2006 Quarterly Report

Q3 Third quarter report for the period ended September 30, 2006

Delivering On Our Potential

energy for people

EnCana's third quarter cash flow reaches US$1.9 billion, or $2.30 per share – up 5 percent

Natural gas sales increase 4 percent to 3.36 billion cubic feet per day

Calgary, Alberta, (October 25, 2006) – EnCana Corporation (TSX & NYSE: ECA) continued to generate solid cash flow and earnings during the third quarter of 2006 due to increased heavy oil prices plus steady natural gas production that benefited from favourable natural gas price hedges and fixed basis positions.

Third quarter 2006 highlights (all year-over-year comparisons are to the third quarter of 2005)

Financial (all currency figures are in U.S. dollars unless otherwise noted)
- Cash flow of US$2.30 per share diluted, or $1.89 billion
- Operating earnings of $1.31 per share diluted, or $1.08 billion
- Net earnings of $1.65 per share diluted, or $1.36 billion
    - Both net earnings and operating earnings include a $255 million after-tax gain, (31 cents per share diluted) on the sale of EnCana's interest in an offshore Brazil oil discovery
    - Net earnings also include an unrealized $285 million after-tax gain, (34 cents per share diluted) due to mark-to-market accounting of commodity price hedges
- Purchased 17.4 million EnCana shares at an average price of $51.95 under the Normal Course Issuer Bid
- Price risk management measures resulted in a realized after-tax gain of $133 million

Operational (continuing operations), (all sales are on an after-royalties basis)
- Natural gas sales increased 4 percent to 3.36 billion cubic feet per day (Bcf/d)
- Oil and natural gas liquids (NGLs) sales were about the same at 150,565 barrels per day (bbls/d)
- Natural gas and liquids sales of 4.26 billion cubic feet of gas equivalent per day (Bcfe/d), up 3 percent
- Key resource play production up 12 percent
- Operating and administrative costs of 98 cents per thousand cubic feet equivalent (Mcfe), compared to 90 cents per Mcfe one year earlier
- Drilled 1,001 net wells , compared to 1,150 net wells one year earlier
- Upstream core capital investment of $1.45 billion, which is as forecast

Strategic events
- On October 5, 2006, EnCana announced it entered into an agreement with ConocoPhillips to create an integrated North American heavy oil business consisting of EnCana's Foster Creek and Christina Lake in-situ oilsands projects in Alberta and ConocoPhillips' Wood River and Borger refineries in Illinois and Texas respectively. Effective January 2, 2007, it is expected that EnCana will become an integrated producer, owning a 50 percent interest in the integrated business
- Completed the sale of a 50 percent interest in the Chinook oil discovery offshore Brazil for proceeds of $367 million
- Filed a project description with regulatory authorities for Deep Panuke natural gas project located offshore Nova Scotia
- In northeast B.C., started up Kakwa gas plant and, in October, began commissioning the Steeprock gas plant
- Began commissioning latest in-situ oilsands expansion at Foster Creek

"During the first nine months of 2006, our cash flow per share is up 16 percent compared to one year earlier and operating earnings continue to grow. Our resource play strategy is continuing to deliver strong performance toward our core goal – steadily increasing the underlying value of every EnCana share," said Randy Eresman, EnCana's President & Chief Executive Officer. "Although we have slowed our natural gas production growth profile from our original plan, we have achieved year-to-date growth of 5 percent. Our current production is about 3.4 billion cubic feet per day and with the planned start up in early November of the new Steeprock gas plant in British Columbia our gas production should approach 3.5 billion cubic feet per day."

"At a time of commodity price uncertainty and high industry inflation, we believe it is prudent to temporarily reduce our growth objectives and return excess cash to shareholders through continued share buybacks rather than pursue growth at elevated costs. Robust activity in the North American natural gas industry this year has continued to fuel cost inflation for field services, while record gas storage levels have resulted in softer realized prices. In some areas experiencing high inflation and operational inefficiencies, we have reduced our activity levels by releasing our least capital efficient rigs and the associated services. This has resulted in delays in bringing on new production. The released rigs will be replaced by new fit-for-purpose rigs, which are about 25 percent more efficient, resulting in an overall high-grading of our fleet. In total we have about 70 rigs running, which is 55 fewer than one year ago. The number of wells we expect to drill this year is now forecast to reach about 3,650, about 650 less than initially forecast," Eresman said.

Jonah production constrained, wet conditions persist in southern Alberta

At Jonah in Wyoming, production growth is about 50 million cubic feet per day less than forecast due to a combination of operational issues and pipeline capacity restrictions. This volume represents the largest proportion of our company's production shortfall. Operational issues are being resolved and additional gathering pipeline capacity is expected to be added by the second quarter of 2007. EnCana has slowed drilling to help preserve the value of new gas production by timing production increases with planned pipeline expansion. EnCana has reduced its Jonah drilling fleet from 15 to 11 rigs by releasing four of its least-efficient rigs while it awaits delivery of eight new, highly-efficient, fit-for-purpose rigs over the next year. In the plains of southern Alberta, operations in coalbed methane and shallow gas development were slowed by wet summer weather. Unusually-heavy rains in 2005 left the land saturated such that even modest rains this year hampered field work.

Natural gas sales guidance updated

With fewer wells and a slower than forecast production ramp up from the Jonah and southern Alberta projects, 2006 gas production is running slightly below the low end of the company's previous forecast. EnCana has updated its 2006 natural gas sales guidance to between 3.36 billion and 3.40 billion cubic feet per day, representing, at the midpoint, a 5 percent increase over 2005 sales. The forecast for oil and NGLs sales is unchanged at between 155,000 and 160,000 bbls/d. Updated guidance is posted on EnCana's website: www.encana.com.

"In the third quarter, growth from our key resource plays continued at a strong pace, up 12 percent in the past year. In the first nine months, key resource play growth is up about 14 percent," Eresman said. "Despite higher inflation and foreign exchange rates, we are stewarding our 2006 capital investment to be within guidance of between \$5.8 billion and \$6.1 billion, which includes about \$600 million directed to growth at our Foster Creek and Christina Lake oilsands projects."

Higher electricity costs offset by EnCana power plants

While increased electricity prices in Alberta have driven up field operating costs in recent months, the company has a natural hedge due to its ownership in three cogeneration power plants. Although power prices increased third quarter operating costs by about 4 cents per Mcfe compared to the same period in 2005, increased revenue from the company's power plants has offset this cost increase.

Focused on generating strong investment returns and free cash flow
"As we look to 2007, we recognize that winter weather will play a strong role in determining 2007 gas prices and we share investors' concerns for potential price weakness in the short term. At the same time, energy demand and the forward prices for natural gas and oil remain strong. We continue to manage price risk with the use of hedging instruments and we do not plan to aggressively push new production into a high-cost, low-price environment," Eresman said.

"We plan to set our 2007 capital budget in mid December when we will have a better sense of the environment for the coming year and consistent with 2006, we will target a significant stream of free cash flow for 2007," Eresman said. "We have hedged about one-third of our expected 2007 gas production: fixed price contracts on about 975 million cubic feet per day at an average price of $8.73 per Mcf and put options on 240 million cubic feet per day at a strike price of $6.00 per Mcf. For 2007, we plan to be even more focused on maximizing shareholder returns by optimizing capital investment complemented with a sizable divestiture program and continued farm out activity on lands not core to EnCana."

EnCana and ConocoPhillips to create integrated heavy oil business in 2007
On October 5, 2006, EnCana announced the signing of a landmark agreement with ConocoPhillips that will see EnCana become an integrated oil producer, holding a 50 percent interest in two significant U.S. refineries. The two companies agreed to create two 50/50 partnerships, one upstream in Canada and one downstream in the United States. This integrated heavy oil business plans to increase production from two in-situ oilsands projects to about 400,000 bbls/d of bitumen over the next decade and expand processing capacity to 275,000 bbls/d for bitumen at refineries in Wood River, Illinois and Borger, Texas. This transaction, which is subject to the execution of final definitive agreements and regulatory approvals, is expected to close on January 2, 2007.

"Under the agreement, EnCana will own about 175,000 bbls/d of refining capacity effective January 2, 2007, increasing to about 250,000 bbls/d by 2009, in key U.S. markets. This will instantly place EnCana among Canada's major refinery owners while providing options for future upgrader development," Eresman said. "These innovative partnerships will strategically align about two-thirds of our industry-leading oilsands projects with high-quality refineries. Through this integrated business, we expect to increase certainty of execution for our oilsands projects by reducing cost and price risk and increasing confidence in our ability to achieve economic returns under a wide range of world oil prices."

Bitumen production expansions underway at Foster Creek and Christina Lake
Over the next decade, the upstream partnership plans to invest $5.4 billion to grow bitumen production capacity at Foster Creek and Christina Lake from 50,000 bbls/d to approximately 400,000 bbls/d. A Foster Creek expansion currently under construction is expected to take production to about 60,000 bbls/d by early 2007. The next two Foster Creek expansions, 30,000 bbls/d each, are expected to come on stream in late 2008 and 2009 respectively. At Christina Lake, the current expansion is expected to take production to about 18,000 bbls/d in the last half of 2008, which means these near term expansions are expected to take total production to about 138,000 bbls/d before 2010. Subsequent expansions at the two projects are expected to continue growth to the targeted level of 400,000 bbls/d.

<u>IMPORTANT NOTE</u>: EnCana reports in U.S. dollars unless otherwise noted and follows U.S. protocols, which report sales and reserves on an after-royalties basis. EnCana's Ecuador interests and its natural gas liquids processing business were sold and are discontinued. The company is reporting its natural gas storage business as discontinued because EnCana is in the process of selling it. Total results, which include results from natural gas liquids processing business, Ecuador and natural gas storage, are reported in the company's financial statements included in this interim report and in supplementary documents posted on its website – www.encana.com. The company's financial statements are prepared in accordance with Canadian generally accepted accounting principles (GAAP).

First nine months of 2006 highlights (all year-over-year comparisons are to the first nine months of 2005)

Financial

- Cash flow per share diluted increased 16 percent to $6.39, or $5.4 billion
- Operating earnings per share increased 40 percent to $3.07, or $2.6 billion
- Net earnings of $5 billion, or $5.90 per share, compared to $1.19 per share one year earlier
- Return on capital employed of 32 percent, based on the trailing 12 months
- Since December 31, 2005, purchased for cancellation 7.1 percent of the common shares then outstanding, resulting in a 6.4 percent decrease, net of dilution due to option exercises.

Operational (continuing operations)

- Key resource play production up 14 percent
- Natural gas sales of 3.35 Bcf/d, up 5 percent
- Oil and NGLs sales about the same at 155,565 bbls/d
- Natural gas and liquids sales increased 4 percent to 4.29 Bcfe/d
- Operating and administrative costs of 98 cents per Mcfe, compared to 84 cents per Mcfe one year earlier
- Drilled 2,841 net wells , compared to 3,520 net wells one year earlier
- Upstream core capital investment of $4.96 billion, which is as forecast

Financial Summary – Total Consolidated

(for the period ended September 30) ($ millions, except per share amounts)	Q3 2006	Q3 2005	% æ	9 months 2006	9 months 2005	% æ
Cash flow	**1,894**	1,931	- 2	**5,400**	4,916	+ 10
Per share diluted	**2.30**	2.20	+ 5	**6.39**	5.50	+ 16
Net earnings	**1,358**	266	n/a	**4,989**	1,060	n/a
Per share diluted	**1.65**	0.30	n/a	**5.90**	1.19	n/a
Operating earnings	**1,078**	704	+ 53	**2,596**	1,970	+ 32
Per share diluted	**1.31**	0.80	+ 64	**3.07**	2.20	+ 40
Earnings Reconciliation Summary – Total Consolidated						
Net earnings from continuing operations	**1,343**	348	n/a	**4,408**	960	n/a
Net earnings (loss) from discontinued operations	**15**	(82)	n/a	**581**	100	n/a
Net earnings	**1,358**	266	n/a	**4,989**	1,060	n/a
(Add back losses & deduct gains)						
Unrealized mark-to-market hedging gain (loss), after-tax	**285**	(604)	n/a	**1,275**	(1,023)	n/a
Unrealized foreign exchange gain (loss) on translation of U.S. dollar debt issued in Canada, after-tax	**(3)**	166	n/a	**128**	113	n/a
Future tax recovery due to Canada and Alberta tax rates reductions	**-**	-	n/a	**457**	-	n/a
Gain (loss) on sale of discontinued operations,[1] after-tax	**(2)**	-	n/a	**533**	-	n/a
Operating earnings	**1,078**	704	+ 53	**2,596**	1,970	+ 32
Per share diluted	**1.31**	0.80	+ 64	**3.07**	2.20	+ 40

[1] Year to date includes $812 million gain on natural gas storage sale and $279 million loss on sale of Ecuador interests

Sales & Drilling Summary

Total Consolidated

(for the period ended September 30) (After royalties)	Q3 2006	Q3 2005	% æ	9 months 2006	9 months 2005	% æ
Natural Gas sales (MMcf/d)	**3,359**	3,222	+ 4	**3,354**	3,193	+ 5
Natural gas sales per 1,000 shares (Mcf)	**382**	347	+ 10	**1,104**	999	+ 11
Oil and NGLs sales (bbls/d) [2]	**150,565**	219,167	- 31	**172,098**	226,335	- 24
Oil and NGLs sales per 1,000 shares (Mcfe) [2]	**103**	141	- 27	**340**	425	- 20
Total sales (MMcfe/d) [2]	**4,262**	4,537	- 6	**4,387**	4,551	- 4
Total sales per 1,000 shares (Mcfe) [2]	**484**	488	- 1	**1,445**	1,423	+ 2
Net wells drilled	**1,001**	1,152	- 13	**2,848**	3,531	- 19
Continuing Operations						
North America Natural Gas sales (MMcf/d)	**3,359**	3,222	+ 4	**3,354**	3,193	+ 5
North America Oil and NGLs (bbls/d)	**150,565**	150,457	0	**155,565**	154,892	0
Total sales (MMcfe/d)	**4,262**	4,125	+ 3	**4,287**	4,122	+ 4
Net wells drilled	**1,001**	1,150	- 13	**2,841**	3,520	- 19

[2] Sales down due primarily to sale of Ecuador interests, which had sales of about 71,400 bbls/d in the first nine months of 2005

Key resource play production up 12 percent in past year

Third quarter 2006 oil and gas production from key North American resource plays increased 12 percent compared to the third quarter of 2005. This was driven mainly by increases in gas production from coalbed methane projects in central and southern Alberta, Bighorn in west-central Alberta, Cutbank Ridge in northeast British Columbia, Piceance in Colorado and the Barnett Shale play in the Fort Worth basin.

Growth from key North American resource plays

Resource Play (After royalties)	Daily Production 2006 YTD	2006 Q3	2006 Q2	2006 Q1	2005 Full Year	2005 Q4	2005 Q3	2005 Q2	2005 Q1	2004 Full Year
Natural Gas (MMcf/d)										
Jonah	**455**	**455**	450	461	435	454	440	416	431	389
Piceance	**324**	**331**	324	316	307	326	302	302	300	261
East Texas	**100**	**106**	93	99	90	98	94	85	82	50
Fort Worth	**102**	**104**	108	93	70	88	66	63	61	27
Greater Sierra	**214**	**209**	224	208	219	226	225	228	195	230
Cutbank Ridge	**160**	**167**	173	140	92	125	105	80	56	40
Bighorn	**88**	**97**	95	72	55	56	57	53	56	42
CBM Integrated[1]	**189**	**209**	179	177	112	165	117	104	59	28
Shallow Gas	**599**	**593**	590	615	625	625	616	633	625	592
Oil (Mbbls/d)										
Foster Creek	**36**	**37**	33	36	29	35	27	24	30	29
Christina Lake	**6**	**6**	6	6	5	5	6	7	4	4
Pelican Lake	**25**	**23**	22	29	26	28	27	27	21	19
Total (MMcfe/d)	**2,628**	**2,668**	2,601	2,609	2,366	2,567	2,381	2,312	2,197	1,971
% change from Q3 2005	**14.4**	**12.1**								
% change from prior period		**2.6**	(0.3)	1.6	20.0	7.8	3.0	5.2	8.0	

[1] Starting this quarter, CBM production from wells drilled as part of the CBM program includes production from coal and other formations, which reflects commingling rulings from regulators and is consistent with the method used to report production for EnCana's other resource plays. Volumes for all periods have been adjusted to comply with this categorization.

Drilling activity in key North American resource plays

Resource Play	Net Wells Drilled 2006 YTD	2006 Q3	2006 Q2	2006 Q1	2005 Full year	2005 Q4	2005 Q3	2005 Q2	2005 Q1	2004 Full Year
Natural Gas										
Jonah	**122**	**48**	48	26	104	21	25	30	28	70
Piceance	**170**	**48**	59	63	266	55	69	65	77	250
East Texas	**48**	**12**	17	19	84	20	21	22	21	50
Fort Worth	**78**	**22**	27	29	59	20	18	12	9	36
Greater Sierra	**110**	**16**	34	60	164	25	33	47	59	187
Cutbank Ridge	**97**	**35**	36	26	135	34	40	38	23	50
Bighorn	**45**	**7**	18	20	51	20	10	10	11	20
CBM Integrated[1]	**572**	**156**	35	381	1,245	344	314	242	345	1,086
Shallow Gas	**838**	**442**	199	197	1,267	288	341	365	273	1,552
Oil										
Foster Creek	**6**	**-**	-	6	39	13	14	2	10	11
Christina Lake	**2**	**-**	-	2	-	-	-	-	-	2
Pelican Lake	**-**	**-**	-	-	52	-	3	33	16	92
Total	**2,088**	**786**	473	829	3,466	840	888	866	872	3,406

Third quarter realized natural gas prices, including hedging, down 5 percent

EnCana's third quarter realized gas price, including the impact of financial hedging, averaged $6.57 per thousand cubic feet (Mcf), down 5 percent from the comparable price of $6.90 per Mcf in the third quarter of 2005. EnCana's natural gas prices, excluding financial hedging, averaged $5.75 per Mcf, down 21 percent from an average of $7.29 per Mcf in the third quarter of 2005. North American gas storage levels remain well above long-term averages for this time of year, a market condition that is expected to put downward pressure on short-term gas prices. The third quarter benchmark NYMEX index gas price averaged $6.58 per Mcf, down 22 percent from $8.49 per Mcf in the third quarter of 2005. The third quarter Canadian benchmark gas price was down 26 percent to C$6.03 per Mcf while U.S. Rockies benchmark gas prices were 21 percent lower to $5.30 per Mcf, compared to last year.

About 1.2 Bcf/d of expected 2007 gas sales hedged, as of September 30, 2006

EnCana has entered into financial contracts, put options and fixed price agreements, for 93 percent of the company's forecast gas sales during the last quarter of 2006 at an average minimum price of NYMEX $7.28 per Mcf. For 2007, the company has 975 million cubic feet per day of expected 2007 gas sales under fixed price contracts at an average price of $8.73 per Mcf and has put options with a strike price of $6.00 per Mcf on an additional 240 million cubic feet per day. This gas price hedging strategy helps assure that cash flow is adequate to fund capital programs.

Managing transportation risk to gas prices

Natural gas transportation constraints between producing regions in the U.S. Rockies and Western Canada and consuming regions increase the volatility in gas prices. To help add further certainty of cash flow, EnCana has entered into basis hedges to reduce this volatility. For the remainder of 2006, EnCana has hedged 100 percent of its anticipated U.S. Rockies basis differential exposure at an average of 64 cents per Mcf. For 2007, EnCana has 100 percent of expected U.S. Rockies basis differential exposure hedged at an average of 67 cents per Mcf. In Canada for 2006, EnCana has hedged about 34 percent of its anticipated AECO basis differential exposure at an average of 70 cents per Mcf and has an additional 39 percent of anticipated production subject to transport and aggregator contracts. For 2007 in Canada, EnCana has hedged about 30 percent of its anticipated AECO basis differential exposure at an average of 72 cents per Mcf and has an additional 37 percent of anticipated production subject to transport and aggregator contracts.

Third quarter realized liquids prices, including hedging, up 16 percent

During the third quarter of 2006, higher prices for West Texas Intermediate (WTI) oil, increased market reach via new pipelines to the southern U.S. refining region and strong asphalt demand during the summer paving season resulted in substantially higher prices for Canadian heavy oil than in the prior year. Third quarter realized liquids prices, including financial hedging, increased 16 percent to average $46.92 per barrel, compared to $40.46 per barrel in the same period in 2005. Excluding financial hedging, realized liquids prices increased 9 percent averaging $50.37 per barrel. In the third quarter, the WTI/Western Canada Select differential averaged $18.83 per barrel, up 4 percent from $18.07 per barrel in the same 2005 period. Concerns over geopolitical events and U.S. gasoline supplies combined to propel the WTI oil price to more than $70 per barrel for most of the third quarter. During the third quarter of 2006, the benchmark WTI crude oil price averaged $70.54 per barrel, up 11 percent from the third quarter 2005 price of $63.31 per barrel.

Risk management strategy

Detailed risk management positions at September 30, 2006 are presented in Note 14 to the unaudited third quarter consolidated financial statements. In the third quarter of 2006, EnCana's financial price risk management measures resulted in a realized after-tax gain of approximately $133 million, comprised of a $167 million gain on gas hedges, a $35 million loss on crude oil hedges and a $1 million gain on other hedges.

Corporate developments

Quarterly dividend of 10 cents per share approved
EnCana's board of directors has approved a quarterly dividend of 10 cents per share, which is payable on December 29, 2006 to common shareholders of record as of December 15, 2006.

Divestitures update
During the third quarter, EnCana closed the sale of its 50 percent interest in the Chinook heavy oil discovery offshore Brazil. EnCana continues to hold non-operated interests in 10 deep water exploration blocks offshore Brazil. Nine of these blocks are operated by Petrobras.

Before the end of 2006, EnCana expects to close the sale of its Wild Goose storage facility in California, which is the second and final phase of the company's $1.5 billion sale of its natural gas storage business. The Wild Goose sale requires approval of the California Public Utilities Commission. The first phase of the gas storage sale to Carlyle/Riverstone Global Energy and Power Fund, an energy private equity fund managed by Riverstone Holdings LLC and The Carlyle Group, included EnCana's Alberta, Oklahoma and Louisiana storage assets and generated proceeds of about $1.3 billion.

EnCana recently initiated processes to sell its interests in Northern Canada and Chad. These exploration properties, which have generated some encouraging natural gas and oil drilling results, are conventional properties and have been deemed non-core.

Normal Course Issuer Bid
To date in 2006, EnCana has purchased for cancellation approximately 61.1 million of its shares at an average price of $48.67 per share, including commissions, under its current Normal Course Issuer Bid. The company intends to file a renewal notice of intention to make a Normal Course Issuer Bid with the Toronto Stock Exchange (TSX) for approval.

Financial strength

EnCana maintains a strong balance sheet. At September 30, 2006 the company's net debt-to-capitalization ratio was 25:75. EnCana's net debt-to-adjusted-EBITDA multiple, on a trailing 12-month basis, was 0.5 times. These ratios are below the company's targeted range for net debt-to-capitalization of between 30 and 40 percent and 1.0 to 2.0 times for net debt-to-adjusted-EBITDA.

In the third quarter of 2006, EnCana invested $1,474 million of core capital. Net divestitures were $365 million, resulting in net capital investment in total operations of $1,109 million. EnCana's 2006 capital program is expected to be within the company's forecast range of between $5.8 billion and $6.1 billion and is expected to be funded by cash flow.

EnCana Corporation
With an enterprise value of approximately US$45 billion, EnCana is one of North America's leading natural gas producers, the largest holder of gas and oil resource lands onshore North America and is a technical and cost leader in the in-situ recovery of oilsands bitumen. EnCana delivers predictable, reliable, profitable growth from its portfolio of long-life resource plays situated in Canada and the United States. Contained in unconventional reservoirs, resource plays are large contiguous accumulations of hydrocarbons, located in thick or areally extensive deposits, that typically have lower geological and commercial development risk, lower average decline rates and longer producing lives than conventional plays. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

NOTE 1: Non-GAAP measures

This interim report contains references to cash flow, total operating earnings and adjusted EBITDA.

- Total operating earnings is a non-GAAP measure that shows net earnings excluding non-operating items such as the after-tax impacts of a gain or loss on the sale of discontinued operations, 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 in Canada and the effect of the reduction in income tax rates.
- Adjusted EBITDA is a non-GAAP measure that is defined as net earnings from continuing operations before gain on disposition, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation, depletion and amortization.

Management believes that the inclusion of total operating earnings enhances the comparability of the company’s underlying financial performance between periods. The majority of the unrealized gains/losses that relate to U.S. dollar debt issued in Canada are for debt with maturity dates in excess of five years. 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.

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 necessarily represent value equivalency at the well head.

Unbooked resource potential

EnCana defines unbooked resource potential as quantities of oil and natural gas on existing landholdings that are not yet classified as proved reserves, but which EnCana believes may be moved into the proved reserves category and produced in the future. EnCana employs a probability-weighted approach in the calculation of these quantities, including statistical distributions of resource play performance and areal extent. Consequently, EnCana's unbooked resource potential necessarily includes quantities of probable and possible reserves and contingent resources, as these terms are defined in the Canadian Oil and Gas Evaluation Handbook.

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, cash flow and increase in net asset value); anticipated life of proved reserves; anticipated unbooked resource potential; anticipated conversion of unbooked resource potential to proved reserves; anticipated growth and success of resource plays and the expected characteristics of resource plays;

anticipated bitumen production expansion including expansions of and production from Foster Creek and Christina Lake and the timing thereof; anticipated expansion of refining capacity at Wood River and Borger; anticipated success of the partnership with ConocoPhillips, including its potential impact on cost and price risk and economic returns; anticipated closing date of the transaction with ConocoPhillips, expected proportion of total production and cash flows contributed by natural gas; anticipated impact and success of EnCana's market risk mitigation strategy; anticipated filing and receiving TSX approval of, and purchases pursuant to, a Normal Course Issuer Bid; potential demand for gas; anticipated production in 2006 and beyond; anticipated drilling; potential divestitures and farm outs planned for 2007 and beyond; potential capital expenditures and investment projections relating to the 2006 and 2007 capital budget and the expected date for the setting of the 2007 capital budget; potential oil, natural gas and NGLs sales in 2006 and beyond; forecast natural gas, crude oil and NGLs sales guidance for 2006 and anticipated ability to meet production, operating cost and sales guidance targets; potential pipeline capacity increases in 2007 and 2008 and its impact on the Jonah project; the expected dates for the delivery of new rigs to the Jonah project and their projected impact on costs; the projected on-stream date and capacity of the Steeprock processing plant; anticipated costs, including costs associated with developing unbooked resource potential and expected costs to develop the company's drilling inventory; the potential for reduced industry activity in the future and the impact thereof on costs; anticipated prices for crude oil and natural gas and the impact of winter weather and natural gas storage levels on natural gas prices; projections of expected cost inflation levels; the expected date for receipt of California regulatory approvals in respect of the sale of the company's remaining gas storage assets and the expected timing for closing this transaction; projections for future debt to capitalization ratios and cash tax expense percentages; and potential risks associated with drilling 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 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 reserve 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 ability to replace and expand oil and gas reserves; the ability of the company and ConocoPhillips to successfully negotiate and execute final definitive agreements relating to the integrated North American 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; 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 ability to secure adequate product transportation; changes in environmental and other regulations or the interpretations of such regulations; political and economic conditions in the countries in which the company operates; the risk of international 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.

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 September 30, 2006, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2005. Readers should also read the "Forward-Looking Statements" legal advisory contained at the end of this MD&A.

The Interim Consolidated Financial Statements and comparative information have been prepared in United States dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production and sales volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This MD&A is dated October 24, 2006.

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

EnCana's Business

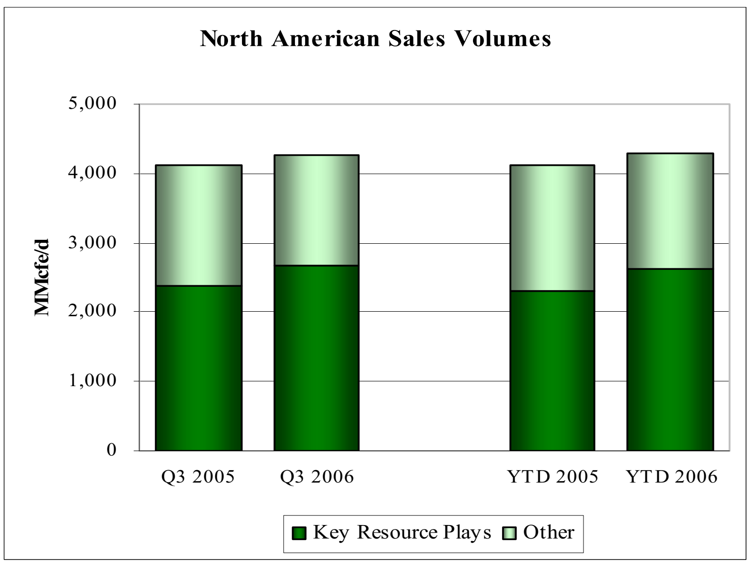
EnCana is a leading independent North American oil and gas company.

EnCana operates two continuing businesses:

- Upstream, which includes the Company's exploration for, and development and production of, natural gas, crude oil, and natural gas liquids ("NGLs") and other related activities. The majority of the Company's Upstream operations are located in Canada and the United States. Frontier and International New Ventures exploration is mainly focused on opportunities in Chad, Brazil, the Middle East, Greenland and France; and

- Market Optimization, which is focused on enhancing the sale of EnCana's production. As part of these activities, Market Optimization buys and sells third party products to enhance EnCana's operating flexibility for transportation commitments, product type, delivery points and customer diversification.

2006 versus 2005 Results Review



EnCana pursues predictable, profitable growth from a portfolio of long-life resource plays in Canada and the United States.

In the third quarter of 2006 compared to the third quarter of 2005, EnCana:

- Grew total North American sales volumes 3 percent to 4,262 million cubic feet ("MMcf") of gas equivalent per day ("MMcfe/d");
- Grew natural gas sales by 4 percent to 3,359 MMcf/d;
- Reported a 21 percent decrease in natural gas prices to $5.75 per Mcf. Realized natural gas prices, including the impact of financial hedging, averaged $6.57 per Mcf, a decrease of 5 percent;
- Achieved third quarter sales of approximately 47,900 barrels per day ("bbls/d") at EnCana's three steam-assisted gravity drainage ("SAGD") projects (Foster Creek, Christina Lake and Senlac). Production at Foster Creek in the third quarter of 2006 was approximately 37,100 bbls/d compared to approximately 27,000 bbls/d in the same period in 2005;
- Increased production from key resource plays by 12 percent;
- Reported operating costs of $0.84 per Mcfe representing a 22 percent increase mainly due to the higher value of the Canadian dollar, increased electricity costs and workovers;
- Completed the sale of its 50 percent interest in the Chinook heavy oil discovery offshore Brazil for approximately $350 million plus adjustments and recorded a gain on sale of approximately $255 million after-tax;
- Increased net earnings by 411 percent to $1.4 billion mainly due to the unrealized mark-to-market gains and the Brazil gain on sale; and
- Purchased 17.4 million common shares at an average price of $51.95 per share under the Normal Course Issuer Bid ("NCIB") for a total cost of $900 million.

In the nine months 2006 compared to the nine months 2005, EnCana:

- Grew total North American sales volumes 4 percent to 4,287 MMcfe/d;
- Grew natural gas sales by 5 percent to 3,354 MMcf/d;
- Achieved year-to-date sales of approximately 46,900 bbls/d at EnCana's three SAGD projects. Production at Foster Creek in the nine months of 2006 averaged over 35,500 bbls/d compared to approximately 27,100 bbls/d in the same period in 2005;
- Added two new key resource plays – a natural gas play at Bighorn in west central Alberta and an in-situ oilsands project at Christina Lake in northeast Alberta;
- Increased production from key resource plays by 14 percent;
- Reported operating costs of $0.82 per Mcfe representing a 24 percent increase mainly due to the higher value of the Canadian dollar, increased industry activity, electricity costs and workovers;
- Increased cash flow by 10 percent to $5.4 billion;
- Increased net earnings by 371 percent to $5.0 billion;
- Completed the sale of EnCana's Ecuador assets for approximately $1.4 billion, the first stage of the sale of EnCana's natural gas storage operations for approximately $1.3 billion, the sale of the Entrega Pipeline for approximately $244 million and the sale of the Brazil Chinook discovery for approximately $350 million; and
- Approved two 30,000 bbls/d expansions at Foster Creek, the first to start up late 2008 and the second by late 2009.

On October 5, 2006 EnCana and ConocoPhillips announced an agreement to create an integrated, North American heavy oil business consisting of upstream and downstream assets. The transaction, which is subject to the execution of final definitive agreements and regulatory approvals, is expected to close January 2, 2007.

EnCana also builds shareholder value through financial discipline, strength and flexibility. In the nine months 2006, EnCana:

- Purchased 61.1 million common shares at an average price of $48.67 per share under the NCIB for a total cost of $3.0 billion;
- Repaid revolving long-term debt of $512 million and fixed rate long-term debt of $73 million; and
- Reduced Net Debt to Capitalization to 25 percent from 33 percent and Net Debt to Adjusted EBITDA to 0.5x from 1.1x at December 31, 2005.

Business Environment

NATURAL GAS

Natural Gas Price Benchmarks (Average for the period)	Three Months Ended September 30 2006	2006 vs 2005	2005	Nine Months Ended September 30 2006	2006 vs 2005	2005	Year Ended 2005
AECO Price *(C$/Mcf)*	**$ 6.03**	**-26%**	$ 8.17	**$ 7.19**	**-3%**	$ 7.41	$ 8.48
NYMEX Price *($/MMBtu)*	**6.58**	**-22%**	8.49	**7.45**	**4%**	7.16	8.62
Rockies (Opal) Price *($/MMBtu)*	**5.30**	**-21%**	6.71	**5.95**	**-2%**	6.08	6.96
Basis Differential *($/MMBtu)*							
AECO/NYMEX	**1.18**	**-32%**	1.74	**1.10**	**-2%**	1.12	1.59
Rockies/NYMEX	**1.28**	**-28%**	1.78	**1.50**	**39%**	1.08	1.66

A warmer than normal summer and lower prices in the third quarter have helped to reduce the natural gas storage overhang from approximately 600 Bcf as of March 31, 2006 to approximately 360 Bcf as of September 29, 2006. However, this storage surplus contributed to the downward trend in NYMEX gas prices with the third quarter of 2006 averaging $6.58/MMBtu, 22 percent lower than the same period in 2005.

The lower average AECO gas price in the third quarter of 2006 compared with the same period in 2005 can be attributed to the decrease in the NYMEX gas price and a stronger Canadian dollar partially offset by the narrowing of the AECO/NYMEX basis differential. A lower average Rockies (Opal) gas price in the third quarter of 2006 compared to the third quarter of 2005 can be attributed to a lower NYMEX gas price partially offset by a reduced Rockies/NYMEX basis differential. Increased demand in the Rockies region during the summer (July through September) relieved some of the pressure that supply growth in the Rockies had exerted on an already highly utilized pipeline grid. This allowed the Rockies basis differential to strengthen in the third quarter compared to the same period last year. However, this continued supply growth in the Rockies is expected to put further downward pressure on the Rockies basis in the future. EnCana has taken steps to mitigate its projected Rockies price risk from the impact of further deterioration in the Rockies basis differential through the use of financial instrument hedging positions, the details of which are disclosed in Note 14 of the Interim Consolidated Financial Statements.

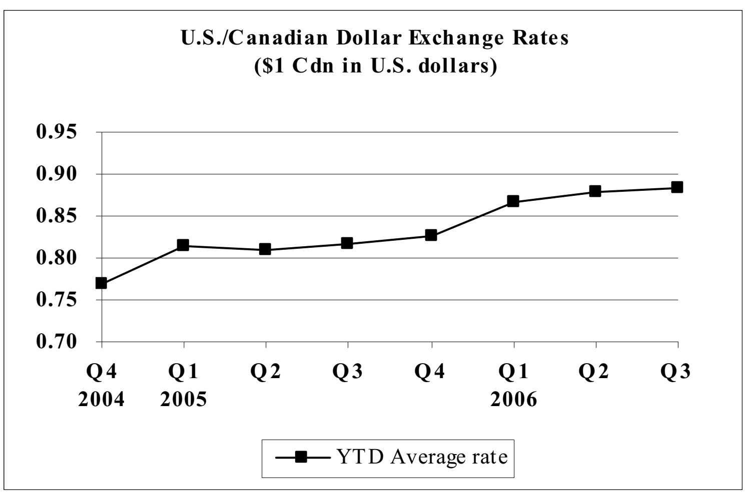
CRUDE OIL

Crude Oil Price Benchmarks	**Three Months Ended September 30**			**Nine Months Ended September 30**			Year Ended
		2006 vs			**2006 vs**		
(Average for the period) ($/bbl)	**2006**	**2005**	2005	**2006**	**2005**	2005	2005
WTI	**$ 70.54**	**11%**	$ 63.31	**$ 68.26**	**23%**	$ 55.61	$ 56.70
WCS	**51.71**	**14%**	45.24	**46.55**	**28%**	36.44	36.39
Differential - WTI/WCS	**18.83**	**4%**	18.07	**21.71**	**13%**	19.17	20.31

Concerns over geopolitical events and U.S. gasoline supplies combined to propel the West Texas Intermediate ("WTI") price above the $70 per bbl level for most of the third quarter. Concerns over Iran's nuclear program, shut-in of Nigerian production due to militant attacks and the ongoing instability in Iraq underscored worries about crude supplies. By the end of the third quarter, crude oil prices had fallen back to the $60 per bbl level as a lack of hurricane activity allowed U.S. refiners to build petroleum product inventories.

Canadian heavy oil differentials in the third quarter were comparable with the same period in 2005 owing to seasonal strength in asphalt and residual fuel oil markets supporting prices for Canadian heavy crude oil. The Western Canadian Select ("WCS") average sales price was 73 percent of WTI for the third quarter of 2006 compared to 71 percent of WTI in the same period of 2005.

U.S./CANADIAN DOLLAR EXCHANGE RATES



The impacts of currency fluctuations on EnCana's results should be considered when analyzing the Interim Consolidated Financial Statements. The value of the Canadian dollar increased by 7 percent or $0.059 to an average of US$0.892 in the third quarter of 2006 from an average of US$0.833 in the same period in 2005.

As a result, EnCana has reported an additional $5.90 of costs for every hundred Canadian dollars spent on capital projects, operating expenses and administrative expenses in the third quarter of 2006 relative to the third quarter of 2005. However, revenues were relatively unaffected by fluctuations in the U.S./Canadian dollar exchange rate because the commodity prices received by EnCana are largely based in U.S. dollars or in Canadian dollars at prices which are closely tied to the value of the U.S. dollar.

	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2006	Year Ended 2005
Average U.S./Canadian dollar exchange rate	**$ 0.892**	**$ 0.883**	$ 0.825
Average U.S./Canadian dollar exchange rate for prior year	**$ 0.833**	**$ 0.817**	$ 0.768
Increase in reported capital, operating and administrative expenditures caused solely by fluctuations in exchange rates, for every hundred Canadian dollars spent	**$ 5.90**	**$ 6.60**	$ 5.70

Acquisitions and Divestitures

In keeping with EnCana's North American resource play strategy, the Company completed the following significant divestitures in 2006:

Three Months Ended March 31

- The sale of the Entrega Pipeline located in Colorado on February 23 for approximately $244 million; and
- The sale of its interests in Ecuador on February 28 for approximately $1.4 billion subject to post-closing adjustments.

Three Months Ended June 30

- The sale of the first stage of EnCana's gas storage business on May 12 for approximately $1.3 billion subject to post-closing adjustments. The second stage is expected to close following receipt of California regulatory approvals, which are expected later this year.

Three Months Ended September 30

- The sale of its 50 percent interest in the Chinook heavy oil discovery offshore Brazil on August 16 for approximately $350 million subject to post-closing adjustments.

Proceeds from these divestitures were directed primarily to the purchase of shares under EnCana's NCIB and debt reduction.

In the third quarter of 2006, EnCana made the decision to divest its assets in Chad and Northern Canada as part of its ongoing program to manage and optimize its portfolio of assets.

Consolidated Financial Results

($ millions, except per share amounts)	Three Months Ended September 30 2006	2006 vs 2005	2005	Nine Months Ended September 30 2006	2006 vs 2005	2005	Year Ended 2005
Total Consolidated							
Cash Flow [1]	**$ 1,894**	**-2%**	$ 1,931	**$ 5,400**	**10%**	$ 4,916	$ 7,426
- per share – diluted	**2.30**	**5%**	2.20	**6.39**	**16%**	5.50	8.35
Net Earnings	**1,358**	**411%**	266	**4,989**	**371%**	1,060	3,426
- per share – basic	**1.68**	**442%**	0.31	**6.02**	**398%**	1.21	3.95
- per share – diluted	**1.65**	**450%**	0.30	**5.90**	**396%**	1.19	3.85
Operating Earnings [2]	**1,078**	**53%**	704	**2,596**	**32%**	1,970	3,241
- per share – diluted	**1.31**	**64%**	0.80	**3.07**	**40%**	2.20	3.64
Continuing Operations							
Cash Flow from Continuing Operations [1]	**1,883**	**3%**	1,823	**5,301**	**16%**	4,572	6,962
Net Earnings from Continuing Operations	**1,343**	**286%**	348	**4,408**	**359%**	960	2,829
- per share – basic	**1.66**	**305%**	0.41	**5.32**	**384%**	1.10	3.26
- per share – diluted	**1.63**	**308%**	0.40	**5.21**	**387%**	1.07	3.18
Operating Earnings from Continuing Operations [2]	**1,064**	**45%**	733	**2,565**	**41%**	1,819	3,048
Revenues, Net of Royalties	**3,921**	**31%**	2,982	**12,395**	**47%**	8,406	14,266

(1) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are described and discussed under “Cash Flow”.

(2) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under “Operating Earnings”.

Consolidated Financial Results (continued)

Quarterly Summary

($ millions, except per share amounts)	**2006** Q3	Q2	Q1	2005 Q4	Q3	Q2	Q1	2004 Q4
Cash Flow [(1)]	**$ 1,894**	$ 1,815	$ 1,691	$ 2,510	$ 1,931	$ 1,572	$ 1,413	$ 1,491
- per share – diluted	**2.30**	2.15	1.96	2.88	2.20	1.76	1.55	1.60
Net Earnings	**1,358**	2,157	1,474	2,366	266	839	(45)	2,580
- per share – basic	**1.68**	2.60	1.74	2.77	0.31	0.96	(0.05)	2.81
- per share – diluted	**1.65**	2.55	1.70	2.71	0.30	0.94	(0.05)	2.77
Operating Earnings [(2)]	**1,078**	824	694	1,271	704	655	611	573
- per share – diluted	**1.31**	0.98	0.80	1.46	0.80	0.73	0.67	0.62
Continuing Operations								
Cash Flow from Continuing Operations [(1)]	**1,883**	1,839	1,579	2,390	1,823	1,502	1,247	1,358
Net Earnings from Continuing Operations	**1,343**	1,593	1,472	1,869	348	774	(162)	1,055
- per share – basic	**1.66**	1.92	1.74	2.19	0.41	0.89	(0.18)	1.15
- per share – diluted	**1.63**	1.88	1.70	2.14	0.40	0.87	(0.18)	1.13
Operating Earnings from Continuing Operations [(2)]	**1,064**	841	660	1,229	733	611	475	513
Revenues, Net of Royalties	**3,921**	3,804	4,670	5,860	2,982	3,386	2,038	3,542

(1) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are described and discussed under "Cash Flow".

(2) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under "Operating Earnings".

CASH FLOW

Cash flow measures are considered non-GAAP but are commonly used in the oil and gas industry to assist management and investors in measuring the Company's ability to finance capital programs and meet financial obligations. The calculation of cash flow is disclosed in the Consolidated Statement of Cash Flows in the Interim Consolidated Financial Statements.

Three Months Ended September 30

EnCana's third quarter 2006 cash flow was $1,894 million, relatively unchanged from the third quarter of 2005. Cash flow from continuing operations increased $60 million as a result of higher liquids prices, realized financial commodity hedge gains and higher natural gas sales volumes offset by lower natural gas prices and higher operating expenses. Cash flow from discontinued operations was $11 million in the third quarter, a decrease of $97 million from the third quarter of 2005.

The increase in cash flow from continuing operations resulted from:

- Average North American liquids prices, excluding financial hedges, increased 9 percent to $50.37 per bbl in the third quarter of 2006 compared to $46.16 per bbl in the same period in 2005;
- North American natural gas sales volumes in the third quarter of 2006 increased 4 percent to 3,359 MMcf/d from 3,222 MMcf/d in the same period in 2005; and
- Realized financial commodity hedging gains were $133 million after-tax (natural gas $167 million gain; crude oil $34 million loss) in the third quarter of 2006 compared with losses of $132 million after-tax (natural gas $85 million loss; crude oil $47 million loss) in the same period in 2005.

The increase in cash flow from continuing operations was partially reduced by:

- Average North American natural gas prices, excluding financial hedges, decreased 21 percent to $5.75 per Mcf in the third quarter of 2006 compared to $7.29 per Mcf in the same period in 2005;
- Operating expenses increased 13 percent to $420 million in the third quarter of 2006 compared with $371 million in the same period in 2005; and
- The current tax provision of $152 million in the third quarter of 2006 compared to $155 million in the same period in 2005. In addition, cash taxes of $49 million in 2006 relating to the sale of the Brazil assets are included in cash flow from investing activities.

Nine Months Ended September 30

EnCana's nine months 2006 cash flow was $5,400 million, an increase of $484 million or 10 percent from the same period in 2005. Cash flow from continuing operations increased $729 million or 16 percent as a result of higher liquids prices, realized financial commodity hedge gains and higher natural gas sales volumes in 2006 partially reduced by increased operating costs and higher cash taxes. Cash flow from discontinued operations was $99 million for the nine months, a decrease of $245 million from the same period in 2005.

The increase in cash flow from continuing operations resulted from:

- Average North American liquids prices, excluding financial hedges, increased 27 percent to $45.36 per bbl in the nine months of 2006 compared to $35.82 per bbl in the same period in 2005;
- North American natural gas sales volumes in the nine months of 2006 increased 5 percent to 3,354 MMcf/d from 3,193 MMcf/d in the same period in 2005; and
- Realized financial commodity hedging gains were $103 million after-tax (natural gas $197 million gain; crude oil $94 million loss) in the nine months of 2006 compared with losses of $212 million after-tax (natural gas $72 million loss; crude oil $140 million loss) in the same period in 2005.

The increase in cash flow from continuing operations was partially reduced by:

- Operating expenses increased 24 percent to $1,227 million in the nine months of 2006 compared with $986 million in the same period in 2005; and
- An increase in the current tax provision of $345 million to $780 million in the nine months of 2006 compared with $435 million in the same period in 2005. In addition, cash taxes of $49 million in 2006 and $591 million in 2005 relating to the sale of assets are included in cash flow from investing activities.

NET EARNINGS

EnCana's nine months 2006 net earnings were $4,989 million compared with $1,060 million in the same period in 2005. Net earnings for the period include unrealized mark-to-market gains after-tax of $1,275 million (2005 – losses after-tax of $1,023 million) and the effect of the tax rate reduction of $457 million (2005 - nil). In addition, net earnings from discontinued operations increased $481 million to $581 million mainly due to the gain on sale of the gas storage assets in the nine months of 2006 offset partially by the loss on sale of Ecuador (discussed in the Discontinued Operations section of this MD&A).

Three Months Ended September 30

EnCana's third quarter 2006 net earnings from continuing operations were $1,343 million, an increase of $995 million compared with 2005. In addition to the items affecting cash flow as detailed previously, significant items affecting net earnings were:

- Unrealized mark-to-market gains of $282 million after-tax (natural gas $227 million gain; crude oil and other $55 million gain) in 2006 compared with losses of $551 million after-tax (natural gas $586 million loss; crude oil and other $35 million gain) in 2005;
- A gain on sale of approximately $255 million after-tax from the sale of a 50 percent interest in the Chinook heavy oil discovery offshore Brazil;
- Lower interest expense in 2006 of $136 million mainly due to a one time charge of $121 million in 2005 related to the early retirement of long-term debt;
- An increase in depreciation, depletion and amortization ("DD&A") of $121 million as a result of the higher value of the Canadian dollar, higher DD&A rates and increased sales volumes; and
- Unrealized foreign exchange losses of $3 million after-tax in 2006 compared with gains of $166 million after-tax in 2005.

Nine Months Ended September 30

Net earnings from continuing operations for the nine months 2006 were $4,408 million, an increase of $3,448 million compared with 2005. In addition to the items affecting cash flow as detailed previously, significant items affecting net earnings were:

- Unrealized mark-to-market gains of $1,258 million after-tax (natural gas $1,191 million gain; crude oil and other $67 million gain) in 2006 compared with losses of $972 million after-tax (natural gas $951 million loss; crude oil and other $21 million loss) in 2005;
- Lower interest expense in 2006 of $166 million mainly due to a one time charge of $121 million in 2005 related to the early retirement of long-term debt;
- An increase in DD&A of $328 million as a result of the higher value of the Canadian dollar, higher DD&A rates and increased sales volumes; and
- A decrease in future income taxes due to Canadian federal and provincial tax rate reductions of $457 million.

OPERATING EARNINGS

Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures that adjust net earnings and net earnings from continuing operations by non-operating items that Management believes reduce the comparability of the Company's underlying financial performance between periods. The following reconciliation of Operating Earnings and Operating Earnings from Continuing Operations has been prepared to provide investors with information that is more comparable between periods.

Summary of Total Operating Earnings

	Three Months Ended September 30			**Nine Months Ended September 30**			Year Ended
($ millions)	**2006**	**2006 vs 2005**	2005	**2006**	**2006 vs 2005**	2005	2005
Net Earnings, as reported	**$ 1,358**	**411%**	$ 266	**$ 4,989**	**371%**	$ 1,060	$ 3,426
Add back (losses) & deduct gains:							
- Unrealized mark-to-market accounting gain (loss), after-tax	**285**	**147%**	(604)	**1,275**	**225%**	(1,023)	(277)
- Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt, after-tax (1)	**(3)**	**-102%**	166	**128**	**13%**	113	92
- Gain (loss) on sale of discontinued operations, after-tax	**(2)**	**-**	-	**533**	**-**	-	370
- Future tax recovery due to tax rate reductions	**-**	**-**	-	**457**	**-**	-	-
Operating Earnings (2) (3)	**$ 1,078**	**53%**	$ 704	**$ 2,596**	**32%**	$ 1,970	$ 3,241

(1) The majority of the unrealized gains or losses that relate to U.S. dollar debt issued in Canada are for debt with maturity dates in excess of 5 years.

(2) Operating Earnings is a non-GAAP measure that shows net earnings excluding the after-tax gain or loss from the disposition of discontinued operations, the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the after-tax gain or loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the changes in statutory income tax rates.

(3) Unrealized gains or losses have no impact on cash flow.

Summary of Total Operating Earnings (continued)

($ per Common Share – Diluted)	Three Months Ended September 30 2006	2006 vs 2005	2005	Nine Months Ended September 30 2006	2006 vs 2005	2005	Year Ended 2005
Net Earnings, as reported	**$ 1.65**	**450%**	$ 0.30	**$ 5.90**	**396%**	$ 1.19	$ 3.85
Add back (losses) & deduct gains:							
- Unrealized mark-to-market accounting gain (loss), after-tax	**0.34**	**149%**	(0.69)	**1.51**	**232%**	(1.14)	(0.31)
- Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt, after-tax (1)	**-**	**-**	0.19	**0.15**	**15%**	0.13	0.10
- Gain on sale of discontinued operations, after-tax	**-**	**-**	-	**0.63**	**-**	-	0.42
- Future tax recovery due to tax rate reductions	**-**	**-**	-	**0.54**	**-**	-	-
Operating Earnings (2) (3)	**$ 1.31**	**64%**	$ 0.80	**$ 3.07**	**40%**	$ 2.20	$ 3.64

(1) The majority of the unrealized gains or losses that relate to U.S. dollar debt issued in Canada are for debt with maturity dates in excess of 5 years.

(2) Operating Earnings is a non-GAAP measure that shows net earnings excluding the after-tax gain or loss from the disposition of discontinued operations, the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the after-tax gain or loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the changes in statutory income tax rates.

(3) Unrealized gains or losses have no impact on cash flow.

Summary of Operating Earnings from Continuing Operations

($ millions)	Three Months Ended September 30 2006	2006 vs 2005	2005	Nine Months Ended September 30 2006	2006 vs 2005	2005	Year Ended 2005
Net Earnings from Continuing Operations, as reported	**$ 1,343**	**286%**	$ 348	**$ 4,408**	**359%**	$ 960	$ 2,829
Add back (losses) & deduct gains:							
- Unrealized mark-to-market accounting gain (loss), after-tax	**282**	**151%**	(551)	**1,258**	**229%**	(972)	(311)
- Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt, after-tax (1)	**(3)**	**-102%**	166	**128**	**13%**	113	92
- Future tax recovery due to tax rate reductions	**-**	**-**	-	**457**	**-**	-	-
Operating Earnings from Continuing Operations (2) (3)	**$ 1,064**	**45%**	$ 733	**$ 2,565**	**41%**	$ 1,819	$ 3,048

(1) The majority of the unrealized gains or losses that relate to U.S. dollar debt issued in Canada are for debt with maturity dates in excess of 5 years.

(2) Operating Earnings from Continuing Operations is a non-GAAP measure that shows net earnings from continuing operations excluding the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the after-tax gain or loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the changes in statutory income tax rates.

(3) Unrealized gains or losses have no impact on cash flow.

RESULTS OF OPERATIONS

Upstream Operations

Financial Results from Continuing Operations

Three Months Ended September 30

($ millions)	2006				2005			
	Produced Gas	**Crude Oil & NGLs**	**Other**	**Total**	Produced Gas	Crude Oil & NGLs	Other	Total
Revenues, Net of Royalties	**$ 2,037**	**$ 650**	**$ 75**	**$ 2,762**	$ 2,043	$ 561	$ 76	$ 2,680
Expenses								
Production and mineral taxes	**65**	**14**	**-**	**79**	96	11	-	107
Transportation and selling	**138**	**21**	**-**	**159**	119	14	-	133
Operating	**221**	**109**	**71**	**401**	190	73	85	348
Operating Cash Flow	**$ 1,613**	**$ 506**	**$ 4**	**2,123**	$ 1,638	$ 463	$ (9)	2,092
Depreciation, depletion and amortization				**770**				649
Segment Income				**$ 1,353**				$ 1,443

Financial Results from Continuing Operations

Nine Months Ended September 30

($ millions)	2006				2005			
	Produced Gas	**Crude Oil & NGLs**	**Other**	**Total**	Produced Gas	Crude Oil & NGLs	Other	Total
Revenues, Net of Royalties	**$ 6,187**	**$ 1,786**	**$ 229**	**$ 8,202**	$ 5,525	$ 1,293	$ 195	$ 7,013
Expenses								
Production and mineral taxes	**228**	**41**	**-**	**269**	254	37	-	291
Transportation and selling	**394**	**56**	**-**	**450**	345	45	-	390
Operating	**670**	**290**	**217**	**1,177**	525	222	189	936
Operating Cash Flow	**$ 4,895**	**$ 1,399**	**$ 12**	**6,306**	$ 4,401	$ 989	$ 6	5,396
Depreciation, depletion and amortization				**2,282**				1,957
Segment Income				**$ 4,024**				$ 3,439

Upstream Revenues

Three Months Ended September 30

Revenues, net of royalties, increased in the third quarter of 2006 compared with the same period in 2005 due to:

- A 9 percent increase in North American liquids prices and a 4 percent increase in North American natural gas volumes; and
- Realized financial commodity hedging gains totaled $206 million in the third quarter of 2006 compared to losses of $196 million for the same period in 2005.

Nine Months Ended September 30

Revenues, net of royalties, increased in the nine months 2006 compared with the same period in 2005 as a result of:

- A 27 percent increase in North American liquids prices combined with a slight increase in liquids sales volumes;
- A 5 percent increase in North American natural gas sales volumes; and
- Realized financial commodity hedging gains totaled $157 million in the nine months of 2006 compared to losses of $330 million for the same period in 2005.

Revenue Variances for 2006 Compared to 2005 from Continuing Operations

Three Months Ended September 30
($ millions)

	2005 Revenues, Net of Royalties	Revenue Variances in: Price [(1)]	Volume	**2006 Revenues, Net of Royalties**
Produced Gas				
Canada	$ 1,317	$ (38)	$ 23	**$ 1,302**
United States	726	(51)	60	**735**
Total Produced Gas	$ 2,043	$ (89)	$ 83	**$ 2,037**
Crude Oil and NGLs				
Canada	$ 490	$ 76	$ 8	**$ 574**
United States	71	16	(11)	**76**
Total Crude Oil and NGLs	$ 561	$ 92	$ (3)	**$ 650**

(1) Includes the impact of realized financial hedging.

Nine Months Ended September 30
($ millions)

	2005 Revenues, Net of Royalties	Revenue Variances in: Price [(1)]	Volume	**2006 Revenues, Net of Royalties**
Produced Gas				
Canada	$ 3,634	$ 294	$ 111	**$ 4,039**
United States	1,891	73	184	**2,148**
Total Produced Gas	$ 5,525	$ 367	$ 295	**$ 6,187**
Crude Oil and NGLs				
Canada	$ 1,113	$ 440	$ 25	**$ 1,578**
United States	180	55	(27)	**208**
Total Crude Oil and NGLs	$ 1,293	$ 495	$ (2)	**$ 1,786**

(1) Includes the impact of realized financial hedging.

Three Months Ended September 30

The increase in liquids sales prices and natural gas realized financial commodity hedging gains accounts for the majority of the approximately 3 percent increase in revenues, net of royalties, in the third quarter of 2006 compared with the same period in 2005. The balance of the increase in revenues results from an increase in natural gas sales volumes.

Produced gas volumes in Canada increased slightly in the third quarter of 2006 mainly due to drilling success in the key resource plays of Coalbed Methane ("CBM") in central and southern Alberta, Cutbank Ridge in northeast British Columbia and Bighorn in west central Alberta. Natural declines, planned turnarounds, unscheduled maintenance and weather related delays for the Shallow Gas and Greater Sierra key resource plays and conventional properties resulted in lower production volumes.

Produced gas volumes in the U.S. increased 9 percent in the third quarter of 2006 as a result of drilling success at Fort Worth, Piceance, East Texas and Jonah as well as the impact of property acquisitions in the Fort Worth Basin in late 2005.

North American crude oil and NGLs volumes were basically unchanged as a result of production increases at Foster Creek offset by the Pelican Lake royalty payout, lower production due to weather related delays in southern Alberta and natural declines. EnCana's

Pelican Lake property reached payout in April 2006 which increased the royalty payments to the Alberta Government and reduced EnCana's net revenue interest crude oil volumes by approximately 6,000 bbls/d from the point of payout.

Nine Months Ended September 30

The increase in liquids sales prices and realized financial commodity hedging gains accounts for approximately 75 percent of the increase in revenues, net of royalties, in the nine months of 2006 compared with the same period in 2005. The balance of the increase in revenues results from an increase in natural gas sales volumes.

Produced gas volumes in Canada increased 3 percent in the nine months of 2006 mainly due to drilling success in the key resource plays of CBM, Cutbank Ridge and Bighorn. Natural declines, unscheduled maintenance and weather related delays resulted in lower production volumes from the Shallow Gas key resource play as well as conventional properties.

Produced gas volumes in the U.S. increased 9 percent in the nine months of 2006 as a result of drilling success at Fort Worth, Jonah, Piceance and East Texas as well as the impact of property acquisitions in the Fort Worth Basin in late 2005.

North American crude oil and NGLs volumes increased slightly as a result of production increases at Foster Creek and Senlac heavy oil properties. These increases were offset somewhat by the Pelican Lake royalty payout early in the second quarter of 2006, the dispositions of non-core Canadian conventional producing assets in June 2005, weather related delays in southern Alberta and natural declines.

Upstream Sales Volumes

Quarterly Sales Volumes

	2006			2005				2004
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Produced Gas *(MMcf/d)*	**3,359**	3,361	3,343	3,326	3,222	3,212	3,146	3,087
Crude Oil *(bbls/d)*	**126,658**	129,070	138,370	134,178	124,402	132,294	130,826	132,061
NGLs *(bbls/d)*	**23,907**	24,400	24,421	25,111	26,055	24,814	26,358	27,409
Continuing Operations *(MMcfe/d)* (1)	**4,262**	4,282	4,320	4,282	4,125	4,155	4,089	4,044
Discontinued Operations								
Ecuador *(bbls/d)* (2)	**-**	-	50,150	69,943	68,710	73,176	72,487	77,876
United Kingdom *(BOE/d)* (3)	**-**	-	-	-	-	-	-	13,927
Discontinued Operations *(MMcfe/d)* (1)	**-**	-	301	419	412	439	435	551
Total *(MMcfe/d)* (1)	**4,262**	4,282	4,621	4,701	4,537	4,594	4,524	4,595

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.
(2) As the Ecuador sale occurred on February 28, 2006 only two months of volumes are included in Q1 2006.
(3) Includes natural gas and liquids (converted to BOE).

Sales volumes from continuing operations in the third quarter of 2006 increased 3 percent or 137 MMcfe/d from the comparable period in 2005 due to:

- Production from EnCana's key resource plays increased 12 percent; 12 percent for natural gas and 10 percent for crude oil;
- Drilling success in the key resource gas plays of CBM, Cutbank Ridge, Bighorn, Fort Worth, Piceance, East Texas and Jonah offset somewhat by natural declines, planned turnarounds, unscheduled maintenance and weather related delays for the Shallow Gas and Greater Sierra key resource plays; and
- Expansion of Foster Creek facilities partially offset by the Pelican Lake royalty payout in April 2006.

Sales volumes from continuing operations in the nine months 2006 increased 4 percent or 165 MMcfe/d from the comparable period in 2005 for the following reasons:

- Production from EnCana's key resource plays increased 14 percent; 14 percent for natural gas and 18 percent for crude oil;

- Drilling success in the key resource gas plays of CBM, Cutbank Ridge, Bighorn, Fort Worth, Jonah, Piceance and East Texas as well as the impact of property acquisitions in the Fort Worth Basin in late 2005; and
- Expansion of Foster Creek facilities in the fourth quarter of 2005.

Key Resource Plays

	Daily Production							
	2006				2005			
	YTD	**Q3**	Q2	Q1	YTD	Q3	Q2	Q1
Natural Gas *(MMcf/d)*								
Jonah	**455**	**455**	450	461	429	440	416	431
Piceance	**324**	**331**	324	316	300	302	302	300
East Texas	**100**	**106**	93	99	87	94	85	82
Fort Worth	**102**	**104**	108	93	64	66	63	61
Greater Sierra	**214**	**209**	224	208	217	225	228	195
Cutbank Ridge	**160**	**167**	173	140	81	105	80	56
Bighorn	**88**	**97**	95	72	55	57	53	56
CBM Integrated [(1)]	**189**	**209**	179	177	94	117	104	59
Shallow Gas	**599**	**593**	590	615	624	616	633	625
Oil *(Mbbls/d)*								
Foster Creek	**36**	**37**	33	36	27	27	24	30
Christina Lake	**6**	**6**	6	6	5	6	7	4
Pelican Lake	**25**	**23**	22	29	25	27	27	21
Total *(MMcfe/d)*	**2,628**	**2,668**	2,601	2,609	2,298	2,381	2,312	2,197

(1) CBM quarterly volumes restated to report commingled gas volumes from the coal and sand intervals based on regulatory approval.

Per Unit Results – Produced Gas

Three Months Ended September 30

	Canada			**United States**		
($ per thousand cubic feet)	**2006**	**2006 vs 2005**	2005	**2006**	**2006 vs 2005**	2005
Price [(1)]	**$ 5.59**	**-22%**	$ 7.18	**$ 6.04**	**-20%**	$ 7.51
Expenses						
Production and mineral taxes	**0.09**	**-10%**	0.10	**0.43**	**-43%**	0.75
Transportation and selling	**0.37**	**3%**	0.36	**0.57**	**16%**	0.49
Operating	**0.78**	**15%**	0.68	**0.59**	**7%**	0.55
Netback	**$ 4.35**	**-28%**	$ 6.04	**$ 4.45**	**-22%**	$ 5.72
Gas Sales Volumes *(MMcf/d)*	**2,162**	**2%**	2,123	**1,197**	**9%**	1,099

(1) Excludes the impact of realized financial hedging.

Per Unit Results – Produced Gas

Nine Months Ended September 30

($ per thousand cubic feet)	Canada 2006	Canada 2006 vs 2005	Canada 2005	United States 2006	United States 2006 vs 2005	United States 2005
Price [1]	**$ 6.31**	**-**	$ 6.33	**$ 6.60**	**-2%**	$ 6.73
Expenses						
Production and mineral taxes	**0.12**	**20%**	0.10	**0.49**	**-28%**	0.68
Transportation and selling	**0.36**	**-3%**	0.37	**0.52**	**13%**	0.46
Operating	**0.78**	**20%**	0.65	**0.64**	**28%**	0.50
Netback	**$ 5.05**	**-3%**	$ 5.21	**$ 4.95**	**-3%**	$ 5.09
Gas Sales Volumes *(MMcf/d)*	**2,178**	**3%**	2,118	**1,176**	**9%**	1,075

(1) Excludes the impact of realized financial hedging.

Three Months Ended September 30

EnCana's North American natural gas price for the third quarter of 2006, excluding the impact of financial hedges, was $5.75 per Mcf, a decrease of 21 percent compared to the same period in 2005. North American realized financial commodity hedging gains on natural gas for the third quarter of 2006 were approximately $254 million or $0.82 per Mcf compared to losses of approximately $117 million or $0.39 per Mcf in the third quarter of 2005.

Natural gas per unit production and mineral taxes, which are generally calculated as a percentage of revenues, have decreased slightly in Canada for the third quarter of 2006 compared to the same period in 2005, mainly due to lower natural gas prices offset partially by the higher value of the Canadian dollar. Natural gas per unit production and mineral taxes in the U.S. decreased $0.32 per Mcf or 43 percent in the third quarter of 2006 compared to the same period in 2005 mainly as a result of reduced production and severance tax rates for Colorado properties.

Natural gas per unit transportation and selling costs for the U.S. increased $0.08 per Mcf or 16 percent for the third quarter of 2006 compared to the same period in 2005 primarily as a result of higher transportation costs on operated wells from Piceance, East Texas, Fort Worth and certain other Colorado properties.

Natural gas per unit operating expenses in Canada for the third quarter of 2006 were 15 percent or $0.10 per Mcf higher than the comparable period in 2005 as a result of the higher value of the Canadian dollar, increased industry activity, prior period equalizations and increased electricity rates. Natural gas per unit operating expenses in the U.S. increased 7 percent or $0.04 per Mcf for the third quarter of 2006 compared to the same period in 2005 mainly as a result of increased industry activity, higher water disposal costs, chemicals, salaries and repairs and maintenance expenses primarily in the Piceance area. Increases in operating costs in both Canada and the U.S. were offset partially by lower long-term compensation costs in the third quarter of 2006 compared to the same period in 2005 due to the lower EnCana share price.

Nine Months Ended September 30

EnCana's North American natural gas price for the nine months 2006, excluding the impact of financial hedges, was $6.41 per Mcf, down slightly compared to the same period in 2005. North American realized financial commodity hedging gains on natural gas for the nine months 2006 were approximately $298 million or $0.33 per Mcf compared to losses of approximately $108 million or $0.12 per Mcf in the nine months of 2005.

Natural gas per unit production and mineral taxes increased $0.02 per Mcf or 20 percent in Canada for the nine months 2006 compared to the same period in 2005, mainly due to higher natural gas prices and the higher value of the Canadian dollar. Natural gas per unit production and mineral taxes in the U.S. decreased $0.19 per Mcf or 28 percent in the nine months 2006 compared to the same period in 2005 mainly as a result of reduced production and severance tax rates for Colorado properties.

Natural gas per unit transportation and selling costs for the U.S. increased $0.06 per Mcf or 13 percent for the nine months 2006 compared to the same period of 2005 primarily as a result of higher transportation costs on operated wells from Piceance, Fort Worth, East Texas and certain other Colorado properties. Natural gas transportation and selling costs in the U.S. include $14 million for the one time charge for the buyout of a third party physical gas contract in the first quarter of 2006, which had been in place since 2000. The buyout amount has not been included in the per unit calculation.

Natural gas per unit operating expenses in Canada for the nine months 2006 were 20 percent or $0.13 per Mcf higher than the comparable period in 2005 as a result of increased industry activity, the higher value of the Canadian dollar, increased salaries, property taxes and electricity rates. Natural gas per unit operating expenses in the U.S. increased 28 percent or $0.14 per Mcf for the nine months of 2006 compared to the same period in 2005 mainly as a result of increased industry activity, higher water disposal costs, higher salaries and benefits due to increased staffing levels, repairs and maintenance and workover expenses primarily in the Piceance area. Increases in operating costs in both Canada and the U.S. were offset partially by lower long-term compensation costs in the nine months of 2006 compared to the same period in 2005 due to the lower EnCana share price.

Per Unit Results – Crude Oil

	North America					
	Three Months Ended September 30			Nine Months Ended September 30		
($ per barrel)	**2006**	**2006 vs 2005**	2005	**2006**	**2006 vs 2005**	2005
Price [1]	**$ 48.74**	**8%**	$ 45.16	**$ 43.44**	**28%**	$ 34.06
Expenses						
Production and mineral taxes	**0.81**	**69%**	0.48	**0.78**	**39%**	0.56
Transportation and selling	**1.74**	**51%**	1.15	**1.50**	**22%**	1.23
Operating	**9.55**	**48%**	6.45	**8.11**	**28%**	6.32
Netback	**$ 36.64**	**-1%**	$ 37.08	**$ 33.05**	**27%**	$ 25.95
Crude Oil Sales Volumes *(bbls/d)*	**126,658**	**2%**	124,402	**131,323**	**2%**	129,151

(1) Excludes the impact of realized financial hedging.

Three Months Ended September 30

The increase in EnCana's North American crude oil price for the third quarter of 2006, excluding the impact of financial hedges, reflects the 14 percent increase in the benchmark WCS crude oil price compared to the same period in 2005. North American realized financial commodity hedging losses on crude oil were approximately $48 million or $3.45 per bbl for the third quarter of 2006 compared to losses of approximately $79 million or $5.70 per bbl for the comparable period in 2005.

Heavy oil sales in the third quarter of 2006 were unchanged from the comparable period of 2005, approximately 65% of total oil sales, with the increase in heavy oil production from Foster Creek being offset by the Pelican Lake royalty payout in April 2006.

North American crude oil per unit production and mineral taxes increased 69 percent or $0.33 per bbl in the third quarter of 2006 compared to the same period in 2005 primarily due to the impact of higher overall prices, increased production from the Weyburn and Senlac properties in Saskatchewan which are subject to freehold production tax and Saskatchewan resource tax and the higher value of the Canadian dollar.

North American crude oil per unit transportation and selling costs increased 51 percent or $0.59 per bbl in the third quarter of 2006 compared to the same period in 2005 primarily due to a higher proportion of Canadian heavy crude oil volumes being delivered to the U.S. Gulf Coast to capture higher selling prices and the higher value of the Canadian dollar.

North American crude oil per unit operating costs for the third quarter of 2006 increased 48 percent or $3.10 per bbl compared to the same period in 2005 mainly due to workovers at Foster Creek, increased electricity rates, a prior period adjustment for a non-operated property, increased industry activity, the higher value of the Canadian dollar and lower production from Pelican Lake as a result of the royalty payout in the second quarter of 2006. The increased proportion of crude oil volumes from SAGD projects, which have higher operating costs compared to EnCana's other properties, also increased the overall crude oil per unit operating costs.

Nine Months Ended September 30

The increase in EnCana's North American crude oil price for the nine months 2006, excluding the impact of financial hedges, reflects the 28 percent increase in the benchmark WCS crude oil price compared to the same period in 2005. North American realized financial commodity hedging losses on crude oil were approximately $141 million or $3.33 per bbl for the nine months of 2006 compared to losses of approximately $222 million or $5.25 per bbl for the comparable period in 2005.

Heavy oil sales in the nine months 2006 increased to 66 percent of total oil sales from 63 percent in the comparable period of 2005. This increase was mainly due to an increase in heavy oil production from the Foster Creek and Senlac properties combined with the dispositions of non-core conventional assets in June 2005 primarily producing light/medium oil offset by the Pelican Lake royalty payout in April 2006.

North American crude oil per unit production and mineral taxes increased 39 percent or $0.22 per bbl in the nine months 2006 compared to the same period in 2005 primarily due to the impact of higher overall prices, increased production from the Weyburn property in Saskatchewan which is subject to freehold production tax and Saskatchewan resource tax and the higher value of the Canadian dollar.

North American crude oil per unit transportation and selling costs increased 22 percent or $0.27 per bbl in the nine months 2006 compared to the same period in 2005 primarily due to a higher proportion of Canadian heavy crude oil volumes being delivered to the U.S. Gulf Coast to capture higher selling prices and the higher value of the Canadian dollar.

North American crude oil per unit operating costs for the nine months 2006 increased 28 percent or $1.79 per bbl compared to the same period in 2005 mainly due to workovers at Foster Creek, the higher value of the Canadian dollar, higher electricity rates, increased industry activity and lower production from Pelican Lake as a result of the royalty payout in the second quarter of 2006. The increased proportion of crude oil volumes from SAGD projects, which have higher operating costs compared to EnCana's other properties, also increased the overall crude oil per unit operating costs.

Per Unit Results – NGLs

Three Months Ended September 30

($ per barrel)	Canada 2006	Canada 2006 vs 2005	Canada 2005	United States 2006	United States 2006 vs 2005	United States 2005
Price [(1)]	**$ 55.95**	**18%**	$ 47.39	**$ 61.76**	**15%**	$ 53.92
Expenses						
Production and mineral taxes	**-**	**-**	-	**4.42**	**-19%**	5.46
Transportation and selling	**0.74**	**54%**	0.48	**0.01**	**-**	0.01
Netback	**$ 55.21**	**18%**	$ 46.91	**$ 57.33**	**18%**	$ 48.45
NGLs Sales Volumes *(bbls/d)*	**11,387**	**-5%**	11,924	**12,520**	**-11%**	14,131

(1) Excludes the impact of realized financial hedging.

Per Unit Results – NGLs

Nine Months Ended September 30

($ per barrel)	Canada 2006	Canada 2006 vs 2005	Canada 2005	United States 2006	United States 2006 vs 2005	United States 2005
Price [1]	**$ 53.29**	**26%**	$ 42.39	**$ 58.07**	**25%**	$ 46.57
Expenses						
Production and mineral taxes	**-**	**-**	-	**4.05**	**-13%**	4.68
Transportation and selling	**0.69**	**68%**	0.41	**0.01**	**-**	0.01
Netback	**$ 52.60**	**25%**	$ 41.98	**$ 54.01**	**29%**	$ 41.88
NGLs Sales Volumes *(bbls/d)*	**11,665**	**-1%**	11,779	**12,577**	**-10%**	13,962

[1] Excludes the impact of realized financial hedging.

Three Months Ended September 30

The increase in NGLs realized prices in the third quarter of 2006 compared to the same period in 2005 generally correlates with higher WTI oil prices.

U.S. NGLs per unit production and mineral taxes in the U.S. decreased 19 percent or $1.04 per bbl in the third quarter of 2006 compared to the same period in 2005 mainly as a result of reduced production and severance tax rates for Colorado properties.

U.S. NGLs sales volumes decreased 11 percent as a result of natural declines at certain Colorado properties which have a high liquids component.

Nine Months Ended September 30

The increase in NGLs realized prices in the nine months 2006 compared to the same period in 2005 generally correlates with higher WTI oil prices.

U.S. NGLs per unit production and mineral taxes in the U.S. decreased 13 percent or $0.63 per bbl in the nine months 2006 compared to the same period in 2005 mainly as a result of reduced production and severance tax rates for Colorado properties.

U.S. NGLs sales volumes decreased 10 percent as a result of natural declines at certain Colorado properties which have a high liquids component.

Upstream Depreciation, Depletion and Amortization

DD&A expenses in the nine months 2006 increased $325 million or 17 percent from the same period in 2005 for the following reasons:

- North American sales volumes increased 4 percent; and
- Unit of production DD&A rates were $1.93 per Mcfe in the nine months of 2006 compared to $1.72 per Mcfe in the same period in 2005. Rates were higher in the nine months of 2006 compared to the same period of 2005 as a result of increased future development costs and the higher value of the Canadian dollar partially reduced by the effect of the Gulf of Mexico sale in May 2005.

Market Optimization

Financial Results ($ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
Revenues	**$ 731**	$ 1,112	**$ 2,272**	$ 2,850
Expenses				
Transportation and selling	**4**	4	**17**	10
Operating	**18**	24	**49**	53
Purchased product	**677**	1,083	**2,160**	2,783
Operating Cash Flow	**32**	1	**46**	4
Depreciation, depletion and amortization	**3**	2	**8**	7
Segment Income (Loss)	**$ 29**	$ (1)	**$ 38**	$ (3)

Market Optimization results for the third quarter of 2006 and for the nine months of 2006 include power generation income of $13 million and $11 million respectively, reflecting very high Alberta power pool prices realized by the Company's 100% owned Cavalier and 50% owned Balzac power plants.

On January 1, 2006, EnCana adopted Emerging Issues Task Force ("EITF") Abstract No. 04-13 – Accounting for Purchases and Sales of Inventory with the Same Counterparty. The effect is to record purchases and sales of inventory that are entered into in contemplation of each other with the same counterparty on a net basis in the Consolidated Statement of Earnings. This change has been adopted prospectively and has no effect on the earnings of the reported periods. These purchases and sales are used to optimize transportation or fulfill marketing arrangements. As a result of the adoption of this policy, reported revenues and purchased product costs for the nine months of 2006 included offsets of $2,339 million.

Corporate

Financial Results ($ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
Revenues	**$ 428**	$ (810)	**$ 1,921**	$ (1,457)
Expenses				
Operating	**1**	(1)	**1**	(3)
Depreciation, depletion and amortization	**18**	19	**56**	54
Segment Income (Loss)	**$ 409**	$ (828)	**$ 1,864**	$ (1,508)
Administrative	**54**	78	**187**	205
Interest, net	**83**	219	**254**	420
Accretion of asset retirement obligation	**13**	9	**37**	27
Foreign exchange (gain) loss, net	**-**	(212)	**(158)**	(61)
Stock-based compensation – options	**-**	4	**-**	12
(Gain) on dispositions	**(304)**	-	**(321)**	-

The nine months 2006 corporate revenues include $1,921 million in unrealized mark-to-market gains related to financial commodity hedge contracts compared with $1,457 million unrealized mark-to-market losses in the same period in 2005.

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

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2006**	2005	**2006**	2005
Continuing Operations				
Natural Gas	**$ 348**	$ (861)	**$ 1,820**	$ (1,425)
Crude Oil	**80**	51	**101**	(32)
	428	(810)	**1,921**	(1,457)
Expenses	**-**	(1)	**2**	(3)
	428	(809)	**1,919**	(1,454)
Income Tax Expense (Recovery)	**146**	(258)	**661**	(482)
Unrealized Mark-to-Market Gains (Losses)	**$ 282**	$ (551)	**$ 1,258**	$ (972)

Price volatility has impacted net earnings as a result of EnCana's price risk management activities. On September 30, 2006 the forward price curve for the remainder of 2006 for WTI was basically unchanged from December 31, 2005 at $64.36 per bbl while NYMEX gas decreased by 48 percent to $5.72 per Mcf.

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

Administrative expenses decreased $24 million in the third quarter and $18 million for the nine months ended September 30, 2006 compared to the same periods in 2005. The year-to-date decrease is primarily due to lower long-term compensation expenses of $37 million as a result of the lower EnCana share price offset by an increase of $15 million due to the change in U.S./Canadian dollar exchange rates. Administrative expenses in the nine months 2006 were $0.16 per Mcfe, compared with $0.18 per Mcfe in 2005.

Interest expense in the third quarter of 2006 decreased by $136 million from the same period in 2005 mainly as a result of a $121 million one time charge incurred in 2005 to retire certain medium term notes and lower outstanding debt in 2006 due to repayments using the sales proceeds from the Ecuador and gas storage dispositions. EnCana's total long-term debt, including current portion, decreased $549 million to $6,227 million at September 30, 2006 compared with $6,776 million at December 31, 2005. EnCana's 2006 year-to-date weighted average interest rate on outstanding debt was 5.7 percent, up from an average of approximately 5.3 percent in the same period in 2005 as a result of a higher proportion of fixed rate debt outstanding as well as increases in interest rates.

The foreign exchange gain of $158 million in the nine months ended September 30, 2006 is primarily due to the change in the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada and by other miscellaneous gains offset by a foreign exchange loss which resulted when EnCana reduced its net investment in debt amounts owed to it by a foreign self-sustaining subsidiary. Under Canadian GAAP, EnCana is required to translate U.S. dollar denominated long-term debt issued from Canada into Canadian dollars at the period-end exchange rate. Resulting unrealized foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings. Other foreign exchange gains and losses result from the settlement of foreign currency transactions and the translation of EnCana's monetary assets and liabilities.

The gain on dispositions in 2006 relates to the dispositions of the Chinook heavy oil discovery offshore Brazil in the third quarter and the Entrega pipeline in the first quarter.

Income Tax

The effective tax rate for the nine months ended September 2006 is 25.6 percent compared to 27.5 percent for the equivalent period in 2005. The decrease is largely due to a decrease in future income tax expense of $457 million as a result of reductions in the Canadian federal and Alberta corporate tax rates which were enacted in the second quarter of 2006. The Canadian federal tax rate is to be reduced by one percent annually over the 2008 - 2010 period. The Alberta tax rate has been reduced from 11.5 percent to 10.0 percent effective April 1, 2006.

Cash taxes included in cash flow for the nine months 2006 were $780 million compared to $435 million in the same period in 2005; an increase of $345 million due to the increased taxable income in 2006. An additional $49 million of cash tax was incurred in the third quarter 2006 resulting from the disposition of the Brazil operations compared to $591 million of cash tax in the second quarter 2005 as a result of the disposition of the Gulf of Mexico operations. These amounts are included in investing activities in the consolidated statement of cash flows.

Further information regarding EnCana's effective tax rate can be found in Note 8 to the Interim Consolidated Financial Statements. Income tax is an annual calculation and EnCana's effective rate in any year is a function of the relationship between the amount of net earnings before income taxes for the year and the magnitude of the items representing "permanent differences" that are excluded from the earnings which are subject to tax, either current or future. There are a variety of items of this type, including:

- The effects of asset dispositions where the tax values of the assets sold differ from their accounting values;
- Adjustments for the impact of legislative tax changes which have a prospective impact on future income tax obligations;
- The non-taxable half of Canadian capital gains or losses; and
- Items such as resource allowance and non-deductible crown payments where the income tax treatment is different from the accounting treatment.

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 Expenditures

Capital Summary

($ millions)	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
Upstream	**$ 1,452**	$ 1,390	**$ 4,963**	$ 4,168
Market Optimization	**2**	14	**40**	129
Corporate	**20**	34	**49**	49
Total Core Capital Expenditures	**1,474**	1,438	**5,052**	4,346
Acquisitions	**12**	179	**298**	217
Dispositions	**(377)**	(34)	**(634)**	(2,493)
Discontinued Operations	**-**	72	**(2,415)**	197
Net Capital Investment	**$ 1,109**	$ 1,655	**$ 2,301**	$ 2,267

EnCana's capital investment for the nine months ended September 30, 2006 was funded primarily by cash flow.

Upstream Capital Expenditures

Capital spending during the third quarter and year-to-date was primarily focused on continued development of our North American key resource plays.

The $62 million increase in Upstream core capital expenditures in the third quarter of 2006 compared to 2005 was primarily due to:

- Canadian core capital expenditures decreased $45 million including an increase of $65 million due to foreign exchange; and
- U.S. core capital expenditures increased $105 million to $576 million primarily due to additional drilling and completion costs at Fort Worth related to the development of the Barnett Shale play, increased activity at Jonah upon receipt of the Bureau of Land Management Record of Decision approving further development of the field and the drilling of several deep gas wells at the Deep Bossier play in East Texas.

The $795 million increase in Upstream core capital expenditures for the nine months 2006 compared to 2005 was primarily due to:

- Canadian core capital expenditures increased $386 million to $3.2 billion. The increased expenditures were mainly due to the change in the U.S./Canadian dollar exchange rate, higher drilling and completion costs as a result of industry activity levels and increased facility costs relating to facility expansions at Foster Creek and Bighorn, construction of a new gas plant at Cutbank Ridge and increased well tie-ins; and
- U.S. core capital expenditures increased $397 million to $1.7 billion primarily due to additional drilling and completion costs at Fort Worth related to the development of the Barnett Shale play, increased activity at Jonah upon receipt of the Bureau of Land Management Record of Decision approving further development of the field and the drilling of several deep gas wells at the Deep Bossier play in East Texas.

Market Optimization Capital Expenditures

Expenditures were mostly focused on the completion of construction for the Entrega Pipeline prior to the sale in February 2006.

Corporate Capital Expenditures

Corporate capital expenditures have generally been directed to business information systems and leasehold improvements. In addition, 2005 and 2006 include certain purchases of land and costs related to the development of a Calgary office complex.

Acquisitions, Dispositions and Discontinued Operations

Acquisitions included minor property acquisitions in 2006 and 2005 while dispositions included the sale of the Entrega Pipeline in Colorado and the Brazil oil discovery in 2006 and the sale of the Gulf of Mexico assets and other minor property dispositions in 2005.

Included in Discontinued Operations are the dispositions of EnCana's Ecuador and gas storage assets (discussed in the Discontinued Operations section of this MD&A) in 2006 with the proceeds reduced by capital spending prior to the sales.

Discontinued Operations

Discontinued operations in the Interim Consolidated Financial Statements include:

- Ecuador
- Midstream

EnCana's 2006 net earnings for the nine months ended September 30 from discontinued operations were $581 million compared to $100 million in 2005 and include realized financial hedge gains of $3 million after-tax and unrealized financial hedge gains of $17 million after-tax.

Ecuador

On February 28, 2006 EnCana completed the sale of its interests in Ecuador operations for $1.4 billion before indemnifications and recorded a loss on sale of $47 million. During the second quarter, the Government of Ecuador seized the Block 15 assets, in relation to which EnCana previously held a 40 percent economic interest, from the operator. This was an event requiring indemnification under the terms of EnCana's sale agreement with Andes Petroleum Company. During the third quarter EnCana paid the previously accrued indemnity claim of approximately $265 million calculated in accordance with the terms of the agreement. EnCana does not expect that any further significant indemnification payments relating to any other business matters addressed in the share sale agreements will be required to be made to the purchaser.

	Three Months Ended September 30		**Nine Months Ended September 30**	
	2006	2005	**2006**	2005
Sales Volumes				
Crude Oil *(bbls/d)*	**-**	68,710	**16,533**	71,443
($ millions)				
Net Earnings (Loss) from Discontinued Operations [1] [3]	**$ -**	$ -	**$ (279)**	$ 131
Capital Investment [2]	**-**	33	**(1,116)**	133

(1) 2006 Net Loss is a result of the sale and the 2005 Net Earnings are the result of operations.

(2) Capital Investment in 2006 includes the net proceeds of disposition of $1.4 billion, reduced by the indemnity claim which was paid in the third quarter.

(3) In accordance with Canadian generally accepted accounting principles, DD&A expense for Ecuador has not been recorded in the Consolidated Statement of Earnings for discontinued operations. Net earnings in the third quarter of 2005 were $123 million. Net earnings were reduced by a provision of $123 million to reflect the recoverable value of the Ecuador investment as of the July 1, 2005 sales date.

Midstream

On March 6, 2006 EnCana announced that it had reached an agreement to sell its gas storage business interests for approximately $1.5 billion. The sale, to a single producer, is subject to closing conditions and regulatory approvals and is expected to close in two stages. The first stage of the sale closed on May 12, 2006 for proceeds of approximately $1.3 billion. The second stage is expected to close following receipt of California regulatory approvals which are expected to be received later this year.

($ millions)	Three Months Ended September 30 2006	2005	Nine Months Ended September 30 2006	2005
Net Earnings (Loss) from Discontinued Operations [(1)]	**$ 8**	$ (82)	**$ 855**	$ (33)
Capital Investment	**-**	39	**5**	64

(1) In accordance with Canadian generally accepted accounting principles, DD&A expense for the natural gas storage business has not been recorded in the Consolidated Statement of Earnings for discontinued operations.

Midstream's net earnings from discontinued operations in 2006 mainly result from the gain on sale of the first stage of the gas storage operations in May 2006 which totaled $812 million after-tax. The 2005 comparative amounts also included the NGLs processing business, which was sold in December 2005.

Liquidity and Capital Resources

($ millions)	Three Months Ended September 30 2006	2005	Nine Months Ended September 30 2006	2005
Net cash provided by (used in)				
Operating activities	**$ 1,655**	$ 1,215	**$ 6,277**	$ 4,014
Investing activities	**(1,232)**	(2,011)	**(2,595)**	(2,781)
Financing activities	**(542)**	626	**(3,653)**	(1,681)
Deduct: Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**-**	(4)	**-**	(2)
Increase (decrease) in cash and cash equivalents	**$ (119)**	$ (174)	**$ 29**	$ (450)

Operating Activities

Cash flow from continuing operations was $1,883 million during the third quarter of 2006 compared to $1,823 million for the same period in 2005. On a year-to-date basis cash flow from continuing operations was $5,301 million compared to $4,572 million for the same period in 2005. This increase in cash flow from continuing operations in 2006 was primarily due to increased revenues driven by higher liquids prices, realized financial commodity hedge gains and natural gas sales volumes partially reduced by lower natural gas prices, increased operating expenses and higher cash taxes. Cash flow from continuing operations comprises most of EnCana's cash provided by operating activities.

Investing Activities

Net cash of $1,232 million was used for investing activities in the third quarter of 2006, a decrease of $779 million compared to the same period in 2005. Capital expenditures, including property acquisitions, decreased $131 million for the three months ended September 30, 2006. On a year-to-date basis cash flow used in investing activities was $2,595 million compared to $2,781 million for the same period in 2005.

Financing Activities

Total long-term debt as at September 30, 2006, including current portion, was reduced by revolving long-term debt repayments of $512 million and a fixed rate long-term debt repayment of $73 million since December 31, 2005. EnCana's net debt adjusted for working capital was $6,261 million as at September 30, 2006 compared with $7,970 million at December 31, 2005. During the nine months 2006, EnCana purchased 61.1 million of its Common Shares for a total consideration of $2,973 million. The working capital deficit at September 30, 2006 was $34 million compared to a deficit of $1,267 million as at December 31, 2005.

On September 22, 2006 EnCana filed a multi-jurisdictional shelf prospectus whereby it may issue from time to time up to $2 billion of debt securities. This shelf prospectus replaces EnCana's previous $2 billion debt shelf prospectus which expired on October 16, 2006. EnCana had available unused committed bank credit facilities in the amount of $3.6 billion and unused shelf prospectuses for up to $4.4 billion at September 30, 2006.

EnCana maintains investment grade credit ratings on its senior unsecured debt. Standard & Poor's has assigned a rating of A- with a 'Negative Outlook', Dominion Bond Rating Services has assigned a rating of A(low) with a 'Stable Trend' and Moody's has assigned a rating of Baa2 'Stable'.

Financial Metrics

	September 30 2006	December 31 2005
Net Debt to Capitalization	**25%**	33%
Net Debt to Adjusted EBITDA [1]	**0.5x**	1.1x

[1] Adjusted EBITDA is a non-GAAP measure that is defined as earnings from Continuing Operations before gain on dispositions, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation, depletion and amortization.

Net Debt to Capitalization and Net 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.

Outstanding Share Data

(millions)	September 30 2006
Common shares outstanding, beginning of year	**854.9**
Issued under option plans	**6.3**
Shares purchased (Normal Course Issuer Bid)	**(61.1)**
Common shares outstanding, end of period	**800.1**
Weighted average common shares outstanding – diluted	**845.6**

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 September 30, 2006.

Employees and directors have been granted options to purchase Common Shares under various plans. At September 30, 2006, 14.1 million options without Tandem Share Appreciation Rights ("TSAR") attached were outstanding, of which 13.9 million are exercisable.

Long-term incentives may be granted to EnCana employees in the form of stock options and Performance Share Units ("PSUs"). Stock options granted since 2004 have an associated TSAR attached and employees may elect to exercise either the stock option or the associated Share Appreciation Right ("SAR"). Stock option exercises result in the issuance of new Common Shares while TSAR exercises result in cash payments by the Company. PSUs will not result in the issuance of new Common Shares by the Company as shares are purchased through a trust for payment, should performance considerations be met.

EnCana has obtained regulatory approval under Canadian securities laws to purchase Common Shares under four consecutive NCIBs which commenced in October 2002 and may continue until October 31, 2006. As of September 30, 2006 EnCana had purchased approximately 61.1 million Common Shares and had 800.1 million Common Shares outstanding.

EnCana pays quarterly dividends to shareholders at the discretion of the Board of Directors. These dividends totaled $226 million in the nine months 2006 and $174 million for the same period in 2005. These dividends were funded by cash flow.

Normal Course Issuer Bid

	Share Purchases			
	Three Months Ended September 30		Nine Months Ended September 30	
(millions)	**2006**	2005	**2006**	2005
Bid expired October 2005	**-**	10.5	**-**	55.2
Bid expiring October 2006	**17.4**	-	**61.1**	-

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 commitments of $6,227 million at September 30, 2006 are $913 million in commitments related to Commercial Paper. 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. Further details regarding EnCana's long-term debt are described in Note 9 to the Interim Consolidated Financial Statements.

As at September 30, 2006, EnCana remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 38 MMcf/d with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 128 Bcf at a weighted average price of $3.93 per Mcf. At September 30, 2006 these transactions had an unrealized loss of $288 million.

Leases

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

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

California

As disclosed previously, in July 2003, the Company's indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), concluded a settlement with the U.S. Commodity Futures Trading Commission ("CFTC") of a previously disclosed CFTC investigation whereby WD agreed to pay a civil monetary penalty in the amount of $20 million without admitting or denying the findings in the CFTC's order.

EnCana Corporation and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California, further described below. 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.

Along with other energy companies, EnCana Corporation and WD are defendants in several other lawsuits relating to sales of natural gas in California from 1999 to 2002 (some of which are class actions and some of which are brought by individual parties on their own behalf). As is customary, these lawsuits do not specify the precise amount of damages claimed. The Gallo and other California lawsuits contain allegations that the defendants engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws.

In the Gallo action, the decision dealing with the issue of whether the scope of the Federal Energy Regulatory Commission's exclusive jurisdiction over natural gas prices precludes the plaintiffs from maintaining their claims is on appeal to the United States Court of Appeals for the Ninth Circuit. The Gallo lawsuit is stayed pending this appeal.

Without admitting any liability in the lawsuits, WD has paid $20.5 million to settle the class action lawsuits that were consolidated in San Diego Superior Court. WD has also agreed to pay $2.4 million to settle the class action lawsuits filed in the United States District Court in California, without admitting any liability in the lawsuits, subject to final documentation and approval by the United States District Court. The individual parties who had brought their own actions are not parties to these settlements.

New York

WD was a defendant in a consolidated class action lawsuit filed in the United States District Court in New York. The consolidated New York lawsuit claims that the defendants' alleged manipulation of natural gas price indices affected natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. EnCana Corporation was dismissed from the New York lawsuit, leaving WD and several other companies unrelated to EnCana Corporation as the remaining defendants. Without admitting any liability in the lawsuit, WD agreed to pay $8.2 million to settle the New York class action lawsuit. Final documentation and approval by the New York District Court have been obtained and WD has paid the stated settlement amount.

Based on the aforementioned settlements, a total of $31 million has been expensed. EnCana Corporation and WD intend to vigorously defend against the remaining outstanding claims; 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

On January 1, 2006, the Company adopted EITF Abstract No. 04-13 – Accounting for Purchases and Sales of Inventory with the Same Counterparty. As of January 1, 2006, purchases and sales of inventory with the same counterparty that are entered into in contemplation of each other are recorded on a net basis in the Consolidated Statement of Earnings. This change has been adopted prospectively and has no effect on the net earnings of the reported periods.

Risk Management

EnCana's results are affected by

- financial risks (including commodity price, foreign exchange, interest rate and credit risks)
- operational risks
- environmental, health, safety and security risks
- reputational risks

EnCana partially mitigates its exposure to financial risks through the use of various financial instruments and physical contracts. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. As a means of mitigating exposure to commodity price risk volatility, the Company has entered into various financial instrument agreements. The details of these instruments, including any unrealized gains or losses, as of September 30, 2006, are disclosed in Note 14 to the Interim Consolidated Financial Statements. EnCana does not use derivative financial instruments for speculative purposes.

EnCana has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of price risk to achieve targeted investment returns and growth objectives, while maintaining prescribed financial metrics.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by EnCana are swaps or options which are entered into with major financial institutions, integrated energy companies or commodities trading institutions.

Commodity Price

To partially mitigate the natural gas commodity price risk, the Company enters into swaps which fix the AECO and NYMEX prices and put options which fix the range of AECO and NYMEX prices. To help protect against widening natural gas price differentials in various production areas, EnCana has entered into swaps to fix the AECO and Rockies price differential from the NYMEX price. Physical contracts relating to these activities had an unrecognized gain of $21 million at September 30, 2006.

EnCana has also entered into contracts to purchase and sell natural gas as part of its daily ongoing operations of the Company's proprietary production management. Physical contracts associated with this activity had an unrecognized gain of $30 million at September 30, 2006.

For crude oil price risk, the Company has partially mitigated its exposure to the WTI NYMEX price for a portion of its oil production with fixed price swaps, purchased call options to allow participation at higher WTI levels and put options.

Foreign Exchange

As a means of mitigating the exposure to fluctuations in the U.S. to Canadian exchange rate, EnCana may enter into foreign exchange contracts. The Company also enters into foreign exchange contracts in conjunction with crude oil marketing transactions. Gains or losses on these contracts are recognized when the difference between the average month spot rate and the rate on the date of settlement is determined.

EnCana also maintains a mix of both U.S. dollar and Canadian dollar debt which helps to offset the exposure to the fluctuations in the U.S./Canadian dollar exchange rate. In addition to direct issuance of U.S. dollar denominated debt, the Company has entered into cross currency swaps on a portion of its debt as a means of managing the U.S./Canadian dollar debt mix.

Interest Rates

The Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt. EnCana has entered into interest rate swap transactions from time to time as an additional means of managing the fixed/floating rate debt portfolio mix.

Credit Risk

EnCana is exposed to credit related losses in the event of default by counterparties. This credit 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 and transactions that are fully collateralized. A substantial portion of EnCana's accounts receivable is with customers in the oil and gas industry.

Operational Risks

EnCana mitigates operational risk through a number of policies and processes. As part of the capital approval process, the Company's projects are evaluated on a fully risked basis, including geological risk and engineering risk. In addition, the asset teams undertake a process called Lookback and Learning. In this process, each asset team undertakes a thorough review of their previous capital program to identify key learnings, which often includes operational issues that positively and negatively impacted the project's results. Mitigation plans are developed for the operational issues which had a negative impact on results. These mitigation plans are then incorporated into the current year plan for the project. On an annual basis, these Lookback results are analyzed for EnCana's capital program with the results and identified learnings shared across the Company.

Projects include a Business Risk Burden that is intended to account for the unforeseen risks. The amount of Business Risk Burden that is used on a particular project depends on the project's history of Lookback results and the type of expenditure. A peer review process is used to ensure that capital projects are appropriately risked and that knowledge is shared across the Company. Peer reviews are undertaken primarily for exploration projects and early stage resource plays, although they may occur for any type of project.

EnCana also partially mitigates operational risks by maintaining a comprehensive insurance program.

Environment, Health, Safety and Security Risks

These risks are managed by executing policies and standards that are designed to comply with or exceed government regulations and industry standards. In addition, EnCana maintains a system that identifies, assesses and controls safety and environmental risk and requires regular reporting to senior management and the Board of Directors. The Corporate Responsibility, Environment, Health & Safety Committee of EnCana's Board of Directors recommends approval of environmental policy and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation strategies are utilized to restore the environment.

Security risks are managed through a Security Program designed to protect EnCana's personnel and assets. EnCana has established an Investigations Committee with the mandate to address potential violations of Company policies and practices and an Integrity Hotline that can be used to raise any concerns regarding EnCana's operations, accounting or internal control matters.

Climate Change

The Federal Government is currently developing a framework that outlines its clean air and climate change action plan. Currently there are few technical details regarding the implementation of the Government's plan to regulate industrial greenhouse gas (GHG) emissions, but they have made a commitment to work with industry to develop the specifics.

As this federal program is under development, EnCana is unable to predict the total impact of the potential regulations upon its business; therefore, it is possible that the Corporation could face increases in operating costs in order to comply with greenhouse gas emissions legislation. However, EnCana in cooperation with the Canadian Association of Petroleum Producers will continue to work with the Government to develop an approach to deal with climate change issues which protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector. We do not anticipate that the cost implications of government climate change plans will have a material impact on operations or future growth plans.

EnCana will continue our activity to reduce our emissions intensity and improve our energy efficiency. Our efforts with respect to emissions management are founded on three key elements:

- our significant weighting in natural gas and our high quality in-situ oilsands assets;
- we are recognized as an industry leader in CO_2 sequestration; and
- our focus on the development of technology to reduce GHG emissions.

EnCana is committed to transparency with its stakeholders and will keep them apprised of how these issues affect operations. Additional detail on EnCana's greenhouse gas emissions is available in the Corporate Responsibility Report that was published in the second quarter of 2006. The Report is available on www.encana.com.

Reputational Risks

EnCana takes a pro-active approach to the identification and management of issues that affect the Company's reputation and has established consistent and clear procedures, guidelines and responsibility for identifying and managing these issues. Issues affecting or with the potential to affect EnCana's reputation are generally either emerging issues that can be identified early and then managed or unforeseen issues that arise unexpectedly and must be managed on an urgent basis.

Outlook

EnCana plans to continue to focus principally on growing natural gas production from unconventional resource plays in North America and developing its high quality in-situ oilsands resources. EnCana is continuing to evaluate marketing, development and other options that will help expand the development of the oilsands resources.

Volatility in crude oil prices is expected to continue throughout 2006 as a result of market uncertainties over supply and refining disruptions, continued demand growth in China, OPEC actions, demand destruction from high energy prices and the overall state of the world economies. In the near term, the new pipeline capacity to the U.S. Gulf Coast should reduce the volatility on Canadian crude oil relative to world oil prices.

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 in the past two years and that unconventional resource plays can at least partially offset conventional gas production declines. The industry's ability to respond to the gas supply constrained situation in North America remains challenged by land access and regulatory issues.

The Company expects its 2006 core capital investment program to be funded from cash flow.

EnCana's results are affected by external market factors, such as fluctuations in the prices of crude oil and natural gas, as well as movements in foreign currency exchange rates and inflationary pressures on service costs.

Advisories

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 MD&A 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 MD&A include, but are not limited to, statements with respect to: projections with respect to growth of natural gas production from unconventional resource plays and in-situ oilsands resources; projected production volumes in 2006 for natural gas, crude oil and NGLs in Canada and the United States; projections relating to the volatility of crude oil prices in 2006 and beyond and the reasons therefor; the Company's projected capital investment levels for 2006 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 Kyoto Accord on operating costs; the adequacy of the Company's provision for taxes; the Company's plans to divest of its remaining natural gas storage assets in California and the date for receipt of regulatory approvals in respect thereof; projections relating to the use of proceeds therefrom, including debt repayment; the impact of new pipeline capacity to the U.S. Gulf Coast 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; and projections relating to North American conventional natural gas supplies and the ability of unconventional resource plays to partially offset future conventional gas production declines. 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 reserve 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 EnCana and ConocoPhillips to successfully negotiate and execute final definitive agreements relating to the integrated North American 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; 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 environmental and other regulations or the interpretations of such 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 MD&A are made as of the date of this MD&A, 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 MD&A are expressly qualified by this cautionary statement.

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"). 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, Natural Gas Liquids and Natural Gas Conversions

In this MD&A, certain crude oil and natural gas liquids ("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, Estimated Ultimate Recovery, and Unbooked Resource Potential

EnCana uses the terms resource play, estimated ultimate recovery and unbooked resource potential. 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. As used by EnCana, estimated ultimate recovery ("EUR") has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom. EnCana defines Unbooked Resource Potential as quantities of oil and gas on existing landholdings that are not yet classified as proved reserves, but which EnCana believes may be moved into the proved reserves category and produced in the future. EnCana employs a probability-weighted approach in the calculation of these quantities, including statistical distributions of resource play potential and areal extent. Consequently, EnCana's unbooked resource potential necessarily includes quantities of probable and possible reserves and contingent resources, as these terms are defined in the Canadian Oil and Gas Evaluation Handbook.

CURRENCY, NON-GAAP MEASURES AND REFERENCES TO ENCANA

All information included in this MD&A and the Interim Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after-royalties basis unless otherwise noted. Sales forecasts reflect the mid-point of current public guidance on an after royalties basis. Current Corporate Guidance assumes a U.S. dollar exchange rate of $0.88 for every Canadian dollar.

Non-GAAP Measures

Certain measures in this MD&A do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles ("Canadian GAAP") such as Cash Flow from Continuing Operations, Cash Flow, Cash Flow per share-diluted, Operating Earnings and Operating Earnings per share-diluted, Operating Earnings from Continuing Operations and Adjusted EBITDA 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 MD&A 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 MD&A as these measures are discussed and presented.

References to EnCana

For convenience, references in this MD&A to “EnCana”, the “Company”, “we”, “us” and “our” 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 September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
REVENUES, NET OF ROYALTIES	*(Note 3)*				
Upstream		**$ 2,762**	$ 2,680	**$ 8,202**	$ 7,013
Market Optimization		**731**	1,112	**2,272**	2,850
Corporate - Unrealized gain (loss) on risk management		**428**	(810)	**1,921**	(1,457)
		3,921	2,982	**12,395**	8,406
EXPENSES	*(Note 3)*				
Production and mineral taxes		**79**	107	**269**	291
Transportation and selling		**163**	137	**467**	400
Operating		**420**	371	**1,227**	986
Purchased product		**677**	1,083	**2,160**	2,783
Depreciation, depletion and amortization		**791**	670	**2,346**	2,018
Administrative		**54**	78	**187**	205
Interest, net	*(Note 6)*	**83**	219	**254**	420
Accretion of asset retirement obligation	*(Note 10)*	**13**	9	**37**	27
Foreign exchange (gain) loss, net	*(Note 7)*	**-**	(212)	**(158)**	(61)
Stock-based compensation - options		**-**	4	**-**	12
(Gain) on dispositions	*(Note 5)*	**(304)**	-	**(321)**	-
		1,976	2,466	**6,468**	7,081
NET EARNINGS BEFORE INCOME TAX		**1,945**	516	**5,927**	1,325
Income tax expense	*(Note 8)*	**602**	168	**1,519**	365
NET EARNINGS FROM CONTINUING OPERATIONS		**1,343**	348	**4,408**	960
NET EARNINGS (LOSS) FROM DISCONTINUED OPERATIONS	*(Note 4)*	**15**	(82)	**581**	100
NET EARNINGS		**$ 1,358**	$ 266	**$ 4,989**	$ 1,060
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	*(Note 13)*				
Basic		**$ 1.66**	$ 0.41	**$ 5.32**	$ 1.10
Diluted		**$ 1.63**	$ 0.40	**$ 5.21**	$ 1.07
NET EARNINGS PER COMMON SHARE	*(Note 13)*				
Basic		**$ 1.68**	$ 0.31	**$ 6.02**	$ 1.21
Diluted		**$ 1.65**	$ 0.30	**$ 5.90**	$ 1.19

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(unaudited)*

($ millions)		Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
RETAINED EARNINGS, BEGINNING OF YEAR		**$ 9,481**	$ 7,935
Net Earnings		**4,989**	1,060
Dividends on Common Shares		**(226)**	(174)
Charges for Normal Course Issuer Bid	*(Note 11)*	**(2,450)**	(1,495)
Charges for Shares Repurchased and Held		**-**	(147)
RETAINED EARNINGS, END OF PERIOD		**$ 11,794**	$ 7,179

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET *(unaudited)*

($ millions)		**As at September 30, 2006**	As at December 31, 2005
ASSETS			
Current Assets			
Cash and cash equivalents		**$ 134**	$ 105
Accounts receivable and accrued revenues		**1,467**	1,851
Risk management	*(Note 14)*	**1,293**	495
Inventories		**152**	103
Assets of discontinued operations	*(Note 4)*	**203**	1,050
		3,249	3,604
Property, Plant and Equipment, net	*(Note 3)*	**28,489**	24,881
Investments and Other Assets		**580**	496
Risk Management	*(Note 14)*	**243**	530
Assets of Discontinued Operations	*(Note 4)*	**-**	2,113
Goodwill		**2,617**	2,524
	(Note 3)	**$ 35,178**	$ 34,148
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 2,163**	$ 2,741
Income tax payable		**989**	392
Risk management	*(Note 14)*	**60**	1,227
Liabilities of discontinued operations	*(Note 4)*	**71**	438
Current portion of long-term debt	*(Note 9)*	**-**	73
		3,283	4,871
Long-Term Debt	*(Note 9)*	**6,227**	6,703
Other Liabilities		**86**	93
Risk Management	*(Note 14)*	**5**	102
Asset Retirement Obligation	*(Note 10)*	**929**	816
Liabilities of Discontinued Operations	*(Note 4)*	**-**	267
Future Income Taxes		**6,162**	5,289
		16,692	18,141
Shareholders' Equity			
Share capital	*(Note 11)*	**4,748**	5,131
Paid in surplus		**151**	133
Retained earnings		**11,794**	9,481
Foreign currency translation adjustment		**1,793**	1,262
		18,486	16,007
		$ 35,178	$ 34,148

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*

($ millions)		Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
OPERATING ACTIVITIES					
Net earnings from continuing operations		**$ 1,343**	$ 348	**$ 4,408**	$ 960
Depreciation, depletion and amortization		**791**	670	**2,346**	2,018
Future income taxes	*(Note 8)*	**401**	13	**690**	(661)
Cash tax on sale of assets	*(Note 5)*	**49**	-	**49**	591
Unrealized (gain) loss on risk management	*(Note 14)*	**(428)**	809	**(1,919)**	1,454
Unrealized foreign exchange (gain) loss		**4**	(202)	**(79)**	(79)
Accretion of asset retirement obligation	*(Note 10)*	**13**	9	**37**	27
(Gain) on dispositions		**(304)**	-	**(321)**	-
Other		**14**	176	**90**	262
Cash flow from continuing operations		**1,883**	1,823	**5,301**	4,572
Cash flow from discontinued operations		**11**	108	**99**	344
Cash flow		**1,894**	1,931	**5,400**	4,916
Net change in other assets and liabilities		**21**	(160)	**48**	(174)
Net change in non-cash working capital from continuing operations		**(247)**	(579)	**3,305**	(652)
Net change in non-cash working capital from discontinued operations		**(13)**	23	**(2,476)**	(76)
		1,655	1,215	**6,277**	4,014
INVESTING ACTIVITIES					
Capital expenditures	*(Note 3)*	**(1,486)**	(1,617)	**(5,350)**	(4,563)
Proceeds on disposal of assets	*(Note 5)*	**377**	34	**634**	2,493
Cash tax on sale of assets	*(Note 5)*	**(49)**	-	**(49)**	(591)
Net change in investments and other		**(56)**	35	**(38)**	27
Net change in non-cash working capital from continuing operations		**(18)**	(352)	**(169)**	99
Discontinued operations		**-**	(111)	**2,377**	(246)
		(1,232)	(2,011)	**(2,595)**	(2,781)
FINANCING ACTIVITIES					
Net issuance (repayment) of revolving long-term debt		**470**	1,691	**(512)**	976
Issuance of long-term debt		**-**	428	**-**	428
Repayment of long-term debt		**(73)**	(958)	**(73)**	(959)
Issuance of common shares	*(Note 11)*	**39**	86	**140**	270
Purchase of common shares	*(Note 11)*	**(900)**	(452)	**(2,973)**	(2,114)
Dividends on common shares		**(80)**	(64)	**(226)**	(174)
Other		**2**	(105)	**(9)**	(108)
		(542)	626	**(3,653)**	(1,681)
DEDUCT: FOREIGN EXCHANGE (GAIN) LOSS ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		**-**	4	**-**	2
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		**(119)**	(174)	**29**	(450)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		**253**	317	**105**	593
CASH AND CASH EQUIVALENTS, END OF PERIOD		**$ 134**	$ 143	**$ 134**	$ 143

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. The Company is in the business of exploration for, and production and marketing of, natural gas, crude oil and natural gas liquids, as well as natural gas storage, natural gas liquids processing 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, 2005, 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, 2005.

2. CHANGE IN ACCOUNTING POLICIES AND PRACTICES

On January 1, 2006, the Company adopted Emerging Issues Task Force ("EITF") Abstract No. 04-13 - Accounting for Purchases and Sales of Inventory with the Same Counterparty. As of January 1, 2006, purchases and sales of inventory with the same counterparty that are entered into in contemplation of each other are recorded on a net basis in the Consolidated Statement of Earnings. This change has been adopted prospectively and has no effect on the net earnings of the reported periods.

3. SEGMENTED INFORMATION

The Company has defined its continuing operations into the following segments:

- **Upstream** includes the Company’s exploration for, and development and production of, natural gas, crude oil and natural gas liquids and other related activities. The majority of the Company's Upstream operations are located in Canada and the United States. Frontier and international new venture exploration is mainly focused on opportunities in Chad, Brazil, the Middle East, Greenland and France.

- **Market Optimization** is conducted by the Midstream & Marketing division. The Marketing groups' primary responsibility is the sale of the Company's proprietary production. The results are included in the Upstream segment. Correspondingly, the Marketing groups also undertake market optimization activities which comprise 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** includes unrealized gains or losses recorded on derivative instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

Market Optimization purchases substantially all of the Company's North American Upstream production for sale to third party customers. Transactions between business segments are based on market values and eliminated on consolidation. The tables in this note present financial information on an after eliminations basis.

Operations that have been discontinued are disclosed in Note 4.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. SEGMENTED INFORMATION (continued)

Results of Continuing Operations *(For the three months ended September 30)*

	Upstream		Market Optimization	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 2,762**	$ 2,680	**$ 731**	$ 1,112
Expenses				
Production and mineral taxes	**79**	107	**-**	-
Transportation and selling	**159**	133	**4**	4
Operating	**401**	348	**18**	24
Purchased product	**-**	-	**677**	1,083
Depreciation, depletion and amortization	**770**	649	**3**	2
Segment Income (Loss)	**$ 1,353**	$ 1,443	**$ 29**	$ (1)

	Corporate *		Consolidated	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 428**	$ (810)	**$ 3,921**	$ 2,982
Expenses				
Production and mineral taxes	**-**	-	**79**	107
Transportation and selling	**-**	-	**163**	137
Operating	**1**	(1)	**420**	371
Purchased product	**-**	-	**677**	1,083
Depreciation, depletion and amortization	**18**	19	**791**	670
Segment Income (Loss)	**$ 409**	$ (828)	**1,791**	614
Administrative			**54**	78
Interest, net			**83**	219
Accretion of asset retirement obligation			**13**	9
Foreign exchange (gain) loss, net			**-**	(212)
Stock-based compensation - options			**-**	4
(Gain) on divestitures *(Note 5)*			**(304)**	-
			(154)	98
Net Earnings Before Income Tax			**1,945**	516
Income tax expense			**602**	168
Net Earnings From Continuing Operations			**$ 1,343**	$ 348

* For the three months ended September 30, the pre-tax unrealized gain (loss) on risk management is recorded in the Consolidated Statement of Earnings as follows (see Note 14):

	2006	2005
Revenues, Net of Royalties - Corporate	**$ 428**	$ (810)
Operating Expenses and Other - Corporate	**-**	1
Total Unrealized Gain (Loss) on Risk Management before-tax - Continuing Operations	**$ 428**	$ (809)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. SEGMENTED INFORMATION (continued)

Results of Continuing Operations *(For the three months ended September 30)*

Upstream	Canada		United States	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 1,876**	$ 1,807	**$ 811**	$ 797
Expenses				
Production and mineral taxes	**27**	24	**52**	83
Transportation and selling	**95**	84	**64**	49
Operating	**266**	207	**64**	56
Depreciation, depletion and amortization	**541**	485	**222**	157
Segment Income	**$ 947**	$ 1,007	**$ 409**	$ 452

	Other		Total Upstream	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 75**	$ 76	**$ 2,762**	$ 2,680
Expenses				
Production and mineral taxes	**-**	-	**79**	107
Transportation and selling	**-**	-	**159**	133
Operating	**71**	85	**401**	348
Depreciation, depletion and amortization	**7**	7	**770**	649
Segment Income (Loss)	**$ (3)**	$ (16)	**$ 1,353**	$ 1,443

Upstream Geographic and Product Information (Continuing Operations) *(For the three months ended September 30)*

	Produced Gas					
	Canada		United States		Total	
	2006	2005	**2006**	2005	**2006**	2005
Revenues, Net of Royalties	**$ 1,302**	$ 1,317	**$ 735**	$ 726	**$ 2,037**	$ 2,043
Expenses						
Production and mineral taxes	**18**	19	**47**	77	**65**	96
Transportation and selling	**74**	70	**64**	49	**138**	119
Operating	**157**	134	**64**	56	**221**	190
Operating Cash Flow	**$ 1,053**	$ 1,094	**$ 560**	$ 544	**$ 1,613**	$ 1,638

	Oil & NGLs					
	Canada		United States		Total	
	2006	2005	**2006**	2005	**2006**	2005
Revenues, Net of Royalties	**$ 574**	$ 490	**$ 76**	$ 71	**$ 650**	$ 561
Expenses						
Production and mineral taxes	**9**	5	**5**	6	**14**	11
Transportation and selling	**21**	14	**-**	-	**21**	14
Operating	**109**	73	**-**	-	**109**	73
Operating Cash Flow	**$ 435**	$ 398	**$ 71**	$ 65	**$ 506**	$ 463

	Other		Total Upstream	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 75**	$ 76	**$ 2,762**	$ 2,680
Expenses				
Production and mineral taxes	**-**	-	**79**	107
Transportation and selling	**-**	-	**159**	133
Operating	**71**	85	**401**	348
Operating Cash Flow	**$ 4**	$ (9)	**$ 2,123**	$ 2,092

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. SEGMENTED INFORMATION (continued)

Results of Continuing Operations *(For the nine months ended September 30)*

	Upstream		Market Optimization	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 8,202**	$ 7,013	**$ 2,272**	$ 2,850
Expenses				
Production and mineral taxes	**269**	291	**-**	-
Transportation and selling	**450**	390	**17**	10
Operating	**1,177**	936	**49**	53
Purchased product	**-**	-	**2,160**	2,783
Depreciation, depletion and amortization	**2,282**	1,957	**8**	7
Segment Income (Loss)	**$ 4,024**	$ 3,439	**$ 38**	$ (3)

		Corporate *		Consolidated	
		2006	2005	**2006**	2005
Revenues, Net of Royalties		**$ 1,921**	$ (1,457)	**$ 12,395**	$ 8,406
Expenses					
Production and mineral taxes		**-**	-	**269**	291
Transportation and selling		**-**	-	**467**	400
Operating		**1**	(3)	**1,227**	986
Purchased product		**-**	-	**2,160**	2,783
Depreciation, depletion and amortization		**56**	54	**2,346**	2,018
Segment Income (Loss)		**$ 1,864**	$ (1,508)	**5,926**	1,928
Administrative				**187**	205
Interest, net				**254**	420
Accretion of asset retirement obligation				**37**	27
Foreign exchange (gain) loss, net				**(158)**	(61)
Stock-based compensation - options				**-**	12
(Gain) on dispositions	*(Note 5)*			**(321)**	-
				(1)	603
Net Earnings Before Income Tax				**5,927**	1,325
Income tax expense				**1,519**	365
Net Earnings From Continuing Operations				**$ 4,408**	$ 960

* For the nine months ended September 30, the pre-tax unrealized gain (loss) on risk management is recorded in the Consolidated Statement of Earnings as follows (see Note 14):

	2006	2005
Revenues, Net of Royalties - Corporate	**$ 1,921**	$ (1,457)
Operating Expenses and Other - Corporate	**(2)**	3
Total Unrealized Gain (Loss) on Risk Management before-tax - Continuing Operations	**$ 1,919**	$ (1,454)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. SEGMENTED INFORMATION (continued)

Results of Continuing Operations *(For the nine months ended September 30)*

Upstream	Canada		United States	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 5,617**	$ 4,747	**$ 2,356**	$ 2,071
Expenses				
Production and mineral taxes	**96**	75	**173**	216
Transportation and selling	**268**	256	**182**	134
Operating	**753**	599	**207**	148
Depreciation, depletion and amortization	**1,606**	1,416	**648**	516
Segment Income	**$ 2,894**	$ 2,401	**$ 1,146**	$ 1,057

Transportation and selling for the United States includes a one time payment in the first quarter of 2006 of $14 million to terminate a long-term physical delivery contract.

	Other		Total Upstream	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 229**	$ 195	**$ 8,202**	$ 7,013
Expenses				
Production and mineral taxes	**-**	-	**269**	291
Transportation and selling	**-**	-	**450**	390
Operating	**217**	189	**1,177**	936
Depreciation, depletion and amortization	**28**	25	**2,282**	1,957
Segment Income (Loss)	**$ (16)**	$ (19)	**$ 4,024**	$ 3,439

Upstream Geographic and Product Information (Continuing Operations) *(For the nine months ended September 30)*

	Produced Gas					
	Canada		United States		Total	
	2006	2005	**2006**	2005	**2006**	2005
Revenues, Net of Royalties	**$ 4,039**	$ 3,634	**$ 2,148**	$ 1,891	**$ 6,187**	$ 5,525
Expenses						
Production and mineral taxes	**69**	56	**159**	198	**228**	254
Transportation and selling	**212**	211	**182**	134	**394**	345
Operating	**463**	377	**207**	148	**670**	525
Operating Cash Flow	**$ 3,295**	$ 2,990	**$ 1,600**	$ 1,411	**$ 4,895**	$ 4,401

Transportation and selling for the United States includes a one time payment in the first quarter of 2006 of $14 million to terminate a long-term physical delivery contract.

	Oil & NGLs					
	Canada		United States		Total	
	2006	2005	**2006**	2005	**2006**	2005
Revenues, Net of Royalties	**$ 1,578**	$ 1,113	**$ 208**	$ 180	**$ 1,786**	$ 1,293
Expenses						
Production and mineral taxes	**27**	19	**14**	18	**41**	37
Transportation and selling	**56**	45	**-**	-	**56**	45
Operating	**290**	222	**-**	-	**290**	222
Operating Cash Flow	**$ 1,205**	$ 827	**$ 194**	$ 162	**$ 1,399**	$ 989

	Other		Total Upstream	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 229**	$ 195	**$ 8,202**	$ 7,013
Expenses				
Production and mineral taxes	**-**	-	**269**	291
Transportation and selling	**-**	-	**450**	390
Operating	**217**	189	**1,177**	936
Operating Cash Flow	**$ 12**	$ 6	**$ 6,306**	$ 5,396

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. SEGMENTED INFORMATION (continued)

Capital Expenditures (Continuing Operations)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	**2006**	2005
Upstream Core Capital				
Canada	**$ 864**	$ 909	**$ 3,166**	$ 2,780
United States	**576**	471	**1,746**	1,349
Other Countries	**12**	10	**51**	39
	1,452	1,390	**4,963**	4,168
Upstream Acquisition Capital				
Canada	**1**	3	**30**	26
United States	**11**	176	**268**	191
	12	179	**298**	217
Market Optimization	**2**	14	**40**	129
Corporate	**20**	34	**49**	49
Total	**$ 1,486**	$ 1,617	**$ 5,350**	$ 4,563

Property, Plant and Equipment and Total Assets

		Property, Plant and Equipment As at		Total Assets As at	
		September 30, 2006	December 31, 2005	**September 30, 2006**	December 31, 2005
Upstream		**$ 28,051**	$ 24,247	**$ 32,512**	$ 28,858
Market Optimization		**161**	371	**387**	597
Corporate		**277**	263	**2,076**	1,530
Assets of Discontinued Operations	*(Note 4)*			**203**	3,163
Total		**$ 28,489**	$ 24,881	**$ 35,178**	$ 34,148

4. DISCONTINUED OPERATIONS

Midstream

On December 13, 2005, EnCana completed the sale of its Midstream natural gas liquids processing operations for total proceeds of $625 million (C$720 million). The natural gas liquids processing operations included various interests in a number of processing and related facilities as well as a marketing entity. A gain on sale of approximately $370 million, after-tax, was recorded.

During the fourth quarter of 2005, EnCana decided to divest of its natural gas storage operations. EnCana's natural gas storage operations include the 100 percent interest in the AECO storage facility as well as facilities in the United States. On March 6, 2006, EnCana announced that it had reached an agreement to sell the gas storage operations for $1.5 billion. The sale, to a single purchaser, which is subject to closing conditions and applicable regulatory approvals, is expected to close in two stages. On May 12, 2006, the first stage of the sale was closed for proceeds of $1.3 billion. The second stage will close following receipt of regulatory approvals, expected to be later in 2006.

Ecuador

At December 31, 2004, EnCana decided to divest of its Ecuador operations and such operations have been accounted for as discontinued operations. EnCana's Ecuador operations include the 100 percent working interest in the Tarapoa Block, majority operating interest in Blocks 14, 17 and Shiripuno, the non-operated economic interest in relation to Block 15 and the 36.3 percent indirect equity investment in Oleoducto de Crudos Pesados (OCP) Ltd. ("OCP"), which is the owner of a crude oil pipeline in Ecuador that ships crude oil from the producing areas of Ecuador to an export marine terminal. The Company is a shipper on the OCP Pipeline and pays commercial rates for tariffs. The majority of the Company's crude oil produced in Ecuador is sold to a single marketing company. Payments are secured by letters of credit from a major financial institution which has a high quality investment grade credit rating.

On February 28, 2006, EnCana completed the sale of its interest in its Ecuador operations for $1.4 billion before indemnifications which are discussed further in this note.

In accordance with Canadian generally accepted accounting principles, depletion, depreciation and amortization expense has not been recorded in the Consolidated Statement of Earnings for discontinued operations.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. DISCONTINUED OPERATIONS (continued)

Consolidated Statement of Earnings

The following table presents the effect of the discontinued operations in the Consolidated Statement of Earnings:

	For the three months ended September 30,							
	Ecuador		United Kingdom		Midstream		Total	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005
Revenues, Net of Royalties	**$ -**	$ 291	**$ -**	$ -	**$ 14**	$ 107	**$ 14**	$ 398
Expenses								
Production and mineral taxes	**-**	49	**-**	-	**-**	-	**-**	49
Transportation and selling	**-**	15	**-**	-	**-**	2	**-**	17
Operating	**-**	38	**-**	-	**-**	61	**-**	99
Purchased product	**-**	-	**-**	-	**-**	161	**-**	161
Depreciation, depletion and amortization	**-**	123	**-**	-	**-**	7	**-**	130
Interest, net	**-**	-	**-**	-	**-**	(1)	**-**	(1)
Foreign exchange (gain) loss, net	**-**	(1)	**-**	-	**(4)**	(1)	**(4)**	(2)
(Gain) loss on discontinuance	**-**	-	**-**	-	**2**	-	**2**	-
	-	224	**-**	-	**(2)**	229	**(2)**	453
Net Earnings (Loss) Before Income Tax	**-**	67	**-**	-	**16**	(122)	**16**	(55)
Income tax expense (recovery)	**-**	67	**(7)**	-	**8**	(40)	**1**	27
Net Earnings (Loss) From Discontinued Operations	**$ -**	$ -	**$ 7**	$ -	**$ 8**	$ (82)	**$ 15**	$ (82)

	For the nine months ended September 30,							
	Ecuador		United Kingdom		Midstream		Total	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005
Revenues, Net of Royalties *	**$ 200**	$ 723	**$ -**	$ -	**$ 477**	$ 925	**$ 677**	$ 1,648
Expenses								
Production and mineral taxes	**23**	101	**-**	-	**-**	-	**23**	101
Transportation and selling	**10**	46	**-**	-	**-**	6	**10**	52
Operating	**25**	100	**-**	-	**29**	191	**54**	291
Purchased product	**-**	-	**-**	-	**354**	757	**354**	757
Depreciation, depletion and amortization	**84**	123	**-**	-	**-**	20	**84**	143
Interest, net	**(2)**	-	**-**	-	**-**	(1)	**(2)**	(1)
Accretion of asset retirement obligation	**-**	1	**-**	-	**-**	-	**-**	1
Foreign exchange (gain) loss, net	**1**	-	**-**	(3)	**5**	(2)	**6**	(5)
(Gain) loss on discontinuance	**279**	-	**-**	-	**(766)**	-	**(487)**	-
	420	371	**-**	(3)	**(378)**	971	**42**	1,339
Net Earnings (Loss) Before Income Tax	**(220)**	352	**-**	3	**855**	(46)	**635**	309
Income tax expense (recovery)	**59**	221	**(5)**	1	**-**	(13)	**54**	209
Net Earnings (Loss) From Discontinued Operations	**$ (279)**	$ 131	**$ 5**	$ 2	**$ 855**	$ (33)	**$ 581**	$ 100

* Revenues, net of royalties in Ecuador include realized losses of $1 million related to derivative financial instruments. In 2005, revenues, net of royalties included realized losses of $105 million and unrealized mark-to-market gains of $50 million.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. DISCONTINUED OPERATIONS (continued)

Consolidated Balance Sheet

The impact of the discontinued operations in the Consolidated Balance Sheet is as follows:

	As at							
	September 30, 2006				December 31, 2005			
	Ecuador	United Kingdom	Midstream	Total	Ecuador	United Kingdom	Midstream	Total
Assets								
Cash and cash equivalents	**$ -**	**$ 6**	**$ 1**	**$ 7**	$ 207	$ 8	$ (7)	$ 208
Accounts receivable and accrued revenues	**-**	**-**	**10**	**10**	137	-	271	408
Risk management	**-**	**-**	**7**	**7**	-	-	21	21
Inventories	**-**	**-**	**20**	**20**	23	-	390	413
	-	**6**	**38**	**44**	367	8	675	1,050
Property, plant and equipment, net	**1**	**-**	**158**	**159**	1,166	-	520	1,686
Investments and other assets	**-**	**-**	**-**	**-**	360	-	-	360
Goodwill	**-**	**-**	**-**	**-**	-	-	67	67
	$ 1	**$ 6**	**$ 196**	**$ 203**	$ 1,893	$ 8	$ 1,262	$ 3,163
Liabilities								
Accounts payable and accrued liabilities	**$ -**	**$ 27**	**$ -**	**$ 27**	$ 91	$ 27	$ 49	$ 167
Income tax payable	**-**	**-**	**19**	**19**	184	6	40	230
Risk management	**-**	**-**	**-**	**-**	-	-	41	41
	-	**27**	**19**	**46**	275	33	130	438
Asset retirement obligation	**-**	**-**	**-**	**-**	21	-	-	21
Future income taxes (recovery)	**-**	**-**	**25**	**25**	162	(2)	86	246
	-	**27**	**44**	**71**	458	31	216	705
Net Assets of Discontinued Operations	**$ 1**	**$ (21)**	**$ 152**	**$ 132**	$ 1,435	$ (23)	$ 1,046	$ 2,458

Contingencies

EnCana has agreed to indemnify the purchaser of its Ecuador interests against losses that may arise in certain circumstances which are defined in the share sale agreements. The obligation to indemnify will arise should losses exceed amounts specified in the sale agreements and is limited to maximum amounts which are set forth in the share sale agreements.

During the second quarter, the Government of Ecuador seized the Block 15 assets, in relation to which EnCana previously held a 40 percent economic interest, from the operator which is an event requiring indemnification under the terms of EnCana's sale agreement with Andes Petroleum Company. The purchaser requested payment and EnCana paid the maximum amount in the third quarter, calculated in accordance with the terms of the agreements, of approximately $265 million. EnCana does not expect that any further significant indemnification payments relating to any other business matters addressed in the share sale agreements will be required to be made to the purchaser.

5. DIVESTITURES

Total proceeds received on sale of assets and investments was $634 million (2005 - $2,493 million) as described below:

Upstream

In 2006, the Company has completed the disposition of mature conventional oil and natural gas assets for proceeds of $23 million (2005 - $440 million).

In August 2006, the Company completed the sale of its 50 percent interest in the Chinook heavy oil discovery offshore Brazil for approximately $367 million which resulted in a gain on sale of $304 million. After recording income tax of $49 million, EnCana recorded an after-tax gain of $255 million.

In May 2005, the Company completed the sale of its Gulf of Mexico assets for approximately $2.1 billion resulting in net proceeds of approximately $1.5 billion after deducting $591 million in tax plus other adjustments. In accordance with full cost accounting for oil and gas activities, proceeds were credited to property, plant and equipment.

Market Optimization

In February 2006, the Company sold its investment in Entrega Gas Pipeline LLC for approximately $244 million which resulted in a gain on sale of $17 million.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

6. INTEREST, NET

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Interest Expense - Long-Term Debt	**$ 88**	$ 104	**$ 269**	$ 310
Early Retirement of Long-Term Debt	**-**	121	**-**	121
Interest Expense - Other	**9**	5	**19**	12
Interest Income	**(14)**	(11)	**(34)**	(23)
	$ 83	$ 219	**$ 254**	$ 420

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Unrealized Foreign Exchange (Gain) Loss on Translation of U.S. Dollar Debt Issued from Canada	**$ 4**	$ (205)	**$ (155)**	$ (140)
Other Foreign Exchange (Gain) Loss	**(4)**	(7)	**(3)**	79
	$ -	$ (212)	**$ (158)**	$ (61)

8. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Current				
Canada	**$ 105**	$ 6	**$ 694**	$ 288
United States	**51**	153	**87**	744
Other	**45**	(4)	**48**	(6)
Total Current Tax	**201**	155	**829**	1,026
Future	**401**	13	**690**	(661)
	$ 602	$ 168	**$ 1,519**	$ 365

Current income tax in the United States for the nine months ended September 30, 2005 of $591 million relates to income tax on the sale of the Gulf of Mexico assets.

The following table reconciles income taxes calculated at the Canadian statutory rate with the actual income taxes:

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Net Earnings Before Income Tax	**$ 1,945**	$ 516	**$ 5,927**	$ 1,325
Canadian Statutory Rate	**34.7%**	37.9%	**34.7%**	37.9%
Expected Income Tax	**674**	196	**2,055**	502
Effect on Taxes Resulting from:				
Non-deductible Canadian crown payments	**23**	53	**75**	139
Canadian resource allowance	**(1)**	(51)	**(20)**	(141)
Canadian resource allowance on unrealized risk management losses	**1**	13	**2**	26
Statutory and other rate differences	**(63)**	(31)	**(80)**	(111)
Effect of tax rate changes*	**-**	-	**(457)**	-
Non-taxable capital (gains) losses	**3**	(43)	**(30)**	(27)
Tax basis retained on dispositions	**-**	-	**-**	(68)
Large corporations tax	**-**	20	**-**	24
Other	**(35)**	11	**(26)**	21
	$ 602	$ 168	**$ 1,519**	$ 365
Effective Tax Rate	**31.0%**	32.6%	**25.6%**	27.5%

*During the second quarter, the Canadian federal and Alberta governments substantively enacted income tax rate reductions.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

9. LONG-TERM DEBT

	As at September 30, 2006	As at December 31, 2005
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	**$ 838**	$ 1,425
Unsecured notes	**829**	793
	1,667	2,218
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	**75**	-
Unsecured notes	**4,421**	4,494
	4,496	4,494
Increase in Value of Debt Acquired *	**64**	64
Current Portion of Long-Term Debt	**-**	(73)
	$ 6,227	$ 6,703

* Certain of the notes and debentures of EnCana were acquired in business combinations and were accounted for at their fair value at the dates of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 21 years.

10. 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 properties:

	As at September 30, 2006	As at December 31, 2005
Asset Retirement Obligation, Beginning of Year	**$ 816**	$ 611
Liabilities Incurred	**54**	77
Liabilities Settled	**(37)**	(42)
Liabilities Disposed	**-**	(23)
Change in Estimated Future Cash Flows	**21**	135
Accretion Expense	**37**	37
Other	**38**	21
Asset Retirement Obligation, End of Period	**$ 929**	$ 816

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

11. SHARE CAPITAL

(millions)	September 30, 2006 Number	September 30, 2006 Amount	December 31, 2005 Number	December 31, 2005 Amount
Common Shares Outstanding, Beginning of Year	**854.9**	**$ 5,131**	900.6	$ 5,299
Common Shares Issued under Option Plans	**6.3**	**140**	15.0	294
Common Shares Repurchased	**(61.1)**	**(523)**	(60.7)	(462)
Common Shares Outstanding, End of Period	**800.1**	**$ 4,748**	854.9	$ 5,131

Information related to common shares and stock options has been restated to reflect the effect of the common share split approved in April 2005.

Normal Course Issuer Bid

To September 30, 2006, the Company purchased 61.1 million Common Shares for total consideration of approximately $2,973 million. Of the amount paid, $523 million was charged to Share capital and $2,450 million was charged to Retained earnings.

EnCana has obtained regulatory approval each year under Canadian securities laws to purchase Common Shares under four consecutive Normal Course Issuer Bids ("Bids") which commenced in October 2002 and may continue until October 30, 2006. EnCana is entitled to purchase, for cancellation, up to approximately 85.6 million Common Shares under the renewed Bid which commenced on October 31, 2005 and will terminate no later than October 30, 2006.

Stock Options

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

The following tables summarize the information about options to purchase Common Shares that do not have Tandem Share Appreciation Rights ("TSAR's") attached to them at September 30, 2006. Information related to TSAR's is included in Note 12.

	Stock Options *(millions)*	**Weighted Average Exercise Price *(C$)***
Outstanding, Beginning of Year	**20.7**	**23.36**
Exercised	**(6.3)**	**23.58**
Forfeited	**(0.3)**	**23.80**
Outstanding, End of Period	**14.1**	**23.25**
Exercisable, End of Period	**13.9**	**23.24**

	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$)*
11.00 to 22.99	1.2	2.1	14.48	1.2	14.26
23.00 to 23.49	0.2	1.4	23.21	0.2	23.23
23.50 to 23.99	5.5	1.6	23.89	5.4	23.89
24.00 to 24.49	6.8	0.6	24.17	6.8	24.17
24.50 to 25.99	0.4	1.9	25.23	0.3	25.27
	14.1	1.1	23.25	13.9	23.24

At September 30, 2006, the balance in Paid in surplus relates to Stock-Based Compensation programs.

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

12. COMPENSATION PLANS

The tables below outline certain information related to EnCana's compensation plans at September 30, 2006. Additional information is contained in Note 15 of the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2005.

A) Pensions

The following table summarizes the net benefit plan expense:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	**2006**	2005
Current Service Cost	**$ 3**	$ 1	**$ 10**	$ 5
Interest Cost	**5**	5	**13**	11
Expected Return on Plan Assets	**(4)**	(4)	**(12)**	(10)
Expected Actuarial Loss on Accrued Benefit Obligation	**1**	2	**4**	3
Expected Amortization of Past Service Costs	**-**	-	**1**	1
Amortization of Transitional Obligation	**-**	(2)	**(1)**	(2)
Expense for Defined Contribution Plan	**9**	6	**20**	16
Net Benefit Plan Expense	**$ 14**	$ 8	**$ 35**	$ 24

For the period ended September 30, 2006, contributions of $9 million have been made to the defined benefit pension plans.

B) Share Appreciation Rights ("SAR's")

The following table summarizes the information about SAR's at September 30, 2006:

	Outstanding SAR's	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**246,739**	**23.13**
Exercised	**(242,739)**	**23.18**
Outstanding, End of Period	**4,000**	**20.25**
Exercisable, End of Period	**4,000**	**20.25**
U.S. Dollar Denominated *(US$)*		
Outstanding, Beginning of Year	**319,511**	**14.33**
Exercised	**(307,423)**	**14.41**
Outstanding, End of Period	**12,088**	**12.37**
Exercisable, End of Period	**12,088**	**12.37**

For the period ended September 30, 2006, EnCana has recorded a reduction of $1 million to compensation costs related to the outstanding SAR's (2005 - costs of $19 million).

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

12. COMPENSATION PLANS (continued)

C) Tandem Share Appreciation Rights ("TSAR's")

The following table summarizes the information about Tandem SAR's at September 30, 2006:

	Outstanding TSAR's	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**8,403,967**	**38.41**
Granted	**11,006,350**	**48.92**
Exercised - SAR's	**(519,696)**	**34.66**
Exercised - Options	**(29,484)**	**32.97**
Forfeited	**(1,017,452)**	**42.84**
Outstanding, End of Period	**17,843,685**	**44.75**
Exercisable, End of Period	**2,018,553**	**37.23**

For the period ended September 30, 2006, EnCana recorded compensation costs of $28 million related to the outstanding TSAR's (2005 - $86 million).

D) Deferred Share Units ("DSU's")

The following table summarizes the information about DSU's at September 30, 2006:

	Outstanding DSU's	Average Share Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**836,561**	**26.81**
Granted, Directors	**70,000**	**56.71**
Exercised	**(52,562)**	**27.92**
Units, in Lieu of Dividends	**8,980**	**55.11**
Outstanding, End of Period	**862,979**	**29.46**
Exercisable, End of Period	**862,979**	**29.46**

For the period ended September 30, 2006, EnCana recorded compensation costs of $3 million related to the outstanding DSU's (2005 - $26 million).

E) Performance Share Units ("PSU's")

The following table summarizes the information about PSU's at September 30, 2006:

	Outstanding PSU's	Average Share Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**4,704,348**	**30.65**
Granted	**27,557**	**30.11**
Exercised	**(239,794)**	**23.26**
Forfeited	**(282,021)**	**31.35**
Outstanding, End of Period	**4,210,090**	**31.03**
U.S. Dollar Denominated *(US$)*		
Outstanding, Beginning of Year	**739,649**	**25.22**
Granted	**3,621**	**25.56**
Forfeited	**(156,652)**	**23.79**
Outstanding, End of Period	**586,618**	**25.61**

For the period ended September 30, 2006, EnCana recorded compensation costs of $14 million related to the outstanding PSU's (2005 - $57 million).

At September 30, 2006, EnCana has approximately 5.5 million Common Shares held in trust for issuance upon vesting of the PSU's.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

13. PER SHARE AMOUNTS

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

	Three Months Ended				Nine Months Ended	
	March 31,	June 30,	September 30,		September 30,	
(millions)	2006	2006	**2006**	2005	**2006**	2005
Weighted Average Common Shares Outstanding - Basic	847.9	829.6	**809.7**	855.1	**829.1**	872.9
Effect of Dilutive Securities	16.9	15.5	**14.6**	20.7	**16.5**	21.3
Weighted Average Common Shares Outstanding - Diluted	864.8	845.1	**824.3**	875.8	**845.6**	894.2

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

As a means of managing commodity price volatility, EnCana entered into various financial instrument agreements and physical contracts. The following information presents all positions for financial instruments.

Realized and Unrealized Gain (Loss) on Risk Management Activities

The following tables summarize the gains and losses on risk management activities:

	Realized Gain (Loss)			
	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 199**	$ (196)	**$ 153**	$ (329)
Operating Expenses and Other	**1**	7	**4**	17
Gain (Loss) on Risk Management - Continuing Operations	**200**	(189)	**157**	(312)
Gain (Loss) on Risk Management - Discontinued Operations	**-**	(55)	**4**	(111)
	$ 200	$ (244)	**$ 161**	$ (423)

	Unrealized Gain (Loss)			
	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2006	2005	**2006**	2005
Revenues, Net of Royalties	**$ 428**	$ (810)	**$ 1,921**	$ (1,457)
Operating Expenses and Other	**-**	1	**(2)**	3
Gain (Loss) on Risk Management - Continuing Operations	**428**	(809)	**1,919**	(1,454)
Gain (Loss) on Risk Management - Discontinued Operations	**5**	(90)	**27**	(89)
	$ 433	$ (899)	**$ 1,946**	$ (1,543)

Amounts Recognized on Transition

Upon initial adoption of the current accounting policy for risk management instruments on January 1, 2004, the fair value of all outstanding financial instruments that were not considered accounting hedges was recorded in the Consolidated Balance Sheet with an offsetting net deferred loss amount (the "transition amount"). The transition amount is recognized into net earnings over the life of the related contracts. Changes in fair value after that time are recorded in the Consolidated Balance Sheet with an associated unrealized gain or loss recorded in net earnings.

At September 30, 2006, a net unrealized gain remains to be recognized over the next three years as follows:

	Unrealized Gain
2006	
Three months ended December 31, 2006	$ 6
Total remaining to be recognized in 2006	$ 6
2007	$ 15
2008	1
Total to be recognized	$ 22

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Fair Value of Outstanding Risk Management Positions

The following table presents a reconciliation of the change in the unrealized amounts from January 1, 2006 to September 30, 2006:

	Transition Amount	Fair Market Value	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	$ (40)	$ (640)	$ -
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During 2006	-	2,089	2,089
Fair Value of Contracts in Place at Transition Expired During 2006	18	-	18
Fair Value of Contracts Realized During 2006	-	(161)	(161)
Fair Value of Contracts Outstanding	$ (22)	$ 1,288	$ 1,946
Unamortized Premiums Paid on Options		190	
Fair Value of Contracts and Premiums Paid, End of Period		$ 1,478	
Amounts Allocated to Continuing Operations	$ (22)	$ 1,471	$ 1,919
Amounts Allocated to Discontinued Operations	-	7	27
	$ (22)	$ 1,478	$ 1,946

At September 30, 2006, the remaining net deferred amounts recognized on transition and the risk management amounts are recorded in the Consolidated Balance Sheet as follows:

	As at September 30, 2006
Remaining Deferred Amounts Recognized on Transition	
Accounts receivable and accrued revenues	**$ 1**
Accounts payable and accrued liabilities	**18**
Other liabilities	**5**
Net Deferred Gain - Continuing Operations	**$ 22**
Risk Management	
Current asset	**$ 1,293**
Long-term asset	**243**
Current liability	**60**
Long-term liability	**5**
Net Risk Management Asset - Continuing Operations	**1,471**
Net Risk Management Asset - Discontinued Operations	**7**
	$ 1,478

A summary of all unrealized estimated fair value financial positions is as follows:	**As at September 30, 2006**
Commodity Price Risk	
Natural gas	**$ 1,420**
Crude oil	**47**
Credit Derivatives	**(2)**
Interest Rate Risk	**6**
Total Fair Value Positions - Continuing Operations	**1,471**
Total Fair Value Positions - Discontinued Operations	**7**
	$ 1,478

Information with respect to credit derivatives and interest rate risk contracts in place at December 31, 2005 is disclosed in Note 16 to the Company's annual audited Consolidated Financial Statements. No significant new contracts have been entered into as at September 30, 2006.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Natural Gas

At September 30, 2006, the Company's gas risk management activities from financial contracts had an unrealized gain of $1,332 million and a fair market value position of $1,427 million. The contracts were as follows:

	Notional Volumes *(MMcf/d)*	Term	Average Price		Fair Market Value
Sales Contracts					
Fixed Price Contracts					
NYMEX Fixed Price	495	2006	5.63	US$/Mcf	$ (1)
Colorado Interstate Gas (CIG)	100	2006	4.44	US$/Mcf	-
Houston Ship Channel (HSC)	90	2006	5.08	US$/Mcf	(2)
Other	91	2006	5.07	US$/Mcf	2
NYMEX Fixed Price	945	2007	8.85	US$/Mcf	390
Other	8	2007	8.97	US$/Mcf	5
Options					
Purchased NYMEX Put Options	2,687	2006	7.77	US$/Mcf	474
Purchased NYMEX Put Options	240	2007	6.00	US$/Mcf	21
Basis Contracts					
Fixed NYMEX to AECO Basis	780	2006	(0.70)	US$/Mcf	(8)
Fixed NYMEX to Rockies Basis	254	2006	(0.59)	US$/Mcf	18
Fixed NYMEX to CIG Basis	259	2006	(0.84)	US$/Mcf	11
Other	145	2006	(0.29)	US$/Mcf	2
Fixed NYMEX to AECO Basis	747	2007	(0.72)	US$/Mcf	75
Fixed NYMEX to Rockies Basis	538	2007	(0.65)	US$/Mcf	170
Fixed NYMEX to CIG Basis	390	2007	(0.76)	US$/Mcf	107
Fixed Rockies to CIG Basis	12	2007	(0.10)	US$/Mcf	(1)
Fixed NYMEX to AECO Basis	191	2008	(0.78)	US$/Mcf	10
Fixed NYMEX to Rockies Basis	162	2008	(0.59)	US$/Mcf	39
Fixed NYMEX to Rockies Basis (NYMEX Adjusted)	210	2008	17% of NYMEX	US$/Mcf	-
Fixed NYMEX to CIG Basis	40	2008-2009	(0.68)	US$/Mcf	13
Purchase Contracts					
Fixed Price Contracts					
Waha Purchase	23	2006	5.32	US$/Mcf	-
Other	10	2006	7.84	US$/Mcf	(2)
Other	8	2007	7.84	US$/Mcf	(1)
					1,322
Other Financial Positions *					10
Total Unrealized Gain on Financial Contracts					1,332
Unamortized Premiums Paid on Options					95
Total Fair Value Positions					$ 1,427
Total Fair Value Positions - Continuing Operations					$ 1,420
Total Fair Value Positions - Discontinued Operations					7
Total Fair Value Positions					$ 1,427

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

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Crude Oil

At September 30, 2006, the Company's oil risk management activities from financial contracts had an unrealized loss of $(48) million and a fair market value position of $47 million. The contracts were as follows:

	Notional Volumes *(bbls/d)*	Term	Average Price	Fair Market Value
Fixed WTI NYMEX Price	15,000	2006	34.56 US$/bbl	$ (41)
Unwind WTI NYMEX Fixed Price	(1,300)	2006	52.75 US$/bbl	1
Purchased WTI NYMEX Put Options	59,000	2006	50.44 US$/bbl	(8)
Purchased WTI NYMEX Call Options	(13,700)	2006	61.24 US$/bbl	1
Purchased WTI NYMEX Put Options	91,500	2007	55.34 US$/bbl	(10)
				(57)
Other Financial Positions *				9
Total Unrealized Loss on Financial Contracts				(48)
Unamortized Premiums Paid on Options				95
Total Fair Value Positions				$ 47
Total Fair Value Positions - Continuing Operations				$ 47

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

15. 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

California

As disclosed previously, in July 2003, the Company's indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), concluded a settlement with the U.S. Commodity Futures Trading Commission ("CFTC") of a previously disclosed CFTC investigation whereby WD agreed to pay a civil monetary penalty in the amount of $20 million without admitting or denying the findings in the CFTC's order.

EnCana Corporation and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California, further described below. 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.

Along with other energy companies, EnCana Corporation and WD are defendants in several other lawsuits relating to sales of natural gas in California from 1999 to 2002 (some of which are class actions and some of which are brought by individual parties on their own behalf). As is customary, these lawsuits do not specify the precise amount of damages claimed. The Gallo and other California lawsuits contain allegations that the defendants engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws.

In the Gallo action, the decision dealing with the issue of whether the scope of the Federal Energy Regulatory Commission's exclusive jurisdiction over natural gas prices precludes the plaintiffs from maintaining their claims is on appeal to the United States Court of Appeals for the Ninth Circuit. The Gallo lawsuit is stayed pending this appeal.

Without admitting any liability in the lawsuits, WD has paid $20.5 million to settle the class action lawsuits that were consolidated in San Diego Superior Court. WD has also agreed to pay $2.4 million to settle the class action lawsuits filed in the United States District Court in California, without admitting any liability in the lawsuits, subject to approval by the United States District Court. The individual parties who had brought their own actions are not parties to this settlement.

New York

WD was a defendant in a consolidated class action lawsuit filed in the United States District Court in New York. The consolidated New York lawsuit claims that the defendants' alleged manipulation of natural gas price indices affected natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. EnCana Corporation was dismissed from the New York lawsuit, leaving WD and several other companies unrelated to EnCana Corporation as the remaining defendants. Without admitting any liability in the lawsuit, WD agreed to pay $8.2 million to settle the New York class action lawsuit. Final documentation and approval by the New York District Court have been obtained and WD has paid the stated settlement amount.

Based on the aforementioned settlements, a total of $31 million has been expensed. EnCana Corporation and WD intend to vigorously defend against the remaining outstanding claims; 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.

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)	2006 Year-to-date	2006 Q3	2006 Q2	2006 Q1	2005 Year	2005 Q4	2005 Q3	2005 Q2	2005 Q1
TOTAL CONSOLIDATED									
Cash Flow	**5,400**	**1,894**	1,815	1,691	7,426	2,510	1,931	1,572	1,413
Per share - Basic	**6.51**	**2.34**	2.19	1.99	8.55	2.94	2.26	1.80	1.58
- Diluted	**6.39**	**2.30**	2.15	1.96	8.35	2.88	2.20	1.76	1.55
Net Earnings (Loss)	**4,989**	**1,358**	2,157	1,474	3,426	2,366	266	839	(45)
Per share - Basic	**6.02**	**1.68**	2.60	1.74	3.95	2.77	0.31	0.96	(0.05)
- Diluted	**5.90**	**1.65**	2.55	1.70	3.85	2.71	0.30	0.94	(0.05)
Operating Earnings [(1)]	**2,596**	**1,078**	824	694	3,241	1,271	704	655	611
Per share - Diluted	**3.07**	**1.31**	0.98	0.80	3.64	1.46	0.80	0.73	0.67
CONTINUING OPERATIONS									
Cash Flow from Continuing Operations	**5,301**	**1,883**	1,839	1,579	6,962	2,390	1,823	1,502	1,247
Net Earnings (Loss) from Continuing Operations	**4,408**	**1,343**	1,593	1,472	2,829	1,869	348	774	(162)
Per share - Basic	**5.32**	**1.66**	1.92	1.74	3.26	2.19	0.41	0.89	(0.18)
- Diluted	**5.21**	**1.63**	1.88	1.70	3.18	2.14	0.40	0.87	(0.18)
Operating Earnings - Continuing Operations [(2)]	**2,565**	**1,064**	841	660	3,048	1,229	733	611	475
Effective Tax Rates using									
Net Earnings	**25.6%**				30.8%				
Operating Earnings, excluding dispositions	**35.0%**				33.0%				
Canadian Statutory Rate	**34.7%**				37.9%				
Foreign Exchange Rates (US$ per C$1)									
Average	**0.883**	**0.892**	0.892	0.866	0.825	0.852	0.833	0.804	0.815
Period end	**0.897**	**0.897**	0.897	0.857	0.858	0.858	0.861	0.816	0.827

(1) 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 in Canada and the effect of the reduction in income tax rates.

(2) Operating Earnings - Continuing Operations is a non-GAAP measure defined as Net Earnings from Continuing Operations excluding the 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 in Canada and the effect of the reduction in income tax rates.

Common Share Information	2006 Year-to-date	2006 Q3	2006 Q2	2006 Q1	2005 Year	2005 Q4	2005 Q3	2005 Q2	2005 Q1
Common Shares Outstanding *(millions)*									
Period end	**800.1**	**800.1**	815.8	836.2	854.9	854.9	853.8	860.2	881.7
Average - Basic	**829.1**	**809.7**	829.6	847.9	868.3	854.4	855.1	872.0	891.8
Average - Diluted	**845.6**	**824.3**	845.1	864.8	889.2	872.5	875.8	891.9	909.0
Price Range *($ per share)*									
TSX - C$									
High	**62.52**	**62.52**	59.38	57.10	69.64	69.64	68.70	51.27	44.28
Low	**44.96**	**48.35**	49.51	44.96	32.55	50.04	47.72	39.05	32.55
Close	**52.01**	**52.01**	58.78	54.50	52.56	52.56	67.85	48.33	42.72
NYSE - US$									
High	**55.93**	**55.93**	53.31	50.50	59.82	59.82	58.49	41.56	36.45
Low	**39.54**	**43.32**	44.02	39.54	26.45	42.00	39.26	31.31	26.45
Close	**46.69**	**46.69**	52.64	46.73	45.16	45.16	58.31	39.59	35.21
Share Volume Traded *(millions)*	**1,247.8**	**327.4**	392.0	528.4	1,619.6	552.8	388.9	327.3	350.6
Share Value Traded *(US$ millions weekly average)*	**1,538.8**	**1,272.9**	1,484.8	1,850.5	1,289.1	2,050.1	1,400.4	878.8	852.6

Financial Metrics	2006 Year-to-date	2005 Year
Net Debt to Capitalization	**25%**	33%
Net Debt to Adjusted EBITDA	**0.5x**	1.1x
Return on Capital Employed	**32%**	17%
Return on Common Equity	**46%**	23%

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics (continued)

Net Capital Investment *($ millions)*	**2006**	2005
Upstream		
Canada - excluding Foster Creek/Christina Lake	**$ 2,684**	$ 2,527
Foster Creek/Christina Lake	**482**	253
Total Canada	**3,166**	2,780
United States	**1,746**	1,349
Other Countries	**51**	39
	4,963	4,168
Market Optimization	**40**	129
Corporate	**49**	49
Core Capital from Continuing Operations	**5,052**	4,346
Upstream		
Acquisitions		
Property		
Canada	**30**	26
United States [(1)]	**268**	191
Dispositions		
Property		
Canada	**(16)**	(416)
United States	**(7)**	(2,075)
Corporate [(2)]	**(367)**	-
Market Optimization		
Corporate [(3)]	**(244)**	-
Corporate	**-**	(2)
Net Acquisition and Disposition activity from Continuing Operations	**(336)**	(2,276)
Discontinued Operations		
Ecuador [(4)]	**(1,116)**	133
Midstream [(5)]	**(1,299)**	64
Net Capital Investment	**$ 2,301**	$ 2,267

(1) Acquired additional operated interest in East Texas which closed June 29, 2006.

(2) Sale of shares of EnCanBrasil Limitada closed August 16, 2006.

(3) Sale of shares of Entrega Gas Pipeline LLC closed February 23, 2006.

(4) Sale of Ecuador interests closed February 28, 2006.

(5) Sale of majority of Gas Storage interests closed May 12, 2006.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties

Sales Volumes	**2006**				**2005**				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS									
Produced Gas *(MMcf/d)*									
Canada									
Production	**2,178**	**2,162**	2,192	2,182	2,125	2,172	2,123	2,151	2,052
Inventory withdrawal	**-**	**-**	-	-	7	-	-	-	27
Canada Sales	**2,178**	**2,162**	2,192	2,182	2,132	2,172	2,123	2,151	2,079
United States	**1,176**	**1,197**	1,169	1,161	1,095	1,154	1,099	1,061	1,067
Total Produced Gas	**3,354**	**3,359**	3,361	3,343	3,227	3,326	3,222	3,212	3,146
Oil and Natural Gas Liquids *(bbls/d)*									
North America									
Light and Medium Oil	**45,199**	**45,980**	43,727	45,889	47,328	45,792	43,313	50,020	50,280
Heavy Oil - Foster Creek/Christina Lake	**41,450**	**43,073**	39,215	42,050	34,379	39,839	32,580	31,025	34,027
Heavy Oil - Other	**44,674**	**37,605**	46,128	50,431	48,711	48,547	48,509	51,249	46,519
Natural Gas Liquids [(1)]									
Canada	**11,665**	**11,387**	11,607	12,006	11,907	12,287	11,924	11,719	11,692
United States	**12,577**	**12,520**	12,793	12,415	13,675	12,824	14,131	13,095	14,666
Total Oil and Natural Gas Liquids	**155,565**	**150,565**	153,470	162,791	156,000	159,289	150,457	157,108	157,184
Total Continuing Operations *(MMcfe/d)*	**4,287**	**4,262**	4,282	4,320	4,163	4,282	4,125	4,155	4,089
DISCONTINUED OPERATIONS									
Ecuador									
Production	**16,038**	**-**	-	48,650	72,916	70,480	71,896	73,662	75,695
Over/(under) lifting	**495**	**-**	-	1,500	(1,851)	(537)	(3,186)	(486)	(3,208)
Ecuador Sales *(bbls/d)*	**16,533**	**-**	-	50,150	71,065	69,943	68,710	73,176	72,487
Total Discontinued Operations *(MMcfe/d)*	**100**	**-**	-	301	426	419	412	439	435
Total *(MMcfe/d)*	**4,387**	**4,262**	4,282	4,621	4,589	4,701	4,537	4,594	4,524

(1) Natural gas liquids include condensate volumes.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

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

	2006				2005				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS									
Produced Gas - Canada *($/Mcf)*									
Price	**6.31**	**5.59**	5.71	7.66	7.27	10.00	7.18	6.08	5.70
Production and mineral taxes	**0.12**	**0.09**	0.08	0.18	0.10	0.10	0.10	0.10	0.09
Transportation and selling	**0.36**	**0.37**	0.35	0.34	0.36	0.36	0.36	0.36	0.37
Operating	**0.78**	**0.78**	0.77	0.79	0.67	0.72	0.68	0.62	0.65
Netback	**5.05**	**4.35**	4.51	6.35	6.14	8.82	6.04	5.00	4.59
Produced Gas - United States *($/Mcf)*									
Price	**6.60**	**6.04**	6.08	7.70	7.82	10.84	7.51	6.60	6.04
Production and mineral taxes	**0.49**	**0.43**	0.22	0.85	0.81	1.19	0.75	0.65	0.62
Transportation and selling	**0.52**	**0.57**	0.50	0.49	0.46	0.45	0.49	0.42	0.46
Operating	**0.64**	**0.59**	0.70	0.64	0.53	0.60	0.55	0.50	0.45
Netback	**4.95**	**4.45**	4.66	5.72	6.02	8.60	5.72	5.03	4.51
Produced Gas - Total North America *($/Mcf)*									
Price	**6.41**	**5.75**	5.84	7.68	7.46	10.29	7.29	6.25	5.81
Production and mineral taxes	**0.25**	**0.21**	0.13	0.41	0.34	0.48	0.32	0.28	0.27
Transportation and selling	**0.41**	**0.44**	0.40	0.40	0.40	0.39	0.41	0.38	0.40
Operating	**0.73**	**0.71**	0.74	0.74	0.62	0.68	0.64	0.58	0.58
Netback	**5.02**	**4.39**	4.57	6.13	6.10	8.74	5.92	5.01	4.56
Natural Gas Liquids - Canada *($/bbl)*									
Price	**53.29**	**55.95**	55.19	48.84	44.24	49.51	47.39	39.55	40.04
Production and mineral taxes	-	-	-	-	-	-	-	-	-
Transportation and selling	**0.69**	**0.74**	0.73	0.61	0.42	0.46	0.48	0.39	0.35
Netback	**52.60**	**55.21**	54.46	48.23	43.82	49.05	46.91	39.16	39.69
Natural Gas Liquids - United States *($/bbl)*									
Price	**58.07**	**61.76**	58.25	54.07	48.36	54.14	53.92	44.79	40.93
Production and mineral taxes	**4.05**	**4.42**	2.60	5.18	4.86	5.42	5.46	4.37	4.20
Transportation and selling	**0.01**	**0.01**	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Netback	**54.01**	**57.33**	55.64	48.88	43.49	48.71	48.45	40.41	36.72
Natural Gas Liquids - Total North America *($/bbl)*									
Price	**55.77**	**58.99**	56.80	51.50	46.44	51.87	50.93	42.32	40.53
Production and mineral taxes	**2.10**	**2.31**	1.36	2.63	2.60	2.77	2.96	2.31	2.34
Transportation and selling	**0.34**	**0.36**	0.35	0.31	0.20	0.23	0.23	0.19	0.16
Netback	**53.33**	**56.32**	55.09	48.56	43.64	48.87	47.74	39.82	38.03
Crude Oil - Light and Medium - North America *($/bbl)*									
Price	**54.41**	**56.50**	61.62	45.31	45.09	46.27	55.41	41.44	38.57
Production and mineral taxes	**2.17**	**2.13**	2.47	1.92	1.54	1.83	1.29	1.71	1.32
Transportation and selling	**1.10**	**1.32**	0.65	1.29	1.20	1.14	1.29	1.20	1.19
Operating	**8.50**	**10.00**	7.36	8.06	6.34	6.41	6.24	6.34	6.38
Netback	**42.64**	**43.05**	51.14	34.04	36.01	36.89	46.59	32.19	29.68
Crude Oil - Heavy - Foster Creek/Christina Lake *($/bbl)*									
Price	**35.42**	**37.19**	46.53	23.08	22.02	20.17	33.11	19.28	15.92
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-	-
Transportation and selling	**2.60**	**2.64**	3.38	1.80	1.54	1.53	1.24	2.02	1.42
Operating	**10.06**	**12.14**	9.77	8.14	7.95	8.51	7.29	9.42	6.56
Netback	**22.76**	**22.41**	33.38	13.14	12.53	10.13	24.58	7.84	7.94
Crude Oil - Total Heavy - North America *($/bbl)*									
Price	**37.68**	**44.32**	46.49	23.53	27.92	28.27	39.69	22.77	20.76
Production and mineral taxes	**0.05**	**0.05**	0.07	0.04	0.04	0.05	0.04	0.02	0.03
Transportation and selling	**1.71**	**1.98**	2.00	1.21	1.20	1.11	1.08	1.13	1.52
Operating	**7.91**	**9.29**	7.90	6.68	6.50	6.96	6.57	6.57	5.83
Netback	**28.01**	**33.00**	36.52	15.60	20.18	20.15	32.00	15.05	13.38
Crude Oil - Total North America *($/bbl)*									
Price	**43.44**	**48.74**	51.62	30.76	34.15	34.41	45.16	29.83	27.60
Production and mineral taxes	**0.78**	**0.81**	0.88	0.66	0.58	0.66	0.48	0.66	0.53
Transportation and selling	**1.50**	**1.74**	1.54	1.24	1.20	1.12	1.15	1.15	1.39
Operating	**8.11**	**9.55**	7.72	7.13	6.44	6.77	6.45	6.48	6.04
Netback	**33.05**	**36.64**	41.48	21.73	25.93	25.86	37.08	21.54	19.64

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

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

	2006				2005				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS (continued)									
Total Liquids - Canada *($/bbl)*									
Price	**44.17**	**49.21**	51.91	32.17	34.97	35.65	45.35	30.58	28.60
Production and mineral taxes	**0.71**	**0.73**	0.80	0.61	0.53	0.60	0.43	0.61	0.48
Transportation and selling	**1.44**	**1.67**	1.48	1.19	1.14	1.07	1.09	1.09	1.31
Operating	**7.45**	**8.79**	7.07	6.55	5.89	6.19	5.83	5.96	5.55
Netback	**34.57**	**38.02**	42.56	23.82	27.41	27.79	38.00	22.92	21.26
Total Liquids - Total North America *($/bbl)*									
Price	**45.36**	**50.37**	52.44	33.87	36.17	37.16	46.16	31.80	29.77
Production and mineral taxes	**0.99**	**1.05**	0.96	0.96	0.91	0.99	0.91	0.92	0.83
Transportation and selling	**1.32**	**1.52**	1.35	1.10	1.04	0.98	0.99	1.00	1.18
Operating	**6.85**	**8.03**	6.49	6.06	5.38	5.70	5.33	5.46	5.03
Netback	**36.20**	**39.77**	43.64	25.75	28.84	29.49	38.93	24.42	22.73
Total North America *($/Mcfe)*									
Price	**6.66**	**6.31**	6.46	7.22	7.13	9.37	7.38	6.03	5.62
Production and mineral taxes	**0.23**	**0.20**	0.13	0.36	0.30	0.41	0.29	0.25	0.24
Transportation and selling	**0.37**	**0.40**	0.36	0.35	0.35	0.34	0.35	0.33	0.36
Operating (1)	**0.82**	**0.84**	0.82	0.80	0.68	0.74	0.69	0.66	0.64
Netback	**5.24**	**4.87**	5.15	5.71	5.80	7.88	6.05	4.79	4.38

(1) Year-to-date operating costs include costs related to long-term incentives of $0.01/Mcfe. (Year-to-date 2005 - $0.04/Mcfe)

Impact of Upstream Realized Financial Hedging

	Year-to-date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas *($/Mcf)*	**0.33**	**0.82**	0.66	(0.53)	(0.32)	(0.88)	(0.39)	(0.14)	0.18
Liquids *($/bbl)*	**(3.33)**	**(3.45)**	(3.43)	(3.12)	(5.18)	(5.00)	(5.70)	(4.88)	(5.18)
Total *($/Mcfe)*	**0.13**	**0.53**	0.40	(0.53)	(0.44)	(0.87)	(0.52)	(0.30)	(0.06)

Average Royalty Rates
(excluding impact of realized financial hedging)

	Year-to-date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas									
Canada	**10.7%**	**10.5%**	10.4%	11.2%	11.7%	11.9%	11.8%	11.0%	11.9%
United States	**18.6%**	**18.4%**	18.7%	18.7%	18.6%	18.6%	19.9%	17.9%	18.1%
Crude Oil									
Canada and United States	**9.8%**	**11.4%**	10.5%	7.5%	8.8%	8.8%	8.7%	9.2%	8.7%
Natural Gas Liquids									
Canada	**15.6%**	**16.3%**	14.4%	16.1%	14.9%	14.4%	15.8%	15.6%	13.8%
United States	**18.7%**	**17.7%**	20.1%	18.3%	18.2%	19.4%	20.1%	12.7%	20.0%
Total North America	**13.1%**	**13.2%**	13.1%	12.9%	13.3%	13.5%	13.8%	12.6%	13.3%

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

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

	2006				2005				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
DISCONTINUED OPERATIONS									
Crude Oil - Ecuador *($/bbl)*									
Price	**44.35**	**-**	-	44.35	39.36	37.82	47.76	36.37	35.80
Production and mineral taxes	**5.03**	**-**	-	5.03	5.04	4.63	7.66	4.53	3.42
Transportation and selling	**2.25**	**-**	-	2.25	2.25	1.86	2.45	2.48	2.21
Operating	**5.55**	**-**	-	5.55	5.32	5.82	6.05	5.18	4.26
Netback	**31.52**	**-**	-	31.52	26.75	25.51	31.60	24.18	25.91

Impact of Upstream Realized Financial Hedging - Crude Oil

Ecuador *($/bbl)*	**(0.12)**	**-**	-	(0.12)	(4.92)	(3.57)	(7.81)	(4.90)	(3.48)

Average Royalty Rates
(excluding impact of realized financial hedging)

Crude Oil									
Ecuador	**25.2%**	**-**	-	25.2%	27.2%	29.4%	26.3%	26.3%	26.9%

EnCana Corporation

FOR FURTHER INFORMATION:

Investor contact:

EnCana Corporate Finance

Sheila McIntosh
Vice-President, Investor Relations
(403) 645-2194

Paul Gagne
Manager, Investor Relations
(403) 645-4737

Ryder McRitchie
Manager, Investor Relations
(403) 645-2007

Media contact:

Alan Boras
Manager, Media Relations
(403) 645-4747

EnCana Corporation
1800, 855 – 2nd Street SW
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5
Phone: (403) 645-2000
Fax: (403) 645-3400
www.encana.com

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