DEVON ENERGY CORP/DE
Form 8-K
August 05, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 8-K
CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
Date of Report (Date of earliest event reported): August 5, 2009
DEVON ENERGY CORPORATION
(Exact Name of Registrant as Specified in its Charter)

DELAWARE	**001-32318**	**73-1567067**
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(IRS Employer Identification Number)

20 NORTH BROADWAY, OKLAHOMA CITY, OK	**73102**
(Address of Principal Executive Offices)	(Zip Code)

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

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01. Other Events

We reported our original 2009 forward-looking estimates in a Current Report on Form 8-K dated February 4, 2009, and also in our 2008 Annual Report on Form 10-K. During our May 6, 2009, earnings conference call and webcast, we revised certain estimates. Based on our examination of historical operating trends during the first half of 2009 and other data in our possession or available from third parties, we have made further revisions to our estimates. This report includes our 2009 forward-looking estimates, including any updates we have made to our previous estimates. Also, a summary of our forward-looking estimates is included at the end of this report.

Definitions

This report includes references to various abbreviations relating to volumetric production terms and other defined terms. These abbreviations and terms are defined as follows:

Bbl or Bbls means barrel or barrels.

Bbls/d means barrels per day.

Bcf means billion cubic feet.

Boe means barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas.

Btu means British thermal units, a measure of heating value.

Canada means our operations encompassing oil and gas properties located in Canada.

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*.

International means our operations encompassing oil and gas properties that lie outside the United States and Canada.

LIBOR means London Interbank Offered Rate.

MMBbls means million Bbls.

MMBoe means million Boe.

MMBtu means million Btu.

MMBtu/d means million Btu per day.

Mcf means thousand cubic feet.

MMcf means million cubic feet.

NGL or NGLs means natural gas liquids.

NYMEX means New York Mercantile Exchange.

Oil includes crude oil and condensate.

U.S. Offshore means our operations encompassing oil and gas properties in the Gulf of Mexico.

U.S. Onshore means our operations encompassing oil and gas properties in the continental United States.

Forward-Looking Estimates

General Assumptions and Risks Related to Our Estimates

The forward-looking statements provided in this discussion are based on our examination of historical operating trends, the information used to prepare our December 31, 2008 reserve reports and other data in our possession or available from third parties. We caution that our future oil, gas and NGL production, revenues and expenses are subject to all of the risks and uncertainties normally associated with exploring for, developing, producing and selling oil, gas and NGLs. These risks include, but are not limited to, price volatility, inflation or lack of availability of goods and services, environmental risks, drilling risks, regulatory changes, the uncertainty inherent in estimating future oil and gas production or reserves, and other risks discussed below.

Additionally, we caution that our future marketing and midstream revenues and expenses are subject to all of the risks and uncertainties normally associated with transporting oil, gas and NGLs and processing natural gas. These risks include, but are not limited to, price volatility, environmental risks, regulatory changes, the uncertainty inherent in estimating future processing volumes and pipeline throughput, cost of goods and services and other risks discussed below.

Also, the financial results of our foreign operations are subject to currency exchange rate risks. Unless otherwise noted, all of the following dollar amounts are expressed in U.S. dollars. Financial amounts related to our Canadian operations have been converted to U.S. dollars using an estimated average 2009 exchange rate of $0.86 dollar to $1.00 Canadian dollar. The actual 2009 exchange rate may vary materially from this estimate. Such variations could have a material effect on these forward-looking estimates.

Other specific risks associated with our price and production estimates are provided immediately below. Additional risks are discussed throughout this report in the context of line items most affected by such risks.

Specific Assumptions and Risks Related to Price and Production Estimates

Prices for oil, gas and NGLs are determined primarily by prevailing market conditions. Market conditions for these products are influenced by regional and worldwide economic conditions, weather and other local market conditions. These factors are beyond our control and are difficult to predict. In addition, volatility in general oil, gas and NGL prices may vary considerably due to differences between regional markets, differing quality of oil produced (i.e., sweet crude versus heavy or sour crude), differing Btu content of gas produced, transportation availability and costs and demand for the various products derived from oil, gas and NGLs. Substantially all of our revenues are attributable to sales, processing and transportation of these three commodities. Consequently, our financial results and resources are highly influenced by price volatility. Although we expect this volatility to continue throughout 2009, we expect 2009 oil, gas and NGL prices will be noticeably lower than those for 2008.

Estimates for future production of oil, gas and NGLs are based on the assumption that market demand and prices for oil, gas and NGLs will continue at levels that allow for profitable discovery and production of these products. There can be no assurance of such stability. Most of our Canadian production of oil, gas and NGLs is subject to government royalties that fluctuate with prices. Thus, price fluctuations can affect reported production. Also, our production of oil in Azerbaijan and China is governed by payout agreements with the governments of these countries. If the payout under these agreements is attained earlier than projected, our net production and proved reserves in such areas could be reduced.

Estimates for future processing and transport of oil, gas and NGLs are based on the assumption that market demand and prices for oil, gas and NGLs will continue at levels that allow for profitable processing and transport of these products. There can be no assurance of such stability.

The production, transportation, processing and marketing of oil, gas and NGLs are complex processes which are subject to disruption due to transportation and processing availability, mechanical failure, human error, hurricanes and other meteorological events, and numerous other factors. The forward-looking estimates in this report were prepared assuming demand, curtailment, producibility and general market conditions for our oil, gas and NGLs during 2009 will be substantially similar to those that existed in 2008, unless otherwise noted.

Geographic Reporting Areas

Our estimates of production, average price differentials compared to industry benchmarks and capital expenditures included in this report are provided separately for each of the following geographic areas:

- United States Onshore;
- United States Offshore;
- Canada; and
- International.

Operating Items

Oil, Gas and NGL Production

Set forth below are our estimates of oil, gas and NGL production for 2009. We estimate that our combined 2009 oil, gas and NGL production will total approximately 243 to 247 MMBoe. The following estimates for oil, gas and NGL production are calculated at the midpoint of the estimated range for total production.

	Oil (MMBbls)	**Gas (Bcf)**	**NGLs (MMBbls)**	**Total (MMBoe)**
United States Onshore	12	693	25	153
United States Offshore	5	45		12
Canada	26	216	3	65
International	15	1		15
Total	58	955	28	245

Oil and Gas Prices

We expect our 2009 average prices for the oil and gas production from each of our operating areas to differ from the NYMEX price as set forth in the following table. The expected ranges for gas prices are exclusive of the anticipated effects of the gas financial contracts presented in the Commodity Price Risk Management section below.

The NYMEX price for oil is the monthly average of settled prices on each trading day for benchmark West Texas Intermediate crude oil delivered at Cushing, Oklahoma. The NYMEX price for gas is determined to be the first-of-month South Louisiana Henry Hub price index as published monthly in *Inside FERC*.

	Expected Range of Prices as a % of NYMEX Price	
	Oil	**Gas**
United States Onshore	85% to 95%	75% to 85%
United States Offshore	95% to 105%	100% to 110%
Canada	65% to 75%	83% to 93%
International	90% to 100%	N/M

N/M Not meaningful.

Commodity Price Risk Management

From time to time, we enter into NYMEX related financial commodity collar and price swap contracts. Such contracts are used to manage the inherent uncertainty of future revenues due to oil and gas price volatility. Although these financial contracts do not relate to specific production from our operating areas, they will affect our overall revenues, earnings and cash flow in 2009.

As of August 3, 2009, our financial commodity contracts pertaining to 2009 consisted of gas price collars and swaps. The key terms of these contracts are presented in the following table.

Gas Financial Contracts

	Price Collar Contracts					Price Swap Contracts	
		Floor Price		Ceiling Price			
Period	**Volume (MMBtu/d)**	**Floor Range ($/MMBtu)**	**Weighted Average Price ($/MMBtu)**	**Ceiling Range ($/MMBtu)**	**Weighted Average Price ($/MMBtu)**	**Volume (MMBtu/d)**	**Weighted Average Price ($/MMBtu)**
First Quarter	277,056	$ 8.00 - $8.50	$ 8.25	$ 10.60 - $14.00	$ 12.02		
Second Quarter	265,000	$ 8.00 - $8.50	$ 8.25	$ 10.60 - $14.00	$ 12.05		
Third Quarter	265,000	$ 8.00 - $8.50	$ 8.25	$ 10.60 - $14.00	$ 12.05	52,174	$ 4.01
Fourth Quarter	265,000	$ 8.00 - $8.50	$ 8.25	$ 10.60 - $14.00	$ 12.05	600,000	$ 4.81
2009 Average	267,973	$ 8.00 - $8.50	$ 8.25	$ 10.60 - $14.00	$ 12.05	164,384	$ 4.75

To the extent that monthly NYMEX prices in 2009 are outside of the ranges established by the collars or differ from those established by the swaps, we and the counterparties to the contracts will settle the difference. Such settlements will either increase or decrease our revenues for the period. Also, we will mark-to-market the contracts based on their fair values throughout 2009. Changes in the contracts fair values will also be recorded as increases or decreases to our revenues. The expected ranges of our realized prices as a percentage of NYMEX prices, which are presented earlier in this report, do not include any estimates of the impact on our prices from monthly settlements or changes in the fair values of our price collars and swaps.

In January 2009, we entered into an early settlement arrangement with one of our counterparties. As a result of this early settlement, we received $36 million in January 2009.

Marketing and Midstream Revenues and Expenses

Marketing and midstream revenues and expenses are derived primarily from our gas processing plants and gas pipeline systems. These revenues and expenses vary in response to several factors. The factors include, but are not limited to, changes in production from wells connected to the pipelines and related processing plants, changes in the absolute and relative prices of gas and NGLs, provisions of contractual agreements and the amount of repair and maintenance activity required to maintain anticipated processing levels and pipeline throughput volumes.

These factors increase the uncertainty inherent in estimating future marketing and midstream revenues and expenses. Given these uncertainties, we estimate that our 2009 marketing and midstream operating profit will be between $430 million and $500 million. We estimate that marketing and midstream revenues will be between $1.18 billion and $1.40 billion, and marketing and midstream expenses will be between $0.75 billion and $0.90 billion.

Production and Operating Expenses

Our production and operating expenses include lease operating expenses, transportation costs and production taxes. These expenses vary in response to several factors. Among the most significant of these factors are additions to or deletions from the property base, changes in the general price level of services and materials that are used in the operation of the properties, the amount of repair and workover activity required and changes in production tax rates. Oil, gas and NGL prices also have an effect on lease operating expenses and impact the economic feasibility of planned workover projects.

Given these uncertainties, we expect that our 2009 lease operating expenses will be between $1.93 billion and $2.27 billion. Additionally, we estimate that our production taxes for 2009 will be between 3.00% and 3.50% of total oil, gas and NGL revenues, excluding the effect on revenues from derivative contracts upon which production taxes are not assessed.

Depreciation, Depletion and Amortization (DD&A)

Our 2009 oil and gas property DD&A rate will depend on various factors. Most notable among such factors are the amount of proved reserves that will be added from drilling or acquisition efforts in 2009 compared to the costs incurred for such efforts, revisions to our year-end 2008 reserve estimates that, based on prior experience, are likely to be made during 2009, as well as reductions of carrying value resulting from full cost ceiling tests.

Given these uncertainties, we estimate that our oil and gas property related DD&A rate will be between $8.00 per Boe and $8.50 per Boe. Based on these DD&A rates and the production estimates set forth earlier, oil and gas property related DD&A expense for 2009 is expected to be between $1.95 billion and $2.07 billion.

Additionally, we expect that our depreciation and amortization expense related to non-oil and gas property fixed assets will total between $280 million and $300 million in 2009.

Accretion of Asset Retirement Obligation

Accretion of asset retirement obligation in 2009 is expected to be between $85 million and $95 million.

General and Administrative Expenses (G&A)

Our G&A includes employee compensation and benefits costs and the costs of many different goods and services used in support of our business. G&A varies with the level of our operating activities and the related staffing and professional services requirements. In addition, employee compensation and benefits costs vary due to various market factors that affect the level and type of compensation and benefits offered to employees. Also, goods and services are subject to general price level increases or decreases. Therefore, significant variances in any of these factors from current expectations could cause actual G&A to vary materially from the estimate.

Given these limitations, we estimate our G&A for 2009 will be between $650 million and $680 million. This estimate includes approximately $130 million of non-cash, share-based compensation, net of related capitalization in accordance with the full cost method of accounting for oil and gas properties.

Reduction of Carrying Value of Oil and Gas Properties

We follow the full cost method of accounting for our oil and gas properties. Under the full cost method, our net book value of oil and gas properties, less related deferred income taxes (the costs to be recovered), may not exceed a calculated full cost ceiling. The ceiling limitation is the discounted estimated after-tax future net revenues from oil and gas properties plus the cost of unevaluated properties. The ceiling is imposed separately by country. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. These prices are not changed except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. The costs to be recovered are compared to the ceiling on a quarterly basis. If the costs to be recovered exceed the ceiling, the excess is written off as an expense. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely, and requires a 10% discount factor, the resulting value is not indicative of the true fair value of the reserves. Oil and gas prices have historically been cyclical and, on any particular day at the end of a quarter, can be either substantially higher or lower than our long-term price forecast, which is a more appropriate input for estimating fair value. Therefore, oil and gas property writedowns that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Because of the volatile nature of oil and gas prices, it is not possible to predict whether we will incur full cost writedowns in the last half of 2009. However, such writedowns may be more likely to occur in the future than in recent periods, considering current and near-term estimates of oil and gas prices.

In the first quarter of 2009, we recognized full cost ceiling writedowns related to our oil and gas properties in the United States and Brazil. In the fourth quarter of 2008, we also recognized full cost ceiling writedowns related to our oil and gas properties in Canada, as well as the United States and Brazil. These writedowns resulted primarily from significant declines in oil and gas prices compared to previous quarter-end prices. The weighted average wellhead prices used in the calculation of the full cost ceiling writedowns for these countries are presented in the following table.

	March 31, 2009			December 31, 2008		
Country	**Oil**	**Gas**	**NGLs**	**Oil**	**Gas**	**NGLs**
United States	$47.30	$2.67	$17.04	$42.21	$4.68	$16.16
Canada	N/A	N/A	N/A	$23.23	$5.31	$20.89
Brazil	$36.71	N/A	N/A	$26.61	N/A	N/A

N/A Not applicable.

The March 31, 2009 wellhead prices in the table above compare to the NYMEX cash price of $49.66 per Bbl for crude oil and the Henry Hub spot price of $3.63 per MMBtu for natural gas. The December 31, 2008 wellhead prices in the table above compare to the NYMEX cash price of $44.60 per Bbl for crude oil and the Henry Hub spot price of $5.71 per MMBtu for natural gas. Should quarter-end prices in the last half of 2009 approximate or decrease from these prices, the likelihood that we will incur full cost writedowns during the last half of 2009 will increase.

Interest Expense

Future interest rates and debt outstanding have a significant effect on our interest expense. We can only marginally influence the prices we will receive in 2009 from sales of oil, gas and NGLs and the resulting cash flow. This increases the margin of error inherent in estimating future outstanding debt balances and related interest expense. Other factors which affect outstanding debt balances and related interest expense, such as the amount and timing of capital expenditures are generally within our control.

As of June 30, 2009, we had total debt of $7.4 billion. This included $6.1 billion of fixed-rate debt and $1.3 billion of variable-rate commercial paper borrowings. The fixed-rate debt bears interest at an overall weighted average rate of 7.23%. The commercial paper borrowings bear interest at variable rates based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market. As of June 30, 2009, the weighted average variable rate for our commercial paper borrowings was 0.48%. Additionally, any future borrowings under our credit facilities would bear interest at various fixed-rate options for periods up to twelve months and are generally less than the prime rate.

Based on the factors above, we expect our 2009 interest expense to be between $345 million and $355 million. This estimate assumes no material changes in prevailing interest rates or to our existing interest rate swap contracts presented later in this report. This estimate also assumes that our total debt will increase approximately $1.7 billion during 2009, primarily in the form of commercial paper borrowings.

The 2009 interest expense estimate above is comprised of three primary components interest related to outstanding debt, fees and issuance costs, and capitalized interest. We expect the interest expense in 2009 related to our fixed-rate and floating-rate debt, including net accretion of related discounts, to be between $435 million and $445 million. We expect the interest expense in 2009 related to facility and agency fees, amortization of debt issuance costs and other miscellaneous items not related to outstanding debt balances to be between $5 million and $15 million. We also expect to capitalize between $95 million and $105 million of interest during 2009.

Interest Rate Risk Management

We also have interest rate swaps to mitigate a portion of the fair value effects of interest rate fluctuations on our fixed-rate debt. Under the terms of these swaps, we receive a fixed rate and pay a variable rate on a total notional amount of $1.15 billion. The key terms of these interest rate swaps as of July 31, 2009 are presented in the following table.

Notional (In millions)	Fixed Rate Received	Variable Rate Paid	Expiration
$ 500	3.90%	Federal funds rate	July 18, 2013
$ 300	4.30%	Six month LIBOR	July 18, 2011
$ 250	3.85%	Federal funds rate	July 22, 2013
$ 100	1.90%	Federal funds rate	August 3, 2012
$ 1,150	3.82%		

Including the effects of these swaps, the weighted-average interest rate related to our fixed-rate debt was 6.62% as of June 30, 2009.

Income Taxes

Our financial income tax rate in 2009 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2009 will be significantly affected by the proportional share of consolidated pre-tax earnings generated by U.S., Canadian and International operations due to the different tax rates of each country. There are certain tax deductions and credits that will have a fixed impact on 2009 income tax expense regardless of the level of pre-tax earnings that are produced.

Given the uncertainty of pre-tax earnings, we expect that our consolidated financial income tax rate in 2009 will be between 20% and 40%. The current income tax rate is expected to be between 10% and 20%. The deferred income tax rate is expected to be between 10% and 20%. Significant changes in estimated capital expenditures, production levels of oil, gas and NGLs, the prices of such products, marketing and midstream revenues, or any of the various expense items could materially alter the effect of the aforementioned tax deductions and credits on 2009 financial income tax rates.

Capital Resources, Uses and Liquidity

Capital Expenditures

Though we have completed several major property acquisitions in recent years, these transactions are opportunity driven. Thus, we do not budget, nor can we reasonably predict, the timing or size of such possible acquisitions.

Our capital expenditures budget is based on an expected range of future oil, gas and NGL prices as well as the expected costs of the capital additions. Should actual prices received differ materially from our price expectations for our future production, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2009 capital expenditures. In addition, if the actual material or labor costs of the budgeted items vary significantly from the anticipated amounts, actual capital expenditures could vary materially from our estimates.

Given the limitations discussed above, the following table shows expected ranges for drilling, development and facilities expenditures by geographic area. Development capital includes development activity related to reserves classified as proved and drilling that does not offset currently productive units and for which there is not a certainty of continued production from a known productive formation. Exploration capital includes exploratory drilling to find and produce oil or gas in previously untested fault blocks or new reservoirs.

During the second quarter of 2009, our operations in Angola ceased to qualify as discontinued operations. As a result, the capital expenditure estimates related to our Angolan operations are now included in the continuing operations amounts included in the table below.

	United States Onshore	United States Offshore	Canada	International	Total
			(In millions)		
Development capital	$ 1,520-$1,790	$ 460-$540	$ 740-$870	$ 160-$200	$ 2,880-$3,400
Exploration capital	$ 150-$170	$ 130-$150	$ 40-$50	$ 240-$280	$ 560-$650
Total	$ 1,670-$1,960	$ 590-$690	$ 780-$920	$ 400-$480	$ 3,440-$4,050

In addition to the above expenditures for drilling, development and facilities, we expect to spend between $280 million to $330 million on our marketing and midstream assets, which primarily include our oil pipelines, gas processing plants, and gas pipeline systems. Additionally, we expect to capitalize between $400 million and $420 million of G&A expenses in accordance with the full cost method of accounting and to capitalize between $95 million and $105 million of interest. We also expect to pay between $105 million and $115 million for plugging and abandonment charges, and to spend between $215 million and $225 million for other non-oil and gas property fixed assets.

Other Cash Uses

Our management expects the policy of paying a quarterly common stock dividend to continue. With the current $0.16 per share quarterly dividend rate and 444 million shares of common stock outstanding as of June 30, 2009, dividends are expected to approximate $284 million.

We have various defined benefit pension plans. The vast majority of these plans are subject to minimum funding requirements. During 2008, investment losses significantly reduced the funded status of these plans. Accordingly, our 2009 contributions to these plans are expected to be higher than those made in recent years. We estimate we will contribute approximately $55 million to our defined benefit pension plans during 2009.

Capital Resources and Liquidity

Our estimated 2009 cash uses, including our drilling and development activities and retirement of maturing debt, are expected to be funded primarily through a combination of our existing cash balances and operating cash flow. Any remaining cash uses could be funded by increasing our borrowings under our commercial paper program or with borrowings from the available capacity under our credit facilities, which was approximately $2.0 billion as of July 31, 2009. The amount of operating cash flow to be generated during 2009 is uncertain due to the factors affecting revenues and expenses as previously cited. However, we expect our combined capital resources to be adequate to fund our anticipated capital expenditures and other cash uses for 2009.

If significant other acquisitions or other unplanned capital requirements arise during the year, we could utilize our existing credit facilities and/or seek to establish and utilize other sources of financing.

Summary of Forward-Looking Estimates

Oil production (MMBbls)	
U.S. Onshore	12
U.S. Offshore	5
Canada	26
International	15
Total	58
Gas production (Bcf)	
U.S. Onshore	693
U.S. Offshore	45
Canada	216
International	1
Total	955
NGL production (MMBbls)	
U.S. Onshore	25
Canada	3
Total	28
Total production (MMBoe)	
U.S. Onshore	153
U.S. Offshore	12
Canada	65
International	15
Total	245

	As % of NYMEX Range	
	Low	**High**
Oil Operating Area Prices		
U.S. Onshore	85%	95%
U.S. Offshore	95%	105%
Canada	65%	75%
International	90%	100%
Gas Operating Area Prices [1]		
U.S. Onshore	75%	85%
U.S. Offshore	100%	110%
Canada	83%	93%

[1] The expected ranges for our operating area prices as a percentage of NYMEX prices do not include any estimates of the impact on our gas prices from monthly settlements or changes in the fair values of our gas price collars or swaps as presented on page 5.

	Range	
	Low	**High**
Marketing and midstream (In millions)		
Revenues	$ 1,180	$ 1,400
Expenses	$ 750	$ 900
Operating profit	$ 430	$ 500
Production and operating expenses ($ in millions)		
LOE	$ 1,930	$ 2,270
Production taxes	3.00%	3.50%
DD&A (In millions, except per Boe)		
Oil and gas DD&A	$ 1,950	$ 2,070
Non-oil and gas DD&A	$ 280	$ 300
Total DD&A	$ 2,230	$ 2,370
Oil and gas DD&A per Boe	$ 8.00	$ 8.50
Other (In millions)		
Accretion of ARO	$ 85	$ 95
G&A	$ 650	$ 680
Interest expense	$ 345	$ 355
Income tax rates		
Current	10%	20%
Deferred	10%	20%
Total tax rate	20%	40%

	Range	
	Low	High
	(In millions)	
Development capital		
U.S. Onshore	$ 1,520	$ 1,790
U.S. Offshore	$ 460	$ 540
Canada	$ 740	$ 870
International	$ 160	$ 200
Total	$ 2,880	$ 3,400
Exploration capital		
U.S. Onshore	$ 150	$ 170
U.S. Offshore	$ 130	$ 150
Canada	$ 40	$ 50
International	$ 240	$ 280
Total	$ 560	$ 650
Total drilling and facility capital		
U.S. Onshore	$ 1,670	$ 1,960
U.S. Offshore	$ 590	$ 690
Canada	$ 780	$ 920
International	$ 400	$ 480
Total	$ 3,440	$ 4,050
Other capital		
Marketing & midstream	$ 280	$ 330
Capitalized G&A	$ 400	$ 420
Capitalized interest	$ 95	$ 105
Plugging and abandonment	$ 105	$ 115
Non-oil and gas	$ 215	$ 225
Total	$ 1,095	$ 1,195

Financial amounts related to our Canadian operations in the tables above have been converted to U.S. dollars using an estimated average 2009 exchange rate of $0.86 dollar to $1.00 Canadian dollar.

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 hereto duly authorized.

DEVON ENERGY CORPORATION

By: /s/ Danny J. Heatly
Senior Vice President Accounting and
Chief Accounting Officer

Date: August 5, 2009