Q1 2009

ENCANA
energy for people

EnCana generates first quarter cash flow of US$1.9 billion, or $2.59 per share – down 18 percent

Calgary, Alberta, (April 22, 2009) – EnCana Corporation (TSX & NYSE: ECA) continued to deliver strong financial and operating performance in the first quarter of 2009. Cash flow was US$1.9 billion, or $2.59 per share and operating earnings were $948 million, or $1.26 per share – down 18 and 9 percent respectively on a per share basis compared to the first quarter of 2008. These results are on track with 2009 guidance and were achieved during a quarter when benchmark natural gas prices fell about 39 percent and oil prices were down about 56 percent compared to the same period in 2008. First quarter natural gas and oil production increased 3 percent compared to the same period in 2008 to 4.7 billion cubic feet equivalent per day (Bcfe/d). In addition, this production level is higher than EnCana's first quarter production expectations largely due to the impact of price-sensitive royalty rates in Alberta, which are reduced at lower prices and increased at higher prices. EnCana reports production on an after-royalties basis. Before any price-related royalty impacts, EnCana expects 2009 production to be at levels similar to the volumes produced in 2008.

"Operational excellence in our portfolio of low-cost, low-risk resource plays helped EnCana achieve cost-effective production across North America. Underpinning our strong financial performance was close to $700 million in realized after-tax gains from our natural gas hedges during the first quarter," said Randy Eresman, EnCana's President & Chief Executive Officer.

Modest capital program aligned to economic conditions

"With continued economic uncertainty and low prices, particularly for natural gas, we remain focused on directing our capital investment to only our highest return projects. For 2009, we set a modest capital program with the flexibility to align investments with the industry conditions. Our North American resource play business model and our conservative investment approach will help EnCana generate strong performance through 2009 and withstand the prevailing economic downturn.

"EnCana's financial position is strong. Our debt ratios remain below our targeted ranges and we have hedged about two-thirds of our total expected natural gas production through October of this year at an average price of $9.13 per thousand cubic feet (Mcf), which is about two and a half times the current spot price. Our hedging strategy is aimed at providing an increased level of certainty to our cash flows so that we can efficiently manage our capital programs," Eresman said.

Industry costs starting to drop

"In the first quarter, operating and administrative costs decreased about 31 percent compared with the same period the year before, to $1.06 per thousand cubic feet of gas equivalent (Mcfe), due primarily to a weaker Canadian dollar, lower fuel prices and lower long-term incentive costs. Substantially reduced field activity across North America is starting to result in lower supply and services pricing and, by the end of 2009, we anticipate price reductions could reach more than 20 percent from 2008 average costs, if current trends continue. So far in 2009, we're tracking lower on capital investment and operating and administrative costs, and by mid-year we expect to know how much this will impact our overall expenditures for 2009," Eresman said.

IMPORTANT NOTE: EnCana reports in U.S. dollars unless otherwise noted and follows U.S. protocols, which report gas and oil production, sales and reserves on an after-royalties basis. The company's financial statements are prepared in accordance with Canadian generally accepted accounting principles (GAAP). Per share amounts for cash flow and earnings are on a diluted basis.

First Quarter 2009 Highlights

(all year-over-year comparisons are to the first quarter of 2008)

Financial

- Cash flow decreased 18 percent per share to $2.59, or $1.9 billion
- Operating earnings were down 9 percent per share to $1.26, or $948 million
- Net earnings increased to $1.28 per share, or $962 million, primarily due to an after-tax unrealized mark-to-market hedging gain of $89 million in the first quarter of 2009 compared to an after-tax loss of $737 million in the first quarter of 2008
- Capital investment, excluding acquisitions and divestitures, was down 18 percent to $1.5 billion
- Free cash flow was $436 million, down 19 percent (Free cash flow is defined in Note 1 on page 6)
- EnCana's integrated oil business venture with ConocoPhillips generated $116 million in operating cash flow, comprised of $57 million from the company's Foster Creek and Christina Lake upstream projects, and $59 million from the downstream business. Operating cash flow was down $54 million due largely to lower oil prices
- Realized natural gas prices were down 10 percent to $7.22 per Mcf and realized liquids prices decreased 51 percent to $34.24 per barrel (bbl). These prices include financial hedges
- At the end of the quarter, debt to capitalization was 29 percent and debt to adjusted EBITDA was 0.7 times.

Operating – Upstream

- Key resource play production was up 8 percent, with an 8 percent increase in natural gas production and oil production increasing 7 percent
- Total natural gas production increased 4 percent to 3.87 billion cubic feet per day (Bcf/d), up 4 percent per share
- Total oil and natural gas liquids (NGLs) production decreased 2 percent to 134,280 barrels per day (bbls/d), down 2 percent per share
- Foster Creek and Christina Lake oil production grew 18 percent to 34,729 bbls/d net to EnCana
- Operating and administrative costs of $1.06 per Mcfe decreased from $1.53 per Mcfe in the first quarter of 2008, primarily due to a weaker Canadian dollar, lower fuel costs and lower long-term incentive costs as a result of a declining share price.

Operating – Downstream

- Refined products averaged 421,000 bbls/d (210,500 bbls/d net to EnCana), down 3 percent
- Refinery crude utilization of 88 percent or 398,000 bbls/d crude throughput (199,000 bbls/d net to EnCana), down 2 percent.

Majority of net earnings year-over-year increase related to unrealized mark-to-market accounting gains

EnCana's net earnings in the first quarter were $962 million, an increase of $869 million from the first quarter of 2008. First quarter 2009 net earnings included $89 million of after-tax unrealized gains due to mark-to-market accounting for hedging contracts compared to an after-tax loss of $737 million in the first quarter of 2008, a swing of $826 million in net earnings. It is because of these dramatic mark-to-market accounting swings in net earnings that EnCana focuses on operating earnings as a better measure of quarter-over-quarter earnings performance.

Realized after-tax hedging gains for the first five months of the 2008-2009 natural gas year, which runs from November 1, 2008 to October 31, 2009, were $1.0 billion, and unrealized after-tax gains for the remainder of the gas year are currently forecast to be $1.9 billion, for a total of $2.9 billion, after-tax.

Financial Summary – Total Consolidated

(for the three months ended March 31) ($ millions, except per share amounts)	**Q1 2009**	Q1 2008	% Δ
Cash flow [1]	**1,944**	2,389	-19
Per share diluted	**2.59**	3.17	-18
Net earnings	**962**	93	
Per share diluted	**1.28**	0.12	
Operating earnings [1]	**948**	1,045	-9
Per share diluted	**1.26**	1.39	-9

Earnings Reconciliation Summary – Total Consolidated

	Q1 2009	Q1 2008	% Δ
Net earnings	**962**	93	
Add back (losses) & deduct gains			
Unrealized mark-to-market hedging gain (loss), after-tax	**89**	(737)	
Non-operating foreign exchange gain (loss), after-tax	**(75)**	(215)	
Operating earnings [1]	**948**	1,045	-9
Per share diluted	**1.26**	1.39	-9

1 Cash flow and operating earnings are non-GAAP measures as defined in Note 1 on page 6.

Production & Drilling Summary

Total Consolidated

(for the three months ended March 31) (After royalties)	**Q1 2009**	Q1 2008	% Δ
Natural gas (MMcf/d)	**3,869**	3,733	+4
Natural gas production per 1,000 shares (Mcf/d)	**5.16**	4.98	+4
Oil and NGLs (Mbbls/d)	**134**	137	-2
Oil and NGLs production per 1,000 shares (Mcfe/d)	**1.07**	1.10	-2
Total production (MMcfe/d)	**4,675**	4,557	+3
Total production per 1,000 shares (Mcfe/d)	**6.23**	6.08	+3
Net wells drilled	**883**	1,143	-23

Key resource play production increased in first quarter

Total production from key resource plays was 3.7 Bcfe/d compared to 3.4 Bcfe/d in the first quarter of 2008. This was led by a 50 percent production increase in the East Texas key resource play due to ongoing success at the Deep Bossier play. EnCana continued to drill prolific wells in the Amoruso field, where 30-day initial production rates averaged more than 19 MMcf/d. The Charlene #1 well was completed in January and flowed during initial evaluation in excess of 50 MMcf/d.

EnCana encouraged by resource potential in Haynesville shale play

“While it is early days in the development of the Haynesville play in Louisiana and Texas, there have been some very encouraging results from our program as well as from other producers in the region,” said Jeff Wojahn, EnCana’s Executive Vice-President and President, USA Division. “Given the significant potential of our lands, we plan to re-allocate $290 million of savings from other areas of the company into our Haynesville program this year. With a total capital program of $580 million we will be drilling about 50 net wells which will enable us to continue to increase our understanding of the play, further evaluate our lands, and retain prospective acreage.” In anticipation of increased future production from the region and to facilitate unrestrained market access for the company’s expected production growth, EnCana is advancing plans for midstream processing and gas transportation. This includes recent commitments of 150 million cubic feet per day of capacity on the proposed Gulf South pipeline expansion and 500 million cubic feet per day of service on the proposed ETC Tiger pipeline.

Development continues in promising Horn River shale play

EnCana remains optimistic about the production potential from its land holdings in the Horn River shale play in northeast British Columbia. The company has adopted a more efficient way to develop the natural gas in this play by increasing the number of fracture stimulations per long-reach horizontal well leg. EnCana and its partner Apache now expect to increase their fracs per leg to as many as 14 from the originally-planned eight fracs. This could reduce the number of wells required to recover the resource because more of the natural gas can be accessed from each well. The revised plan is to drill 12 net wells this year, rather than the 20 initially scheduled. Public consultations are underway for the proposed Cabin Gas Plant, to be built about 60 kilometres northeast of Fort Nelson, British Columbia. The proposed plant, in which EnCana holds a 25 percent interest, is expected to have an initial processing capacity of 400 MMcf/d. Processing capacity is expected to expand in stages in conjunction with production growth from the Horn River Basin. The first phase of the project is expected to be commissioned in the third quarter of 2011. EnCana plans to construct the plant on behalf of industry co-owners who are major land holders in the Horn River Basin.

Foster Creek and Christina Lake expansions increase capacity

The commissioning of recent expansions at Foster Creek, which are expected to increase plant capacity to 60,000 bbls/d net to EnCana, is nearly complete and production is ramping up. First quarter production of approximately 28,000 bbls/d is targeted to increase to more than 45,000 bbls/d by year-end. At Christina Lake, first quarter production was more than 6,500 bbls/d – a 152 percent increase over the first quarter of 2008 as a result of an expansion that was completed in mid-2008. Construction continues on the next phase of expansion at Christina Lake, which is targeted to increase net plant capacity to 29,000 bbls/d in 2011.

Growth from key North American resource plays

Resource Play	**Daily Production**						
	2009	2008					2007
(After royalties)	**Q1**	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural gas (MMcf/d)							
Jonah	**623**	603	573	615	630	595	557
Piceance	**386**	385	377	407	383	372	348
East Texas	**409**	334	408	339	316	273	143
Fort Worth	**149**	142	143	148	137	140	124
Greater Sierra	**215**	220	228	228	219	205	211
Cutbank Ridge	**323**	296	311	322	280	271	258
Bighorn	**156**	167	165	185	170	146	126
CBM	**309**	304	308	309	303	298	259
Shallow Gas	**673**	700	683	691	712	715	726
Total natural gas (MMcf/d)	**3,243**	3,151	3,196	3,244	3,150	3,015	2,752
Oil (Mbbls/d)							
Foster Creek	**28**	26	29	27	21	27	24
Christina Lake	**7**	4	6	5	4	2	3
Pelican Lake	**21**	22	20	22	21	24	23
Weyburn	**16**	14	15	14	13	14	15
Total oil (Mbbls/d)[1]	**72**	66	71	67	59	67	65
Total (MMcfe/d)[1]	**3,676**	3,548	3,621	3,648	3,506	3,417	3,141
% change from prior period	**+1.5**	+13.0	-0.7	+4.1	+2.6	+2.7	+12.9

1 Totals may not add due to rounding.

Drilling activity in key North American resource plays

Resource Play	Net Wells Drilled						
	2009	2008					2007
	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural gas							
Jonah	**35**	175	40	43	49	43	135
Piceance	**53**	328	70	94	81	83	286
East Texas	**15**	78	23	22	22	11	35
Fort Worth	**16**	83	21	21	20	21	75
Greater Sierra	**15**	106	14	29	27	36	109
Cutbank Ridge	**20**	82	17	17	24	24	93
Bighorn	**21**	64	5	11	18	30	62
CBM	**278**	698	359	78	10	251	1,079
Shallow Gas	**336**	1,195	383	233	83	496	1,914
Total gas wells	**789**	2,809	932	548	334	995	3,788
Oil							
Foster Creek	**6**	20	1	6	1	12	23
Christina Lake	**-**	-	-	-	-	-	3
Pelican Lake	**4**	-	-	-	-	-	-
Weyburn	**-**	21	3	4	5	9	37
Total oil wells	**10**	41	4	10	6	21	63
Total	**799**	2,850	936	558	340	1,016	3,851

First quarter natural gas and oil prices

Natural gas	**Q1 2009**	Q1 2008	**% Δ**
NYMEX ($/MMBtu)	**4.89**	8.03	-39
EnCana realized gas price[1] ($/Mcf)	**7.22**	8.02	-10
Oil and NGLs ($/bbl)			
WTI	**43.31**	97.82	-56
Western Canadian Select (WCS)	**34.38**	76.37	-55
Differential WTI/WCS	**8.93**	21.45	-58
EnCana realized liquids price[1]	**34.24**	69.59	-51
Chicago 3-2-1 crack spread ($/bbl)	**9.75**	7.69	+27

1 Realized prices include the impact of financial hedging.

Price risk management
Risk management positions at March 31, 2009 are presented in Note 16 to the unaudited Interim Consolidated Financial Statements. In the first quarter of 2009, EnCana's commodity price risk management measures resulted in realized gains of approximately $699 million after-tax, composed of a $693 million after-tax gain on gas price and basis hedges and a $6 million after-tax gain on other hedges.

Two-thirds of expected 2009 gas production hedged during first 10 months of 2009
EnCana has hedged about 2.6 Bcf/d of expected gas production through October 2009 at an average NYMEX equivalent price of $9.13 per Mcf. This price hedging strategy increases certainty in cash flow to help ensure that EnCana can meet its capital and dividend requirements without substantially adding to debt. EnCana continually assesses its hedging needs and the opportunities available prior to establishing its capital program for the upcoming year.

Corporate developments

Quarterly dividend of 40 cents per share declared
EnCana's Board of Directors has declared a quarterly dividend of 40 cents per share payable on June 30, 2009 to common shareholders of record as of June 15, 2009. Based on the April 21, 2009 closing share price on the New York Stock Exchange of $42.94, this represents an annualized yield of about 3.7 percent.

EnCana's corporate guidance is unchanged from the most recent update published February 12, 2009.

Financial strength

EnCana has a very strong balance sheet, with 78 percent of EnCana's outstanding debt comprised of long-term, fixed-rate debt with an average remaining term of more than 14 years. Upcoming debt maturities in 2009 are $250 million and $200 million in 2010. At March 31, 2009, EnCana had $2.0 billion in unused committed credit facilities. EnCana targets a debt to capitalization ratio between 30 and 40 percent and a debt to adjusted EBITDA ratio of 1.0 to 2.0 times. At March 31, 2009, the company's debt to capitalization ratio was 29 percent and debt to adjusted EBITDA, on a trailing 12-month basis, was 0.7 times.

In the first quarter of 2009, EnCana invested $1.5 billion in capital, excluding acquisitions and divestitures, with a focus on continued development of the company's key resource plays and expansion of downstream heavy crude oil refining capacity.

EnCana invested about $79 million in land acquisitions in the first quarter and divested about $33 million of mature properties in Western Canada. Depending on market conditions for the rest of this year, EnCana may divest between $500 million and $1 billion of assets.

NOTE 1: Non-GAAP measures
This interim report contains references to non-GAAP measures as follows:

- Cash flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows, in this interim report and interim financial statements.
- Free cash flow is a non-GAAP measure that EnCana defines as cash flow in excess of capital investment, excluding net acquisitions and divestitures, and is used to determine the funds available for other investing and/or financing activities.
- Operating earnings is a non-GAAP measure that shows net earnings excluding non-operating items such as the after-tax impacts of a gain/loss on discontinuance, the after-tax gain/loss of unrealized mark-to-market accounting for derivative instruments, the after-tax gain/loss on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, the after-tax foreign exchange gain/loss on settlement of intercompany transactions, future income tax on foreign exchange related to U.S. dollar intercompany debt recognized for tax purposes only and the effect of changes in statutory income tax rates. Management believes that these excluded items reduce the comparability of the company's underlying financial performance between periods. The majority of the U.S. dollar debt issued from Canada has maturity dates in excess of five years.
- Capitalization is a non-GAAP measure defined as debt plus shareholders' equity. Debt to capitalization and debt to adjusted EBITDA are two ratios which management uses to steward the company's overall debt position as measures of the company's overall financial strength.
- Adjusted EBITDA is a non-GAAP measure defined as net earnings before gains or losses on divestitures, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation, depletion and amortization.

These measures have been described and presented in this interim report in order to provide shareholders and potential investors with additional information regarding EnCana's liquidity and its ability to generate funds to finance its operations.

EnCana Corporation

With an enterprise value of approximately $40 billion, EnCana is a leading North American unconventional natural gas and integrated oil company. By partnering with employees, community organizations and other businesses, EnCana contributes to the strength and sustainability of the communities where it operates. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

ADVISORY REGARDING RESERVES DATA AND OTHER OIL AND GAS INFORMATION – EnCana's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to EnCana by Canadian securities regulatory authorities which permits it to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by EnCana may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 (NI 51-101). EnCana's reserves quantities represent net proved reserves calculated using the standards contained in Regulation S-X of the U.S. Securities and Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in EnCana's Annual Information Form.

In this interim report, certain crude oil and NGLs volumes have been converted to cubic feet equivalent (cfe) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). Also, certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the same basis. BOE and cfe may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head.

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS – In the interests of providing EnCana shareholders and potential investors with information regarding EnCana, including management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this interim report are forward-looking statements or information within the meaning of applicable securities legislation, collectively referred to herein as "forward-looking statements." Forward-looking statements in this interim report include, but are not limited to: future economic and operating performance (including per share growth, debt to capitalization ratio, debt to adjusted EBITDA ratio, sustainable growth and returns, cash flow, cash flow per share, operating earnings and increases in net asset value); anticipated ability to meet the company's guidance forecasts; anticipated life of proved reserves; anticipated growth and success of resource plays and the expected characteristics of resource plays; anticipated production and drilling in the Horn River and Haynesville areas; anticipated cost reductions and production efficiencies from fracture stimulations; anticipated capacity and timing for the proposed Cabin Gas Plant; planned expansion of in-situ oil production; anticipated crude oil and natural gas prices, including basis differentials for various regions; anticipated expansion and production at Foster Creek and Christina Lake; anticipated divestitures; potential dividends; anticipated success of EnCana's price risk management strategy; anticipated hedging gains; potential demand for natural gas; anticipated drilling; potential capital expenditures and investment; potential oil, natural gas and NGLs production in 2009 and beyond; anticipated costs and cost reductions; and references to potential exploration. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These assumptions, risks and uncertainties include, among other things: volatility of and assumptions regarding oil and gas prices; assumptions based upon the company's current guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the company's marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved reserves; the ability of the company and ConocoPhillips to successfully manage and operate the integrated North American oil business and the ability of the parties to obtain necessary regulatory approvals; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining synthetic crude oil; risks associated with technology; the company's ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the company's ability to secure adequate product transportation; changes in royalty, tax, environmental and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which the company operates; the risk of war, hostilities, civil insurrection and instability affecting countries in which the company operates and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive.

Forward-looking information respecting anticipated 2009 cash flow for EnCana is based upon achieving average production of oil and gas for 2009 of approximately 4.6 Bcfe/d, average commodity prices for 2009 based on a WTI price of $55 - $75/bbl for oil, a NYMEX price of $5.50 - $7.50/Mcf for natural gas, an average U.S./Canadian dollar foreign exchange rate of $0.75 - $0.85, an average Chicago 3-2-1 crack spread for 2009 of $5 - $10/bbl for refining margins, and an average number of outstanding shares for EnCana of approximately 750 million. Assumptions relating to forward-looking statements generally include EnCana's current expectations and projections made by the company in light of, and generally consistent with, its historical experience and its perception of historical trends, as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this interim report.

Furthermore, the forward-looking statements contained in this interim report are made as of the date of this interim report, and, except as required by law, EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this interim report are expressly qualified by this cautionary statement.

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read with the unaudited Interim Consolidated Financial Statements ("Interim Consolidated Financial Statements") for the period ended March 31, 2009, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2008. Readers should also read the "Forward-Looking Statements" legal advisory contained at the end of this document.

The Interim Consolidated Financial Statements and comparative information have been prepared in United States ("U.S.") dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This document is dated April 21, 2009.

Readers can find the definition of certain terms used in this document in the disclosure regarding Oil and Gas Information and Currency, Non-GAAP Measures and References to EnCana contained in the Advisory section located at the end of this document.

EnCana's Financial Strategy in the Current Economic Environment

The current economic environment is challenging and uncertain amidst a global recession, low commodity prices, volatile financial markets and limited access to capital markets. In this economic environment, EnCana is highly focused on the key business objectives of maintaining financial strength, generating significant free cash flow, further optimizing capital investments and continuing to pay a stable dividend to shareholders. This measured investment approach is underpinned by a strong balance sheet and a market risk mitigation strategy where EnCana has hedged about two thirds of its expected gas production from January through October 2009 at an average NYMEX equivalent price of about $9.13 per Mcf, along with other actions within its risk management program that are more fully described in the Risk Management section of this MD&A.

EnCana has a strong balance sheet and continues to employ a conservative capital structure. As at March 31, 2009, 78 percent of EnCana's outstanding debt was composed of long-term, fixed rate debt with an average remaining term of more than 14 years. Upcoming maturities are $250 million in 2009 and $200 million in 2010. As at March 31, 2009, EnCana had available unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for up to $5.0 billion and unused committed bank credit facilities in the amount of $2.0 billion. EnCana targets a Debt to Capitalization ratio of between 30 and 40 percent and a Debt to Adjusted EBITDA multiple of 1.0 to 2.0 times. At March 31, 2009, the Company's Debt to Capitalization ratio was 29 percent and Debt to Adjusted EBITDA was 0.7x.

In addition, EnCana continues to monitor expenses and capital programs. In light of the current market situation, EnCana has planned a measured, flexible approach to 2009 investment and has designed a 2009 capital program with the flexibility to adjust investment depending upon how economic circumstances unfold during the year. Additional detail regarding EnCana's 2009 capital investment is available in the Corporate Guidance on the Company's website at www.encana.com.

EnCana's Business

EnCana is a leading North American unconventional natural gas and integrated oil company.

EnCana's operating and reportable segments are as follows:

- **Canada** includes the Company's exploration for, and development and production of natural gas, crude oil and natural gas liquids ("NGLs") and other related activities within the Canadian cost centre.
- **USA** includes the Company's exploration for, and development and production of natural gas, NGLs and other related activities within the United States cost centre.
- **Downstream Refining** is focused on the refining of crude oil into petroleum and chemical products at two refineries located in the United States. The refineries are jointly owned with ConocoPhillips.
- **Market Optimization** is primarily responsible for the sale of the Company's proprietary production. These results are included in the Canada and USA segments. Market optimization activities include third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment.

- **Corporate and Other** mainly includes unrealized gains or losses recorded on derivative financial instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

Market Optimization sells substantially all of the Company's upstream production to third-party customers. Transactions between segments are based on market values and eliminated on consolidation. Segmented financial information is presented on an after eliminations basis.

EnCana has a decentralized decision making and reporting structure. Accordingly, the Company is organized into divisions as follows:

- **Canadian Plains** Division includes natural gas and crude oil exploration, development and production assets located in eastern Alberta and Saskatchewan.
- **Canadian Foothills** Division includes natural gas exploration, development and production assets located in western Alberta and British Columbia as well as the Company's Canadian offshore assets.
- **USA** Division includes natural gas exploration, development and production assets located in the United States and comprises the USA segment described above.
- **Integrated Oil** Division is the combined total of Integrated Oil – Canada and Downstream Refining. Integrated Oil – Canada includes the Company's exploration for, and development and production of bitumen using enhanced recovery methods. Integrated Oil – Canada is composed of EnCana's interests in the FCCL Oil Sands Partnership jointly owned with ConocoPhillips, the Athabasca natural gas assets and other bitumen interests.

2009 versus 2008 Results Review

In the first quarter of 2009 compared to the first quarter of 2008, EnCana:

- Reported a 19 percent decrease in Cash Flow to $1,944 million primarily due to lower commodity prices partially offset by realized hedging gains of $699 million after-tax and higher production volumes;
- Reported a 9 percent decrease in Operating Earnings to $948 million;
- Reported an $869 million increase in Net Earnings to $962 million primarily due to after-tax unrealized mark-to-market hedging gains of $89 million in 2009 compared to losses of $737 million in 2008;
- Reported a $104 million decrease in Free Cash Flow to $436 million;
- Reported a 3 percent increase in total production to 4,675 million cubic feet equivalent ("MMcfe") per day ("MMcfe/d");
- Reported increased production from natural gas key resource plays of 8 percent and from oil key resource plays of 7 percent; and
- Reported a 45 percent decrease in natural gas prices, excluding financial hedges, to $4.23 per thousand cubic feet ("Mcf") and a 58 percent decrease in liquids prices, excluding financial hedges, to $32.03 per barrel ("bbl").

Business Environment

EnCana's financial results are significantly influenced by fluctuations in commodity prices, which include price differentials and crack spreads, and the U.S./Canadian dollar exchange rate. EnCana has taken steps to reduce pricing risk through a commodity price hedging program. Further information regarding this program can be found under the Risk Management section of this MD&A. The following table shows benchmark information on a quarterly basis to assist in understanding quarterly volatility in prices and foreign exchange rates that have impacted EnCana's financial results.

Quarterly Market Benchmark Prices and Foreign Exchange Rates

	2009	2008				2007		
(Average for the period)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Natural Gas Price Benchmarks								
AECO *(C$/Mcf)*	**$ 5.63**	$ 6.79	$ 9.24	$ 9.35	$ 7.13	$ 6.00	$ 5.61	$ 7.37
NYMEX *($/MMBtu)*	**4.89**	6.94	10.24	10.93	8.03	6.97	6.16	7.55
Rockies (Opal) *($/MMBtu)*	**3.31**	3.53	5.88	8.56	7.02	3.46	2.94	3.85
Texas (HSC) *($/MMBtu)*	**4.21**	6.37	9.98	10.58	7.73	6.64	5.89	7.26
Basis Differential *($/MMBtu)*								
AECO/NYMEX	**0.35**	1.10	1.28	1.71	0.84	0.85	0.84	0.90
Rockies/NYMEX	**1.58**	3.41	4.36	2.37	1.01	3.50	3.22	3.70
Texas/NYMEX	**0.68**	0.58	0.26	0.35	0.30	0.33	0.27	0.29
Crude Oil Price Benchmarks								
West Texas Intermediate (WTI) *($/bbl)*	**43.31**	59.08	118.22	123.80	97.82	90.50	75.15	65.02
Western Canadian Select (WCS) *($/bbl)*	**34.38**	39.95	100.22	102.18	76.37	56.85	52.71	45.84
Differential - WTI/WCS *($/bbl)*	**8.93**	19.13	18.00	21.62	21.45	33.65	22.44	19.18
Refining Margin Benchmark								
Chicago 3-2-1 Crack Spread *($/bbl)* (1)	**9.75**	6.31	17.29	13.60	7.69	9.17	18.48	30.12
Foreign Exchange								
U.S./Canadian Dollar Exchange Rate	**0.803**	0.825	0.961	0.990	0.996	1.019	0.957	0.911

(1) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of Ultra Low Sulphur Diesel.

Consolidated Financial Results

($ millions, except per share amounts)	2009	2008				2007		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Total Consolidated								
Cash Flow (1)	**$ 1,944**	$ 1,299	$ 2,809	$ 2,889	$ 2,389	$ 1,934	$ 2,218	$ 2,549
- per share – diluted	**2.59**	1.73	3.74	3.85	3.17	2.56	2.93	3.33
Net Earnings	**962**	1,077	3,553	1,221	93	1,082	934	1,446
- per share – basic	**1.28**	1.44	4.74	1.63	0.12	1.44	1.24	1.91
- per share – diluted	**1.28**	1.43	4.73	1.63	0.12	1.43	1.24	1.89
Operating Earnings (2)	**948**	449	1,442	1,469	1,045	849	1,032	1,369
- per share – diluted	**1.26**	0.60	1.92	1.96	1.39	1.12	1.37	1.79
Cash Dividends – per share	**0.40**	0.40	0.40	0.40	0.40	0.20	0.20	0.20
Revenues, Net of Royalties	**4,608**	6,359	10,849	7,422	5,434	5,875	5,654	5,674

(1) Cash Flow is a non-GAAP measure and is defined under the Cash Flow section of this MD&A.

(2) Operating Earnings is a non-GAAP measure and is defined under the Operating Earnings section of this MD&A.

Despite the continued low commodity price environment during the first quarter of 2009, EnCana generated strong financial results. Compared to the fourth quarter of 2008, EnCana's upstream operations continued to benefit from its commodity price hedging program and the Company's downstream operations generated Operating Cash Flow of approximately $59 million in the first quarter of 2009 compared to an Operating Cash Flow loss of $580 million in the fourth quarter of 2008. Further discussion of EnCana's financial results can be found in the Results of Operations section of this MD&A.

CASH FLOW

Cash Flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations and net change in non-cash working capital from discontinued operations. While Cash Flow is considered a non-GAAP measure, it is commonly used in the oil and gas industry and by EnCana to assist Management and investors in measuring the Company's ability to finance capital programs and meet financial obligations.

Summary of Cash Flow

	Three Months Ended March 31	
($ millions)	**2009**	2008
Cash From Operating Activities	**$ 1,831**	$ 1,758
(Add back) deduct:		
Net change in other assets and liabilities	**14**	(93)
Net change in non-cash working capital	**(127)**	(538)
Cash Flow	**$ 1,944**	$ 2,389

Three Months Ended March 31, 2009 versus 2008

Cash Flow in 2009 decreased $445 million or 19 percent compared to 2008 as a result of:

- Average total natural gas prices, excluding financial hedges, decreased 45 percent to $4.23 per Mcf in 2009 compared to $7.75 per Mcf in 2008; and
- Average total liquids prices, excluding financial hedges, decreased 58 percent to $32.03 per bbl in 2009 compared to $75.44 per bbl in 2008;

partially offset by:

- Realized financial natural gas, crude oil and other commodity hedging gains of $699 million after-tax in 2009 compared to gains of $13 million after-tax in 2008;
- Natural gas production volumes in 2009 increased 4 percent to 3,869 million cubic feet ("MMcf") per day ("MMcf/d") from 3,733 MMcf/d in 2008;
- Decreases in operating, transportation and selling, administrative, production and mineral taxes and interest expenses excluding long-term compensation costs in 2009 compared to 2008; and
- A decrease in current taxes, excluding tax associated with realized financial hedging mentioned above, primarily due to the decrease in before tax Cash Flow.

NET EARNINGS

Three Months Ended March 31, 2009 versus 2008

Net Earnings in 2009 of $962 million were $869 million higher compared to 2008. In addition to the items affecting Cash Flow as detailed previously, significant items affecting Net Earnings were:

- Unrealized mark-to-market hedging gains of $89 million after-tax in 2009 compared to losses of $737 million after-tax in 2008;
- Non-operating foreign exchange losses of $75 million after-tax in 2009 compared to losses of $215 million after-tax in 2008;
- Long-term compensation costs decreased $143 million in 2009 compared to 2008 due to the change in the EnCana share price and the lower U.S./Canadian dollar exchange rate; and
- DD&A decreased $52 million in 2009 compared to 2008 primarily due to lower DD&A rates as a result of higher proved reserves and the lower U.S./Canadian dollar exchange rate partially offset by the increase in production volumes.

OPERATING EARNINGS

Operating Earnings is a non-GAAP measure that adjusts Net Earnings by non-operating items that Management believes reduces the comparability of the Company's underlying financial performance between periods. The following reconciliation of Operating Earnings has been prepared to provide investors with information that is more comparable between periods.

Summary of Operating Earnings

	Three Months Ended March 31							
	2009				2008			
($ millions, except per share amounts)			Per share[4]				Per share[4]	
Net Earnings, as reported	**$**	**962**	**$**	**1.28**	$	93	$	0.12
Add back (losses) and deduct gains:								
Unrealized mark-to-market accounting gain (loss), after-tax		**89**		**0.12**		(737)		(0.98)
Non-operating foreign exchange gain (loss), after-tax [1]		**(75)**		**(0.10)**		(215)		(0.29)
Operating Earnings [2] [3]	**$**	**948**	**$**	**1.26**	$	1,045	$	1.39

(1) Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt, the partnership contribution receivable, realized foreign exchange gain (loss) on settlement of intercompany transactions, after-tax and future income tax on foreign exchange related to U.S. dollar intercompany debt recognized for tax purposes only. The majority of U.S. dollar debt issued from Canada has maturity dates in excess of five years.
(2) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gain/loss on discontinuance, after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains/losses on settlement of intercompany transactions, future income tax on foreign exchange related to U.S. dollar intercompany debt recognized for tax purposes only and the effect of changes in statutory income tax rates. The Company's calculation of Operating Earnings excludes foreign exchange effects on settlement of significant intercompany transactions to provide information that is more comparable between periods.
(3) Unrealized gains or losses and realized foreign exchange gains or losses on settlement of intercompany transactions have no impact on Cash Flow.
(4) Per Common Share - diluted.

FOREIGN EXCHANGE

As disclosed in the Business Environment section of this MD&A, the average U.S./Canadian dollar exchange rate decreased 19 percent to $0.803 in the first quarter of 2009 compared to $0.996 in the first quarter of 2008. The table below summarizes the impacts of these changes on EnCana's operations when compared to the same period in the prior year.

	Three Months Ended March 31, 2009		
Average U.S./Canadian Dollar Exchange Rate	**$**	**0.803**	
Change from comparative period in prior year		**(0.193)**	
($ millions, except $/Mcfe amounts)		**$ millions**	**$/Mcfe**
Increase (decrease) in:			
Capital Investment	**$**	**(184)**	
Operating Expense		**(67)**	**(0.16)**
Administrative Expense		**(13)**	**(0.03)**
DD&A Expense		**(124)**	

RESULTS OF OPERATIONS

PRODUCTION VOLUMES

	2009	2008				2007		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Produced Gas *(MMcf/d)*	**3,869**	3,858	3,917	3,841	3,733	3,722	3,630	3,506
Crude Oil *(bbls/d)*	**111,981**	110,628	106,826	101,153	111,538	108,958	109,664	108,590
NGLs *(bbls/d)*	**22,299**	25,222	26,730	26,450	25,750	27,179	26,719	24,826
Total *(MMcfe/d)* [1]	**4,675**	4,673	4,718	4,607	4,557	4,539	4,448	4,306

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

KEY RESOURCE PLAYS

	Three Months Ended March 31				
	Daily Production			Drilling Activity (net wells drilled)	
	2009	**2009 vs 2008**	2008	**2009**	2008
Natural Gas *(MMcf/d)*					
Jonah	**623**	**5%**	595	**35**	43
Piceance	**386**	**4%**	372	**53**	83
East Texas	**409**	**50%**	273	**15**	11
Fort Worth	**149**	**6%**	140	**16**	21
Greater Sierra	**215**	**5%**	205	**15**	36
Cutbank Ridge	**323**	**19%**	271	**20**	24
Bighorn	**156**	**7%**	146	**21**	30
CBM	**309**	**4%**	298	**278**	251
Shallow Gas	**673**	**-6%**	715	**336**	496
	3,243	**8%**	3,015	**789**	995
Oil *(bbls/d)*					
Foster Creek	**28,170**	**5%**	26,770	**6**	12
Christina Lake	**6,559**	**152%**	2,606	**-**	-
	34,729	**18%**	29,376	**6**	12
Pelican Lake	**21,280**	**-11%**	23,903	**4**	-
Weyburn	**16,097**	**15%**	13,980	**-**	9
	72,106	**7%**	67,259	**10**	21
Total *(MMcfe/d)*	**3,676**	**8%**	3,417	**799**	1,016

Total production volumes increased 3 percent or 118 MMcfe/d in the first quarter of 2009 compared to 2008 primarily due to increased production from EnCana's natural gas key resource plays of 8 percent and from oil key resource plays of 7 percent partially offset by natural declines in conventional properties.

OPERATING NETBACK INFORMATION

	Three Months Ended March 31					
	2009			2008		
	Gas ($/Mcf)	**Liquids** ($/bbl)	**Total** ($/Mcfe)	Gas ($/Mcf)	Liquids ($/bbl)	Total ($/Mcfe)
Price	**$ 4.23**	**$ 32.03**	**$ 4.42**	$ 7.75	$ 75.44	$ 8.61
Expenses						
Production and mineral taxes	**0.14**	**0.92**	**0.15**	0.28	1.46	0.28
Transportation and selling	**0.49**	**1.36**	**0.44**	0.56	1.46	0.50
Operating	**0.75**	**8.46**	**0.86**	1.02	10.30	1.15
Netback excluding Realized Financial Hedging	**2.85**	**21.29**	**2.97**	5.89	62.22	6.68
Realized Financial Hedging Gain (Loss)	**2.99**	**2.21**	**2.55**	0.27	(5.85)	0.05
Netback including Realized Financial Hedging	**$ 5.84**	**$ 23.50**	**$ 5.52**	$ 6.16	$ 56.37	$ 6.73

Netbacks, excluding financial hedges, decreased significantly during the first quarter of 2009 compared to 2008 primarily due to lower commodity prices partially offset by the impact of the lower U.S./Canadian dollar exchange rate and lower long-term compensation costs due to the change in the EnCana share price.

As part of ongoing efforts to maintain financial resilience and flexibility, EnCana has taken steps to reduce pricing risk through a commodity price hedging program. Further information regarding this program can be found under the Risk Management section of this MD&A. As evidenced in the table above, EnCana has benefited significantly from its hedging program during this period of weaker commodity prices.

NET CAPITAL INVESTMENT

($ millions)	Three Months Ended March 31 2009	2008
Canada		
Canadian Plains	**$ 159**	$ 262
Canadian Foothills	**465**	780
Integrated Oil – Canada	**126**	208
USA	**540**	519
Downstream Refining	**202**	55
Market Optimization	**(3)**	2
Corporate & Other	**19**	23
Capital Investment	**1,508**	1,849
Acquisitions	**79**	58
Divestitures	**(33)**	(72)
Net Capital Investment	**$ 1,554**	$ 1,835

EnCana's capital investment for the three months ended March 31, 2009 was funded by Cash Flow.

Capital investment during the first quarter of 2009 was primarily focused on continued development of EnCana's North American key resource plays and expansion of the Company's downstream heavy oil refining capacity through its joint venture with ConocoPhillips. Reported capital investment was lower due to changes in the average U.S./Canadian dollar exchange rate as well as the EnCana share price in determining long-term compensation costs. The net impact of these factors on capital investment was a decrease of $295 million in the first quarter of 2009 compared to the same period in 2008. Further information regarding the Company's capital investment can be found in the Divisional Results section of this MD&A.

Acquisitions and Divestitures

The Company had some minor property acquisitions and divestitures in the first quarter of 2009 and 2008.

FREE CASH FLOW

EnCana's first quarter 2009 Free Cash Flow of $436 million was lower compared to the same period in 2008. Reasons for the decrease in total Cash Flow and capital investment are discussed under the Cash Flow and Net Capital Investment sections of this MD&A.

($ millions)	Three Months Ended March 31 2009	2008
Cash Flow (1)	**$ 1,944**	$ 2,389
Capital Investment	**1,508**	1,849
Free Cash Flow (2)	**$ 436**	$ 540

(1) Cash Flow is a non-GAAP measure and is defined under the Cash Flow section of this MD&A.

(2) Free Cash Flow is a non-GAAP measure that EnCana defines as Cash Flow in excess of Capital Investment, excluding net acquisitions and divestitures, and is used by Management to determine the funds available for other investing and/or financing activities.

Divisional Results

As discussed in EnCana's Business section of this MD&A, the Company has a decentralized decision making and reporting structure and is organized into divisions. Accordingly, results are presented at the divisional level. Canadian Plains Division and Canadian Foothills Division are included in the Canada segment. USA Division comprises the USA segment. Integrated Oil Division is the combined total of Integrated Oil – Canada and Downstream Refining.

CANADIAN PLAINS

Three Months Ended March 31, 2009 versus 2008

FINANCIAL RESULTS

	2009				2008			
		Oil &				Oil &		
($ millions)	Gas	NGLs	Other	Total	Gas	NGLs	Other	Total
Revenues, Net of Royalties	$ 319	$ 250	$ 2	$ 571	$ 563	$ 586	$ 2	$ 1,151
Realized Financial Hedging Gain (Loss)	202	2	-	204	27	(37)	-	(10)
Expenses								
Production and mineral taxes	3	7	-	10	5	8	-	13
Transportation and selling	11	51	-	62	19	90	-	109
Operating	51	51	1	103	73	68	1	142
Operating Cash Flow	$ 456	$ 143	$ 1	$ 600	$ 493	$ 383	$ 1	$ 877

PRODUCTION VOLUMES

	2009	2008				2007		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Produced Gas *(MMcf/d)*	800	820	831	856	860	876	858	874
Crude Oil *(bbls/d)*	67,043	64,990	64,789	65,097	69,781	70,287	70,711	70,148
NGLs *(bbls/d)*	1,201	1,126	1,147	1,189	1,262	1,422	1,209	1,206
Total *(MMcfe/d)* (1)	1,209	1,217	1,227	1,253	1,286	1,306	1,290	1,302

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

PRODUCED GAS

Revenues, net of royalties, including realized financial hedging, decreased $69 million in the first quarter of 2009 compared to the same period in 2008 due to:

- A $216 million impact resulting from a 39 percent decrease in natural gas prices, excluding the impact of financial hedging; and
- A $28 million impact resulting from a 7 percent decrease in natural gas production volumes. Produced gas volumes decreased in the first quarter of 2009 due to expected natural declines for the Shallow Gas key resource play and conventional properties as well as the impact of freeze-offs and other temporary production shut-ins resulting from extreme winter weather in southern Alberta;

offset by:

- Realized financial hedging gains of $202 million or $2.81 per Mcf in 2009 compared to gains of $27 million or $0.34 per Mcf in 2008.

The decrease in Canadian Plains natural gas price in 2009, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Canadian Plains natural gas transportation and selling costs of $11 million in 2009 decreased $8 million or 42 percent compared to 2008 due to the lower U.S./Canadian dollar exchange rate, lower volumes and costs to eastern Canada and the U.S. and lower fuel gas costs.

Canadian Plains natural gas operating expenses of $51 million in 2009 were $22 million or 30 percent lower compared to 2008 primarily as a result of the lower U.S./Canadian dollar exchange rate, lower long-term compensation costs due to the change in the EnCana share price and lower workovers and repairs and maintenance offset slightly by higher property tax and lease costs and increased salaries and benefits.

CRUDE OIL AND NGLs

Revenues, net of royalties, including realized financial hedging, decreased $297 million in the first quarter of 2009 compared to the same period in 2008 due to:

- A $280 million impact resulting from a 56 percent decrease in crude oil prices and 54 percent decrease in NGLs prices, excluding financial hedges;
- A $38 million impact resulting from a decrease in average prices of condensate used for blending with heavy oil; and
- A $19 million impact resulting from a 4 percent decrease in crude oil volumes and 5 percent decrease in NGLs volumes. Production from the Pelican Lake key resource play in 2009 was 21,280 bbls/d, down 11 percent compared to 2008 primarily due to natural declines. At Suffield, production of 13,703 bbls/d was down 3 percent mainly due to natural declines. These were partially offset by increased production at Weyburn;

offset by:

- Realized financial hedging gains on liquids of $2 million or $0.41 per bbl in 2009 compared to losses of $37 million or $5.63 per bbl in 2008.

Canadian Plains crude oil prices decreased 56 percent to $34.35 per bbl in 2009 from $77.44 per bbl in 2008 as a result of the changes in benchmark WTI and WCS crude oil prices as well as lower average differentials. Total realized financial hedging gains on crude oil for Canadian Plains were approximately $2 million or $0.42 per bbl in 2009 compared to losses of approximately $36 million or $5.65 per bbl in 2008.

Canadian Plains NGLs prices decreased 54 percent to $34.86 per bbl in 2009 from $75.09 per bbl in 2008, which is consistent with the change in WTI benchmark price.

Canadian Plains crude oil transportation and selling costs of $51 million in 2009 decreased $39 million or 43 percent compared to 2008 primarily due to a decrease in average prices of condensate used for blending with heavy oil, the lower U.S./Canadian dollar exchange rate and lower clean oil trucking costs at Weyburn.

Canadian Plains crude oil operating costs of $51 million in 2009 were $17 million or 25 percent lower compared to 2008 mainly due to the lower U.S./Canadian dollar exchange rate, lower long-term compensation costs due to the change in the EnCana share price, reduced workovers and lower chemical costs offset slightly by higher repairs and maintenance and increased property tax and lease costs. NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas.

CAPITAL INVESTMENT

Canadian Plains capital investment of $159 million during the first quarter of 2009 was primarily focused on the Shallow Gas, Pelican Lake and Weyburn key resource plays. The $103 million decrease compared to 2008 was primarily due to the lower U.S./Canadian dollar exchange rate, lower drilling and completion costs resulting from fewer wells drilled and lower capitalized costs for long-term incentives. Canadian Plains drilled 375 net wells in the first quarter of 2009 compared to 558 net wells in 2008, consistent with the planned reduction in spending in 2009.

CANADIAN FOOTHILLS

Canadian Foothills Division includes the Company's Canadian offshore assets.

Three Months Ended March 31, 2009 versus 2008

FINANCIAL RESULTS

	2009				2008			
($ millions)	Gas	Oil & NGLs	Other	Total	Gas	Oil & NGLs	Other	Total
Revenues, Net of Royalties	$ 528	$ 57	$ 10	$ 595	$ 870	$ 158	$ 18	$ 1,046
Realized Financial Hedging Gain (Loss)	320	-	-	320	39	(10)	-	29
Expenses								
Production and mineral taxes	4	1	-	5	3	1	-	4
Transportation and selling	34	3	-	37	53	3	-	56
Operating	120	6	4	130	161	11	6	178
Operating Cash Flow	$ 690	$ 47	$ 6	$ 743	$ 692	$ 133	$ 12	$ 837

PRODUCTION VOLUMES

	2009	2008				2007		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Produced Gas *(MMcf/d)*	1,281	1,302	1,351	1,289	1,256	1,313	1,280	1,231
Crude Oil *(bbls/d)*	8,140	8,437	8,217	8,376	8,867	8,441	7,978	7,959
NGLs *(bbls/d)*	9,427	11,265	11,730	11,779	11,256	10,966	9,932	9,811
Total *(MMcfe/d)* (1)	1,386	1,420	1,471	1,410	1,377	1,429	1,387	1,338

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

PRODUCED GAS

Revenues, net of royalties, including realized financial hedging, decreased $61 million in the first quarter of 2009 compared to the same period in 2008 due to:

- A $347 million impact resulting from a 40 percent decrease in natural gas prices, excluding the impact of financial hedging;

offset by:

- Realized financial hedging gains of $320 million or $2.78 per Mcf in 2009 compared to gains of $39 million or $0.34 per Mcf in 2008; and
- A $5 million impact resulting from a 2 percent increase in natural gas production volumes. Produced gas volumes increased in the first quarter of 2009 due to drilling success as well as increased tie-in and completion activity in the key resource plays of Cutbank Ridge, CBM, Bighorn and Greater Sierra partially offset by natural declines for conventional properties and the volume impact of minor property divestitures in 2008.

The decrease in Canadian Foothills natural gas price in 2009, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Canadian Foothills natural gas transportation and selling costs of $34 million in 2009 decreased $19 million or 36 percent compared to 2008 due to the lower U.S./Canadian dollar exchange rate, lower fuel gas costs and lower volumes transported to the U.S.

Canadian Foothills natural gas operating expenses of $120 million in 2009 were $41 million or 25 percent lower compared to 2008 primarily as a result of the lower U.S./Canadian dollar exchange rate, lower long-term compensation costs due to the change in the EnCana share price and reduced workovers offset by higher security costs, salaries and benefits, property tax and lease costs as well as repairs and maintenance.

CRUDE OIL AND NGLs

Revenues, net of royalties, including realized financial hedging, decreased $91 million in the first quarter of 2009 compared to the same period in 2008 due to:

- A $92 million impact resulting from a 60 percent decrease in crude oil prices and 56 percent decrease in NGLs prices, excluding financial hedges; and
- A $9 million impact resulting from an 8 percent decrease in crude oil volumes and 16 percent decrease in NGLs volumes. The decreases were due to natural declines and the volume impact of property divestitures;

offset by:

- Realized financial hedging losses on liquids were less than $1 million in 2009 compared to losses of $10 million or $5.72 per bbl in 2008.

Canadian Foothills crude oil prices decreased 60 percent to $37.31 per bbl in 2009 from $93.42 per bbl in 2008 as a result of the changes in benchmark WTI and WCS crude oil prices as well as lower average differentials. Total realized financial hedging losses on crude oil for Canadian Foothills were less than $1 million in 2009 compared to losses of approximately $4 million or $5.45 per bbl in 2008.

Canadian Foothills NGLs prices decreased 56 percent to $35.81 per bbl in 2009 from $80.80 per bbl in 2008, which is consistent with the change in WTI benchmark price.

Canadian Foothills crude oil operating costs of $6 million in 2009 were $5 million or 45 percent lower compared to 2008 mainly due to the lower U.S./Canadian dollar exchange rate and lower gathering and processing costs. NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas.

CAPITAL INVESTMENT

Canadian Foothills capital investment of $465 million during the first quarter of 2009 was primarily focused on the CBM, Cutbank Ridge, Greater Sierra and Bighorn key resource plays. The $315 million decrease compared to 2008 was primarily due to the lower U.S./Canadian dollar exchange rate, lower drilling costs as a result of increased focus on well tie-ins and lower capitalized costs for long-term incentives. Canadian Foothills drilled 343 net wells in the first quarter of 2009 compared to 380 net wells in 2008.

USA

Three Months Ended March 31, 2009 versus 2008

FINANCIAL RESULTS

	2009				2008			
($ millions)	Gas	Oil & NGLs	Other	Total	Gas	Oil & NGLs	Other	Total
Revenues, Net of Royalties	$ 610	$ 29	$ 27	$ 666	$ 1,157	$ 99	$ 72	$ 1,328
Realized Financial Hedging Gain (Loss)	508	-	-	508	26	-	-	26
Expenses								
Production and mineral taxes	43	3	-	46	87	9	-	96
Transportation and selling	123	-	-	123	115	-	-	115
Operating	82	-	33	115	101	-	68	169
Operating Cash Flow	$ 870	$ 26	$ (6)	$ 890	$ 880	$ 90	$ 4	$ 974

PRODUCTION VOLUMES

	2009	2008				2007		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Produced Gas *(MMcf/d)*	1,746	1,677	1,674	1,629	1,552	1,464	1,387	1,303
NGLs *(bbls/d)*	11,671	12,831	13,853	13,482	13,232	14,791	15,578	13,809
Total *(MMcfe/d)* (1)	1,816	1,754	1,757	1,710	1,631	1,553	1,480	1,386

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

PRODUCED GAS

Revenues, net of royalties, including realized financial hedging, decreased $65 million in the first quarter of 2009 compared to the same period in 2008 due to:

- A $609 million impact resulting from a 53 percent decrease in natural gas prices, excluding the impact of financial hedging;

offset by:

- Realized financial hedging gains of $508 million or $3.23 per Mcf in 2009 compared to gains of $26 million or $0.18 per Mcf in 2008; and
- A $62 million impact resulting from a 13 percent increase in natural gas production volumes. Produced gas volumes in the USA increased in the first quarter of 2009 as a result of drilling and operational success at East Texas, Jonah, Piceance and Fort Worth partially offset by shut-in production (approximately 90 MMcf/d) at Piceance and Jonah due to the low price environment.

The decrease in USA natural gas prices in 2009, excluding the impact of financial hedges, reflects the changes in NYMEX, Rockies (Opal) and Texas (HSC) benchmark prices and changes in the basis differentials. Natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas production and mineral taxes for the USA of $43 million in 2009 decreased $44 million or 51 percent compared to 2008 primarily as a result of lower natural gas prices.

Natural gas transportation and selling costs for the USA of $123 million in 2009 increased $8 million or 7 percent compared to 2008 mainly as a result of transporting gas greater distances on the Rockies Express Pipeline to improve price realizations and transporting higher volumes.

Natural gas operating expenses for the USA of $82 million in 2009 were $19 million or 19 percent lower compared to 2008 as a result of lower long-term compensation costs due to the change in the EnCana share price, lower workovers, repairs and maintenance and water disposal costs offset slightly by increased property tax and salaries and benefits costs.

CRUDE OIL AND NGLs

All of EnCana's liquids production in the USA relates to NGLs.

Revenues, net of royalties, including realized financial hedging, decreased $70 million in the first quarter of 2009 compared to the same period in 2008 due to:

- A $66 million impact resulting from a 67 percent decrease in NGLs prices, excluding financial hedges;
- A $4 million impact resulting from a 12 percent decrease in NGLs volumes.

USA NGLs prices decreased 67 percent to $27.43 per bbl in 2009 from $82.22 per bbl in 2008 primarily as a result of the change in the WTI benchmark price.

NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas.

CAPITAL INVESTMENT

USA capital investment of $540 million during the first quarter of 2009 was primarily focused on the East Texas, Jonah, Piceance and Fort Worth key resource plays. The $21 million increase compared to 2008 was primarily due to increased drilling and facilities spending in North Louisiana offset by lower activity in Piceance key resource play as well as lower capitalized costs for long term-incentives. The number of net wells drilled in the USA in the first quarter of 2009 decreased to 140 from 178 in 2008.

INTEGRATED OIL

FOSTER CREEK/CHRISTINA LAKE OPERATIONS

EnCana is a 50 percent partner in an integrated North American oil business with ConocoPhillips that consists of an upstream and a downstream entity. The upstream entity includes contributed assets from EnCana, primarily the Foster Creek and Christina Lake oil properties while the downstream entity includes ConocoPhillips' Wood River and Borger refineries located in Illinois and Texas, respectively.

The current plan of the upstream business is to increase production capacity at Foster Creek/Christina Lake to approximately 218,000 bbls/d (on a 100 percent basis) of bitumen with the completion of current expansion phases.

Three Months Ended March 31, 2009 versus 2008

FINANCIAL RESULTS

	Oil	
($ millions)	**2009**	2008
Revenues, Net of Royalties	**$ 140**	$ 261
Realized Financial Hedging Gain (Loss)	**23**	(23)
Expenses		
Transportation and selling	**66**	120
Operating	**40**	41
Operating Cash Flow	**$ 57**	$ 77

PRODUCTION VOLUMES

	2009	2008				2007		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Crude Oil *(bbls/d)*	**34,729**	35,068	31,547	24,671	29,376	27,190	28,740	27,994
Total *(MMcfe/d)* (1)	**208**	210	189	148	176	163	172	168

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

CRUDE OIL

Revenues, net of royalties, including realized financial hedging, decreased $75 million in the first quarter of 2009 compared to the same period in 2008 due to:

- An $81 million impact resulting from a decrease in crude oil prices, excluding financial hedges;
- A $54 million impact resulting from a decrease in average prices of condensate used for blending with heavy oil;

offset by:

- Realized financial hedging gains primarily on condensate used for blending of $23 million in 2009 compared to losses of $23 million or $9.26 per bbl in 2008; and
- A $14 million impact resulting from a 23 percent increase in crude oil sales volumes attributable to an 18 percent increase in production volumes and changes in inventory levels;

Foster Creek/Christina Lake bitumen prices decreased 55 percent to $26.90 per bbl in 2009 from $59.67 per bbl in 2008 as a result of the changes in benchmark WTI and WCS crude oil prices offset by a narrowing of the average differentials. WCS as a percentage of WTI was 79 percent in 2009 compared to 78 percent in 2008.

Crude oil transportation and selling costs of $66 million in 2009 decreased $54 million or 45 percent compared to 2008 primarily due to a decrease in average prices of condensate used for blending with heavy oil and variability in sales destinations and pipelines utilized to transport the product.

Crude oil operating costs of $40 million in 2009 were relatively unchanged compared to 2008. Lower fuel gas costs, lower long-term compensation costs due to the change in the EnCana share price and the lower U.S./Canadian dollar exchange rate were offset by increased workovers.

DOWNSTREAM OPERATIONS

FINANCIAL RESULTS

($ millions)	Three Months Ended March 31 2009	2008
Revenues	**$ 926**	$ 2,046
Expenses		
Operating	**118**	132
Purchased product	**749**	1,821
Operating Cash Flow	**$ 59**	$ 93

The Wood River refinery, located in Roxana, Illinois, has a current capacity of approximately 306,000 bbls/d of crude oil (on a 100 percent basis). In the third quarter of 2008, the Wood River refinery received regulatory approvals to start construction on the Coker and Refinery Expansion ("CORE") project. EnCana's 50 percent share of the CORE project is expected to cost approximately $1.8 billion and is anticipated to be completed and in full operation in 2011. The expansion is expected to increase crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d (on a 100 percent basis) and more than double heavy crude oil refining capacity to 240,000 bbls/d (on a 100 percent basis).

The Borger refinery, located in Borger, Texas, has a current capacity of approximately 146,000 bbls/d of crude oil and approximately 45,000 bbls/d of NGLs (on a 100 percent basis). The coker installed in 2007 is enabling the refinery to upgrade approximately 35,000 bbls/d (on a 100 percent basis) of WCS heavy crude oil.

The current plan of the downstream business is to refine approximately 275,000 bbls/d gross of heavy crude oil (135,000 bbls/d of bitumen equivalent) to primarily motor fuels with the completion of the CORE project in 2011. As at March 31, 2009, the Wood River and Borger refineries have processing capability to refine up to approximately 145,000 bbls/d gross of heavy crude oil (70,000 bbls/d of bitumen equivalent).

The two refineries have a combined crude oil refining capacity of 452,000 bbls/d (on a 100 percent basis) and operated at an average 88 percent of that capacity during the first quarter of 2009 compared to 90 percent during the same period in 2008. Refinery crude utilization was lower in 2009 primarily due to unplanned refinery unit outages and maintenance activities. Refined products averaged 421,000 bbls/d (210,500 bbls/d net to EnCana) in the first quarter of 2009 compared to 435,000 bbls/d (217,500 bbls/d net to EnCana) in 2008.

Purchased products, consisting mainly of crude oil, represented 86 percent of total expenses in the first quarter of 2009 compared to 93 percent in 2008. Operating costs for labour, utilities and supplies comprised the balance of expenses. Revenues and purchased product have decreased 55 percent and 59 percent in the first quarter of 2009, respectively, in line with the significant decrease in crude oil prices offset by higher refining margins.

OTHER INTEGRATED OIL OPERATIONS

In addition to the 50 percent owned Foster Creek/Christina Lake operations, Integrated Oil also manages the 100 percent owned natural gas operations in Athabasca and crude oil operations in Senlac.

Gas production volumes from Athabasca were 42 MMcf/d in the first quarter of 2009 compared to 65 MMcf/d in 2008. The decrease at Athabasca was due to increased internal usage to supply a portion of the fuel gas requirements at Foster Creek and expected natural declines. Oil production volumes from Senlac were 2,069 bbls/d in the first quarter of 2009 compared to 3,514 bbls/d in 2008. The decrease at Senlac was due to expected natural declines.

CAPITAL INVESTMENT

($ millions)	Three Months Ended March 31 2009	2008
Integrated Oil – Canada	**$ 126**	$ 208
Downstream Refining	**202**	55
Total Integrated Oil Division	**$ 328**	$ 263

Integrated Oil Division capital investment of $328 million during the first quarter of 2009 was primarily focused on continued development of the Foster Creek and Christina Lake resource plays and on the CORE project at the Wood River refinery. The $65 million increase in capital investment in the first quarter of 2009 compared to the same period in 2008 was primarily due to:

- Spending related to the Wood River CORE project increased $141 million to $180 million in the first quarter of 2009 compared to $39 million in 2008. The Wood River CORE project received regulatory approvals in the third quarter of 2008 and is expected to cost about $1.8 billion, net to EnCana, over the next three years. The expansion is expected to increase crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d (on a 100 percent basis) and heavy crude oil refining capacity is expected to more than double to 240,000 bbls/d (on a 100 percent basis);

partially offset by:

- Lower facility costs with substantial completion of the Foster Creek Phases D and E expansions late in the fourth quarter of 2008. Facility expenditures at Foster Creek are expected to increase plant capacity to 120,000 bbls/d (on a 100 percent basis) to accommodate Phases D and E expansions. Christina Lake facility costs are expected to increase plant capacity to 58,000 bbls/d (on a 100 percent basis) to accommodate Phase C expansion;
- Lower drilling costs mainly due to drilling of 39 stratigraphic test wells net to EnCana in 2009 (2008 – 134 wells net to EnCana) at Foster Creek, Christina Lake, Borealis and Senlac related to the next phases of development; and
- The lower U.S./Canadian dollar exchange rate and lower capitalized costs for long-term incentives.

DEPRECIATION, DEPLETION AND AMORTIZATION

Total DD&A expenses of $983 million in the first quarter of 2009 decreased $52 million or 5 percent compared to 2008.

UPSTREAM DD&A

EnCana uses full cost accounting for oil and gas activities and calculates DD&A on a country-by-country cost centre basis.

2009 versus 2008

Upstream DD&A expenses of $900 million in the first quarter of 2009 decreased $66 million or 7 percent compared to 2008 due to:

- DD&A rates in Canada for 2009 were lower than 2008 primarily as a result of the lower U.S./Canadian dollar exchange rate and higher proved reserves;
- DD&A rates in the USA for 2009 were lower than 2008 primarily due to lower future development costs and higher proved reserves;

partially offset by:

- Increased production volumes of 3 percent primarily in the USA as well as Foster Creek and Christina Lake.

DOWNSTREAM DD&A

EnCana calculates DD&A on a straight-line basis over estimated service lives of approximately 25 years.

Downstream refining DD&A was $51 million in the first quarter of 2009 compared to $44 million in 2008 as a result of a full year of depreciation on prior year capital additions, as well as accelerated depreciation on certain assets expected to be retired sooner than originally anticipated.

MARKET OPTIMIZATION

FINANCIAL RESULTS

	Three Months Ended March 31	
($ millions)	**2009**	2008
Revenues	**$ 492**	$ 625
Expenses		
Operating	**8**	11
Purchased product	**473**	607
Operating Cash Flow	**11**	7
Depreciation, depletion and amortization	**5**	4
Segment Income	**$ 6**	$ 3

Market Optimization revenues and purchased product expenses relate to activities that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification that enhance the sale of EnCana's production.

Revenues and purchased product expenses decreased in the first quarter of 2009 compared to 2008 mainly due to decreased pricing partially offset by increases in volume required for Market Optimization.

CAPITAL INVESTMENT

Market Optimization capital investment in the first quarter of 2009 and 2008 was focused on developing infrastructure for optimization activities and maintaining power generation facilities.

CORPORATE AND OTHER

FINANCIAL RESULTS

	Three Months Ended March 31	
($ millions)	**2009**	2008
Revenues	**$ 133**	$ (1,094)
Expenses		
Operating	**26**	-
Depreciation, depletion and amortization	**27**	21
Segment Income (Loss)	**$ 80**	$ (1,115)

Revenues represent unrealized mark-to-market gains or losses related to financial natural gas and liquids hedge contracts.

Operating expenses in the first quarter of 2009 primarily relate to mark-to-market accounting losses on long-term power generation contracts.

DD&A includes provisions for corporate assets, such as computer equipment, office furniture and leasehold improvements, as well as for international assets.

Summary of Unrealized Mark-to-Market Gains (Losses)

	Three Months Ended March 31	
($ millions)	**2009**	2008
Revenues		
Natural Gas	**$ 158**	$ (1,113)
Crude Oil	**(25)**	17
	133	(1,096)
Expenses	**22**	(3)
	111	(1,093)
Income Tax Expense (Recovery)	**22**	(356)
Unrealized Mark-to-Market Gains (Losses), after-tax	**$ 89**	$ (737)

Commodity price volatility impacts net earnings. As a means of managing this commodity price volatility, EnCana enters into various financial instrument agreements. The financial instrument agreements were recorded at the date of the financial statements based on mark-to-market accounting. Changes in the mark-to-market gain or loss reflected in corporate revenues are the result of volatility between periods in the forward curve commodity price market and changes in the balance of unsettled contracts. Further information regarding financial instrument agreements can be found in Note 16 to the Interim Consolidated Financial Statements.

CONSOLIDATED EXPENSES

	Three Months Ended March 31	
($ millions)	**2009**	2008
Administrative	**$ 85**	$ 156
Interest, net	**104**	134
Accretion of asset retirement obligation	**17**	21
Foreign exchange (gain) loss, net	**58**	95
(Gain) loss on divestitures	**(1)**	-

Administrative expenses decreased $71 million in the first quarter of 2009 compared to 2008 primarily due to lower long-term compensation expenses of $73 million as a result of the change in the EnCana share price and the lower U.S./Canadian dollar exchange rate partially offset by increased staff levels, higher salaries and other related expenses.

Net interest expense in the first quarter of 2009 decreased $30 million from 2008 primarily as a result of lower average outstanding debt and lower weighted average interest rate. EnCana's total long-term debt, including current portion, decreased $665 million to

$9,442 million at March 31, 2009 compared to $10,107 million at March 31, 2008. EnCana's year-to-date weighted average interest rate on outstanding debt was 5.2 percent in 2009 compared to 5.6 percent in 2008.

The foreign exchange loss of $58 million in the first quarter of 2009 is primarily due to the effects of the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada offset by the foreign exchange revaluation of the partnership contribution receivable. Other foreign exchange gains and losses result primarily from the settlement of foreign currency transactions and the translation of EnCana's monetary assets and liabilities.

INCOME TAX

Total income tax expense in the first quarter of 2009 was $284 million, which remains relatively unchanged from the same period in 2008.

EnCana's effective rate in any year is a function of the relationship between total tax (current and future) and the amount of net earnings before income taxes for the year. The effective tax rate differs from the statutory tax rate as it takes into consideration "permanent differences", adjustment for changes to tax rates and other tax legislation, variation in the estimation of reserves and the estimate to actual differences. Permanent differences are a variety of items, including:

- The non-taxable portion of Canadian capital gains or losses;
- Non-taxable downstream partnership income;
- International financing; and
- Foreign exchange (gains) losses not included in net earnings.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

CAPITAL INVESTMENT

Corporate and Other capital investment in the first quarter of 2009 and 2008 was primarily directed to business information systems, leasehold improvements and office furniture.

Liquidity and Capital Resources

($ millions)	Three Months Ended March 31 2009	2008
Net cash from (used in)		
Operating activities	**$ 1,831**	$ 1,758
Investing activities	**(1,788)**	(1,534)
Financing activities	**207**	116
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**(4)**	(4)
Increase (decrease) in cash and cash equivalents	**$ 246**	$ 336

OPERATING ACTIVITIES

Net cash from operating activities in the first quarter of 2009 increased $73 million compared to 2008. Cash Flow was $1,944 million during the first quarter of 2009 compared to $2,389 million for the same period in 2008. Reasons for this change are discussed under the Cash Flow section of this MD&A. Cash from operating activities was also impacted by net changes in non-cash working capital and net changes in other assets and liabilities, including decreases in accounts payable and accrued liabilities and income tax payable offset by decreases in accounts receivable and accrued revenues. Excluding the impact of current risk management assets and liabilities, the Company had a working capital deficit of $566 million at March 31, 2009 compared to $1,452 million at March 31, 2008. As is typical in the oil and gas industry, there is a timing difference between cash receipts from sales transactions and payments of trade payables, which often results in a working capital deficit. EnCana anticipates that it will continue to meet the payment terms of its suppliers.

INVESTING ACTIVITIES

Net cash used for investing activities in the first quarter of 2009 increased $254 million compared to the same period in 2008. Capital expenditures, including property acquisitions, in the first quarter of 2009 decreased $320 million compared to 2008. Reasons for this change are discussed under the Net Capital Investment and Divisional Results sections of this MD&A. Increases in cash used for investing activities from net changes in non-cash working capital and net changes in investments and other were offset by reductions in capital expenditures and property acquisitions.

FINANCING ACTIVITIES

Net issuance of long-term debt in the first quarter of 2009 was $505 million compared to net issuance of $664 million for the same period in 2008. EnCana's total long-term debt, including current portion, was $9,442 million at March 31, 2009 compared to $10,107 million at March 31, 2008.

EnCana maintains a Canadian and a U.S. dollar shelf prospectus and two committed bank credit facilities.

As at March 31, 2009, EnCana had available unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for up to $5.0 billion.

EnCana has in place a shelf prospectus whereby it may issue from time to time up to $4.0 billion, or the equivalent in foreign currencies, of debt securities in the United States. At March 31, 2009, $4.0 billion of the shelf prospectus remains unutilized, the availability of which is dependent upon market conditions. The shelf prospectus was renewed in 2008 and expires in April 2010.

EnCana has in place a shelf prospectus whereby it may issue from time to time up to C$2.0 billion, or the equivalent in foreign currencies, of debt securities in Canada. At March 31, 2009, C$1.25 billion of the shelf prospectus remains unutilized, the availability of which is dependent upon market conditions. The shelf prospectus was renewed in 2007 and expires in June 2009. The Company plans to renew the shelf prospectus upon expiry.

As at March 31, 2009, EnCana had available unused committed bank credit facilities in the amount of $2.0 billion. EnCana has in place a revolving bank credit facility for C$4.5 billion that remains committed through October 28, 2012. One of EnCana's U.S. subsidiaries has in place a revolving bank credit facility for $600 million, of which $565 million is accessible, that remains committed through February 28, 2013. One of the lenders under the $600 million revolving credit facility, Lehman Brothers Bank, FSB, ceased funding its $35 million commitment as a result of the bankruptcy filing made by its affiliate, Lehman Brothers Holdings Inc., on September 15, 2008.

EnCana is currently in compliance with and anticipates that it will continue to be in compliance with all financial covenants under its credit facility agreements.

EnCana maintains investment grade credit ratings on its senior unsecured debt. On May 12, 2008, following the announcement of the proposed corporate reorganization, Standard & Poor's Ratings Service assigned a rating of A- and placed the Company on "CreditWatch Negative", DBRS Limited assigned a rating of A(low) and placed the Company "Under Review with Developing Implications" and Moody's Investors Services assigned a rating of Baa2 and changed the outlook to "Stable" from "Positive". On March 2, 2009, Standard & Poor's affirmed its A- rating and removed the rating from "CreditWatch". The outlook is "Negative". On March 5, 2009, DBRS Limited maintained the long-term rating of EnCana at A(low) "Under Review with Developing Implications".

EnCana has obtained regulatory approval under Canadian securities laws to purchase Common Shares under a Normal Course Issuer Bid ("NCIB"). During the first quarter of 2009, EnCana did not purchase any of its Common Shares compared to 4.6 million Common Shares purchased for total consideration of approximately $311 million for the same period in 2008. As of March 31, 2009, the number of Common Shares that EnCana will be permitted to purchase in 2009 under the current NCIB is approximately 75.0 million.

EnCana pays quarterly dividends to shareholders at the discretion of the Board of Directors. Dividend payments in the first quarter of 2009 and 2008 totaled $300 million. These dividends were funded by Cash Flow.

Financial Metrics

	March 31 2009	December 31 2008
Debt to Capitalization (1)	**29%**	28%
Debt to Adjusted EBITDA (2)	**0.7x**	0.7x

(1) Capitalization is a non-GAAP measure defined as Long-Term Debt including current portion plus Shareholders' Equity.

(2) Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as Net Earnings from Continuing Operations before gains or losses on divestitures, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation, depletion and amortization.

Debt to Capitalization and Debt to Adjusted EBITDA are two ratios Management uses to steward the Company's overall debt position as measures of the Company's overall financial strength. EnCana targets a Debt to Capitalization ratio of between 30 to 40 percent and a Debt to Adjusted EBITDA of 1.0 to 2.0 times.

At March 31, 2009, EnCana's Debt to Capitalization ratio was 29 percent (December 31, 2008 – 28 percent) and Debt to Adjusted EBITDA was 0.7x (December 31, 2008 – 0.7x).

OUTSTANDING SHARE DATA

(millions)	March 31 2009	December 31 2008
Common Shares outstanding, beginning of year	**750.4**	750.2
Common Shares issued under option plans	**0.2**	3.0
Common Shares purchased	**-**	(2.8)
Common Shares outstanding, end of period	**750.6**	750.4
Weighted average Common Shares outstanding – diluted	**751.4**	751.8

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares. There were no Preferred Shares outstanding as at March 31, 2009 and 2008.

Employees have been granted options to purchase Common Shares under various plans. At March 31, 2009, approximately 0.3 million options without Tandem Share Appreciation Rights ("TSARs") attached were outstanding, all of which are exercisable.

Stock options granted after December 31, 2003 have an associated TSAR attached, which gives employees the right to elect to receive a cash payment equal to the excess of the market price of EnCana's Common Shares over the exercise price of their stock option in exchange for surrendering their stock option. The exercise of a TSAR, for a cash payment, does not result in the issuance of any additional EnCana Common Shares, so has no dilutive effect. Historically, virtually all employees holding options with TSARs attached deciding to realize the value of their options have exercised their TSARs to receive a cash payment. At March 31, 2009, approximately 23.0 million options with TSARs attached were outstanding, of which 13.6 million are exercisable.

In 2007, 2008 and 2009 EnCana also granted Performance TSARs, which vest and expire under the same terms and service conditions as TSARs and are also subject to EnCana attaining prescribed performance relative to pre-determined key measures. Performance TSARs that do not vest when eligible are forfeited. At March 31, 2009, approximately 19.1 million Performance TSARs were outstanding, of which 4.0 million are exercisable.

In 2008, EnCana granted Share Appreciation Rights ("SARs") and Performance SARs to certain employees, which entitle the employee to receive a cash payment equal to the excess of the market price of EnCana's Common Shares at the time of exercise over the grant price. Performance SARs are subject to EnCana attaining prescribed performance relative to pre-determined key measures. Performance SARs that do not vest when eligible are forfeited. At March 31, 2009, approximately 5.9 million SARs and Performance SARs were outstanding, of which 0.5 million are exercisable.

Contractual Obligations and Contingencies

EnCana has entered into various commitments primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements.

Included in EnCana's total long-term debt obligations of $9,464 million at March 31, 2009 are $2,122 million in obligations related to Bankers' Acceptances, Commercial Paper and LIBOR loans. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year. The revolving credit and term loan facilities are fully revolving for the periods disclosed in the Liquidity and Capital Resources section of this MD&A. Further details regarding EnCana's long-term debt are described in Note 10 to the Interim Consolidated Financial Statements.

The Company expects its 2009 commitments to be funded from Cash Flow.

As at March 31, 2009, EnCana remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 33 MMcf/d, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 94 Bcf at a weighted average price of $3.58 per Mcf.

LEASES

In the normal course of business, EnCana leases office space for personnel who support field operations and for corporate purposes.

VARIABLE INTEREST ENTITIES ("VIEs")

On September 25, 2008, EnCana acquired certain land and property in Louisiana for approximately $101 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Haynesville Leasehold LLC ("Brown Haynesville"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. The relationship with Brown Haynesville represented an interest in a VIE from September 25, 2008 to March 24, 2009. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Haynesville. On March 24, 2009, when the arrangement with Brown Haynesville was completed, the assets were transferred to EnCana.

On July 23, 2008, EnCana acquired certain land and mineral interests in Louisiana for approximately $457 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Southwest Minerals LLC ("Brown Southwest"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. On November 12, 2008, an unrelated party exercised an option to purchase certain interests as part of the above acquisition for approximately $157 million, reducing the qualifying like kind exchange to approximately $300 million. The relationship with Brown Southwest represented an interest in a VIE from July 23, 2008 to January 19, 2009. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Southwest. On January 19, 2009, when the arrangement with Brown Southwest was completed, the assets were transferred to EnCana.

LEGAL PROCEEDINGS

EnCana is involved in various legal claims associated with the normal course of operations and believes it has made adequate provision for such legal claims.

DISCONTINUED MERCHANT ENERGY OPERATIONS

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. The lawsuits allege that the defendants engaged in a conspiracy with unnamed competitors in the natural gas markets in California in violation of U.S. and California anti-trust and unfair competition laws. All but one of these lawsuits has been settled prior to 2009, without admitting any liability in the lawsuits.

The remaining lawsuit was commenced by E. & J. Gallo Winery ("Gallo"). The Gallo lawsuit claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

The Company and WD intend to vigorously defend against this outstanding claim; however, the Company cannot predict the outcome of these proceedings or any future proceedings against the Company, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company's financial position, or whether there will be other proceedings arising out of these allegations.

Accounting Policies and Estimates

NEW ACCOUNTING STANDARDS ADOPTED

As disclosed in the year-end MD&A, on January 1, 2009, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3064 "Goodwill and Intangible Assets". The adoption of this standard has had no material impact on EnCana's Consolidated Financial Statements. Additional information on the effects of the implementation of the new standard can be found in Note 2 to the Interim Consolidated Financial Statements.

RECENT ACCOUNTING PRONOUNCEMENTS

International Financial Reporting Standards ("IFRS")

In February 2008, the CICA's Accounting Standards Board confirmed that IFRS will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. EnCana will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information.

The key elements of EnCana's changeover plan include:

- determine appropriate changes to accounting policies and required amendments to financial disclosures;
- identify and implement changes in associated processes and information systems;

- comply with internal control requirements;
- communicate collateral impacts to internal business groups; and
- educate and train internal and external stakeholders.

The Company is currently analyzing accounting policy alternatives and identifying implementation options for the corresponding process changes, with a focus on the areas that have been identified as having the most significant impact. The significant impact areas are those identified as having the greatest potential impact to the Company's financial statements or the greatest risk in terms of complexity to implement. Such areas identified to date include property, plant & equipment ("PP&E"), impairment testing, asset retirement obligation, stock-based compensation, employee future benefits and income taxes.

The Company expects one of the most significant impacts of the IFRS changeover will be in the accounting for certain upstream activities. Under Canadian GAAP, EnCana follows the CICA's guideline on full cost accounting. In moving to IFRS, EnCana will be required to adopt new accounting policies for upstream activities, including pre-exploration costs, exploration and evaluation costs and development costs. Upstream DD&A will be calculated at a lower unit of account level than the current country cost centre basis. In addition, impairment testing will be performed at a lower level than the current country cost centre basis.

In September 2008, the International Accounting Standards Board ("IASB") issued an exposure draft outlining additional exemptions for first-time adopters of IFRS. Included in the exposure draft is an exemption which would permit full cost accounting companies to allocate their existing upstream PP&E net book value (full cost pool) over reserves to the unit of account level upon transition to IFRS. This exemption would relieve the Company from retrospective application of IFRS for upstream PP&E. The IASB will be reviewing the proposed exemption in the second quarter of 2009, which EnCana intends to adopt if it is approved and adopted into IFRS. The Company is also evaluating the impact of other first-time adoption exemptions available upon initial transition to IFRS.

EnCana will update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board. As IFRS is expected to change prior to 2011, the impact of IFRS on the Company's Consolidated Financial Statements is not reasonably determinable at this time.

Business Combinations

As of January 1, 2011, EnCana will be required to adopt CICA Handbook Section 1582 "Business Combinations", which replaces the previous business combinations standard. The standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the statement of earnings. The adoption of this standard will impact the accounting treatment of future business combinations.

Consolidated Financial Statements

As of January 1, 2011, EnCana will be required to adopt CICA Handbook Section 1601 "Consolidated Financials Statements", which together with Section 1602 below, replace the former consolidated financial statements standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

Non-controlling Interests

As of January 1, 2011, EnCana will be required to adopt CICA Handbook Section 1602 "Non-controlling Interests". The standard establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. This standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

Risk Management

EnCana's business, prospects, financial condition, results of operation and cash flows, and in some cases its reputation, are impacted by risks that are categorized as follows:

- financial risks including market risks (such as commodity price, foreign exchange and interest rates), credit and liquidity;
- operational risks including capital, operating and reserves replacement risks; and
- safety, environmental and regulatory risks.

EnCana takes a proactive approach in identifying and managing risks that can affect the Company. Mitigation of these risks include, but are not limited to, the use of financial instruments and physical contracts, credit policies, operational policies, maintaining adequate insurance, environmental and safety policies as well as policies and enforcement procedures that can affect EnCana's reputation. Further discussion regarding the specific risks and mitigation of these risks can be found in the December 31, 2008 Management's Discussion and Analysis and Note 16 to the Interim Consolidated Financial Statements.

Climate Change

A number of federal, provincial and state governments have announced intentions to regulate greenhouse gases ("GHG") and other air pollutants while some jurisdictions have provided details on these regulations. It is anticipated that other jurisdictions will announce emissions reduction plans in the future. As these federal and regional programs are under development, EnCana is unable to predict the total impact of the potential regulations upon its business. Therefore, it is possible that the Company could face increases in operating and capital costs in order to comply with GHG emissions legislation. However, EnCana will continue to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

The Alberta Government has set targets for GHG emissions reductions. In March 2007, regulations were amended to require facilities that emit more than 100,000 tonnes of GHG emissions per year to reduce their emissions intensity by 12 percent from a regulated baseline starting July 1, 2007. To comply, companies can make operating improvements, purchase carbon offsets or make a C$15 per tonne contribution to an Alberta Climate Change and Emissions Management Fund. In Alberta, EnCana has four facilities covered under the emissions regulations. The forecast cost of carbon associated with the Alberta regulations is not material to EnCana at this time and is being actively managed.

In British Columbia, effective July 1, 2008, a 'revenue neutral carbon tax' will be applied to virtually all fossil fuels, including diesel, natural gas, coal, propane, and home heating fuel. The tax applies to combustion emissions and to the purchase or use of fossil fuels within the province. The rate starts at C$10 per tonne of carbon equivalent emissions, rising by C$5 per tonne a year for the next four years. The forecast cost of carbon associated with the British Columbia regulations is not material to EnCana at this time and is being actively managed.

EnCana intends to continue its activity to reduce its emissions intensity and improve its energy efficiency. The Company's efforts with respect to emissions management are founded on the following key elements:

- significant production weighting in natural gas;
- recognition as an industry leader in CO_2 sequestration;
- focus on energy efficiency and the development of technology to reduce GHG emissions;
- involvement in the creation of industry best practices; and
- industry leading steam to oil ratio, which translates directly into lower emissions intensity.

EnCana's strategy for addressing the implications of emerging carbon regulations is proactive and is composed of three principal elements:

1. Manage Existing Costs
   When regulations are implemented, a cost is placed on EnCana's emissions (or a portion thereof) and while these are not material at this stage, they are being actively managed to ensure compliance. Factors such as effective emissions tracking, attention to fuel consumption, and a focus on minimizing the Company's steam to oil ratio help to support and drive its focus on cost reduction.
2. Respond to Price Signals
   As regulatory regimes for GHGs develop in the jurisdictions where EnCana works, inevitably price signals begin to emerge. The Company has initiated an Energy Efficiency Initiative in an effort to improve the energy efficiency of its operations. The price of potential carbon reductions plays a role in the economics of the projects that are implemented. In response to the anticipated price of carbon, EnCana is also attempting, where appropriate, to realize the associated value of its reduction projects.
3. Anticipate Future Carbon Constrained Scenarios
   EnCana continues to work with governments, academics and industry leaders to develop and respond to emerging GHG regulations. By continuing to stay engaged in the debate on the most appropriate means to regulate these emissions, the Company gains useful knowledge that allows it to explore different strategies for managing its emissions and costs. These scenarios inform EnCana's long range planning and its analyses on the implications of regulatory trends.

EnCana incorporates the potential costs of carbon into future planning. Management and the Board review the impact of a variety of carbon constrained scenarios on its strategy, with a current price range from $15 to $65 per tonne of emissions applied to a range of emissions coverage levels. A major benefit of applying a range of carbon prices at the strategic level is that it provides direct guidance to the capital allocation process. EnCana also examines the impact of carbon regulation on its major projects. Although uncertainty remains regarding potential future emissions regulation, EnCana's plan is to continue to assess and evaluate the cost of carbon relative to its investments across a range of scenarios.

EnCana recognizes that there is a cost associated with carbon emissions. EnCana is confident that greenhouse gas regulations and the cost of carbon at various price levels have been adequately considered as part of its business planning and scenarios analysis. EnCana believes that the resource play strategy is an effective way to develop the resource, generate shareholder returns and coordinate overall environmental objectives with respect to carbon, air emissions, water and land. EnCana is committed to transparency with its stakeholders and will keep them apprised of how these issues affect operations. Additional detail on EnCana's GHG emissions is available in the Corporate Responsibility Report that is available on the Company's website at www.encana.com.

Alberta's New Royalty Programs

On October 25, 2007, the Alberta Government announced the New Royalty Framework ("NRF"). The NRF established new royalties for conventional oil, natural gas and bitumen that are linked to commodity prices, well production volumes and well depths for gas wells and oil quality for oil wells. These new rates apply to both new and existing conventional oil and gas activities and oil sands projects in Alberta. The changes introduced by the NRF became effective as of January 1, 2009.

The NRF established new price-sensitive and volume-sensitive rates for conventional oil that range up to 50 percent with the price sensitivity topping out between C$68 and C$116 per barrel dependent on the well productivity, and for natural gas that range from 5 percent to 50 percent with the price sensitivity topping out between C$9.92 and C$17.75 per gigajoule. On November 19, 2008, the Alberta Government introduced the Transitional Royalty Program ("TRP"), which allows for a one time option of selecting between transitional rates and the NRF rates on new natural gas or conventional oil wells drilled between 1,000 metres to 3,500 metres in depth. These would apply until January 1, 2014, at which time all wells would be moved to the NRF. In addition, the NRF introduces royalty rates for bitumen that range from 1 percent to 9 percent (before payout) and from 25 percent to 40 percent (after payout) with rate caps at C$120 WTI per barrel.

On March 3, 2009, the Alberta Government announced an Energy Incentive Program that focuses on keeping drilling and service crews at work. There are two components of this program that affect EnCana; the Drilling Royalty Credit and New Well Incentive. The Drilling Royalty Credit is a depth related credit for the drilling of new conventional oil and gas wells between April 1, 2009 and April 1, 2010. The New Well Incentive provides a 5 percent royalty rate for new gas and conventional oil wells that come on production between April 1, 2009 and March 31, 2010 for a period of 12 months or 0.5 billion cubic feet equivalent ("Bcfe") for gas wells or 50,000 barrels of oil equivalent ("BOE") for oil wells, whichever comes first.

Impacts as a result of the NRF, TRP and Energy Incentive Programs change the economics of operating in Alberta, and accordingly, are reflected in EnCana's capital programs.

Outlook

During the current challenging economic environment, EnCana is highly focused on the key business objectives of maintaining financial strength, generating significant free cash flow, further optimizing capital investments and continuing to pay a stable dividend to shareholders.

EnCana monitors the risks under its control and has policies in place to mitigate those risks. EnCana is managing commodity price risk through its financial risk management program designed to help ensure financial resilience and flexibility and is closely monitoring interest, credit and counterparty risk. In addition, the Company continues to monitor expenses and capital programs and maintain flexibility to adjust to changing economic circumstances. EnCana has planned a conservative, prudent and flexible capital program in 2009 that currently targets total natural gas and oil production at approximately 2008 levels and advances the Company's multi-year projects. EnCana expects to continue to fund the Foster Creek and Christina Lake expansion projects, Wood River CORE project and other capital projects at the present time. EnCana targets a Debt to Capitalization ratio of between 30 and 40 percent and a Debt to Adjusted EBITDA multiple of 1.0 to 2.0 times. At March 31, 2009, the Company's Debt to Capitalization ratio was 29 percent and Debt to Adjusted EBITDA was 0.7x.

Natural gas prices are primarily driven by North American supply and demand, with weather being the key factor in the short term. EnCana believes that North American conventional gas supply has peaked and that unconventional resource plays can offset conventional gas production declines.

Volatility in crude oil prices is expected to continue throughout 2009 as a result of market uncertainties over supply and refining, changes in demand due to the overall state of the world economies, OPEC actions and the worldwide credit and liquidity crisis. Canadian crude oil prices will face added uncertainty due to the risk of refinery disruptions in an already tight United States Midwest market and growing domestic production could result in pipeline constraints out of Western Canada.

The Company expects its 2009 capital investment program to be funded from Cash Flow.

EnCana plans to focus on growing natural gas production from its diversified portfolio of existing and emerging unconventional resource plays in North America, developing its high quality in-situ oil resources and expanding its downstream heavy oil processing capacity through its joint venture with ConocoPhillips.

EnCana's results are affected by external market and risk factors, such as fluctuations in the prices of crude oil and natural gas, movements in foreign currency exchange rates and inflationary pressures on service costs. Additional detail regarding the impact of these factors on EnCana's 2009 results is available in the Corporate Guidance on the Company's website at www.encana.com. EnCana updated its Corporate Guidance to reflect the impact on operations of expected conditions for 2009. EnCana's news release dated April 22, 2009 and financial statements are available on www.sedar.com.

Advisory

FORWARD-LOOKING STATEMENTS

In the interest of providing EnCana shareholders and potential investors with information regarding the Company and its subsidiaries, including Management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this document constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this document include, but are not limited to, statements with respect to: projections relating to the adequacy of the Company's provision for taxes; the potential impact of the Alberta Royalty Framework; projections with respect to natural gas production from unconventional resource plays and in-situ oil resources including with respect to the Foster Creek and Christina Lake projects, the CORE project and planned expansions of the Company's downstream heavy oil processing capacity and the capital costs and expected timing of the same; the projected impact of regulatory issues; projections relating to the volatility of crude oil prices in 2009 and beyond and the reasons therefor; the Company's projected capital investment levels for 2009, the flexibility of capital spending plans and the source of funding therefor; the effect of the Company's risk management program, including the impact of derivative financial instruments; the Company's defence of lawsuits; the impact of the changes and proposed changes in laws and regulations, including greenhouse gas, carbon and climate change initiatives on the Company's operations and operating costs; the impact of Western Canada pipeline constraints and potential refinery disruptions on future Canadian crude oil prices; projections that the Company's Bankers' Acceptances and Commercial Paper Program will continue to be fully supported by committed credit facilities and term loan facilities; the Company's continued compliance with financial covenants under its credit facilities; projections relating to the Company's natural gas, crude oil and natural gas liquids reserves; the Company's plans to renew its Canadian debt shelf prospectus; the Company's assessment of counterparty credit risk and the potential impact thereof; the Company's ability to fund its 2009 capital program and pay dividends to shareholders; the impact of the current business market conditions, including the economic recession and financial market turmoil on the Company's operations and expected results; the effect of the Company's risk mitigation policies, systems, processes and insurance program; the Company's expectations for future Debt to Capitalization ratios; the expected impact and timing of various accounting pronouncements, rule changes and standards on the Company and its Consolidated Financial Statements; projected costs of payouts under the Company's Performance Tandem Share Appreciation Rights, Performance Share Appreciation Rights and Performance Share Units programs; and projections relating to North American conventional natural gas supplies and the ability of unconventional resource plays to offset future conventional gas production declines and the Company's continued ability to meet payment terms with suppliers. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of and assumptions regarding oil and gas prices; assumptions based upon EnCana's current guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company's and its subsidiaries' marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, bitumen, natural gas and liquids from resource plays and other sources not currently classified as proved; the Company's and its subsidiaries' ability to replace and expand oil and gas reserves; the ability of the Company and ConocoPhillips to successfully manage and operate the North American integrated heavy oil business and the ability of the parties to obtain necessary regulatory approvals; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining synthetic crude oil; risks associated with technology and the application thereof to the business of the Company; the Company's ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company's ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's and its subsidiaries' ability to secure adequate product transportation; changes in royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations or the interpretations of such laws or regulations;

political and economic conditions in the countries in which the Company and its subsidiaries operate; the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company and its subsidiaries operate and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company and its subsidiaries; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Statements relating to "reserves" or "resources" or "resource potential" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this document are made as of the date of this document, and except as required by law, EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

Forward-looking information respecting anticipated 2009 cash flow, operating cash flow and pre-tax cash flow for EnCana is based upon achieving average production of oil and gas for 2009 of approximately 4.5 to 4.7 Bcfe/d, average commodity prices for 2009 of a WTI price of $55/bbl to $75/bbl for oil, a NYMEX price of $5.50/Mcf to $7.50/Mcf for natural gas, an average U.S./Canadian dollar foreign exchange rate of $0.75 to $0.85, an average Chicago 3-2-1 crack spread for 2009 of $5.00/bbl to $10.00/bbl for refining margins, and an average number of outstanding shares for EnCana of approximately 750 million. Assumptions relating to forward-looking statements generally include EnCana's current expectations and projections made by the Company in light of, and generally consistent with, its historical experience and its perception of historical trends, as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this document.

EnCana is required to disclose events and circumstances that occurred during the period to which this MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking statements for a period that is not yet complete that EnCana has previously disclosed to the public and the expected differences thereto. Such disclosure can be found in EnCana's news release dated April 22, 2009, which is available on EnCana's website at www.encana.com and on SEDAR at www.sedar.com.

OIL AND GAS INFORMATION

EnCana's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to EnCana by Canadian securities regulatory authorities that permits it to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by EnCana may differ from the corresponding information prepared in accordance with Canadian disclosure standards under NI 51-101. The reserves quantities disclosed by EnCana represent net proved reserves calculated using the standards contained in Regulation S-X of the U.S. Securities and Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in EnCana's Annual Information Form.

Crude Oil, NGLs and Natural Gas Conversions

In this document, certain crude oil and NGLs volumes have been converted to millions of cubic feet equivalent ("MMcfe") or thousands of cubic feet equivalent ("Mcfe") on the basis of one barrel ("bbl") to six thousand cubic feet ("Mcf"). Also, certain natural gas volumes have been converted to barrels of oil equivalent ("BOE"), thousands of BOE ("MBOE") or millions of BOE ("MMBOE") on the same basis. MMcfe, Mcfe, BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the well head.

Resource Play

Resource play is a term used by EnCana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate.

CURRENCY, NON-GAAP MEASURES AND REFERENCES TO ENCANA

All information included in this document and the Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after royalties basis unless otherwise noted.

Non-GAAP Measures

Certain measures in this document do not have any standardized meaning as prescribed by Canadian GAAP such as Cash Flow, Cash Flow per share – diluted, Free Cash Flow, Operating Earnings, Operating Earnings per share – diluted, Adjusted EBITDA, Debt, Net Debt and Capitalization and therefore are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Management's use of these measures has been disclosed further in this document as these measures are discussed and presented.

References to EnCana

For convenience, references in this document to "EnCana", the "Company", "we", "us", "our" and "its" may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships ("Subsidiaries") of EnCana Corporation, and the assets, activities and initiatives of such Subsidiaries.

ADDITIONAL INFORMATION

Further information regarding EnCana Corporation can be accessed under the Company's public filings found at www.sedar.com and on the Company's website at www.encana.com.

CONSOLIDATED STATEMENT OF EARNINGS *(unaudited)*

($ millions, except per share amounts)		Three Months Ended March 31, 2009	2008
REVENUES, NET OF ROYALTIES	*(Note 4)*	**$ 4,608**	$ 5,434
EXPENSES	*(Note 4)*		
Production and mineral taxes		**61**	114
Transportation and selling		**293**	412
Operating		**553**	696
Purchased product		**1,209**	2,393
Depreciation, depletion and amortization		**983**	1,035
Administrative		**85**	156
Interest, net	*(Note 6)*	**104**	134
Accretion of asset retirement obligation	*(Note 11)*	**17**	21
Foreign exchange (gain) loss, net	*(Note 7)*	**58**	95
(Gain) loss on divestitures	*(Note 5)*	**(1)**	-
		3,362	5,056
NET EARNINGS BEFORE INCOME TAX		**1,246**	378
Income tax expense	*(Note 8)*	**284**	285
NET EARNINGS		**$ 962**	$ 93
NET EARNINGS PER COMMON SHARE	*(Note 15)*		
Basic		**$ 1.28**	$ 0.12
Diluted		**$ 1.28**	$ 0.12

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(unaudited)*

($ millions)		Three Months Ended March 31, 2009	2008
RETAINED EARNINGS, BEGINNING OF YEAR		**$ 17,584**	$ 13,082
Net Earnings		**962**	93
Dividends on Common Shares		**(300)**	(300)
Charges for Normal Course Issuer Bid	*(Note 12)*	**-**	(229)
RETAINED EARNINGS, END OF PERIOD		**$ 18,246**	$ 12,646

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME *(unaudited)*

($ millions)	Three Months Ended March 31, 2009	2008
NET EARNINGS	**$ 962**	$ 93
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Foreign Currency Translation Adjustment	**(271)**	(400)
COMPREHENSIVE INCOME	**$ 691**	$ (307)

CONSOLIDATED STATEMENT OF ACCUMULATED OTHER COMPREHENSIVE INCOME *(unaudited)*

($ millions)	Three Months Ended March 31, 2009	2008
ACCUMULATED OTHER COMPREHENSIVE INCOME, BEGINNING OF YEAR	**$ 833**	$ 3,063
Foreign Currency Translation Adjustment	**(271)**	(400)
ACCUMULATED OTHER COMPREHENSIVE INCOME, END OF PERIOD	**$ 562**	$ 2,663

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET *(unaudited)*

($ millions)		**As at March 31, 2009**	As at December 31, 2008
ASSETS			
Current Assets			
Cash and cash equivalents		**$ 629**	$ 383
Accounts receivable and accrued revenues		**1,360**	1,568
Current portion of partnership contribution receivable		**317**	313
Risk management	*(Note 16)*	**3,038**	2,818
Inventories	*(Note 9)*	**536**	520
		5,880	5,602
Property, Plant and Equipment, net	*(Note 4)*	**35,657**	35,424
Investments and Other Assets		**862**	727
Partnership Contribution Receivable		**2,753**	2,834
Risk Management	*(Note 16)*	**63**	234
Goodwill		**2,370**	2,426
	(Note 4)	**$ 47,585**	$ 47,247
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 2,482**	$ 2,871
Income tax payable		**366**	424
Current portion of partnership contribution payable		**310**	306
Risk management	*(Note 16)*	**18**	43
Current portion of long-term debt	*(Note 10)*	**250**	250
		3,426	3,894
Long-Term Debt	*(Note 10)*	**9,192**	8,755
Other Liabilities		**745**	576
Partnership Contribution Payable		**2,778**	2,857
Risk Management	*(Note 16)*	**3**	7
Asset Retirement Obligation	*(Note 11)*	**1,238**	1,265
Future Income Taxes		**6,835**	6,919
		24,217	24,273
Shareholders' Equity			
Share capital	*(Note 12)*	**4,560**	4,557
Retained earnings		**18,246**	17,584
Accumulated other comprehensive income		**562**	833
Total Shareholders' Equity		**23,368**	22,974
		$ 47,585	$ 47,247

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*

($ millions)		Three Months Ended March 31, 2009	2008
OPERATING ACTIVITIES			
Net earnings		**$ 962**	$ 93
Depreciation, depletion and amortization		**983**	1,035
Future income taxes	*(Note 8)*	**37**	(79)
Unrealized (gain) loss on risk management	*(Note 16)*	**(111)**	1,093
Unrealized foreign exchange (gain) loss		**20**	76
Accretion of asset retirement obligation	*(Note 11)*	**17**	21
(Gain) loss on divestitures	*(Note 5)*	**(1)**	-
Other		**37**	150
Net change in other assets and liabilities		**14**	(93)
Net change in non-cash working capital		**(127)**	(538)
Cash From Operating Activities		**1,831**	1,758
INVESTING ACTIVITIES			
Capital expenditures	*(Note 4)*	**(1,587)**	(1,907)
Proceeds from divestitures	*(Note 5)*	**33**	72
Net change in investments and other		**(142)**	9
Net change in non-cash working capital		**(92)**	292
Cash (Used in) Investing Activities		**(1,788)**	(1,534)
FINANCING ACTIVITIES			
Net issuance (repayment) of revolving long-term debt		**505**	(59)
Issuance of long-term debt	*(Note 10)*	**-**	723
Issuance of common shares	*(Note 12)*	**2**	63
Purchase of common shares	*(Note 12)*	**-**	(311)
Dividends on common shares		**(300)**	(300)
Cash From (Used in) Financing Activities		**207**	116
FOREIGN EXCHANGE GAIN (LOSS) ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		**(4)**	(4)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		**246**	336
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR		**383**	553
CASH AND CASH EQUIVALENTS, END OF PERIOD		**$ 629**	$ 889

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements *(unaudited)*
(All amounts in $ millions unless otherwise specified)

1. BASIS OF PRESENTATION

The interim Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries ("EnCana" or the "Company"), and are presented in accordance with Canadian generally accepted accounting principles ("GAAP"). EnCana's operations are in the business of the exploration for, the development of, and the production and marketing of natural gas, crude oil and natural gas liquids ("NGLs"), refining operations and power generation operations.

The interim Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as the annual audited Consolidated Financial Statements for the year ended December 31, 2008, except as noted below. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements. The interim Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2008.

2. CHANGES IN ACCOUNTING POLICIES AND PRACTICES

On January 1, 2009, the Company adopted the following Canadian Institute of Chartered Accountants ("CICA") Handbook Section:

- "Goodwill and Intangible Assets", Section 3064. The new standard replaces the previous goodwill and intangible asset standard and revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard has had no material impact on EnCana's Consolidated Financial Statements.

3. RECENT ACCOUNTING PRONOUNCEMENTS

In February 2008, the CICA's Accounting Standards Board confirmed that International Financial Reporting Standards ("IFRS") will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. EnCana will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information. The impact of IFRS on the Company's Consolidated Financial Statements is not reasonably determinable at this time.

As of January 1, 2011, EnCana will be required to adopt the following CICA Handbook sections:

- "Business Combinations", Section 1582, which replaces the previous business combinations standard. The standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the statement of earnings. The adoption of this standard will impact the accounting treatment of future business combinations.

- "Consolidated Financial Statements", Section 1601, which together with Section 1602 below, replace the former consolidated financial statements standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

- "Non-controlling Interests", Section 1602. The standard establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. This standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this standard should not have a material impact on EnCana's Consolidated Financial Statements.

Notes to Consolidated Financial Statements *(unaudited)*
(All amounts in $ millions unless otherwise specified)

4. SEGMENTED INFORMATION

The Company's operating and reportable segments are as follows:

- **Canada** includes the Company's exploration for, and development and production of natural gas, crude oil and NGLs and other related activities within the Canadian cost centre.
- **USA** includes the Company's exploration for, and development and production of natural gas, NGLs and other related activities within the United States cost centre.
- **Downstream Refining** is focused on the refining of crude oil into petroleum and chemical products at two refineries located in the United States. The refineries are jointly owned with ConocoPhillips.
- **Market Optimization** is primarily responsible for the sale of the Company's proprietary production. These results are included in the Canada and USA segments. Market optimization activities include third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment.
- **Corporate and Other** mainly includes unrealized gains or losses recorded on derivative financial instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

Market Optimization sells substantially all of the Company's upstream production to third-party customers. Transactions between segments are based on market values and eliminated on consolidation. The tables in this note present financial information on an after eliminations basis.

On December 31, 2008, EnCana updated its segmented reporting to present the upstream Canadian and United States cost centres and Downstream Refining as separate reportable segments. This resulted in EnCana presenting the Canadian portion of the Integrated Oil Division as part of the Canada segment. Previously, this was aggregated and presented in the Integrated Oil segment. Prior periods have been restated to reflect the new presentation.

EnCana has a decentralized decision making and reporting structure. Accordingly, the Company is organized into Divisions as follows:

- **Canadian Plains** Division includes natural gas and crude oil exploration, development and production assets located in eastern Alberta and Saskatchewan.
- **Canadian Foothills** Division includes natural gas exploration, development and production assets located in western Alberta and British Columbia as well as the Company's Canadian offshore assets.
- **USA** Division includes natural gas exploration, development and production assets located in the United States and comprises the USA segment described above.
- **Integrated Oil** Division is the combined total of Integrated Oil – Canada and Downstream Refining. Integrated Oil – Canada includes the Company's exploration for, and development and production of bitumen using enhanced recovery methods. Integrated Oil – Canada is composed of EnCana's interests in the FCCL Oil Sands Partnership jointly owned with ConocoPhillips, the Athabasca natural gas assets and other bitumen interests.

Notes to Consolidated Financial Statements *(unaudited)*
(All amounts in $ millions unless otherwise specified)

4. SEGMENTED INFORMATION (continued)

Results of Operations (For the three months ended March 31)

Segment and Geographic Information

	Canada		USA		Downstream Refining	
	2009	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 1,883**	$ 2,503	**$ 1,174**	$ 1,354	**$ 926**	$ 2,046
Expenses						
Production and mineral taxes	**15**	18	**46**	96	**-**	-
Transportation and selling	**170**	297	**123**	115	**-**	-
Operating	**286**	384	**115**	169	**118**	132
Purchased product	**(13)**	(35)	**-**	-	**749**	1,821
	1,425	1,839	**890**	974	**59**	93
Depreciation, depletion and amortization	**484**	569	**416**	397	**51**	44
Segment Income (Loss)	**$ 941**	$ 1,270	**$ 474**	$ 577	**$ 8**	$ 49

	Market Optimization		Corporate & Other		Consolidated	
	2009	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 492**	$ 625	**$ 133**	$ (1,094)	**$ 4,608**	$ 5,434
Expenses						
Production and mineral taxes	**-**	-	**-**	-	**61**	114
Transportation and selling	**-**	-	**-**	-	**293**	412
Operating	**8**	11	**26**	-	**553**	696
Purchased product	**473**	607	**-**	-	**1,209**	2,393
	11	7	**107**	(1,094)	**2,492**	1,819
Depreciation, depletion and amortization	**5**	4	**27**	21	**983**	1,035
Segment Income (Loss)	**$ 6**	$ 3	**$ 80**	$ (1,115)	**1,509**	784
Administrative					**85**	156
Interest, net					**104**	134
Accretion of asset retirement obligation					**17**	21
Foreign exchange (gain) loss, net					**58**	95
(Gain) loss on divestitures					**(1)**	-
					263	406
Net Earnings Before Income Tax					**1,246**	378
Income tax expense					**284**	285
Net Earnings					**$ 962**	$ 93

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. SEGMENTED INFORMATION (continued)

Results of Operations (For the three months ended March 31)

Product and Divisional Information

Canada Segment	Canadian Plains		Canadian Foothills		Integrated Oil - Canada		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 775**	$ 1,141	**$ 915**	$ 1,075	**$ 193**	$ 287	**$ 1,883**	$ 2,503
Expenses								
Production and mineral taxes	**10**	13	**5**	4	**-**	1	**15**	18
Transportation and selling	**62**	109	**37**	56	**71**	132	**170**	297
Operating	**103**	142	**130**	178	**53**	64	**286**	384
Purchased product	**-**	-	**-**	-	**(13)**	(35)	**(13)**	(35)
Operating Cash Flow	**$ 600**	$ 877	**$ 743**	$ 837	**$ 82**	$ 125	**$ 1,425**	$ 1,839

Canadian Plains Division	Gas		Oil & NGLs		Other		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 521**	$ 590	**$ 252**	$ 549	**$ 2**	$ 2	**$ 775**	$ 1,141
Expenses								
Production and mineral taxes	**3**	5	**7**	8	**-**	-	**10**	13
Transportation and selling	**11**	19	**51**	90	**-**	-	**62**	109
Operating	**51**	73	**51**	68	**1**	1	**103**	142
Operating Cash Flow	**$ 456**	$ 493	**$ 143**	$ 383	**$ 1**	$ 1	**$ 600**	$ 877

Canadian Foothills Division	Gas		Oil & NGLs		Other		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 848**	$ 909	**$ 57**	$ 148	**$ 10**	$ 18	**$ 915**	$ 1,075
Expenses								
Production and mineral taxes	**4**	3	**1**	1	**-**	-	**5**	4
Transportation and selling	**34**	53	**3**	3	**-**	-	**37**	56
Operating	**120**	161	**6**	11	**4**	6	**130**	178
Operating Cash Flow	**$ 690**	$ 692	**$ 47**	$ 133	**$ 6**	$ 12	**$ 743**	$ 837

USA Division	Gas		Oil & NGLs		Other		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 1,118**	$ 1,183	**$ 29**	$ 99	**$ 27**	$ 72	**$ 1,174**	$ 1,354
Expenses								
Production and mineral taxes	**43**	87	**3**	9	**-**	-	**46**	96
Transportation and selling	**123**	115	**-**	-	**-**	-	**123**	115
Operating	**82**	101	**-**	-	**33**	68	**115**	169
Operating Cash Flow	**$ 870**	$ 880	**$ 26**	$ 90	**$ (6)**	$ 4	**$ 890**	$ 974

Integrated Oil Division	Oil *		Downstream Refining		Other *		Total	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008
Revenues, Net of Royalties	**$ 163**	$ 238	**$ 926**	$ 2,046	**$ 30**	$ 49	**$ 1,119**	$ 2,333
Expenses								
Production and mineral taxes	**-**	-	**-**	-	**-**	1	**-**	1
Transportation and selling	**66**	120	**-**	-	**5**	12	**71**	132
Operating	**40**	41	**118**	132	**13**	23	**171**	196
Purchased product	**-**	-	**749**	1,821	**(13)**	(35)	**736**	1,786
Operating Cash Flow	**$ 57**	$ 77	**$ 59**	$ 93	**$ 25**	$ 48	**$ 141**	$ 218

* Oil and Other comprise Integrated Oil - Canada. Other includes production of natural gas and bitumen from the Athabasca and Senlac properties.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. SEGMENTED INFORMATION (continued)

Capital Expenditures

	Three Months Ended March 31, 2009	2008
Capital		
Canadian Plains	**$ 159**	$ 262
Canadian Foothills	**465**	780
Integrated Oil - Canada	**126**	208
Canada	**750**	1,250
USA	**540**	519
Downstream Refining	**202**	55
Market Optimization	**(3)**	2
Corporate & Other	**19**	23
	1,508	1,849
Acquisition Capital		
Canadian Foothills	**73**	72
USA *	**6**	(14)
	79	58
Total	**$ 1,587**	$ 1,907

* 2008 includes purchase price adjustments for the November 2007 Leor acquisition in East Texas.

On September 25, 2008, EnCana acquired certain land and property in Louisiana for approximately $101 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Haynesville Leasehold LLC ("Brown Haynesville"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. The relationship with Brown Haynesville represented an interest in a variable interest entity ("VIE") from September 25, 2008 to March 24, 2009. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Haynesville. On March 24, 2009, when the arrangement with Brown Haynesville was completed, the assets were transferred to EnCana.

On July 23, 2008, EnCana acquired certain land and mineral interests in Louisiana for approximately $457 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Southwest Minerals LLC ("Brown Southwest"), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. On November 12, 2008, an unrelated party exercised an option to purchase certain interests as part of the above acquisition for approximately $157 million, reducing the qualifying like kind exchange to approximately $300 million. The relationship with Brown Southwest represented an interest in a VIE from July 23, 2008 to January 19, 2009. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Southwest. On January 19, 2009, when the arrangement with Brown Southwest was completed, the assets were transferred to EnCana.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. SEGMENTED INFORMATION (continued)

Property, Plant and Equipment and Total Assets by Segment

	Property, Plant and Equipment		Total Assets	
	As at		As at	
	March 31, 2009	December 31, 2008	**March 31, 2009**	December 31, 2008
Canada	**$ 16,976**	$ 17,082	**$ 23,248**	$ 23,419
USA	**13,669**	13,541	**14,696**	14,635
Downstream Refining	**4,189**	4,032	**4,752**	4,637
Market Optimization	**129**	140	**391**	429
Corporate & Other	**694**	629	**4,498**	4,127
Total	**$ 35,657**	$ 35,424	**$ 47,585**	$ 47,247

On February 9, 2007, EnCana announced that it had entered into a 25 year lease agreement with a third party developer for The Bow office project. As at March 31, 2009, Corporate and Other Property, Plant and Equipment and Total Assets includes EnCana's accrual to date of $323 million ($252 million at December 31, 2008) related to this office project as an asset under construction.

On January 4, 2008, EnCana signed the contract for the design and construction of the Production Field Centre ("PFC") for the Deep Panuke project. As at March 31, 2009, Canada Property, Plant, and Equipment and Total Assets includes EnCana's accrual to date of $280 million ($199 million at December 31, 2008) related to this offshore facility as an asset under construction.

Corresponding liabilities for these projects are included in Other Liabilities in the Consolidated Balance Sheet. There is no effect on the Company's net earnings or cash flows related to the capitalization of The Bow office project or the Deep Panuke PFC.

5. DIVESTITURES

Total year-to-date proceeds received on the sale of assets were $33 million (2008 - $72 million). The significant items are described below.

Canada

In 2009, the Company completed the divestiture of mature conventional oil and natural gas assets for proceeds of $33 million (2008 - $61 million) in Canadian Foothills and did not complete any divestitures in Canadian Plains (2008 - $31 million).

6. INTEREST, NET

	Three Months Ended March 31,	
	2009	2008
Interest Expense - Long-Term Debt	**$ 118**	$ 140
Interest Expense - Other *	**39**	54
Interest Income *	**(53)**	(60)
	$ 104	$ 134

* Interest Expense - Other and Interest Income are primarily due to the Partnership Contribution Payable and Receivable, respectively.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three Months Ended March 31, 2009	2008
Unrealized Foreign Exchange (Gain) Loss on:		
Translation of U.S. dollar debt issued from Canada *	**$ 150**	$ 217
Translation of U.S. dollar partnership contribution receivable issued from Canada *	**(87)**	(143)
Other Foreign Exchange (Gain) Loss	**(5)**	21
	$ 58	$ 95

* Reflects the current year change in foreign exchange rates calculated on the period end balance.

8. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended March 31, 2009	2008
Current		
Canada	**$ 172**	$ 234
United States	**76**	129
Other Countries	**(1)**	1
Total Current Tax	**247**	364
Future	**37**	(79)
	$ 284	$ 285

9. INVENTORIES

	As at March 31, 2009	As at December 31, 2008
Product		
Canada	**$ 55**	$ 46
USA	**11**	8
Downstream Refining	**333**	323
Market Optimization	**123**	127
Parts and Supplies	**14**	16
	$ 536	$ 520

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

10. LONG-TERM DEBT

		As at March 31, 2009		As at December 31, 2008
Canadian Dollar Denominated Debt				
Revolving credit and term loan borrowings	**$**	**1,745**	$	1,410
Unsecured notes		**992**		1,020
		2,737		2,430
U.S. Dollar Denominated Debt				
Revolving credit and term loan borrowings		**377**		247
Unsecured notes		**6,350**		6,350
		6,727		6,597
Increase in Value of Debt Acquired		**46**		49
Debt Discounts and Financing Costs		**(68)**		(71)
Current Portion of Long-Term Debt		**(250)**		(250)
	$	**9,192**	$	8,755

11. ASSET RETIREMENT OBLIGATION

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas assets and refining facilities:

		As at March 31, 2009		As at December 31, 2008
Asset Retirement Obligation, Beginning of Year	**$**	**1,265**	$	1,458
Liabilities Incurred		**7**		54
Liabilities Settled		**(15)**		(115)
Liabilities Divested		**-**		(38)
Change in Estimated Future Cash Flows		**(8)**		54
Accretion Expense		**17**		79
Foreign Currency Translation		**(28)**		(227)
Asset Retirement Obligation, End of Period	**$**	**1,238**	$	1,265

12. SHARE CAPITAL

	March 31, 2009			December 31, 2008		
(millions)	**Number**		**Amount**	Number		Amount
Common Shares Outstanding, Beginning of Year	**750.4**	**$**	**4,557**	750.2	$	4,479
Common Shares Issued under Option Plans	**0.2**		**2**	3.0		80
Stock-Based Compensation	**-**		**1**	-		11
Common Shares Purchased	**-**		**-**	(2.8)		(13)
Common Shares Outstanding, End of Period	**750.6**	**$**	**4,560**	750.4	$	4,557

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

12. SHARE CAPITAL (continued)

Normal Course Issuer Bid

EnCana has received regulatory approval each year under Canadian securities laws to purchase Common Shares under seven consecutive Normal Course Issuer Bids ("Bids"). EnCana is entitled to purchase, for cancellation, up to approximately 75.0 million Common Shares under the renewed Bid which commenced on November 13, 2008 and terminates on November 12, 2009. To March 31, 2009 there have been no purchases under the current bid (2008 - 4.6 million Common Shares for approximately $311 million).

Stock Options

EnCana has stock-based compensation plans that allow employees to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were granted. Options granted under the plans are generally fully exercisable after three years and expire five years after the date granted. Options granted under predecessor and/or related company replacement plans expire up to 10 years from the date the options were granted.

The following tables summarize the information related to options to purchase Common Shares that do not have Tandem Share Appreciation Rights ("TSARs") attached to them at March 31, 2009. Information related to TSARs is included in Note 14.

	Stock Options *(millions)*	**Weighted Average Exercise Price *(C$)***
Outstanding, Beginning of Year	**0.5**	**11.62**
Exercised	**(0.2)**	**11.57**
Outstanding, End of Period	**0.3**	**11.78**
Exercisable, End of Period	**0.3**	**11.78**

	Outstanding Options			**Exercisable Options**	
Range of Exercise Price (C$)	Number of Options Outstanding *(millions)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *(C$)*	Number of Options Outstanding *(millions)*	Weighted Average Exercise Price *(C$)*
11.50 to 14.50	0.3	0.9	11.78	0.3	11.78

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

13. CAPITAL STRUCTURE

The Company's capital structure is comprised of Shareholders' Equity plus Long-Term Debt. The Company's objectives when managing its capital structure are to:

i) maintain financial flexibility to preserve EnCana's access to capital markets and its ability to meet its financial obligations; and
ii) finance internally generated growth as well as potential acquisitions.

The Company monitors its capital structure and short-term financing requirements using non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"). These metrics are used to steward the Company's overall debt position as measures of the Company's overall financial strength.

EnCana targets a Debt to Capitalization ratio of between 30 and 40 percent. At March 31, 2009, EnCana's Debt to Capitalization ratio was 29 percent (December 31, 2008 - 28 percent) calculated as follows:

	As at	
	March 31, 2009	December 31, 2008
Debt	**$ 9,442**	$ 9,005
Total Shareholders' Equity	**23,368**	22,974
Total Capitalization	**$ 32,810**	$ 31,979
Debt to Capitalization ratio	**29%**	28%

EnCana targets a Debt to Adjusted EBITDA of 1.0 to 2.0 times. At March 31, 2009, Debt to Adjusted EBITDA was 0.7x (December 31, 2008 - 0.7x) calculated on a trailing twelve-month basis as follows:

	As at	
	March 31, 2009	December 31, 2008
Debt	**$ 9,442**	$ 9,005
Net Earnings	**$ 6,813**	$ 5,944
Add (deduct):		
Interest, net	**556**	586
Income tax expense	**2,632**	2,633
Depreciation, depletion and amortization	**4,171**	4,223
Accretion of asset retirement obligation	**75**	79
Foreign exchange (gain) loss, net	**386**	423
(Gain) loss on divestitures	**(141)**	(140)
Adjusted EBITDA	**$ 14,492**	$ 13,748
Debt to Adjusted EBITDA	**0.7x**	0.7x

EnCana has a long-standing practice of maintaining capital discipline, managing its capital structure and adjusting its capital structure according to market conditions to maintain flexibility while achieving the objectives stated above. To manage the capital structure, the Company may adjust capital spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt or repay existing debt.

The Company's capital management objectives, evaluation measures, definitions and targets have remained unchanged over the periods presented. EnCana is subject to certain financial covenants in its credit facility agreements and is in compliance with all financial covenants.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. COMPENSATION PLANS

The following tables outline certain information related to EnCana's compensation plans at March 31, 2009. Additional information is contained in Note 19 of the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2008.

A) Pensions

The following table summarizes the net benefit plan expense:

	Three Months Ended March 31, 2009	2008
Current Service Cost	**$ 4**	$ 4
Interest Cost	**5**	5
Expected Return on Plan Assets	**(4)**	(5)
Amortization of Net Actuarial Losses	**2**	1
Expected Amortization of Past Service Costs	**1**	1
Amortization of Transitional Obligation	**-**	(1)
Expense for Defined Contribution Plan	**11**	10
Net Benefit Plan Expense	**$ 19**	$ 15

For the period ended March 31, 2009, no contributions have been made to the defined benefit pension plans (2008 - nil).

B) Tandem Share Appreciation Rights ("TSARs")

The following table summarizes information related to the TSARs at March 31, 2009:

	Outstanding TSARs	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**19,411,939**	**53.97**
Granted	**3,904,660**	**55.30**
Exercised - SARs	**(166,067)**	**39.29**
Exercised - Options	**(38,754)**	**33.92**
Forfeited	**(139,795)**	**57.78**
Outstanding, End of Period	**22,971,983**	**54.32**
Exercisable, End of Period	**13,551,066**	**49.59**

For the period ended March 31, 2009, EnCana recorded a reduction of compensation costs of $18 million related to the outstanding TSARs (2008 - costs of $169 million).

C) Performance Tandem Share Appreciation Rights ("Performance TSARs")

The following table summarizes information related to the Performance TSARs at March 31, 2009:

	Outstanding TSARs	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**12,979,725**	**63.13**
Granted	**7,751,720**	**55.31**
Exercised - SARs	**(3,917)**	**56.09**
Forfeited	**(1,622,171)**	**62.87**
Outstanding, End of Period	**19,105,357**	**59.98**
Exercisable, End of Period	**3,955,358**	**60.38**

For the period ended March 31, 2009, EnCana recorded a reduction of compensation costs of $3 million related to the outstanding Performance TSARs (2008 - costs of $46 million).

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. COMPENSATION PLANS (continued)

D) Share Appreciation Rights ("SARs")

The following table summarizes information related to the SARs at March 31, 2009:

	Outstanding SARs	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**1,285,065**	**72.13**
Granted	**1,089,520**	**55.33**
Forfeited	**(20,400)**	**67.90**
Outstanding, End of Period	**2,354,185**	**64.39**
Exercisable, End of Period	**242,403**	**69.46**

For the period ended March 31, 2009, EnCana has not recorded any compensation costs related to the outstanding SARs (2008 - $1 million).

E) Performance Share Appreciation Rights ("Performance SARs")

The following table summarizes information related to the Performance SARs at March 31, 2009:

	Outstanding SARs	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**1,620,930**	**69.40**
Granted	**2,140,440**	**55.31**
Forfeited	**(199,071)**	**68.83**
Outstanding, End of Period	**3,562,299**	**60.97**
Exercisable, End of Period	**299,265**	**69.40**

For the period ended March 31, 2009, EnCana has not recorded any compensation costs related to the outstanding Performance SARs (2008 - $1 million).

F) Deferred Share Units ("DSUs")

The following table summarizes information related to the DSUs at March 31, 2009:

	Outstanding DSUs
Canadian Dollar Denominated	
Outstanding, Beginning of Year	**656,841**
Granted	**71,519**
Converted from HPR awards	**46,884**
Units, in Lieu of Dividends	**7,561**
Outstanding, End of Period	**782,805**

For the period ended March 31, 2009, EnCana has not recorded any compensation costs related to the outstanding DSUs (2008 - $12 million).

In 2009, employees had the option to convert either 25 or 50 percent of their annual High Performance Results ("HPR") award into DSUs. The number of DSUs is based on the value of the award divided by the closing value of EnCana's share price at the end of the performance period of the HPR award. DSUs vest immediately, can be redeemed in accordance with the terms of the agreement and expire on December 15 of the calendar year following the year of termination.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

15. PER SHARE AMOUNTS

The following table summarizes the Common Shares used in calculating Net Earnings per Common Share:

	Three Months Ended March 31,	
(millions)	**2009**	2008
Weighted Average Common Shares Outstanding - Basic	**750.5**	749.5
Effect of Dilutive Securities	**0.9**	3.5
Weighted Average Common Shares Outstanding - Diluted	**751.4**	753.0

16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

EnCana's financial assets and liabilities are comprised of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, the partnership contribution receivable and payable, risk management assets and liabilities, and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments. Fair values of financial assets and liabilities, summarized information related to risk management positions, and discussion of risks associated with financial assets and liabilities are presented as follows:

A) Fair Value of Financial Assets and Liabilities

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, and accounts payable and accrued liabilities approximate their carrying amount due to the short-term maturity of those instruments.

The fair values of the partnership contribution receivable and partnership contribution payable approximate their carrying amount due to the specific nature of these instruments in relation to the creation of the integrated oil joint venture. Further information about these notes is disclosed in Note 11 to the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2008.

Risk management assets and liabilities are recorded at their estimated fair value based on the mark-to-market method of accounting, using quoted market prices or, in their absence, third-party market indications and forecasts.

Long-term debt is carried at amortized cost using the effective interest method of amortization. The estimated fair values of long-term borrowings have been determined based on market information where available, or by discounting future payments of interest and principal at estimated interest rates expected to be available to the Company at period end.

The fair value of financial assets and liabilities were as follows:

	As at March 31, 2009		As at December 31, 2008	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets				
Held-for-Trading:				
Cash and cash equivalents	**$ 629**	**$ 629**	$ 383	$ 383
Risk management assets *	**3,101**	**3,101**	3,052	3,052
Loans and Receivables:				
Accounts receivable and accrued revenues	**1,360**	**1,360**	1,568	1,568
Partnership contribution receivable *	**3,070**	**3,070**	3,147	3,147
Financial Liabilities				
Held-for-Trading:				
Risk management liabilities *	**$ 21**	**$ 21**	$ 50	$ 50
Other Financial Liabilities:				
Accounts payable and accrued liabilities	**2,482**	**2,482**	2,871	2,871
Long-term debt *	**9,442**	**8,959**	9,005	8,242
Partnership contribution payable *	**3,088**	**3,088**	3,163	3,163

* Including current portion.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

B) Risk Management Assets and Liabilities

Net Risk Management Position	**As at March 31, 2009**	As at December 31, 2008
Risk Management		
Current asset	**$ 3,038**	$ 2,818
Long-term asset	**63**	234
	3,101	3,052
Risk Management		
Current liability	**18**	43
Long-term liability	**3**	7
	21	50
Net Risk Management Asset (Liability)	**$ 3,080**	$ 3,002

Summary of Unrealized Risk Management Positions

	As at March 31, 2009			As at December 31, 2008		
	Risk Management			Risk Management		
	Asset	**Liability**	**Net**	Asset	Liability	Net
Commodity Prices						
Natural gas	**$ 3,060**	**$ 4**	**$ 3,056**	$ 2,941	$ 10	$ 2,931
Crude oil	**35**	**17**	**18**	92	40	52
Power	**6**	**-**	**6**	19	-	19
Total Fair Value	**$ 3,101**	**$ 21**	**$ 3,080**	$ 3,052	$ 50	$ 3,002

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

	As at March 31, 2009	As at December 31, 2008
Prices actively quoted	**$ 2,291**	$ 2,055
Prices sourced from observable data or market corroboration	**789**	947
Total Fair Value	**$ 3,080**	$ 3,002

Prices actively quoted refers to the fair value of contracts valued using quoted prices in an active market. Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

B) Risk Management Assets and Liabilities *(continued)*

Net Fair Value of Commodity Price Positions at March 31, 2009

	Notional Volumes	Term	Average Price	Fair Value
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	1,549 MMcf/d	2009	9.28 US$/Mcf	$ 2,225
NYMEX Fixed Price	35 MMcf/d	2010	9.21 US$/Mcf	43
Purchased Options				
NYMEX Call	(140) MMcf/d	2009	11.67 US$/Mcf	(18)
NYMEX Put	482 MMcf/d	2009	9.10 US$/Mcf	614
Basis Contracts				
Canada	80 MMcf/d	2009		5
United States	687 MMcf/d	2009		39
Canada and United States *		2010-2013		66
				2,974
Other Financial Positions **				5
Total Unrealized Gain on Financial Contracts				2,979
Premiums Paid on Unexpired Options				77
Natural Gas Fair Value Position				$ 3,056

* EnCana has entered into swaps to protect against widening natural gas price differentials between production areas, including Canada, the U.S. Rockies and Texas, and various sales points. These basis swaps are priced using both fixed prices and basis prices determined as a percentage of NYMEX.

** Other financial positions are part of the ongoing operations of the Company's proprietary production management.

	Fair Value
Crude Oil Contracts	
Crude Oil Fair Value Position *	$ 18

* The Crude Oil financial positions are part of the ongoing operations of the Company's proprietary production and condensate management.

	Fair Value
Power Purchase Contracts	
Power Fair Value Position	$ 6

Net Earnings Impact of Realized and Unrealized Gains (Losses) on Risk Management Positions

	Realized Gain (Loss) Three Months Ended March 31,	
	2009	2008
Revenues, Net of Royalties	**$ 1,069**	$ 20
Operating Expenses and Other	**(24)**	2
Gain (Loss) on Risk Management	**$ 1,045**	$ 22

	Unrealized Gain (Loss) Three Months Ended March 31,	
	2009	2008
Revenues, Net of Royalties	**$ 133**	$ (1,096)
Operating Expenses and Other	**(22)**	3
Gain (Loss) on Risk Management	**$ 111**	$ (1,093)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

B) Risk Management Assets and Liabilities *(continued)*

Reconciliation of Unrealized Risk Management Positions from January 1 to March 31, 2009

	2009		2008
	Fair Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**$ 2,892**		
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Period	**1,156**	**$ 1,156**	$ (1,071)
Fair Value of Contracts Realized During the Period	**(1,045)**	**(1,045)**	(22)
Fair Value of Contracts Outstanding	**$ 3,003**	**$ 111**	$ (1,093)
Premiums Paid on Unexpired Options	**77**		
Fair Value of Contracts and Premiums Paid, End of Period	**$ 3,080**		

Commodity Price Sensitivities

The following table summarizes the sensitivity of the fair value of the Company's risk management positions to fluctuations in commodity prices, with all other variables held constant. When assessing the potential impact of these commodity price changes, the Company believes 10% volatility is a reasonable measure. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting net earnings as at March 31, 2009 as follows:

	Favourable 10% Change	Unfavourable 10% Change
Natural gas price	$ 204	$ (203)
Crude oil price	4	(4)
Power price	4	(4)

C) Risks Associated with Financial Assets and Liabilities

The Company is exposed to financial risks arising from its financial assets and liabilities. Financial risks include market risks (such as commodity prices, foreign exchange and interest rates), credit risk and liquidity risk. The fair value or future cash flows of financial assets or liabilities may fluctuate due to movement in market prices and the exposure to credit and liquidity risks.

Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is to not use derivative financial instruments for speculative purposes.

Natural Gas - To partially mitigate the natural gas commodity price risk, the Company has entered into option contracts and swaps, which fix the NYMEX prices. To help protect against widening natural gas price differentials in various production areas, EnCana has entered into swaps to manage the price differentials between these production areas and various sales points.

Crude Oil - The Company has partially mitigated its exposure to commodity price risk on its condensate supply with fixed price swaps.

Power - The Company has in place two Canadian dollar denominated derivative contracts, which commenced January 1, 2007 for a period of 11 years, to manage its electricity consumption costs.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

C) Risks Associated with Financial Assets and Liabilities *(continued)*

Credit Risk

Credit risk arises from the potential the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings. A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at March 31, 2009, approximately 97 percent of EnCana's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At March 31, 2009, EnCana had two counterparties whose net settlement position individually account for more than 10 percent of the fair value of the outstanding in-the-money net financial instrument contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets and the partnership contribution receivable is the total carrying value.

Liquidity Risk

Liquidity risk is the risk the Company will encounter difficulties in meeting a demand to fund its financial liabilities as they come due. The Company manages its liquidity risk through cash and debt management. As disclosed in Note 13, EnCana targets a Debt to Capitalization ratio between 30 and 40 percent and a Debt to Adjusted EBITDA of 1.0 to 2.0 times to steward the Company's overall debt position.

In managing liquidity risk, the Company has access to a wide range of funding at competitive rates through commercial paper, capital markets and banks. As at March 31, 2009, EnCana had available unused committed bank credit facilities in the amount of $2.0 billion and unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for $5.0 billion. The Company believes it has sufficient funding through the use of these facilities to meet foreseeable borrowing requirements.

EnCana maintains investment grade credit ratings on its senior unsecured debt. On May 12, 2008, following the announcement of the proposed corporate reorganization, Standard & Poor's Ratings Service assigned a rating of A- and placed the Company on "CreditWatch Negative", DBRS Limited assigned a rating of A(low) and placed the Company "Under Review with Developing Implications" and Moody's Investors Services assigned a rating of Baa2 and changed the outlook to "Stable" from "Positive". On March 2, 2009, Standard & Poor's affirmed its A- rating and removed the rating from "CreditWatch". The outlook is "Negative". On March 5, 2009, DBRS Limited maintained the long-term rating of EnCana at A(low) "Under Review with Developing Implications".

The timing of cash outflows relating to financial liabilities are outlined in the table below:

	Less Than 1 Year	1 - 3 Years	4 - 5 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	$ 2,482	$ -	$ -	$ -	$ 2,482
Risk Management Liabilities	18	3	-	-	21
Long-Term Debt *	720	1,990	3,381	10,282	16,373
Partnership Contribution Payable *	489	978	978	1,466	3,911

* Principal and interest, including current portion.

Included in EnCana's total long-term debt obligations of $16,373 million at March 31, 2009 are $2,122 million in principal obligations related to Bankers' Acceptances, Commercial Paper and LIBOR loans. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year. The revolving credit and term loan facilities are fully revolving for a period of up to five years. Based on the current maturity dates of the credit facilities, these amounts are included in cash outflows for the period disclosed as 4 - 5 Years. Further information on Long-term Debt is contained in Note 10.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

C) Risks Associated with Financial Assets and Liabilities *(continued)*

Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of the Company's financial assets or liabilities. As EnCana operates primarily in North America, fluctuations in the exchange rate between the U.S./Canadian dollar can have a significant effect on the Company's reported results. EnCana's functional currency is Canadian dollars, however, the Company reports its results in U.S. dollars as most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American oil and gas companies. As the effects of foreign exchange fluctuations are embedded in the Company's results, the total effect of foreign exchange fluctuations are not separately identifiable.

To mitigate the exposure to the fluctuating U.S./Canadian exchange rate, EnCana maintains a mix of both U.S. dollar and Canadian dollar debt.

As disclosed in Note 7, EnCana's foreign exchange (gain) loss is primarily comprised of unrealized foreign exchange gains and losses on the translation of U.S. dollar debt issued from Canada and the translation of the U.S. dollar partnership contribution receivable issued from Canada. At March 31, 2009, EnCana had $5,350 million in U.S. dollar debt issued from Canada ($5,350 million at December 31, 2008) and $3,070 million related to the U.S. dollar partnership contribution receivable ($3,147 million at December 31, 2008). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in an $18 million change in foreign exchange (gain) loss at March 31, 2009.

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect the fair value or future cash flows from the Company's financial assets or liabilities. The Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt.

At March 31, 2009, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $15 million (2008 - $14 million).

17. CONTINGENCIES

Legal Proceedings

The Company is involved in various legal claims associated with the normal course of operations. The Company believes it has made adequate provision for such legal claims.

Discontinued Merchant Energy Operations

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. The lawsuits allege that the defendants engaged in a conspiracy with unnamed competitors in the natural gas markets in California in violation of U.S. and California anti-trust and unfair competition laws. All but one of these lawsuits has been settled prior to 2009, without admitting any liability in the lawsuits.

The remaining lawsuit was commenced by E. & J. Gallo Winery ("Gallo"). The Gallo lawsuit claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

The Company and WD intend to vigorously defend against this outstanding claim; however, the Company cannot predict the outcome of these proceedings or any future proceedings against the Company, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company's financial position, or whether there will be other proceedings arising out of these allegations.

18. RECLASSIFICATION

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2009.

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)		**2009**	2008				
		Q1	Year	Q4	Q3	Q2	Q1
Total Consolidated							
Cash Flow [1]		**1,944**	9,386	1,299	2,809	2,889	2,389
Per share	- Basic	**2.59**	12.51	1.73	3.74	3.85	3.19
	- Diluted	**2.59**	12.48	1.73	3.74	3.85	3.17
Net Earnings		**962**	5,944	1,077	3,553	1,221	93
Per share	- Basic	**1.28**	7.92	1.44	4.74	1.63	0.12
	- Diluted	**1.28**	7.91	1.43	4.73	1.63	0.12
Operating Earnings [2]		**948**	4,405	449	1,442	1,469	1,045
Per share	- Diluted	**1.26**	5.86	0.60	1.92	1.96	1.39
Effective Tax Rates using							
Net Earnings		**22.8%**	30.7%				
Operating Earnings, excluding divestitures		**22.4%**	28.0%				
Canadian Statutory Rate		**29.2%**	29.7%				
Foreign Exchange Rates *(US$ per C$1)*							
Average		**0.803**	0.938	0.825	0.961	0.990	0.996
Period end		**0.794**	0.817	0.817	0.944	0.982	0.973
Cash Flow Information							
Cash from Operating Activities		**1,831**	8,855	2,043	3,058	1,996	1,758
Deduct (Add back):							
Net change in other assets and liabilities		**14**	(262)	21	(19)	(171)	(93)
Net change in non-cash working capital		**(127)**	(269)	723	268	(722)	(538)
Cash Flow [1]		**1,944**	9,386	1,299	2,809	2,889	2,389

(1) Cash Flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows.

(2) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gain/loss on discontinuance, after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated Notes issued from Canada, after-tax foreign exchange gains/losses on settlement of intercompany transactions, future income tax on foreign exchange related to U.S. dollar intercompany debt recognized for tax purposes only and the effect of changes in statutory income tax rates.

	2009	2008
Financial Metrics		
Debt to Capitalization [1]	**29%**	28%
Debt to Adjusted EBITDA [1, 2]	**0.7x**	0.7x
Return on Capital Employed [1, 2]	**23%**	20%
Return on Common Equity [2]	**32%**	27%

(1) Calculated using Debt defined as the current and long-term portions of Long-Term Debt.

(2) Calculated on a trailing twelve-month basis.

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics (continued)

($ millions, except per share amounts)

Common Share Information	**2009**	2008				
	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*						
Period end	**750.6**	750.4	750.4	750.3	750.2	750.0
Average - Basic	**750.5**	750.1	750.3	750.3	750.2	749.5
Average - Diluted	**751.4**	751.8	751.3	751.3	751.3	753.0
Price Range *($ per share)*						
TSX - C$						
High	**63.50**	97.81	68.04	95.91	97.81	79.26
Low	**44.64**	41.36	41.36	63.84	76.41	59.95
Close	**51.60**	56.96	56.96	67.96	93.36	78.20
NYSE - US$						
High	**53.81**	99.36	64.19	94.41	99.36	79.75
Low	**35.46**	34.00	34.00	61.13	74.16	58.13
Close	**40.61**	46.48	46.48	65.73	90.93	75.75
Dividends Paid *($ per share)*	**0.40**	1.60	0.40	0.40	0.40	0.40
Share Volume Traded *(millions)*	**441.7**	1,893.7	614.9	547.7	376.4	354.7
Share Value Traded *(US$ millions weekly average)*	**1,495.5**	2,348.6	2,114.5	2,912.5	2,486.0	1,900.5

Net Capital Investment *($ millions, for the three months ended March 31)*	**2009**	2008
Capital Investment		
Canada		
Canadian Plains	**$ 159**	$ 262
Canadian Foothills	**465**	780
Integrated Oil - Canada	**126**	208
USA	**540**	519
Downstream Refining	**202**	55
Market Optimization	**(3)**	2
Corporate & Other	**19**	23
Capital Investment	**1,508**	1,849
Acquisitions		
Property		
Canada		
Canadian Foothills	**73**	72
USA [(1)]	**6**	(14)
Divestitures		
Property		
Canada		
Canadian Plains	**-**	(31)
Canadian Foothills	**(33)**	(61)
USA	**-**	(4)
Corporate & Other	**-**	24
Net Acquisition and Divestiture Activity	**46**	(14)
Net Capital Investment	**$ 1,554**	$ 1,835

(1) In 2008, mainly includes Haynesville properties and purchase price adjustments for the November 2007 Leor acquisition in East Texas.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties

Production Volumes by Geographic Region	**2009**	2008				
	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas *(MMcf/d)*						
Canada	**2,123**	2,205	2,181	2,243	2,212	2,181
USA	**1,746**	1,633	1,677	1,674	1,629	1,552
	3,869	3,838	3,858	3,917	3,841	3,733
Oil and Natural Gas Liquids [(1)] *(bbls/d)*						
Canada	**122,609**	120,230	123,019	119,703	114,121	124,056
USA	**11,671**	13,350	12,831	13,853	13,482	13,232
	134,280	133,580	135,850	133,556	127,603	137,288
Total *(MMcfe/d)*						
Canada	**2,859**	2,926	2,919	2,961	2,897	2,926
USA	**1,816**	1,713	1,754	1,757	1,710	1,631
	4,675	4,639	4,673	4,718	4,607	4,557

(1) Natural gas liquids include condensate volumes.

Production Volumes	**2009**	2008				
	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas *(MMcf/d)*						
Canadian Plains	**800**	842	820	831	856	860
Canadian Foothills	**1,281**	1,300	1,302	1,351	1,289	1,256
USA	**1,746**	1,633	1,677	1,674	1,629	1,552
Integrated Oil - Other	**42**	63	59	61	67	65
Total Produced Gas	**3,869**	3,838	3,858	3,917	3,841	3,733
Oil and Natural Gas Liquids *(bbls/d)*						
Light and Medium Oil						
Canadian Plains	**31,946**	31,128	32,147	30,134	30,479	31,752
Canadian Foothills	**8,140**	8,473	8,437	8,217	8,376	8,867
Heavy Oil						
Canadian Plains	**35,097**	35,029	32,843	34,655	34,618	38,029
Integrated Oil - Foster Creek/Christina Lake	**34,729**	30,183	35,068	31,547	24,671	29,376
Integrated Oil - Other	**2,069**	2,729	2,133	2,273	3,009	3,514
Natural Gas Liquids [(1)]						
Canadian Plains	**1,201**	1,181	1,126	1,147	1,189	1,262
Canadian Foothills	**9,427**	11,507	11,265	11,730	11,779	11,256
USA	**11,671**	13,350	12,831	13,853	13,482	13,232
Total Oil and Natural Gas Liquids	**134,280**	133,580	135,850	133,556	127,603	137,288
Total *(MMcfe/d)*	**4,675**	4,639	4,673	4,718	4,607	4,557

(1) Natural gas liquids include condensate volumes.

Downstream Refining	**2009**	2008				
	Q1	Year	Q4	Q3	Q2	Q1
Refinery Operations [(1)]						
Crude oil capacity *(Mbbls/d)*	**452**	452	452	452	452	452
Crude oil runs *(Mbbls/d)*	**398**	423	434	412	437	408
Crude utilization *(%)*	**88%**	93%	96%	91%	97%	90%
Refined products *(Mbbls/d)*	**421**	448	456	438	464	435

(1) Represents 100% of the Wood River and Borger refinery operations.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

Per-unit Results
(excluding impact of realized financial hedging)

	2009	2008				
	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas - Canadian Plains *($/Mcf)*						
Price	**4.42**	7.77	5.65	8.67	9.50	7.19
Production and mineral taxes	**0.05**	0.12	0.06	0.17	0.17	0.06
Transportation and selling	**0.15**	0.23	0.21	0.24	0.22	0.25
Operating	**0.71**	0.78	0.65	0.59	0.96	0.93
Netback	**3.51**	6.64	4.73	7.67	8.15	5.95
Produced Gas - Canadian Foothills *($/Mcf)*						
Price	**4.58**	8.12	5.87	9.03	9.94	7.61
Production and mineral taxes	**0.03**	0.06	0.03	0.09	0.09	0.03
Transportation and selling	**0.30**	0.42	0.37	0.43	0.43	0.47
Operating	**1.04**	1.15	0.98	0.87	1.39	1.41
Netback	**3.21**	6.49	4.49	7.64	8.03	5.70
Produced Gas - Canada *($/Mcf)*						
Price	**4.51**	7.97	5.78	8.88	9.76	7.44
Production and mineral taxes	**0.04**	0.08	0.04	0.12	0.12	0.04
Transportation and selling	**0.24**	0.35	0.31	0.36	0.35	0.38
Operating	**0.94**	1.03	0.87	0.77	1.23	1.25
Netback	**3.29**	6.51	4.56	7.63	8.06	5.77
Produced Gas - USA *($/Mcf)*						
Price	**3.88**	7.89	5.01	8.54	9.93	8.19
Production and mineral taxes	**0.27**	0.56	0.35	0.56	0.72	0.62
Transportation and selling	**0.78**	0.84	0.87	0.86	0.81	0.81
Operating	**0.51**	0.59	0.56	0.38	0.71	0.71
Netback	**2.32**	5.90	3.23	6.74	7.69	6.05
Produced Gas - Total *($/Mcf)*						
Price	**4.23**	7.94	5.44	8.74	9.83	7.75
Production and mineral taxes	**0.14**	0.28	0.17	0.31	0.37	0.28
Transportation and selling	**0.49**	0.56	0.55	0.57	0.55	0.56
Operating	**0.75**	0.84	0.74	0.61	1.01	1.02
Netback	**2.85**	6.26	3.98	7.25	7.90	5.89
Natural Gas Liquids - Canadian Plains *($/bbl)*						
Price	**34.86**	78.91	45.13	98.35	96.34	75.09
Production and mineral taxes	**-**	-	-	-	-	-
Transportation and selling	**-**	-	-	0.01	-	-
Netback	**34.86**	78.91	45.13	98.34	96.34	75.09
Natural Gas Liquids - Canadian Foothills *($/bbl)*						
Price	**35.81**	80.22	42.03	95.49	101.23	80.80
Production and mineral taxes	**-**	-	-	-	-	-
Transportation and selling	**1.19**	1.33	1.33	1.20	1.73	1.04
Netback	**34.62**	78.89	40.70	94.29	99.50	79.76
Natural Gas Liquids - Canada *($/bbl)*						
Price	**35.70**	80.10	42.31	95.74	100.78	80.23
Production and mineral taxes	**-**	-	-	-	-	-
Transportation and selling	**1.06**	1.21	1.21	1.10	1.57	0.94
Netback	**34.64**	78.89	41.10	94.64	99.21	79.29
Natural Gas Liquids - USA (1) *($/bbl)*						
Price	**27.43**	83.18	45.39	97.63	105.73	82.22
Production and mineral taxes	**2.48**	7.25	3.79	8.19	9.75	7.13
Transportation and selling	**-**	-	-	-	-	-
Netback	**24.95**	75.93	41.60	89.44	95.98	75.09
Natural Gas Liquids - Total *($/bbl)*						
Price	**31.37**	81.67	43.88	96.72	103.29	81.24
Production and mineral taxes	**1.30**	3.70	1.93	4.25	4.94	3.63
Transportation and selling	**0.51**	0.59	0.59	0.53	0.78	0.46
Netback	**29.56**	77.38	41.36	91.94	97.57	77.15

(1) The Natural Gas Liquids - USA netback is equivalent to the Total Liquids - USA netback.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

Per-unit Results
(excluding impact of realized financial hedging)

	2009	2008				
	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil - Light and Medium - Canadian Plains *($/bbl)*						
Price	**37.51**	84.84	41.60	107.59	107.08	85.90
Production and mineral taxes	**2.69**	3.33	2.05	4.70	3.97	2.72
Transportation and selling	**0.96**	1.20	0.96	1.41	1.27	1.16
Operating	**9.50**	10.56	8.28	9.40	13.05	11.60
Netback	**24.36**	69.75	30.31	92.08	88.79	70.42
Crude Oil - Light and Medium - Canadian Foothills *($/bbl)*						
Price	**37.31**	91.78	47.51	112.73	114.28	93.42
Production and mineral taxes	**1.02**	1.48	1.11	1.65	2.05	1.16
Transportation and selling	**2.09**	2.07	1.55	2.12	2.70	1.92
Operating	**8.52**	12.75	11.68	10.02	15.39	13.84
Netback	**25.68**	75.48	33.17	98.94	94.14	76.50
Crude Oil - Heavy - Canadian Plains *($/bbl)*						
Price	**31.34**	74.08	31.30	95.86	98.65	70.44
Production and mineral taxes	**(0.07)**	0.03	0.06	0.07	(0.10)	0.07
Transportation and selling	**1.17**	1.60	1.13	2.42	1.60	1.29
Operating	**7.82**	9.04	7.17	7.62	11.30	9.93
Netback	**22.42**	63.41	22.94	85.75	85.85	59.15
Crude Oil - Total - excluding Foster Creek/Christina Lake *($/bbl)*						
Price	**34.49**	80.31	37.20	102.66	103.40	78.82
Production and mineral taxes	**1.22**	1.56	1.02	2.16	1.81	1.28
Transportation and selling	**1.21**	1.52	1.13	2.00	1.61	1.36
Operating	**8.83**	10.43	8.28	8.99	13.00	11.39
Netback	**23.23**	66.80	26.77	89.51	86.98	64.79
Crude Oil - Heavy - Foster Creek/Christina Lake *($/bbl)*						
Price (1)	**26.90**	62.44	19.86	91.21	93.64	59.67
Production and mineral taxes	**-**	-	-	-	-	-
Transportation and selling	**2.29**	2.36	2.04	2.10	2.77	2.72
Operating	**13.28**	15.53	10.73	15.53	21.41	16.62
Netback	**11.33**	44.55	7.09	73.58	69.46	40.33
Crude Oil - Total (2) *($/bbl)*						
Price	**32.16**	75.36	31.58	99.39	100.99	74.10
Production and mineral taxes	**0.84**	1.13	0.69	1.54	1.36	0.96
Transportation and selling	**1.54**	1.75	1.43	2.03	1.90	1.69
Operating	**10.19**	11.84	9.08	10.86	15.08	12.68
Netback	**19.59**	60.64	20.38	84.96	82.65	58.77
Total Liquids - Canada *($/bbl)*						
Price	**32.48**	75.85	32.63	98.99	100.97	74.69
Production and mineral taxes	**0.77**	1.01	0.62	1.37	1.20	0.86
Transportation and selling	**1.50**	1.70	1.41	1.93	1.86	1.62
Operating	**9.29**	10.57	8.19	9.68	13.34	11.30
Netback	**20.92**	62.57	22.41	86.01	84.57	60.91
Total Liquids *($/bbl)*						
Price	**32.03**	76.58	33.81	98.85	101.46	75.44
Production and mineral taxes	**0.92**	1.63	0.92	2.09	2.09	1.46
Transportation and selling	**1.36**	1.53	1.28	1.72	1.67	1.46
Operating	**8.46**	9.55	7.43	8.66	12.00	10.30
Netback	**21.29**	63.87	24.18	86.38	85.70	62.22
Total *($/Mcfe)*						
Price	**4.42**	8.77	5.48	10.04	11.02	8.61
Production and mineral taxes	**0.15**	0.28	0.17	0.32	0.37	0.28
Transportation and selling	**0.44**	0.50	0.49	0.53	0.50	0.50
Operating (3)	**0.86**	0.97	0.83	0.75	1.17	1.15
Netback	**2.97**	7.02	3.99	8.44	8.98	6.68

(1) 2008 price includes the impact of the write-down of condensate inventories to net realizable value (2008 - $4.26/bbl; Q4 2008 - $11.21/bbl; Q3 2008 - $3.07/bbl).
(2) The Crude Oil - Total netback is equivalent to the Crude Oil - Canada netback.
(3) 2009 operating costs include a recovery of costs related to long-term incentives of $0.02/Mcfe (2008 - costs of $0.14/Mcfe).

Impact of Realized Financial Hedging

Natural Gas *($/Mcf)*	**2.99**	(0.02)	1.74	(0.80)	(1.29)	0.27
Liquids *($/bbl)*	**2.21**	(5.46)	2.35	(7.97)	(10.99)	(5.85)
Total *($/Mcfe)*	**2.55**	(0.17)	1.50	(0.89)	(1.38)	0.05

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