	(2)
Common stock retired			(2)			2	
Common stock dividends				(70)			(70)
Share-based compensation			49				49
Share-based compensation tax benefits			2				2
Balance as of March 31, 2009	444	$ 44	$ 6,310	$ 6,347	$ 241	$	$ 12,942

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended March 31, 2010	2009
	(Unaudited) (In millions)	
Cash flows from operating activities:		
Earnings (loss) from continuing operations	$ 1,074	$ (3,882)
Adjustments to reconcile earnings (loss) from continuing operations to net cash provided by operating activities:		
Depreciation, depletion and amortization	489	630
Deferred income tax expense (benefit)	215	(2,272)
Reduction of carrying value of oil and gas properties		6,408
Net unrealized gain on oil and gas derivative financial instruments	(524)	(36)
Other noncash charges	57	63
Net decrease in working capital	50	128
Increase in long-term other assets	(2)	
Decrease in long-term other liabilities	(18)	(29)
Cash provided by operating activities continuing operations	1,341	1,010
Cash provided by operating activities discontinued operations	154	37
Net cash provided by operating activities	1,495	1,047
Cash flows from investing activities:		
Proceeds from property and equipment divestitures	1,257	1
Capital expenditures	(1,247)	(1,926)
Redemptions of long-term investments	8	2
Cash provided by (used in) investing activities continuing operations	18	(1,923)
Cash used in investing activities discontinued operations	(107)	(107)
Net cash used in investing activities	(89)	(2,030)
Cash flows from financing activities:		
Proceeds from borrowings of long-term debt, net of issuance costs		1,187
Net commercial paper repayments	(1,192)	(111)
Debt repayments		(1)
Proceeds from stock option exercises	8	4
Dividends paid on common stock	(72)	(70)
Excess tax benefits related to share-based compensation	3	2
Net cash (used in) provided by financing activities	(1,253)	1,011
Effect of exchange rate changes on cash	18	(11)

Net increase in cash and cash equivalents	171	17
Cash and cash equivalents at beginning of period (including cash related to assets held for sale)	1,011	384
Cash and cash equivalents at end of period (including cash related to assets held for sale)	$ 1,182	$ 401

See accompanying notes to consolidated financial statements.

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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 2009 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 March 31, 2010 and Devon s results of operations and cash flows for the three-month periods ended March 31, 2010 and 2009.

2. Accounts Receivable

The components of accounts receivable include the following:

	March 31, 2010	December 31, 2009
	(In millions)	
Oil, gas and NGL sales	$ 835	$ 752
Joint interest billings	157	151
Marketing and midstream revenues	169	188
Production tax credits	128	110
Other	19	19
Gross accounts receivable	1,308	1,220
Allowance for doubtful accounts	(12)	(12)
Net accounts receivable	$ 1,296	$ 1,208

3. Derivative Financial Instruments

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 and gas price volatility and to manage Devon s exposure to interest rate volatility.

The following table presents the fair values of derivative assets and liabilities included in the accompanying consolidated balance sheets. None of Devon s derivative instruments included in the table have been designated as hedging instruments.

	Balance Sheet Caption	Asset Derivatives	Liability Derivatives
		(In millions)	
March 31, 2010:			
Gas price swaps	Derivative financial instruments, current	$ 659	$
Gas price collars	Derivative financial instruments, current	35	
Gas basis swaps	Other current liabilities		2
Oil price collars	Other current liabilities		34

Interest rate swaps	Derivative financial instruments, current	39	
Interest rate swaps	Other long-term assets	130	
Total derivatives		$ 863	$ 36

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

	Balance Sheet Caption	Asset Derivatives	Liability Derivatives
		(In millions)	
December 31, 2009:			
Gas price swaps	Derivative financial instruments, current	$ 169	$
Gas basis swaps	Derivative financial instruments, current	3	
Oil price collars	Other current liabilities		38
Interest rate swaps	Derivative financial instruments, current	39	
Interest rate swaps	Other long-term assets	131	
Total derivatives		$ 342	$ 38

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. None of Devon s derivative instruments have been designated as hedging instruments.

	Statement of Operations Caption	Three Months Ended March 31, 2010	2009
		(In millions)	
Cash settlements:			
Gas price swaps	Net gain on oil and gas derivative financial instruments	$ 98	$
Gas price collars	Net gain on oil and gas derivative financial instruments	1	118
Gas basis swaps	Net gain on oil and gas derivative financial instruments	(3)	
Interest rate swaps	Change in fair value of other financial instruments	16	16
Total cash settlements		112	134
Unrealized gains (losses):			
Gas price swaps	Net gain on oil and gas derivative financial instruments	490	
Gas price collars	Net gain on oil and gas derivative financial instruments	35	36
Gas basis swaps	Net gain on oil and gas derivative financial instruments	(5)	
Oil price collars	Net gain on oil and gas derivative financial instruments	4	
Interest rate swaps	Change in fair value of other financial instruments	(1)	(11)

Total unrealized gains	523	25
Net gain recognized	$ 635	$ 159

4. Other Current Assets

The components of other current assets include the following:

	March 31, 2010	December 31, 2009
	(In millions)	
Inventories	$ 180	$ 182
Prepaid assets	39	33
Income taxes receivable	21	53
Other	24	2
Other current assets	$ 264	$ 270

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

5. Property and Equipment

Divestitures

In November 2009, Devon announced plans to reposition itself strategically as a high-growth, North American onshore exploration and production company. As part of this strategic repositioning, Devon is bringing forward the value of its offshore assets by divesting them.

During the first quarter of 2010, Devon sold its interests in the Jack, St. Malo and Cascade Lower Tertiary projects in the deepwater Gulf of Mexico for $1.3 billion ($1.1 billion after taxes). These divestitures involved oil and gas properties with no proved reserves, current production or revenues. Devon used the proceeds from these divestitures to repay commercial paper borrowings.

On March 10, 2010, Devon entered into agreements to sell all of its remaining assets in the deepwater Gulf of Mexico, Brazil and Azerbaijan to BP for $7.0 billion. In addition, BP will assume Devon s leases of the Seadrill West Sirius and Transocean Deepwater Discovery drilling rigs for the duration of the contract terms. Devon closed the deepwater Gulf of Mexico transaction in April 2010. Devon expects to close the Azerbaijan and Brazil transactions before the end of 2010.

On April 9, 2010, Devon entered into an agreement to sell all its shallow-water Gulf of Mexico assets for $1.05 billion (approximately $840 million after taxes). Devon expects to close this transaction in the second quarter of 2010.

On April 30, 2010, Devon entered into an agreement to sell its producing Panyu field located offshore China for $515 million (approximately $370 million after taxes). Devon expects to close this transaction in the second quarter of 2010.

Under full cost accounting rules, sales or other dispositions of oil and gas properties are generally accounted for as adjustments to capitalized costs, with no recognition of gain or loss. However, if not recognizing a gain or loss on the disposition would otherwise significantly alter the relationship between a cost center s capitalized costs and proved reserves, then a gain or loss must be recognized. The Gulf of Mexico divestitures discussed above will not significantly alter such relationship for Devon s United States cost center. Therefore, Devon will not recognize a gain in connection with the Gulf of Mexico divestitures. Because the Azerbaijan, Brazil and China divestitures will ultimately involve a complete disposition of a cost center, Devon expects to record gains when such transactions close.

Oil Sands Joint Venture

In conjunction with the announced divestitures to BP, Devon also announced a heavy oil joint venture to operate and develop BP s Kirby oil sands leases in Alberta, Canada. Devon will acquire 50 percent of BP s interest in the Kirby oil sands leases for $500 million. Devon expects to close this transaction in the second quarter of 2010. Devon will also fund $150 million of capital costs on BP s behalf. The majority of these costs are expected to be paid during 2011 and 2012.

6. Goodwill

During the first three months of 2010, Devon s Canadian goodwill increased $88 million. This increase was entirely due to foreign currency translation.

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

7. Other Current Liabilities

The components of other current liabilities include the following:

	March 31, 2010	December 31, 2009
	(In millions)	
Income taxes payable	$ 283	$ 40
Deferred income taxes	176	
Accrued interest	67	120
Restructuring costs	61	61
Derivative financial instruments	36	38
Other	107	159
Other current liabilities	$ 730	$ 418

8. Debt

Commercial Paper

During the first quarter of 2010, Devon repaid $1.2 billion of commercial paper borrowings primarily with proceeds received from Gulf of Mexico property divestitures. As of March 31, 2010, Devon s average borrowing rate on its $240 million of commercial paper debt was 0.22%.

In early May 2010, Devon reduced the maximum allowed borrowings under its commercial paper program from $2.85 billion to approximately $2.2 billion.

Credit Lines

As of March 31, 2010, Devon had two revolving lines of credit that could be accessed to provide liquidity as needed. The following schedule summarizes the capacity of Devon s credit facilities by maturity date, as well as its available capacity as of March 31, 2010 (in millions).

Senior Credit Facility:	
April 7, 2012 maturity	$ 500
April 7, 2013 maturity	2,150
Total Senior Credit Facility	2,650
Short-Term Facility November 2, 2010 maturity	700
Total credit facilities	3,350
Less:	
Outstanding credit facility borrowings	
Outstanding commercial paper borrowings	240
Outstanding letters of credit	88
Total available capacity	$ 3,022

In early May 2010, Devon cancelled the Short-Term Facility prior to its maturity date. Devon incurred no cost to cancel the facility and will avoid paying the facility fee that pertains to the cancellation period.

The Senior Credit Facility and Short-Term Facility contain only one material financial covenant. This covenant requires Devon s ratio of total funded debt to total capitalization to be less than 65%. 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 March 31, 2010, Devon was in compliance with this covenant. Devon s debt-to-capitalization ratio at March 31, 2010, as calculated pursuant to the terms of the agreement, was 17.1%.

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

9. Asset Retirement Obligations

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

	Three Months Ended March 31, 2010	2009
	(In millions)	
Asset retirement obligations as of beginning of period	$ 1,513	$ 1,387
Liabilities incurred	16	8
Liabilities settled	(47)	(26)
Revision of estimated obligation	205	22
Liabilities assumed by others	(8)	
Accretion expense on discounted obligation	26	23
Foreign currency translation adjustment	22	(17)
Asset retirement obligations as of end of period	1,727	1,397
Less current portion	90	157
Asset retirement obligations, long-term	$ 1,637	$ 1,240

During the first quarter of 2010 and 2009, Devon recognized revisions to its asset retirement obligations totaling $205 million and $22 million, respectively. The primary factors causing the 2010 and 2009 increases were an overall increase in abandonment cost estimates and a decrease in the discount rate used to present value the obligations.

10. Retirement Plans

Net Periodic Benefit Cost and Other Comprehensive Earnings

The following table presents the components of net periodic benefit cost and other comprehensive earnings for Devon s pension and other post retirement benefit plans.

	Pension Benefits Three Months Ended March 31,		Other Postretirement Benefits Three Months Ended March 31,	
	2010	2009	2010	2009
Net periodic benefit cost:				
Service cost	$ 8	$ 11	$	$
Interest cost	14	14	1	1
Expected return on plan assets	(9)	(9)		
Amortization of prior service cost	1	1		
Net actuarial loss	7	11		
Net periodic benefit cost	21	28	1	1
Other comprehensive earnings:				
Recognition of prior service cost in net periodic benefit cost	(1)	(1)		
Recognition of net actuarial loss in net periodic benefit cost	(7)	(11)		

Total recognized	$ 13	$ 16	$ 1	$ 1

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11. Stockholders Equity

Dividends

Devon paid common stock dividends of $72 million and $70 million (quarterly rates of $0.16 per share) in the first quarter of 2010 and 2009, respectively.

12. 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 that 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. However, actual amounts could differ materially from management s estimate.

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 uninsured costs associated with remediation. Devon s monetary exposure for environmental matters is not expected to be material.

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.

Other Matters

Devon is involved in other various routine legal proceedings incidental to its business. However, to Devon s knowledge as of the date of this report, neither Devon nor its property is subject to any material pending legal proceedings.

Commitments

At the end of 2009, Devon s commitments included $1.4 billion that related to long-term contracts for three deepwater drilling rigs. This total includes $1.2 billion related to two contracts to be assumed by BP in connection with the associated divestiture transactions as discussed in Note 5.

At the end of 2009, Devon s commitments also included $0.4 billion that related to leases of floating, production, storage and offloading facilities being used in the Gulf of Mexico, Brazil and China. Devon s commitments for these leases will be assumed by the buyers of Devon s assets in these locations when the associated divestiture transactions close.

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

13. Fair Value Measurements

The following tables provide carrying value and fair value measurement information for Devon s financial assets and liabilities.

			Fair Value Measurements Using:		
			Quoted Prices in Active	Significant Other Observable	Significant Unobservable
	Carrying Amount	Total Fair Value	Markets (Level 1)	Inputs (Level 2)	Inputs (Level 3)
			(In millions)		
March 31, 2010 assets (liabilities):					
Gas price swaps	$ 659	$ 659	$	$ 659	$
Gas price collars	$ 35	$ 35	$	$ 35	$
Gas basis swaps	$ (2)	$ (2)	$	$ (2)	$
Oil price collars	$ (34)	$ (34)	$	$ (34)	$
Interest rate swaps	$ 169	$ 169	$	$ 169	$
Debt	$(6,085)	$ (6,985)	$ (240)	$ (6,745)	$
Long-term investments	$ 107	$ 107	$	$	$ 107
December 31, 2009 assets (liabilities):					
Gas price swaps	$ 169	$ 169	$	$ 169	$
Gas basis swaps	$ 3	$ 3	$	$ 3	$
Oil price collars	$ (38)	$ (38)	$	$ (38)	$
Interest rate swaps	$ 170	$ 170	$	$ 170	$
Debt	$(7,279)	$ (8,214)	$(1,432)	$ (6,782)	$
Long-term investments	$ 115	$ 115	$	$	$ 115

14. Restructuring Costs

In the fourth quarter of 2009, Devon recognized $153 million of estimated employee severance costs associated with the planned divestitures of its offshore assets that was announced in November 2009. This amount was based on estimates of the number of employees that will ultimately be impacted by the divestitures and includes $63 million related to accelerated vesting of share-based grants. Of the $153 million total, $105 million relates to Devon s U.S. Offshore operations and the remainder relates to its International discontinued operations.

Devon s estimate of employee severance costs recognized in the fourth quarter of 2009 was based upon certain key estimates that could change as properties are sold. These estimates include the number of impacted employees, the number of employees offered comparable positions with the buyers and the date of separation for impacted employees. As discussed in Note 5, Devon has only closed a limited number of divestiture transactions, which did not impact a significant number of employees. As a result, Devon did not revise its estimate of employee severance costs during the first quarter of 2010.

15. Reduction of Carrying Value of Oil and Gas Properties

In the first quarter of 2009, Devon reduced the carrying value of its United States oil and gas properties $6.4 billion, or $4.1 billion after taxes, due to a full cost ceiling limitation. The reduction resulted from a significant decrease in the full cost ceiling compared to the immediately preceding quarter due to the effects of declining natural gas prices subsequent to December 31, 2008.

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16. Discontinued Operations

Revenues related to Devon s discontinued operations totaled $212 million and $128 million in the three months ended March 31, 2010 and March 31, 2009, respectively.

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

	March 31, 2010	December 31, 2009
	(In millions)	
Cash and cash equivalents	$ 458	$ 365
Accounts receivable	122	165
Other current assets	151	127
Current assets	$ 731	$ 657
Property and equipment, net	$ 1,260	$ 1,099
Goodwill	68	68
Other long-term assets	81	83
Total long-term assets	$ 1,409	$ 1,250
Accounts payable	$ 209	$ 158
Other current liabilities	94	76
Current liabilities	$ 303	$ 234
Asset retirement obligations	$ 102	$ 109
Deferred income taxes	102	101
Other liabilities	4	3
Long-term liabilities	$ 208	$ 213

Reductions of Carrying Value of Oil and Gas Properties

In the first quarter of 2009, Devon reduced the carrying values of its Brazilian and other International oil and gas properties, which are now held for sale, $109 million due to full cost ceiling limitations. The Brazilian reduction of $103 million, which had no related tax benefit, resulted largely from an exploratory well drilled at the BM-BAR-3 block in the offshore Barreirinhas Basin. After drilling this well in the first quarter of 2009, Devon concluded that the well did not have adequate reserves for commercial viability. As a result, the seismic, leasehold and drilling costs associated with this well contributed to the reduction recognized in the first quarter of 2009.

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17. Earnings (Loss) Per Share

The following table reconciles earnings (loss) from continuing operations and common shares outstanding used in the calculations of basic and diluted earnings (loss) per share for the three-month periods ended March 31, 2010 and 2009. Because a net loss from continuing operations was generated during the three-month period ended March 31, 2009, the dilutive shares produce an antidilutive net loss per share result. Therefore, the diluted loss per share from continuing operations reported in the accompanying 2009 consolidated statement of operations is the same as the basic loss per share amount.

	Earnings (Loss)	Common Shares	Earnings (Loss) per Share
	(In millions, except per share amounts)		
Three Months Ended March 31, 2010:			
Earnings from continuing operations	$ 1,074	447	
Attributable to participating securities	(13)	(6)	
Basic earnings per share	1,061	441	$ 2.40
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		2	
Diluted earnings per share	$ 1,061	443	$ 2.39
Three Months Ended March 31, 2009:			
Loss from continuing operations	$ (3,882)	444	
Attributable to participating securities	48	(5)	
Basic and diluted loss per share	$ (3,834)	439	$ (8.74)

Certain options to purchase shares of Devon s common stock are excluded from the dilution calculations because the options are antidilutive. These excluded options totaled 1.7 million and 8.9 million during the three-month periods ended March 31, 2010 and 2009, respectively.

18. Segment Information

Devon manages its operations through seven 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 business. However, Devon s Canadian and International divisions are reported as separate reporting segments primarily due to significant differences in the respective regulatory environments.

Following is certain financial information regarding Devon s reporting segments. The revenues reported are all from external customers.

	U.S.	Canada	International	Total
	(In millions)			
As of March 31, 2010:				
Current assets	$ 1,955	$ 1,062	$ 731	$ 3,748
Property and equipment, net	12,750	6,062		18,812

Goodwill	3,046	2,972		6,018
Other assets	622	68	1,409	2,099
Total assets	$ 18,373	$ 10,164	$ 2,140	$ 30,677
Current liabilities	$ 2,171	$ 634	$ 303	$ 3,108
Long-term debt	2,864	2,981		5,845
Asset retirement obligations	814	823		1,637
Other liabilities	875	46	208	1,129
Deferred income taxes	919	1,084		2,003
Stockholders equity	10,730	4,596	1,629	16,955
Total liabilities and stockholders equity	$ 18,373	$ 10,164	$ 2,140	$ 30,677

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	U.S.	Canada	Total
		(In millions)	
Three Months Ended March 31, 2010:			
Revenues:			
Oil, gas and NGL sales	$ 1,370	$ 700	$ 2,070
Net gain (loss) on oil and gas derivative financial instruments	625	(5)	620
Marketing and midstream revenues	496	34	530
Total revenues	2,491	729	3,220
Expenses and other income, net:			
Lease operating expenses	224	190	414
Taxes other than income taxes	90	11	101
Marketing and midstream operating costs and expenses	369	28	397
Depreciation, depletion and amortization of oil and gas properties	261	165	426
Depreciation and amortization of non-oil and gas properties	56	7	63
Accretion of asset retirement obligations	13	13	26
General and administrative expenses	108	30	138
Interest expense	30	56	86
Change in fair value of other financial instruments	(15)		(15)
Other income, net	(3)	(1)	(4)
Total expenses and other income, net	1,133	499	1,632
Earnings from continuing operations before income taxes	1,358	230	1,588
Income tax expense (benefit):			
Current	214	85	299
Deferred	235	(20)	215
Total income tax expense	449	65	514
Earnings from continuing operations	$ 909	$ 165	$ 1,074
Capital expenditures, before revision of future asset retirement obligations	$ 1,033	$ 370	$ 1,403
Revision of future asset retirement obligations	83	122	205
Capital expenditures	$ 1,116	$ 492	$ 1,608

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

	U.S.	Canada (In millions)	Total
Three Months Ended March 31, 2009:			
Revenues:			
Oil, gas and NGL sales	$ 938	$ 437	$ 1,375
Net gain on oil and gas derivative financial instruments	154		154
Marketing and midstream revenues	364	7	371
Total revenues	1,456	444	1,900
Expenses and other income, net:			
Lease operating expenses	270	170	440
Taxes other than income taxes	81	8	89
Marketing and midstream operating costs and expenses	220	4	224
Depreciation, depletion and amortization of oil and gas properties	440	120	560
Depreciation and amortization of non-oil and gas properties	64	6	70
Accretion of asset retirement obligations	14	9	23
General and administrative expenses	135	28	163
Interest expense	27	56	83
Change in fair value of other financial instruments	(5)		(5)
Reduction of carrying value of oil and gas properties	6,408		6,408
Other (income) expense, net	(3)	10	7
Total expenses and other income, net	7,651	411	8,062
(Loss) earnings from continuing operations before income taxes	(6,195)	33	(6,162)
Income tax (benefit) expense:			
Current	(10)	2	(8)
Deferred	(2,279)	7	(2,272)
Total income tax (benefit) expense	(2,289)	9	(2,280)
(Loss) earnings from continuing operations	$ (3,906)	$ 24	$ (3,882)
Capital expenditures, before revision of future asset retirement obligations	$ 1,145	$ 301	$ 1,446
Revision of future asset retirement obligations	37	(15)	22
Capital expenditures	$ 1,182	$ 286	$ 1,468

19. Supplemental Information to Statements of Cash Flows

Information related to Devon s cash flows is presented below.

Three Months

	Ended March 31, 2010	2009
	(In millions)	
Net decrease (increase) in working capital:		
(Increase) decrease in accounts receivable	$ (78)	$ 201
(Increase) decrease in other current assets	(2)	194
Decrease in accounts payable	(29)	(27)
Increase (decrease) in revenues and royalties due to others	58	(115)
Increase (decrease) in income taxes payable	269	(3)
Decrease in other current liabilities	(168)	(122)
Net decrease in working capital	$ 50	$ 128
Supplementary cash flow data continuing and discontinued operations:		
Interest paid net of capitalized interest	$ 137	$ 98
Income taxes paid (received)	$ 50	$ (177)

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

The following discussion addresses material changes in our results of operations and capital resources and uses for the three-month period ended March 31, 2010, compared to the three-month period ended March 31, 2009, and in our financial condition and liquidity since December 31, 2009. For information regarding our critical accounting policies and estimates, see our 2009 Annual Report on Form 10-K under Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations. Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.

Business Overview

Net earnings in the first three months of 2010 were $1.2 billion, or $2.66 per diluted share. This compared to a net loss of $4.0 billion, or $8.92 per diluted share in the first three months of 2009. Our first three months of 2009 earnings were negatively impacted by a $6.4 billion ($4.1 billion after tax) reduction of the carrying value of our United States oil and gas properties. Excluding the reduction of carrying value, our 2010 first quarter earnings increased primarily due to the effects of higher commodity prices, partially offset by a decrease in production.

Key measures of our performance for the first three months of 2010 compared to the first three months of 2009 are summarized below:

- The combined realized price without hedges for oil, gas and NGLs increased 58% to $37.07 per Boe.

- Oil and gas derivatives generated a net gain of $620 million and $154 million in the first three months of 2010 and 2009, respectively. Included in these amounts were cash receipts of $96 million and $118 million, respectively.

- Operating cash flow increased 43% to $1.5 billion.

- Production decreased 5% to 56 million Boe.

- Marketing and midstream operating profit decreased 9% to $133 million.

- Cash spent on capital expenditures was approximately $1.3 billion in the first quarter of 2010.

Additionally, we have made significant progress toward completion of our offshore divestiture program. Through April 2010, we had announced divestiture transactions of our oil and gas properties in the Gulf of Mexico, Azerbaijan, Brazil and our producing Panyu field offshore China. Furthermore, in connection with BP s acquisition of our Gulf of Mexico and Brazilian properties, BP is also assuming our leases of the Seadrill West Sirius and Transocean Deepwater Discovery drilling rigs for the duration of the contract terms. Through April 2010, we had closed the transactions related to all our deepwater Gulf of Mexico properties. The divestiture process is ongoing for the remaining announced transactions, as well as our exploration assets in China and Angola and other minor International assets. We expect the closing of all divestitures to be completed by the end of 2010.

Our announced divestitures have proceeds that total $9.9 billion before taxes. Once all divestiture assets are sold, we estimate the total pre-tax proceeds will exceed $10 billion and the after-tax proceeds will be approximately $8 billion. As a result of the success we have experienced with our offshore divestiture program, we announced a share repurchase program in early May 2010. The program authorizes the repurchase of up to $3.5 billion of our common shares.

In conjunction with divestitures to BP, we also announced a heavy oil joint venture to operate and develop BP s Kirby oil sands leases in Alberta, Canada. We will acquire 50 percent of BP s interest in the Kirby oil sands leases for $500 million. We expect to close this transaction in the second quarter of 2010. We will also fund $150 million of capital costs on BP s behalf. The majority of these costs are expected to be paid during 2011 and 2012.

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Results of Operations

Revenues

Our oil, gas and NGL production volumes are shown in the following table.

	Three Months Ended March 31,		
	2010	2009	Change (2)
Oil (MMBbls)			
U.S. Onshore	3	3	0%
Canada	7	6	+1%
North American Onshore	10	9	0%
U.S. Offshore	1	1	+6%
Total	11	10	+1%
Gas (Bcf)			
U.S. Onshore	166	181	-8%
Canada	50	53	-4%
North American Onshore	216	234	-7%
U.S. Offshore	10	11	-8%
Total	226	245	-7%
NGLs (MMBbls)			
U.S. Onshore	7	6	+6%
Canada	1	1	-6%
North American Onshore	8	7	+4%
U.S. Offshore			-21%
Total	8	7	+3%
Total (MMBoe) (1)			
U.S. Onshore	37	40	-6%
Canada	16	16	-2%
North American Onshore	53	56	-5%
U.S. Offshore	3	3	-4%
Total	56	59	-5%

(1) Gas volumes are converted to Boe at the rate of six Mcf of gas per barrel of oil, based upon

the approximate relative energy content of gas and oil, which rate is not necessarily indicative of the relationship of gas and oil prices. NGL volumes are converted to Boe on a one-to-one basis with oil.

(2) All percentage changes included in this table are based on actual figures and not the rounded figures included in the table.

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The following table presents the prices we realized on our production volumes. These prices exclude any effects due to our oil and gas derivative financial instruments.

	Three Months Ended March 31,		
	2010	2009	Change
Oil (per Bbl)			
U.S. Onshore	$74.81	$34.88	+114%
Canada	$62.50	$27.89	+124%
North American Onshore	$66.41	$30.12	+120%
U.S. Offshore	$76.99	$42.38	+82%
Total	$67.58	$31.41	+115%
Gas (per Mcf)			
U.S. Onshore	$ 4.66	$ 3.43	+36%
Canada	$ 5.08	$ 4.48	+13%
North American Onshore	$ 4.76	$ 3.67	+30%
U.S. Offshore	$ 5.63	$ 5.15	+9%
Total	$ 4.80	$ 3.73	+29%
NGLs (per Bbl)			
U.S. Onshore	$34.22	$17.43	+96%
Canada	$48.95	$25.85	+89%
North American Onshore	$35.98	$18.54	+94%
U.S. Offshore	$40.59	$20.48	+98%
Total	$36.09	$18.60	+94%
Combined (per Boe) (1)			
U.S. Onshore	$32.81	$21.16	+55%
Canada	$44.50	$27.21	+64%
North American Onshore	$36.29	$22.92	+58%
U.S. Offshore	$51.07	$34.21	+49%
Total	$37.07	$23.51	+58%

(1) Gas volumes are converted to Boe at the rate of six Mcf of gas per barrel of oil, based upon the approximate relative energy content of gas and oil, which rate is not necessarily indicative of the relationship of gas and oil prices. NGL volumes are converted to Boe on a

one-to-one basis
with oil.

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 March 31, 2010 and 2009.

	Oil	Gas	NGLs	Total
		(In millions)		
2009 sales	$ 327	$ 912	$ 136	$ 1,375
Changes due to volumes	3	(67)	5	(59)
Changes due to prices	380	241	133	754
2010 sales	$ 710	$ 1,086	$ 274	$ 2,070

Oil Sales

Oil sales increased $380 million in the first three months of 2010 as a result of a 115% increase in our realized price without hedges. The largest contributor to the increase in our realized price was the increase in the average NYMEX West Texas Intermediate index price over the same time period. In addition, our price differential based upon the NYMEX index price also improved, which contributed to our higher realized price. The improved differential resulted primarily from the tightening of the heavy oil differentials related to our Canadian operations.

Gas Sales

Gas sales increased $241 million during the first three months of 2010 as a result of a 29% increase in our realized price without hedges. This increase was largely due to increases in the North American regional index prices upon which our gas sales are based.

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A 19 Bcf decrease in production during the first three months of 2010 caused gas sales to decrease by $67 million. The decrease in production was primarily due to reduced drilling during most of 2009 for our North American Onshore properties. As a result of the reduced drilling in response to lower gas prices, natural declines of existing wells outpaced production gains from new drilling.

NGL Sales

NGL sales increased $133 million during the first three months of 2010 as a result of a 94% increase in our realized price without hedges. This increase was largely due to increases in the regional index prices upon which our NGL sales are based.

Net Gain on Oil and Gas Derivative Financial Instruments

The following tables provide financial information associated with our oil and gas 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 March 31,	
	2010	**2009**
	(In millions)	
Cash settlement receipts (payments):		
Gas price swaps	$ 98	$
Gas price collars	1	118
Gas basis swaps	(3)	
Oil price collars		
Total cash settlements	96	118
Unrealized gains (losses) on fair value changes:		
Gas price swaps	490	
Gas price collars	35	36
Gas basis swaps	(5)	
Oil price collars	4	
Total unrealized gains	524	36
Net gain	$ 620	$ 154

	Three Months Ended March 31, 2010			
	Oil (Per Bbl)	**Gas (Per Mcf)**	**NGLs (Per Bbl)**	**Total (Per Boe)**
Realized price without hedges	$ 67.58	$ 4.80	$ 36.09	$ 37.07
Cash settlements of hedges		0.42		1.71
Realized price, including cash settlements	$ 67.58	$ 5.22	$ 36.09	$ 38.78

	Three Months Ended March 31, 2009			
	Oil	**Gas**	**NGLs**	**Total**

	(Per Bbl)	(Per Mcf)	(Per Bbl)	(Per Boe)
Realized price without hedges	$ 31.41	$ 3.73	$ 18.60	$ 23.51
Cash settlements of hedges		0.48		2.02
Realized price, including cash settlements	$ 31.41	$ 4.21	$ 18.60	$ 25.53

In the first three months of 2010, our oil and gas derivative financial instruments included gas price swaps, gas basis swaps and oil and gas costless price collars. In the first three months of 2009, our oil and gas derivative financial instruments included only gas price collars. 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 our price swaps, price collars and basis swaps.

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During the first three months of 2010, we received $96 million, or $0.42 per Mcf from counterparties to settle our gas derivatives. During the first three months of 2009, we received $118 million, or $0.48 per Mcf, 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 and gas derivative instruments in each reporting period. We estimate the fair values of our oil and gas derivative financial instruments primarily by using internal discounted cash flow calculations. From time to time, we 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 derivatives at March 31, 2010, a 10% increase in these forward curves would have decreased the fair value of our gas derivative financial instruments by approximately $159 million. A 10% increase in the forward curves associated with our oil derivatives would have decreased the fair value of our oil derivative financial instruments by approximately $75 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.

Counterparty credit risk is also a component of commodity derivative valuations. We have mitigated our exposure to any single counterparty by contracting with numerous counterparties. Our commodity derivative contracts are held with twelve 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 threshold for collateral posting decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $50 million for the majority of our contracts. As of March 31, 2010, the credit ratings of all our counterparties were investment grade.

During the first three months of 2010 and 2009, the fair value of our commodity derivative financial instruments increased by $524 million and $36 million, respectively. These unrealized gains primarily resulted from decreases in the Inside FERC Henry Hub forward curve during the first quarter of each year.

Marketing and Midstream Revenues and Operating Costs and Expenses

The details of the changes in marketing and midstream revenues, operating costs and expenses and the resulting operating profit are shown in the table below.

	Three Months Ended March 31,		
	2010	2009	Change(1)
	($ in millions)		
Marketing and midstream:			
Revenues	$ 530	$ 371	43%
Operating costs and expenses	397	224	77%
Operating profit	$ 133	$ 147	-9%

(1) All percentage changes included in this table are based on actual figures and are not calculated using the rounded figures included

in this table.

During the first three months of 2010, marketing and midstream revenues increased $159 million and operating costs and expenses increased $173 million, causing operating profit to decrease $14 million. Revenues, expenses and operating profit increased due to higher natural gas and NGL production and processing prices, partially offset by the effects of lower gas pipeline throughput. However, the increase in operating profit resulting from these factors was more than offset by the effect of lower prices realized from gas marketing activities.

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Lease Operating Expenses (LOE)

The details of the changes in LOE are shown in the table below.

	Three Months Ended March 31,		
	2010	2009	Change(1)
Lease operating expenses ($ in millions):			
U.S. Onshore	$ 191	$ 229	-17%
Canada	190	170	+12%
North American Onshore	381	399	-5%
U.S. Offshore	33	41	-19%
Total	$ 414	$ 440	-6%
Lease operating expenses per Boe:			
U.S. Onshore	$ 5.12	$ 5.82	-12%
Canada	$ 12.09	$ 10.57	+14%
North American Onshore	$ 7.19	$ 7.20	0%
U.S. Offshore	$ 11.18	$ 13.33	-16%
Total	$ 7.41	$ 7.52	-2%

(1) All percentage changes included in this table are based on actual figures and are not calculated using the rounded figures included in this table.

LOE decreased $26 million in the first three months of 2010. LOE dropped $31 million due to declining costs for fuel, materials, equipment and personnel, as well as declines in maintenance and well workover projects. Such declines largely resulted from decreased demand for field services. Our 5% decrease in production also reduced LOE by $20 million. Additionally, LOE decreased $7 million due to additional costs incurred in the first three months of 2009 as a result of hurricane damages sustained in 2008. These decreases were partially offset by changes in the exchange rate between the U.S. and Canadian dollar which increased LOE by $32 million. Excluding the decrease due to lower production, these factors were also the main contributors to the changes in LOE per Boe.

Taxes Other Than Income Taxes

The following table details the changes in our taxes other than income taxes.

	Three Months Ended March 31,		
	2010	2009	Change(1)
		($ in millions)	
Production	$ 59	$ 32	+83%
Ad valorem	40	54	-27%
Other	2	3	-36%

Total	$ 101	$ 89	+13%

(1) All percentage changes included in this table are based on actual figures and not the rounded figures included in this table.

Production taxes increased $27 million in the first three months of 2010 primarily due to an increase in our U.S. Onshore revenues. Ad valorem taxes decreased $14 million primarily due to lower estimated assessed values of our oil and gas property and equipment.

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

The changes in our production volumes, DD&A rate per unit and DD&A of oil and gas properties are shown in the table below.

	Three Months Ended March 31,		
	2010	**2009**	**Change(1)**
Total production volumes (MMBoe)	56	59	-5%
DD&A rate ($ per Boe)	$ 7.63	$ 9.57	-20%
DD&A expense ($ in millions)	$ 426	$ 560	-24%

(1) All percentage changes included in this table are based on actual figures and are not calculated using the rounded figures included in this table.

The following table details the changes in DD&A of oil and gas properties between the three months ended March 31, 2010 and 2009 (in millions).

2009 DD&A	$ 560
Change due to rate	(108)
Change due to volumes	(26)
2010 DD&A	$ 426

Oil and gas property-related DD&A decreased $108 million during the first three months of 2010 due to a 20% decrease in the DD&A rate. The largest contributor to the rate decrease was a reduction of the carrying value of our United States oil and gas properties recognized in the first quarter of 2009. This reduction totaled $6.4 billion and resulted from a full cost ceiling limitation. Additionally, our drilling activities subsequent to the end of the first quarter of 2009 have resulted in proved reserve additions at a cost lower than the first quarter 2009 DD&A rate, causing the rate to decrease. These decreases were partially offset by the effects of changes in the exchange rate between the U.S. and Canadian dollar.

General and Administrative Expenses (G&A)

The following schedule includes the components of G&A expense.

	Three Months Ended March 31,		
	2010	**2009**	**Change (1)**
	(In millions)		
Gross G&A	$ 245	$ 288	-15%
Capitalized G&A	(80)	(90)	-11%
Reimbursed G&A	(27)	(35)	-21%
Net G&A	$ 138	$ 163	-16%

(1) All percentage changes included in this table are based on actual figures and are not calculated using the rounded figures included in this table.

Gross G&A decreased $43 million in the first three months of 2010 compared to the same period in 2009. The largest contributor to the decrease was lower severance costs associated with employee departures and other decreases in employee compensation and benefits. Also, gross G&A decreased as a result of our initiatives to manage spending in certain discretionary cost categories. These decreases were partially offset by the effects of changes in the exchange rate between the U.S. and Canadian dollar. These factors were also the primary drivers of the decrease in capitalized G&A.

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Change in Fair Value of Other Financial Instruments

The details of the changes in fair value of other financial instruments are shown in the table below.

	Three Months Ended March 31,	
	2010	2009
	(In millions)	
(Gains) losses from interest rate swaps:		
Cash settlements	$ (16)	$ (16)
Unrealized fair value changes	1	11
Total	$ (15)	$ (5)

Interest Rate Swaps

During the first three months of 2010 and 2009, we received cash settlements totaling $16 million from counterparties to settle our interest rate swaps.

In addition to recognizing cash settlements, we also recognize unrealized changes in the fair values of our interest rate swaps each reporting period. In the first three months of 2010 and 2009, we recorded unrealized losses of $1 million and $11 million, respectively, as a result of changes in interest rates.

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.

The most significant variable to our cash flow calculation 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 amounts subject to interest rate swaps at March 31, 2010, a 10% increase in these forward curves would have increased the fair value of our interest rate swaps by approximately $50 million.

As previously discussed for 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 several counterparties. Our interest rate derivative contracts are held 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 $50 million for the majority of our contracts. The credit ratings of all our counterparties were investment grade as of March 31, 2010.

Reduction of Carrying Value of Oil and Gas Properties

In the first quarter of 2009, we reduced the carrying value of our United States oil and gas properties by $6.4 billion, or $4.1 billion after taxes, due to a full cost ceiling limitation. The reduction resulted from a significant decrease in the full cost ceiling compared to the immediately preceding quarter due to the effects of declining natural gas prices subsequent to December 31, 2008.

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Income Taxes

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Total income tax expense (benefit) (in millions)	$ 514	$ (2,280)
United States statutory income tax rate	35%	(35%)
State income taxes	1%	(1%)
Taxation on Canadian operations	(1%)	
Other	(3%)	(1%)
Effective income tax (benefit) rate	32%	(37%)

Earnings (Loss) From Discontinued Operations

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Total production (MMBoe)	3	3
Combined price without hedges (per Boe)	$ 72.65	$ 40.68
	(In millions)	
Operating revenues	$ 212	$ 128
Expenses and other income, net:		
Operating expenses	78	86
Reduction of carrying value of oil and gas properties		109
Other income	(3)	(1)
Total expenses and other income, net	75	194
Earnings (loss) before income taxes	137	(66)
Income tax expense	19	11
Earnings (loss) from discontinued operations	$ 118	$ (77)

Earnings increased $195 million in the first three months of 2010 primarily as a result of two factors. First, operating revenues increased largely due to a 79% increase in the price realized on our production, which was driven by an increase in crude oil index prices.

Also, earnings increased $109 million due to 2009 reductions of the carrying values of our oil and gas properties, which primarily related to Brazil. The Brazilian reduction resulted largely from an exploratory well drilled at the BM-BAR-3 block in the offshore Barreirinhas Basin. After drilling this well in the first quarter of 2009, we concluded that the well did not have adequate reserves for commercial viability. As a result, the seismic, leasehold and drilling costs associated with this well contributed to the reduction recognized in the first quarter of 2009.

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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

	Three Months Ended March 31,	
	2010	**2009**
	(In millions)	
Sources of cash and cash equivalents:		
Operating cash flow continuing operations	$ 1,341	$ 1,010
Commercial paper borrowings		894
Debt issuance, net of commercial paper repayments		182
Divestitures of property and equipment	1,257	1
Stock option exercises	8	4
Redemptions of long-term investments	8	2
Other	3	2
Total sources of cash and cash equivalents	**2,617**	**2,095**
Uses of cash and cash equivalents:		
Capital expenditures	(1,247)	(1,926)
Commercial paper repayments	(1,192)	
Debt repayments		(1)
Dividends	(72)	(70)
Total uses of cash and cash equivalents	**(2,511)**	**(1,997)**
Increase from continuing operations	106	98
Increase (decrease) from discontinued operations	47	(70)
Effect of foreign exchange rates	18	(11)
Net increase in cash and cash equivalents	**$ 171**	**$ 17**
Cash and cash equivalents at end of period	**$ 1,182**	**$ 401**

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 three months of 2010. Changes in operating cash flow are largely due to the same factors that affect our net earnings, with the exception of those earnings changes due to noncash expenses such as DD&A, property impairments, financial instrument fair value changes and deferred income taxes. Our operating cash flow increased approximately 33% in 2010 primarily due to the increase in revenues as discussed in the Results of Operations section of this report.

During the first three months of 2010, our operating cash flow was sufficient to fund our cash payments for capital expenditures. During the first three months of 2009, our operating cash flow funded approximately half of our cash payments for capital expenditures. Commercial paper and other borrowings were used to fund the remainder of our cash-based capital expenditures.

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.

During the first three months of 2010, we sold our interests in the Jack, St. Malo and Cascade Lower Tertiary projects in the Gulf of Mexico for $1.3 billion. We used the proceeds from these divestitures to repay commercial paper borrowings.

In January 2009, we issued $500 million of 5.625% senior unsecured notes due January 15, 2014 and $700 million of 6.30% senior unsecured notes due January 15, 2019. The net proceeds received of $1.187 billion, after discounts and issuance costs, were used primarily to repay our $1.0 billion of outstanding commercial paper as of December 31, 2008.

Subsequent to the $1.0 billion commercial paper repayment in January 2009, we utilized additional commercial paper borrowings of $894 million to fund capital expenditures.

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 three months of 2010 and 2009 were approximately $1.6 billion and $1.5 billion, respectively.

	Three Months Ended March 31,	
	2010	2009
	(In millions)	
U.S. Onshore	$ 627	$ 1,107
Canada	377	327
North American Onshore	1,004	1,434
U.S. Offshore	126	333
Total exploration and development	1,130	1,767
Midstream	48	128
Other	69	31
Total continuing operations	$ 1,247	$ 1,926

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 or development of oil and gas properties, which totaled $1.1 billion and $1.8 billion in the first three months of 2010 and 2009, respectively. The decrease in exploration and development capital spending in the first three months of 2010 was primarily due to reduced drilling activities. Compared to the first quarter of 2009, we reduced drilling in response to lower commodity prices that were negatively impacting our operating cash flow. With rising oil prices and proceeds from our offshore divestiture program, we are increasing drilling to grow production across our North American Onshore portfolio of properties.

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 reduction in development drilling also decreased midstream capital activities.

Net Repayments of Debt

During the first three months of 2010, we repaid $1.2 billion of commercial paper borrowings primarily with proceeds received from Gulf of Mexico property divestitures.

Dividends

Our common stock dividends were $72 million and $70 million (quarterly rates of $0.16 per share) in the first three months of 2010 and 2009, respectively.

Liquidity

Our primary source of capital and liquidity has historically been our operating cash flow. Additionally, we maintain revolving lines of credit and a commercial paper program, which can be accessed as needed to supplement operating cash flow. 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 these capital resources and the divestiture proceeds discussed below will provide sufficient liquidity to fund our planned uses of capital. The following sections discuss changes to our liquidity subsequent to filing our 2009 Annual Report on Form 10-K.

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Operating Cash Flow

Our operating cash flow increased approximately 43% to $1.5 billion in the first three months of 2010. 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, natural gas and NGLs produced. To mitigate some of the risk inherent in prices, we have utilized various price collars to set minimum and maximum prices on a portion of our production. We have also utilized various price swap contracts and fixed-price physical delivery contracts to fix the price of a portion of our future natural gas production. As of March 31, 2010, approximately 56% of our estimated 2010 natural gas production and 69% of our estimated oil production are subject to either price collars, swaps or fixed-price contracts.

Offshore Divestitures

During 2010, another major source of liquidity will be proceeds generated from divestitures of our offshore assets. During the first quarter of 2010, we made significant progress toward completion of our offshore divestiture program. In the first quarter of 2010, we closed the divestitures of our interests in the Jack, St. Malo and Cascade Lower Tertiary projects in the deepwater Gulf of Mexico for $1.3 billion ($1.1 billion after taxes).

In March 2010, we announced that we had entered into agreements to sell all of our remaining assets in the deepwater Gulf of Mexico, Brazil and Azerbaijan to BP for $7.0 billion. In addition, BP will assume our leases of the Seadrill West Sirius and Transocean Deepwater Discovery drilling rigs for the duration of the contract terms. We closed the deepwater Gulf of Mexico transaction in April 2010. We expect to close the Azerbaijan and Brazil transactions before the end of 2010.

In April 2010, we announced that we had entered into an agreement to sell all our shallow-water Gulf of Mexico assets for $1.05 billion (approximately $840 million after taxes). We expect to close this transaction in the second quarter of 2010.

Also in April 2010, we announced that we had entered into an agreement to sell our producing Panyu field located offshore China for $515 million (approximately $370 million after taxes). We expect to close this transaction in the second quarter of 2010.

Through April 2010, we have completely exited the deepwater Gulf of Mexico and announced divestiture transactions with proceeds that total $9.9 billion before taxes. Once all divestiture assets are sold, we estimate total pre-tax proceeds will exceed $10 billion and the after-tax proceeds will be approximately $8 billion. We expect to use the offshore divestiture proceeds to reduce debt, fund North American Onshore opportunities and repurchase shares of our common stock.

Credit Availability

In early May 2010, we cancelled our Short-Term Credit Facility prior to its November 2, 2010 maturity date. We incurred no cost to cancel the facility and will avoid paying the facility fee that pertains to the cancellation period. As of May 3, 2010, excluding the Short-Term Credit Facility, we had $2.6 billion of available capacity under our Senior Credit Facility that can be used to supplement our operating cash flow and available cash to fund our capital expenditures and other commitments. The following schedule summarizes the capacity of our Senior Credit Facility by maturity date, as well as our available capacity as of May 3, 2010 (in millions).

Senior Credit Facility:	
April 7, 2012 maturity	$ 500
April 7, 2013 maturity	2,150
Total Senior Credit Facility	2,650
Less:	
Outstanding credit facility borrowings	
Outstanding commercial paper borrowings	
Outstanding letters of credit	88
Total available capacity	$ 2,562

The 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%. As of March 31, 2010, we were in compliance with this covenant. Our debt-to-capitalization ratio at March 31, 2010, as calculated pursuant to the terms of the agreement, was 17.1%.

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In early May 2010, we reduced the maximum allowed borrowings under our commercial paper program from $2.85 billion to approximately $2.2 billion.

Contractual Obligations

At the end of 2009, our commitments included $1.4 billion that related to long-term contracts for three deepwater drilling rigs. This total includes $1.2 billion related to two contracts that will be assumed by BP when the associated divestiture transactions close.

At the end of 2009, our commitments also included $0.4 billion that related to leases of floating, production, storage and offloading facilities being used in the Gulf of Mexico, Brazil and China. Our commitments for these leases will be assumed by the buyers of our assets in these locations when the associated divestiture transactions close.

Common Share Repurchase Program

As a result of the success we have experienced with our offshore divestiture program, we announced a share repurchase program in early May 2010. The program authorizes the repurchase of up to $3.5 billion of our common shares.

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

Commodity Price Risk

The key terms to all our oil and gas derivative financial instruments as of March 31, 2010 are presented in the following tables.

2010 Gas Price Swaps

Period	Volume (MMBtu/d)	Weighted Average Price ($/MMBtu)
Second quarter	1,342,473	$ 6.04
Third quarter	1,265,000	$ 6.16
Fourth quarter	1,265,000	$ 6.16
April December	1,290,636	$ 6.12

2010 Gas Price Collars

		Floor Price		Ceiling Price	
Period	Volume (MMBtu/d)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/MMBtu)
April December	95,000	$ 5.50 $5.50	$ 5.50	$ 6.80 $7.10	$ 6.94

2010 Gas Basis Swaps

Period	Index	Volume (MMBtu/d)	Weighted Average Differential to Henry Hub ($/MMBtu)
April December	AECO	150,000	$ 0.33
April December	CIG	70,000	$ 0.37

2010 Oil Price Collars

	Floor Price		Ceiling Price	
Volume	Floor Range	Weighted	Ceiling Range	Weighted

Period	(Bbls/d)	($/Bbl)		Average Price ($/Bbl)	($/Bbl)		Average Price ($/Bbl)
April December	79,000	$ 65.00	$70.00	$ 67.47	$ 90.35	$103.30	$ 96.48

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		2011 Oil Price Collars			
		Floor Price		Ceiling Price	
Period	Volume (Bbls/d)	Floor Range ($/Bbl)	Weighted Average Price ($/Bbl)	Ceiling Range ($/Bbl)	Weighted Average Price ($/Bbl)
Total year	3,000	$ 75.00 - $75.00	$ 75.00	$ 105.00 - $105.75	$ 105.50

The fair values of our gas price swaps and collars and oil collars are largely determined by estimates of the forward curves of relevant oil and gas price indexes. At March 31, 2010, a 10% increase in the forward curves associated with our gas price swaps and collars would have decreased the fair value of such instruments by approximately $159 million. A 10% increase in the forward curves associated with our oil collars would have decreased the fair value of such instruments by approximately $75 million.

Interest Rate Risk

At March 31, 2010, we had debt outstanding of $6.1 billion. Of this amount, $5.9 billion bears interest at fixed rates averaging 7.2%. Additionally, we had $0.2 billion of outstanding commercial paper, bearing interest at floating rates which averaged 0.22%.

The key terms of our interest rate derivative financial instruments as of March 31, 2010 are presented in the following tables.

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%		

Forward Starting Swaps

Notional (In millions)	Fixed Rate Paid	Variable Rate Received	Expiration
$ 700	3.99%	Three month LIBOR	September 30, 2011

The fair values of our interest rate instruments are largely determined by estimates of the forward curves of the Federal Funds Rate and LIBOR. At March 31, 2010, a 10% increase in these forward curves would have increased the fair value of our interest rate swaps by approximately $50 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% unfavorable change in the Canadian-to-U.S. dollar exchange rate would not materially impact our March 31, 2010 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.

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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 March 31, 2010 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 first quarter of 2010 that has materially affected, or is reasonably likely to materially affect, Devon s internal control over financial reporting.

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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 2009 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 2009 Annual Report on Form 10-K.

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

None.

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

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	DEVON ENERGY CORPORATION
Date: May 6, 2010	*/s/ Danny J. Heatly* Danny J. Heatly *Senior Vice President Accounting and* *Chief Accounting Officer*

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INDEX TO EXHIBITS

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101.DEF	XBRL Taxonomy Extension Definition Linkbase Document