DISH Network CORP
Form 10-Q
May 08, 2018
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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 MARCH 31, 2018.

OR

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

FOR THE TRANSITION PERIOD FROM TO .

Commission File Number: 0-26176

DISH Network Corporation

(Exact name of registrant as specified in its charter)

Nevada (State or other jurisdiction of incorporation or organization)	88-0336997 (I.R.S. Employer Identification No.)
9601 South Meridian Boulevard Englewood, Colorado (Address of principal executive offices)	 80112 (Zip code)

(303) 723-1000

(Registrant's telephone number, including area code)

Not Applicable

(Former name, former address and former fiscal year, if changed since last report)

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 website, 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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth 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

Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

As of May 1, 2018, the registrant's outstanding common stock consisted of 228,944,932 shares of Class A common stock and 238,435,208 shares of Class B common stock.

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PART I — FINANCIAL INFORMATION

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

Unless otherwise required by the context, in this report, the words “DISH Network,” the “Company,” “we,” “our” and “us” refe to DISH Network Corporation and its subsidiaries, “EchoStar” refers to EchoStar Corporation and its subsidiaries, and “DISH DBS” refers to DISH DBS Corporation, a wholly-owned, indirect subsidiary of DISH Network, and its subsidiaries.

This Quarterly Report on Form 10-Q contains “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995, including, in particular, statements about our plans, objectives and strategies, growth opportunities in our industries and businesses, our expectations regarding future results, financial condition, liquidity and capital requirements, our estimates regarding the impact of regulatory developments and legal proceedings, and other trends and projections. Forward-looking statements are not historical facts and may be identified by words such as “future,” “anticipate,” “intend,” “plan,” “goal,” “seek,” “believe,” “estimate,” “expect,” “predict,” “will,” “would,” “could,” similar terms. These forward-looking statements are based on information available to us as of the date of this Quarterly Report on Form 10-Q and represent management’s current views and assumptions. Forward-looking statements are not guarantees of future performance, events or results and involve known and unknown risks, uncertainties and other factors, which may be beyond our control. Accordingly, actual performance, events or results could differ materially from those expressed or implied in the forward-looking statements due to a number of factors, including, but not limited to, the following:

Competition and Economic Risks

- As the pay-TV industry has matured and bundled offers combining video, broadband and/or wireless services have become more prevalent and competitive, we face intense and increasing competition from providers of video, broadband and/or wireless services, which may require us to further increase subscriber acquisition and retention spending or accept lower subscriber activations and higher subscriber churn.

- Changing consumer behavior and competition from digital media companies that provide or facilitate the delivery of video content via the Internet may reduce our subscriber activations and may cause our subscribers to purchase fewer services from us or to cancel our services altogether, resulting in less revenue to us.

- Economic weakness and uncertainty may adversely affect our ability to grow or maintain our business.

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Our competitors may be able to leverage their relationships with programmers to reduce their programming costs and/or offer exclusive content that will place them at a competitive advantage to us.

· Our over-the-top ("OTT") Sling TV Internet-based services face certain risks, including, among others, significant competition.

· If government regulations relating to the Internet change, we may need to alter the manner in which we conduct our Sling TV business, and/or incur greater operating expenses to comply with those regulations.

· Changes in how network operators handle and charge for access to data that travels across their networks could adversely impact our business.

· We face increasing competition from other distributors of unique programming services such as foreign language, sports programming, and original content that may limit our ability to maintain subscribers that desire these unique programming services.

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Operational and Service Delivery Risks

- If our operational performance and customer satisfaction were to deteriorate, our subscriber activations and our subscriber churn rate may be negatively impacted, which could in turn adversely affect our revenue.

- If our subscriber activations continue to decrease, or if our subscriber churn rate, subscriber acquisition costs or retention costs increase, our financial performance will be adversely affected.

- Programming expenses are increasing and may adversely affect our future financial condition and results of operations.

- We depend on others to provide the programming that we offer to our subscribers and, if we fail to obtain or lose access to this programming, our subscriber activations and our subscriber churn rate may be negatively impacted.

- We may not be able to obtain necessary retransmission consent agreements at acceptable rates, or at all, from local network stations.

- We may be required to make substantial additional investments to maintain competitive programming offerings.

- Any failure or inadequacy of our information technology infrastructure and communications systems, including without limitation those caused by cyber-attacks or other malicious activities, could disrupt or harm our business.

- We currently depend on EchoStar to provide the vast majority of our satellite transponder capacity and other related services to us. Our business would be adversely affected if EchoStar ceases to provide these services to us and we are unable to obtain suitable replacement services from third parties.

- Technology in the pay-TV industry changes rapidly, and our success may depend in part on our timely introduction and implementation of, and effective investment in, new competitive products and services and more advanced equipment, and our failure to do so could cause our products and services to become obsolete and could negatively impact our business.

- We rely on a single vendor or a limited number of vendors to provide certain key products or services to us such as information technology support, billing systems, and security access devices, and the inability of these key vendors to meet our needs could have a material adverse effect on our business.

- We rely on a few suppliers and in some cases a single supplier for many components of our new set-top boxes, and any reduction or interruption in supplies or significant increase in the price of supplies could have a negative impact

on our business.

- Our programming signals are subject to theft, and we are vulnerable to other forms of fraud that could require us to make significant expenditures to remedy.
- We depend on independent third parties to solicit orders for our DISH TV services that represent a meaningful percentage of our total gross new DISH TV subscriber activations.
- We have limited satellite capacity and failures or reduced capacity could adversely affect our DISH TV services.
- Our owned and leased satellites are subject to construction, launch, operational and environmental risks that could limit our ability to utilize these satellites.

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- We generally do not carry commercial launch or in-orbit insurance on any of the satellites that we use, other than certain satellites leased from third parties, and could face significant impairment charges if any of our owned satellites fail.

- We may have potential conflicts of interest with EchoStar due to our common ownership and management.

- We rely on key personnel and the loss of their services may negatively affect our business.

Acquisition and Capital Structure Risks

- We have made substantial investments to acquire certain wireless spectrum licenses and other related assets. In addition, we have made substantial non-controlling investments in the Northstar Entities and the SNR Entities related to AWS-3 wireless spectrum licenses.

- We face certain risks related to our non-controlling investments in the Northstar Entities and the SNR Entities, which may have a material adverse effect on our business, results of operations and financial condition.

- To the extent that we commercialize our wireless spectrum licenses, we will face certain risks entering and competing in the wireless services industry and operating a wireless services business.

- Our wireless spectrum licenses are subject to certain interim and final build-out requirements and the failure to meet such build-out requirements may have a material adverse effect on our business, results of operations and financial condition.

- We rely on highly skilled personnel for our wireless business and, if we are unable to hire and retain key personnel or hire qualified personnel then our wireless business may be adversely affected.

- We may pursue acquisitions and other strategic transactions to complement or expand our business that may not be successful, and we may lose up to the entire value of our investment in these acquisitions and transactions.

- We may need additional capital, which may not be available on acceptable terms or at all, to continue investing in our business and to finance acquisitions and other strategic transactions.

- We have substantial debt outstanding and may incur additional debt.

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The conditional conversion features of our 3 3/8% Convertible Notes due 2026 (the "Convertible Notes due 2026") and our 2 3/8% Convertible Notes due 2024 (the "Convertible Notes due 2024," and collectively with the Convertible Notes due 2026, the "Convertible Notes"), if triggered, may adversely affect our financial condition.

- The convertible note hedge and warrant transactions that we entered into in connection with the offering of the Convertible Notes due 2026 may affect the value of the Convertible Notes due 2026 and our Class A common stock.

- We are subject to counterparty risk with respect to the convertible note hedge transactions.

- From time to time a portion of our investment portfolio may be invested in securities that have limited liquidity and may not be immediately accessible to support our financing needs, including investments in public companies that are highly speculative and have experienced and continue to experience volatility.

- It may be difficult for a third party to acquire us, even if doing so may be beneficial to our shareholders, because of our ownership structure.

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· We are controlled by one principal stockholder who is also our Chairman.

Legal and Regulatory Risks

· The rulings in the Telemarketing litigation requiring us to pay up to an aggregate amount of $341 million and imposing certain injunctive relief against us, if upheld, would have a material adverse effect on our cash, cash equivalents and marketable investment securities balances and our business operations.

· Our business may be materially affected by the Tax Cuts and Jobs Act of 2017 (the “Tax Reform Act”). Negative or unexpected tax consequences could adversely affect our business, financial condition and results of operations.

· Our business depends on certain intellectual property rights and on not infringing the intellectual property rights of others.

· We are, and may become, party to various lawsuits which, if adversely decided, could have a significant adverse impact on our business, particularly lawsuits regarding intellectual property.

· Our ability to distribute video content via the Internet, including our Sling TV services, involves regulatory risk.

· Changes in the Cable Act of 1992 (“Cable Act”), and/or the rules of the Federal Communications Commission (“FCC”) that implement the Cable Act, may limit our ability to access programming from cable-affiliated programmers at nondiscriminatory rates.

· The injunction against our retransmission of distant networks, which is currently waived, may be reinstated.

· We are subject to significant regulatory oversight, and changes in applicable regulatory requirements, including any adoption or modification of laws or regulations relating to the Internet, could adversely affect our business.

· Our business depends on FCC licenses that can expire or be revoked or modified and applications for FCC licenses that may not be granted.

· We are subject to digital high-definition (“HD”) “carry-one, carry-all” requirements that cause capacity constraints.

· Our business, investor confidence in our financial results and stock price may be adversely affected if our internal controls are not effective.

- We may face other risks described from time to time in periodic and current reports we file with the Securities and Exchange Commission ("SEC").

Other factors that could cause or contribute to such differences include, but are not limited to, those discussed under the caption "Risk Factors" in Part I, Item 1A of our most recent Annual Report on Form 10-K (the "10-K") filed with the SEC, those discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein and in the 10-K and those discussed in other documents we file with the SEC. All cautionary statements made or referred to herein should be read as being applicable to all forward-looking statements wherever they appear. Investors should consider the risks and uncertainties described or referred to herein and should not place undue reliance on any forward-looking statements. The forward-looking statements speak only as of the date made, and we expressly disclaim any obligation to update these forward-looking statements.

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Item 1. FINANCIAL STATEMENTS

DISH NETWORK CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands, except share amounts)

(Unaudited)

	As of March 31, 2018	December 31, 2017
Assets		
Current Assets:		
Cash and cash equivalents	$ 2,115,349	$ 1,479,508
Marketable investment securities	163,714	501,165
Trade accounts receivable, net of allowance for doubtful accounts of $12,739 and $15,511, respectively	601,673	653,948
Inventory	347,746	321,008
Other current assets	237,079	329,394
Total current assets	3,465,561	3,285,023
Noncurrent Assets:		
Restricted cash, cash equivalents and marketable investment securities	72,638	72,407
Property and equipment, net	2,106,931	2,183,661
FCC authorizations	23,987,355	23,725,789
Other investment securities	115,429	113,460
Other noncurrent assets, net	407,019	393,426
Total noncurrent assets	26,689,372	26,488,743
Total assets	$ 30,154,933	$ 29,773,766
Liabilities and Stockholders' Equity (Deficit)		
Current Liabilities:		
Trade accounts payable	$ 331,388	$ 393,305
Deferred revenue and other	742,838	709,074
Accrued programming	1,595,619	1,571,273
Accrued interest	223,590	282,006
Other accrued expenses (Note 9)	790,000	803,822
Current portion of long-term debt and capital lease obligations	1,008,902	1,068,524
Total current liabilities	4,692,337	4,828,004
Long-Term Obligations, Net of Current Portion:		
Long-term debt and capital lease obligations, net of current portion	15,152,076	15,134,441
Deferred tax liabilities	2,112,421	2,019,538
Long-term deferred revenue and other long-term liabilities	471,634	470,487

Total long-term obligations, net of current portion	17,736,131	17,624,466
Total liabilities	22,428,468	22,452,470
Commitments and Contingencies (Note 9)		
Redeemable noncontrolling interests (Note 2)	401,202	383,390
Stockholders' Equity (Deficit):		
Class A common stock, $.01 par value, 1,600,000,000 shares authorized, 228,363,705 and 228,033,671 shares issued and outstanding, respectively	2,284	2,280
Class B common stock, $.01 par value, 800,000,000 shares authorized, 238,435,208 shares issued and outstanding	2,384	2,384
Additional paid-in capital	3,313,535	3,296,488
Accumulated other comprehensive income (loss)	1,359	882
Accumulated earnings (deficit)	4,005,260	3,635,380
Total DISH Network stockholders' equity (deficit)	7,324,822	6,937,414
Noncontrolling interests	441	492
Total stockholders' equity (deficit)	7,325,263	6,937,906
Total liabilities and stockholders' equity (deficit)	$ 30,154,933	$ 29,773,766

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)

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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.

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	**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	**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.

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.
32.2	Certification of principal financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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

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.
32.2	Certification of principal financial officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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