DEVON ENERGY CORP/DE

FORM 8-K
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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): February 4, 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:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ 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 are providing our 2009 forward-looking estimates in this report. These estimates 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. A summary of these 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.

"Federal Funds Rate" means the interest rate at which depository institutions lend balances at the Federal Reserve to other depository institutions overnight.

"Inside FERC" refers to the publication *Inside F.E.R.C.'s Gas Market Report* .

"LIBOR" means London Interbank Offered Rate.

"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.

Forward-Looking Estimates

General Assumptions and Risks Related to Our Estimates

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 $0.80 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:

- the United States Onshore;

- the United States Offshore, which encompasses all oil and gas properties in the Gulf of Mexico;
- Canada; and
- International, which encompasses all oil and gas properties that lie outside of the United States and Canada.

Year 2009 Potential 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 235 to 241 MMBoe. Of this total, approximately 97% is estimated to be produced from reserves classified as "proved" at December 31, 2008. 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	676	25	149
United States Offshore	4	42	—	11
Canada	29	185	3	63
International	15	1	—	15
Total	60	904	28	238

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	55% to 65%	83% to 93%
International	85% to 95%	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 February 3, 2009, our financial commodity contracts pertaining to 2009 consisted only of gas collars. The key terms of these contracts are presented in the following table.

		Floor Price		Ceiling Price	
Period	Volume (MMBtu/d)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/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
Fourth Quarter	265,000	$8.00 - $8.50	$8.25	$10.60 - $14.00	$12.05
2009 Average	267,973	$8.00 - $8.50	$8.25	$10.60 - $14.00	$12.05

To the extent that monthly NYMEX prices in 2009 are outside of the ranges established by the gas collars, 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 gas prices as a percentage of NYMEX prices, which are presented earlier in this report, do not include any estimates of the impact on our gas prices from monthly settlements or changes in the fair values of our gas collars.

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 $375 million and $425 million. We estimate that marketing and midstream revenues will be between $1.075 billion and $1.425 billion, and marketing and midstream expenses will be between $0.700 billion and $1.000 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 3.25% and 3.75% of total oil, gas and NGL revenues, excluding the effect on revenues from financial collar 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 and revisions to our year-end 2008 reserve estimates that, based on prior experience, are likely to be made during 2009. Our reserve estimates as of December 31, 2008 included negative price revisions of 473 MMBoe. The following oil and gas property related DD&A estimates are largely based on the assumption that the year-end 2008 negative price revisions will not reverse during 2009. However, if such negative price revisions reverse, in whole or in part, our actual oil and gas property related DD&A rate could vary materially from our estimate.

Given these uncertainties, we estimate that our oil and gas property related DD&A rate will be between $10.25 per Boe and $10.75 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 $2.44 billion and $2.56 billion.

Additionally, we expect that our depreciation and amortization expense related to non-oil and gas property fixed assets will total between $315 million and $335 million in 2008.

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 $565 million and $605 million. This estimate includes approximately $110 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 2009. However, such writedowns may be more likely to occur during 2009 than in recent periods, considering current and near-term estimates of oil and gas prices.

We recognized full cost ceiling writedowns related to our oil and gas properties in the United States, Canada and Brazil in the fourth quarter of 2008. These writedowns resulted primarily from significant declines in oil and gas prices compared to previous quarter-end prices. The December 31, 2008 weighted average wellhead prices for these countries are presented in the following table.

Country	Oil	Gas	NGLs
United States	$42.21	$4.68	$16.16
Canada	$23.23	$5.31	$20.89
Brazil	$26.61	N/A	N/A

N/A — Not applicable.

The wellhead prices in the table above compare to the December 31, 2008 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 2009 quarter-end prices approximate or decrease from these December 31, 2008 prices, the likelihood that we will incur full cost writedowns during 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 January 31, 2009, we had total debt of $6.2 billion. This included $6.0 billion of fixed-rate debt and $0.2 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 January 31, 2009, the weighted average variable rate for our commercial paper borrowings was 3.33%. 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 $330 million and $340 million. This estimate assumes no material changes in prevailing interest rates or to our existing interest rate swap contracts presented above. This estimate also assumes that our total debt will increase approximately $1.0 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 $110 million and $120 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 $1.05 billion. The key terms of these interest rate swaps are presented in the following table.

Notional	Fixed Rate Received	Variable Rate Paid	Expiration
(In millions)			
$ 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
$ 1,050	4.00%		

Including the effects of these swaps, the weighted-average interest rate related to our fixed-rate debt was 6.64% as of January 31, 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.

Year 2008 Potential 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.

	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	$ 200-$230	$ 520-$600
Total	$ 1,670-$1,960	$590-$690	$780-$920	$ 360-$430	$3,400-$4,000

In addition to the above expenditures for drilling, development and facilities, we expect to spend between $325 million to $425 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 $460 million and $480 million of G&A expenses in accordance with the full cost method of accounting and to capitalize between $110 million and $120 million of interest. We also expect to pay between $105 million and $115 million for plugging and abandonment charges, and to spend between $230 million and $250 million for other non-oil and gas property fixed assets. We anticipate spending between $40 million and $50 million to fulfill drilling commitments related to our assets held for sale.

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 December 31, 2008, 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 significantly higher than those made in recent years. Depending on the funding targets we may attempt to achieve, we estimate we will contribute between $100 million and $175 million to our 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 $3.1 billion as of January 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 2009 Forward-Looking Estimates

Oil production (MMBbls)	
U.S. Onshore	12
U.S. Offshore	4
Canada	29
International	15
Total	60
Gas production (Bcf)	
U.S. Onshore	676
U.S. Offshore	42
Canada	185
International	1
Total	904
NGL production (MMBbls)	
U.S. Onshore	25
Canada	3
Total	28
Total production (MMBoe)	
U.S. Onshore	149
U.S. Offshore	11
Canada	63
International	15
Total	238

	As % of NYMEX Range	
	Low	**High**
Oil Operating Area Prices		
U.S. Onshore	85%	95%
U.S. Offshore	95%	105%
Canada	55%	65%
International	85%	95%
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 as presented on page 5.

	Range	
	Low	High
Marketing and midstream (In millions)		
Revenues	$ 1,075	$ 1,425
Expenses	$ 700	$ 1,000
Operating profit	$ 375	$ 425
Production and operating expenses ($ in millions)		
LOE	$ 1,930	$ 2,270
Production taxes	3.25%	3.75%
DD&A (In millions, except per Boe)		
Oil and gas DD&A	$ 2,440	$ 2,560
Non-oil and gas DD&A	$ 315	$ 335
Total DD&A	$ 2,755	$ 2,895
Oil and gas DD&A per Boe	$ 10.25	$ 10.75
Other (In millions)		
Accretion of ARO	$ 85	$ 95
G&A	$ 565	$ 605
Interest expense	$ 330	$ 340
Income tax rates		
Current	10%	20%
Deferred	10%	20%
Total tax rate	20%	40%

	Range Low	Range 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	$ 200	$ 230
Total	$ 520	$ 600
Total drilling and facility capital		
U.S. Onshore	$ 1,670	$ 1,960
U.S. Offshore	$ 590	$ 690
Canada	$ 780	$ 920
International	$ 360	$ 430
Total	$ 3,400	$ 4,000
Other capital		
Marketing & midstream	$ 325	$ 425
Capitalized G&A	$ 460	$ 480
Capitalized interest	$ 110	$ 120
Plugging and abandonment	$ 105	$ 115
Non-oil and gas	$ 230	$ 250
Assets held for sale	$ 40	$ 50
Total	$ 1,270	$ 1,440

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: February 4, 2009