Second quarter report
for the period ended
June 30, 2005

Q2

UNCONVENTIONAL

EnCana
energy for people

EnCana's second quarter cash flow exceeds US$1.5 billion, or $1.76 per share – up 45 percent

Natural gas sales increase 6 percent to 3.2 billion cubic feet per day

Calgary, Alberta, (July 28, 2005) – EnCana Corporation's (TSX & NYSE: ECA) second quarter 2005 total cash flow per share increased 45 percent to US$1.76 per share diluted, or $1.57 billion, compared to the second quarter of 2004. Total operating earnings per share increased 78 percent to 73 cents per share diluted, or $655 million, compared to the second quarter of 2004. Cash flow and operating earnings increased due to higher sales, stronger natural gas and liquids prices and improved netbacks related to asset portfolio upgrading. EnCana's total second quarter net earnings per share increased 248 percent to 94 cents per share diluted, or $839 million, which includes an unrealized mark-to-market after-tax gain of $222 million due to changes in the value of commodity hedging positions at quarter-end compared to the previous quarter and an unrealized foreign exchange loss on translation of Canadian issued U.S. dollar debt of $38 million. Total second quarter revenues net of royalties were $3.82 billion. NOTE: All prior-period share and per-share references have been adjusted to reflect the two-for-one common share split which occurred in May 2005.

Second quarter sales of natural gas, oil and natural gas liquids (NGLs) from total operations were 4.59 billion cubic feet of gas equivalent (Bcfe) per day, down 1 percent from the same period in 2004. Total natural gas sales increased 6 percent to 3.2 billion cubic feet per day. Oil and NGLs sales were 230,300 barrels per day, down 15 percent mainly due to divestitures of conventional oil properties in Canada and the U.K. North Sea.

"EnCana continues to achieve strong operating and financial performance. Production and profitability from our portfolio of long-life North American resource plays continue to distinguish the EnCana story. Second quarter production from our 10 key resource plays increased 16 percent compared to the same period one year earlier. We closed the $2.1 billion sale of our Gulf of Mexico assets, divested of additional mature conventional production in Western Canada and announced plans to divest of our natural gas storage and natural gas liquids businesses – strategic initiatives that continue to sharpen our focus on North American resource plays – assets where we can apply our competitive advantage in pursuit of strong, profitable growth and returns. In the first half of 2005, we have redeployed about $1.3 billion of divestiture proceeds to buy EnCana shares under our Normal Course Issuer Bid, reducing the shares outstanding by close to 4 percent. Each share now represents a higher proportion of the company's more focused asset base, which includes the upside opportunity in our Unbooked Resource Potential," said Gwyn Morgan, EnCana President & Chief Executive Officer.

First half cash flow up 45 percent per share

First half total cash flow per share increased 45 percent to $3.31 per share diluted, or $2.99 billion, compared to the first half of 2004. Total first half operating earnings per share increased 57 percent to $1.41 per share diluted, or $1.27 billion, compared to the first half of 2004. EnCana's total first half net earnings per share increased 52 percent to 88 cents per share diluted, or $794 million, which includes an unrealized mark-to-market after-tax loss of $419 million due to changes in the value of commodity hedging positions at June 30, 2005 and an unrealized foreign exchange loss on translation of Canadian issued U.S. dollar debt of $53 million.

First half sales of natural gas, oil and NGLs from total operations were 4.56 Bcfe per day, up 2 percent from the same period in 2004. Total natural gas sales increased 11 percent to 3.18 billion cubic feet per day. Total oil and NGLs sales were 230,000 barrels per day, down 14 percent mainly due to divestitures of conventional oil properties in Canada and the U.K. North Sea.

IMPORTANT NOTE: EnCana reports in U.S. dollars and follows U.S. protocols, which report sales and reserves on an after-royalties basis. All dollar figures are U.S. dollars unless otherwise noted. EnCana is treating its Ecuador operations as discontinued because EnCana plans to sell its Ecuador assets. Total results, which include results from Ecuador, are reported in the company's financial statements included in this interim report and in supplementary documents posted on its Web site – www.encana.com.

All references in the remaining text of this interim report are on a continuing operations basis.

Continuing operations: Cash flow up 48 percent; Operating earnings up 72 percent

Second quarter 2005 cash flow from continuing operations increased 48 percent to $1.51 billion compared to the same period in 2004. Second quarter cash flow from continuing operations includes cash taxes of $83 million. Operating earnings from continuing operations increased 72 percent to $623 million compared to the second quarter of 2004. EnCana's second quarter net earnings from continuing operations increased 197 percent to $786 million, which included $201 million in after-tax unrealized mark-to-market gains as a result of changes in the value of commodity hedging positions at quarter-end compared to the previous quarter and an after-tax unrealized loss of $38 million due to translation of U.S. dollar denominated debt issued in Canada.

Sales from continuing operations up 3 percent, natural gas sales up 7 percent

Second quarter sales of natural gas, oil and NGLs from continuing operations were 4.16 Bcfe per day, up 3 percent from the second quarter of 2004. Second quarter natural gas sales from continuing operations rose 7 percent to 3.21 billion cubic feet per day compared with the second quarter of 2004. Oil and NGLs sales from continuing operations were 157,100 barrels per day, down 8 percent from the second quarter one year earlier due primarily to the divestiture of conventional oil properties.

Capital and operating costs impacted by inflation and a depreciating U.S. dollar

Operating costs from continuing operations in the second quarter of 2005 were 66 cents per thousand cubic feet of gas equivalent (Mcfe), which is slightly higher than the company's full year forecast range due mainly to industry inflation, the impact of a depreciating U.S. dollar and weather delays in the timing of planned production additions. While EnCana expects full year operating costs to be near the higher end of its guidance of 55 to 60 cents per Mcfe, the company continues to be amongst the lowest cost operators in the industry. EnCana drilled 1,017 net wells during the second quarter. Second quarter core capital investment was $1.4 billion. The company previously stated that supply and service cost increases have been higher than expected, and with the impacts of the depreciating U.S. dollar, full-year core upstream capital is now expected to be between $5.1 billion and $5.4 billion, up $600 million of which $100 million relates to the depreciating U.S. dollar. The company's corporate guidance has been updated on www.encana.com.

"EnCana's costs are about 10 percent higher than we had forecasted when we established our budgets last fall. While some cost increases are due to execution delays caused by weather, they are primarily driven by higher service sector pricing, higher steel pricing and the overall shortage of completion services – all three directly related to the robust commodity price environment we are currently benefiting from. In our effort to continually find ways to manage costs, we have reached a number of long-term arrangements with established drilling companies to supply 27 additional rigs, many built new to fit EnCana's purpose and utilizing the latest technology. These will expand the industry's overall fleet and should help EnCana mitigate the inflationary impact of high industry activity levels by reducing drilling days on its large suite of North American resource plays," said Randy Eresman, EnCana's Chief Operating Officer.

"Employing fit-for-purpose rigs under long-term contracts is one example of how we have adapted to higher input costs through optimizing the components of the manufacturing line. Although costs are higher, so are commodity futures prices. Future strip prices for natural gas and oil are about 30 percent higher than were forecast at this time in 2004, resulting in stronger returns for all of EnCana's development projects," Eresman said.

First half operating earnings from continuing operations up 38 percent
First half 2005 operating earnings increased 38 percent to $1.14 billion compared to the first half of 2004. First half 2005 cash flow from continuing operations increased 47 percent to $2.82 billion compared to the first half of 2004. EnCana’s first half net earnings from continuing operations were up 12 percent to $661 million, which includes two non-cash items: an after-tax unrealized mark-to-market hedge loss of $427 million and an after-tax unrealized mark-to-market loss on foreign exchange on US$ denominated debt issued in Canada of $53 million. First half 2005 revenues net of royalties were $6.24 billion. EnCana drilled 2,370 net wells in the first half, close to half of the company’s 2005 forecast of between 5,000 and 5,500 net wells.

2005 gas production build delayed
Given the shorter than usual winter operating season, wet spring conditions in many operating areas, and shortages of industry services, EnCana experienced delays in bringing wells on stream. About 150 million cubic feet per day of additional gas production is available from wells that will be tied in as soon as services become available. The company expects fourth quarter production to build strongly to exit the year between 3.6 billion and 3.7 billion cubic feet per day. The annualized impact of these delays is expected to result in total 2005 natural gas production to be towards the lower end of the 2005 guidance range. Oil and liquids sales, which were not as affected by the weather, are expected to be at the midpoint of the guidance range.

North American natural gas prices remain strong in the second quarter of 2005
The average second quarter benchmark NYMEX index gas price was $6.73 per thousand cubic feet, up 12 percent from $5.99 per thousand cubic feet in the second quarter of 2004. EnCana’s North American realized natural gas prices averaged $6.25 per thousand cubic feet, up 17 percent from an average of $5.34 per thousand cubic feet in the second quarter of 2004. Natural gas prices have continued to increase due primarily to high world oil prices, continued strength in the economy and a lack of growth in domestic natural gas production.

Second quarter world oil prices remain strong; Canadian heavy oil price differentials widen
Oil and NGLs continued to trade at strong prices during the second quarter of 2005 due to strong global demand and concern over lack of spare production capacity. During the second quarter of 2005, the average benchmark West Texas Intermediate (WTI) crude oil price was $53.22 per barrel, up 39 percent from the second quarter 2004 average of $38.28 per barrel. The substantially higher level of WTI, combined with limited worldwide upgrading capacity for heavy crude oils, resulted in a significant widening of light/heavy crude oil price differentials. In the second quarter, the WTI/Bow River differential increased 83 percent to $20.17 per barrel compared to the same 2004 period. In the second quarter, EnCana’s average realized oil and NGLs price was $31.80 per barrel, up 16 percent; including hedging it was $26.92 per barrel, up 29 percent compared to the same period in 2004.

Price risk management
EnCana's price risk mitigation strategy is intended to provide downside protection delivering greater certainty of cash flows and returns on its investments. Detailed risk management positions at June 30, 2005 are presented in Note 12 to the unaudited second quarter consolidated financial statements. In the second quarter of 2005, EnCana’s financial price risk management measures resulted in after-tax realized losses of approximately $71 million, comprised of a $47 million loss on oil hedges, a $26 million loss on gas hedges and a $2 million gain on other hedges. A review of the company’s hedging strategy in 2004 resulted in more frequent use of price hedging instruments which provide downside protection, but do not limit upside in a rising price environment.

As of June 30, 2005, about 74 percent of 2005 forecast gas sales is exposed to price upside, while about 60 percent has downside price protection. For oil, at current price levels, about 98 percent of 2005 forecast oil sales is exposed to price upside, while about 32 percent has downside protection. Overall, on a Mcfe basis, at current price levels about 82 percent of EnCana’s forecast 2005 sales are exposed to market price upside. Beyond 2005, fixed price hedges are in place for approximately 808 million cubic feet per day of forecast 2006 gas production, 13,700 barrels per day of forecast 2006 oil production and 29 million cubic feet per day of forecast 2007 gas production.

EnCana Continuing Operations Highlights
US$ and U.S. protocols

Financial Highlights (as at and for the period ended June 30) ($ millions)	**Q2 2005**	Q2 2004	% Δ	**6 months 2005**	6 months 2004	% Δ
Revenues, net of royalties	**3,581**	2,552	+ 40	**6,242**	5,282	+18
Pre-tax cash flow	**1,595**	1,204	+ 32	**3,128**	2,325	+ 35
Less:						
Cash tax	**83**	183	-55	**308**	408	- 25
Cash flow	**1,512**	1,021	+ 48	**2,820**	1,917	+ 47
Net acquisitions & divestitures	**(1,789) ***	2,234	- 180	**(1,830) ***	1,935	- 195
Core capital	**1,426**	1,030	+ 38	**2,933**	2,287	+ 28
Net capital investment	**(363)**	3,264	-111	**1,103**	4,222	- 74
Net earnings	**786**	265	+ 197	**661**	591	+ 12
Add (Deduct):						
Unrealized mark-to-market hedging (gain) loss, after-tax	**(201)**	72	- 379	**427**	285	+ 50
Unrealized foreign exchange loss on translation of U.S. dollar debt issued in Canada, after-tax	**38**	25	+ 52	**53**	57	- 7
Future tax (recovery) due to tax rate change	**-**	-	n/a	**-**	(109)	n/a
Operating earnings	**623**	362	+ 72	**1,141**	824	+ 38

* Includes proceeds from Gulf of Mexico sale of $2.1 billion, minus tax of $591 million

EnCana financial results in U.S. dollars and operating results according to U.S. protocols
EnCana reports in U.S. dollars and according to U.S. protocols in order to facilitate a more direct comparison to other North American upstream oil and natural gas exploration and development companies. Reserves and production are reported on an after-royalty basis.

Operating Highlights (for the period ended June 30) (After royalties)	**Q2 2005**	Q2 2004	% Δ	**6 months 2005**	6 months 2004	% Δ
North America Natural Gas (MMcf/d)						
Production	**3,212**	3,001	+ 7	**3,166**	2,843	+ 11
Inventory withdrawal	**-**	-	n/a	**13**	-	n/a
Natural gas sales (MMcf/d)	**3,212**	3,001	+ 7	**3,179**	2,843	+ 12
North America Oil and NGLs (bbls/d)	**157,108**	170,687	- 8	**157,145**	168,283	- 7
Total sales (MMcfe/d)	**4,155**	4,025	+ 3	**4,122**	3,853	+ 7

Key resource play production growth up about 16 percent across EnCana's portfolio

Development capital continues to be focused on turning EnCana's Unbooked Resource Potential into production and reserves. Second quarter gas and oil production from key North American resource plays has increased approximately 16 percent since the second quarter of 2004. Gas production growth is driven mainly by the Piceance basin in Colorado, the impact of the Tom Brown, Inc. acquisition, shallow gas and coalbed methane (CBM) on legacy Suffield and Palliser Blocks in Alberta, Cutbank Ridge in northeast British Columbia and the acquisition of the Fort Worth property. Oil production grew at Pelican Lake in northeast Alberta while Foster Creek production decreased temporarily in the second quarter due to scheduled maintenance and work required to prepare for a 30,000 barrel per day facility expansion, of which 10,000 barrels per day is planned to come on production late in the fourth quarter of 2005.

Growth from key North American resource plays

Resource Play	Daily Production								
	2005			2004					2003
(After royalties)	**YTD**	**Q2**	**Q1**	**Full Year**	**Q4**	**Q3**	**Q2**	**Q1**	**Full Year**
Natural Gas (MMcf/d)									
Jonah	**424**	**416**	431	389	404	373	387	394	374
Piceance	**300**	**302**	300	261	291	282	251	218	151
East Texas	**83**	**85**	82	50	83	81	36	-	-
Fort Worth	**62**	**63**	61	27	34	31	23	21	7
Greater Sierra	**213**	**228**	195	230	211	244	247	216	143
Cutbank Ridge	**68**	**80**	56	40	50	45	41	22	3
CBM	**41**	**46**	36	17	27	19	11	10	4
Shallow Gas	**629**	**633**	625	592	629	595	590	554	507
Oil (Mbbls/d)									
Foster Creek	**27**	**24**	30	29	28	29	30	28	22
Pelican Lake	**24**	**27**	21	19	23	22	15	15	16
Total (MMcfe/d)	**2,128**	**2,161**	2,094	1,892	2,034	1,976	1,858	1,696	1,416
% change from prior year's quarter		**16.3**	23.5						
% change from prior period		**3.2**	2.9	33.6	2.9	6.4	9.6	7.1	

Drilling activity in key North American resource plays

Resource Play	Net Wells Drilled								
	2005			2004					2003
	YTD	Q2	Q1	Full year	Q4	Q3	Q2	Q1	Full Year
Natural Gas									
Jonah	**58**	**30**	28	70	21	17	21	11	59
Piceance	**142**	**65**	77	250	47	66	66	71	284
East Texas	**43**	**22**	21	50	23	20	7	-	-
Fort Worth	**21**	**12**	9	36	8	10	10	8	5
Greater Sierra	**106**	**47**	59	187	18	13	21	135	199
Cutbank Ridge	**61**	**38**	23	50	17	12	4	17	20
CBM	**486**	**202**	284	760	234	347	98	81	267
Shallow Gas	**638**	**365**	273	1,552	222	384	416	530	2,366
Oil									
Foster Creek	**12**	**2**	10	11	7	-	-	4	8
Pelican Lake	**53**	**34**	19	92	-	33	30	29	134
Total net wells	**1,620**	**817**	803	3,058	597	902	673	886	3,342

Corporate developments

Quarterly dividend of 7.5 cents per share declared

EnCana's board of directors has declared a quarterly dividend of 7.5 cents per share which is payable on September 30, 2005 to common shareholders of record as of September 15, 2005.

Normal Course Issuer Bid purchases

In the first half of 2005, EnCana has purchased for cancellation approximately 44.7 million of its shares at an average price of $32.86 per share under its current Normal Course Issuer Bid (Bid), which commenced October 29, 2004. Under the Bid, which was amended in February 2005 to allow for the purchase of up to 10 percent of EnCana's public float, the company has purchased about 8.5 percent of the public float since October 2004. Share option exercises during the same period resulted in the issue of approximately 1.5 percent of the public float. The company had approximately 860.2 million shares outstanding at June 30, 2005.

Changes in Share Capital (millions of shares)	First six months 2005	Full Year 2004	% Δ
Common shares outstanding, beginning of period	900.6	921.2	- 2.2
Shares issued under option plan	9.8	19.4	
Shares purchased under Normal Course Issuer Bid	(44.7)	(40.0)	
Subtotal	**865.7**	**900.6**	**- 3.9**
Shares purchased for Performance Share Unit plan	(5.5)	-	
Common shares outstanding, end of period	860.2	900.6	

Two-for-one share split

On April 27, 2005, EnCana's shareholders approved the split of EnCana's outstanding common shares on a two-for-one basis. The common shares began trading on a sub-divided basis on the Toronto Stock Exchange on May 10, 2005 and on the New York Stock Exchange on May 23, 2005.

Financial strength

EnCana maintains a strong balance sheet. At June 30, 2005 the company's net debt-to-capitalization ratio was 36:64. Completion of planned asset divestitures is expected to further reduce debt levels. Proceeds of these proposed divestitures are also expected to be directed to purchase the company's shares under its Normal Course Issuer Bid and debt repayment. EnCana's net debt-to-EBITDA multiple, on a trailing 12-month basis, was 1.3 times. In the second quarter of 2005, EnCana invested $1,426 million of core capital. Acquisitions and divestitures resulted in net proceeds of $1,789 million, after deducting $591 million of tax on sale of Gulf of Mexico assets. Overall, divestiture proceeds were $363 million in excess of core capital investment during the second quarter.

EnCana Corporation
With an enterprise value of approximately US$44 billion, EnCana is one of North America's leading natural gas producers, is among the largest holders 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 low geological and commercial development risk, low average decline rates and very long producing lives. The application of technology to unlock the huge resource potential of these plays typically results in continuous increases in production and reserves and decreases in costs over multiple decades of resource play life. 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, pre-tax cash flow, cash flow from continuing operations, operating earnings from continuing operations, total operating earnings and 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 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. Management believes these items reduce 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. EBIDTA is a non-GAAP measure that shows net earnings from continuing operations before gain on disposition, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation and depletion, depreciation and amortization. These measures have been described and presented in this interim report in order to provide shareholders and potential investors with additional information regarding EnCana's liquidity and its ability to generate funds to finance its operations.

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.

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 within the meaning of the "safe harbour" provisions of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements in this interim report include, but are not limited to: future economic and operating performance; anticipated growth and success of resource plays and the expected characteristics of resource plays; the planned sale of interests in Ecuador, the midstream NGLs business unit and the natural gas storage business and the timing of such potential transactions; the expected proceeds from planned divestitures and the use of proceeds from divestitures for share purchases under the company's Normal Course Issuer Bid program and debt repayment; projections with respect to the company's unbooked resource potential and projected production growth over the next five years; expected debt levels and debt to capitalization ratios; anticipated effect of EnCana's market risk mitigation strategy and EnCana's ability to participate in commodity price upside; anticipated purchases pursuant to the Normal Course Issuer Bid; anticipated production in 2005 and beyond; anticipated drilling; the capacity of the company's SAGD expansion project and the timing thereof; potential capital expenditures and investment and the impact of inflation; potential oil, natural gas and NGLs sales in 2005 and beyond; anticipated ability to meet production, operating cost, cash tax and sales guidance targets; anticipated costs and the ability to mitigate against drilling costs increases; anticipated commodity prices; projections relating to project returns from EnCana's North American resource plays 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 oil and gas prices; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the company's marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved reserves; the company's ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the company's ability to secure adequate product transportation; changes in environmental and other regulations or the interpretations of such regulations; political and economic conditions in the countries in which the company operates, including Ecuador; the risk of war, hostilities, civil insurrection and instability affecting countries in which the company operates and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive.

Furthermore, the forward-looking statements contained in this interim report are made as of the date of this interim report, and 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 & ANALYSIS

This Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read in conjunction with the unaudited interim Consolidated Financial Statements ("Interim Consolidated Financial Statements") for the period ended June 30, 2005, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2004. Readers are referred to the legal advisory detailing "Forward-Looking Statements" contained at the end of this MD&A. The Interim Consolidated Financial Statements and comparative information have been prepared in accordance with Canadian GAAP in United States dollars (except where indicated as being in another currency).

This MD&A has been prepared in United States dollars with production and sales volumes presented on an after royalties basis consistent with U.S. protocol reporting. This MD&A is dated July 27, 2005.

SUMMARY OF KEY SECTIONS

Certain terms used in this MD&A (and not otherwise defined) are defined in the notes regarding Oil and Gas Information and Currency, Non-GAAP Measures and References to EnCana, found at the end of this MD&A.

SUMMARY OF KEY EVENTS AND FINANCIAL RESULTS

Key events in the second quarter of 2005:

- Cash flow from continuing operations was $1,512 million compared with $1,021 million in 2004, an increase of 48 percent;
- Net earnings from continuing operations increased 197 percent to $786 million compared with $265 million in 2004;
- Operating earnings from continuing operations increased 72 percent to $623 million compared with $362 million in 2004;

- Sales volumes from continuing operations increased three percent to 4,155 million cubic feet equivalent per day ("MMcfe/d") comprised of 3,212 million cubic feet per day ("MMcf/d") of natural gas and 157,108 barrels per day ("bbls/d") of liquids;
- Average sales prices, excluding hedges, increased 17 percent for North American natural gas and 16 percent for North American liquids compared with the same period in 2004;
- EnCana sold its Gulf of Mexico assets for net proceeds of approximately $1.5 billion after-tax and other adjustments and sold certain Canadian conventional oil and gas assets for proceeds of $326 million before adjustments; and
- EnCana recorded realized commodity hedging losses from continuing operations of $71 million after-tax and unrealized commodity hedging gains of $201 million after-tax.

Key events year-to-date in 2005:

- Cash flow from continuing operations was $2,820 million compared with $1,917 million in 2004, an increase of 47 percent;
- Net earnings from continuing operations increased 12 percent to $661 million compared with $591 million in 2004;
- Operating earnings from continuing operations increased 38 percent to $1,141 million compared with $824 million in 2004;
- Sales volumes from continuing operations increased seven percent to 4,122 MMcfe/d comprised of 3,179 MMcf/d of natural gas and 157,145 bbls/d of liquids;
- Average sales prices, excluding hedges, increased 14 percent for North American natural gas and 17 percent for North American liquids;
- EnCana sold its Gulf of Mexico assets for net proceeds of approximately $1.5 billion after-tax and other adjustments and sold certain Canadian conventional oil and gas assets for proceeds of $326 million before adjustments;
- EnCana recorded realized commodity hedging losses from continuing operations of $81 million after-tax and unrealized commodity hedging losses of $427 million after-tax; and
- EnCana purchased approximately 45 million shares under the Normal Course Issuer Bid ("Bid") for a total cost of $1,472 million.

OVERVIEW

EnCana is a leading independent North American based oil and gas company. EnCana pursues predictable, profitable growth from its portfolio of long-life resource plays in Canada and the United States. EnCana's disciplined pursuit of these unconventional resources has enabled it to become North America's leading natural gas producer and a technical and cost performance leader in the development of oilsands through in-situ recovery.

EnCana reports the results of its continuing operations under two operating segments:

- Upstream, which focuses on the Company's exploration for and development and production of natural gas, crude oil and natural gas liquids ("NGLs"), and other related activities; and
- Midstream & Market Optimization, which is conducted by the Midstream & Marketing division. Marketing undertakes market optimization activities to enhance the sale of Upstream's proprietary production. Market Optimization results reflect third party purchases and sales of product which provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. Midstream focuses on natural gas storage, NGLs processing and power generation.

BUSINESS ENVIRONMENT

NATURAL GAS

Concerns that a warm summer could increase gas demand for power generation combined with continued high crude oil prices have resulted in historically high average NYMEX gas prices.

Higher average AECO gas prices in the second quarter of 2005 compared with the same period in 2004 can be attributed to increased NYMEX prices and decreased AECO/NYMEX basis differentials in the second quarter of 2005 compared to the second quarter of 2004.

	Three months ended June 30			Six months ended June 30			Year Ended
Natural Gas Price Benchmarks ***(Average for the period)***	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004	2004
AECO Price *(C$/Mcf)*	**$ 7.37**	8%	$ 6.80	**$ 7.03**	5%	$ 6.71	$ 6.79
NYMEX Price *($/MMBtu)*	**6.73**	12%	5.99	**6.50**	11%	5.84	6.14
Rockies (Opal) Price *($/MMBtu)*	**6.00**	19%	5.04	**5.77**	16%	4.99	5.23
AECO/NYMEX Basis Differential *($/MMBtu)*	**0.78**	-19%	0.96	**0.82**	-1%	0.83	0.91
Rockies/NYMEX Basis Differential *($/MMBtu)*	**0.73**	-23%	0.95	**0.73**	-14%	0.85	0.91

CRUDE OIL

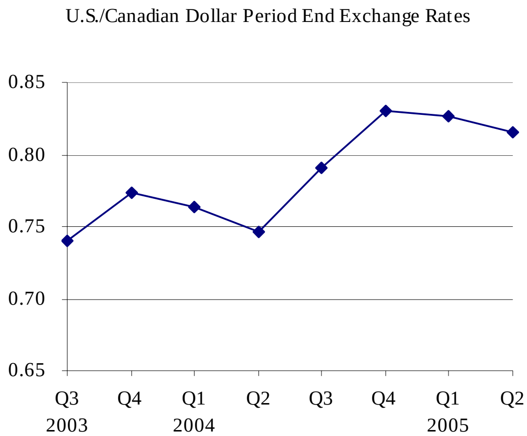
The West Texas Intermediate ("WTI") crude oil price was significantly higher in the second quarter of 2005 than the same period in 2004. This is attributed to continued world oil demand growth, concern over limited world spare production capacity and anticipated tight supply/demand in the fourth quarter of 2005. Second quarter Canadian heavy oil differentials were still significantly wider than in 2004 due to the higher price for WTI and the wider U.S. Gulf Coast light to heavy product differentials reflected in the wider Maya differential, which is the North American heavy crude benchmark. Increased Canadian heavy crude-on-crude competition also contributed to widening Canadian heavy oil differentials. The Bow River Blend average sales price for the second quarter of 2005 was 62 percent of WTI compared to 71 percent in the second quarter of 2004.

The WTI/NAPO differential for the second quarter of 2005, as a percentage of WTI, was relatively unchanged compared to the same period in 2004, despite a widening of light/heavy differentials in the U.S. Gulf Coast. This was primarily related to better refinery economics on NAPO crude translating into better pricing.

	Three months ended June 30			Six months ended June 30			Year Ended
Crude Oil Price Benchmarks ***(Average for the period $/bbl)***	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004	2004
WTI	**$ 53.22**	39%	$ 38.28	**$ 51.66**	40%	$ 36.78	$ 41.47
WTI/Maya Differential	**13.17**	51%	8.71	**15.20**	69%	8.99	11.58
WTI/Bow River Differential	**20.17**	83%	11.02	**19.34**	93%	10.03	12.82
WTI/OCP NAPO Differential (Ecuador)	**15.82**	30%	12.17	**16.50**	39%	11.91	14.33

U.S./CANADIAN DOLLAR EXCHANGE RATES

The June 30, 2005 U.S./Canadian dollar exchange rate of US$0.816 per C$1 increased by nine percent compared with the June 30, 2004 rate of $0.746. The June 2005 rate is approximately two percent lower than the 2004 year-end rate of $0.831.



	Three months ended June 30 2005	Six months ended June 30 2005	Year Ended 2004
Average U.S. / Canadian dollar exchange rate	$ 0.804	$ 0.810	$ 0.768
Average U.S. / Canadian dollar exchange rate for prior year	$ 0.736	$ 0.747	$ 0.716
Additional U.S. costs incurred for every C$100 spent on capital projects, operating & administrative expenses compared to prior year	$ 6.80	$ 6.30	$ 5.20

The impacts on results from the conversion of Canadian to U.S. dollars should be considered when analyzing specific components contained in the Interim Consolidated Financial Statements. Revenues were relatively unaffected by the increase in the exchange rate since commodity prices received are largely based in U.S. dollars or in Canadian dollar prices which are closely tied to the value of the U.S. dollar.

ACQUISITIONS AND DIVESTITURES

During the second quarter, EnCana completed two significant transactions:

- On May 26, 2005, EnCana closed the sale of its Gulf of Mexico assets for approximately $2.1 billion in cash, resulting in net proceeds of approximately $1.5 billion after-tax and other adjustments; and
- On June 30, 2005, EnCana closed the sale of certain Canadian conventional oil and gas assets producing approximately 6,400 barrels of oil equivalent per day for proceeds of approximately $326 million before adjustments.

Proceeds from these divestitures were directed primarily to a combination of debt reduction and the purchase of EnCana shares.

EnCana is continuing with plans to divest of its NGLs extraction business, natural gas storage business and Ecuador operations.

CONSOLIDATED FINANCIAL RESULTS

Consolidated Financial Summary *($ millions, except per share [(1)] amounts)*	Three months ended June 30 2005	2005 vs 2004	2004	Six months ended June 30 2005	2005 vs 2004	2004	Year Ended 2004
Cash Flow[(2)]	**$ 1,572**	39%	$ 1,131	**$ 2,985**	40%	$ 2,126	$ 4,980
- per share - diluted	**1.76**	45%	1.21	**3.31**	45%	2.28	5.32
Net Earnings	**839**	236%	250	**794**	47%	540	3,513
- per share - basic	**0.96**	256%	0.27	**0.90**	53%	0.59	3.82
- per share - diluted	**0.94**	248%	0.27	**0.88**	52%	0.58	3.75
Operating Earnings[(3)]	**655**	73%	379	**1,266**	50%	844	1,976
- per share diluted	**0.73**	78%	0.41	**1.41**	57%	0.90	2.11
Cash Flow from Continuing Operations[(2)]	**1,512**	48%	1,021	**2,820**	47%	1,917	4,605
Net Earnings from Continuing Operations	**786**	197%	265	**661**	12%	591	2,211
- per share - basic	**0.90**	210%	0.29	**0.75**	17%	0.64	2.40
- per share - diluted	**0.88**	214%	0.28	**0.73**	16%	0.63	2.36
Operating Earnings from Continuing Operations [(3)]	**623**	72%	362	**1,141**	38%	824	1,989
Revenues, Net of Royalties	**3,581**	40%	2,552	**6,242**	18%	5,282	11,810

(1) Per share amounts have been restated for the effect of the common share split approved in April, 2005.

(2) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are discussed under "Cash Flow" in this MD&A.

(3) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under Operating Earnings in this MD&A.

Quarterly Summary *($ millions, except per share [(1)] amounts)*	2005 Q2	2005 Q1	2004 Q4	2004 Q3	2004 Q2	2004 Q1	2003 Q4	2003 Q3
Cash Flow[(2)]	**$ 1,572**	$ 1,413	$ 1,491	$ 1,363	$ 1,131	$ 995	$ 1,254	$ 977
- per share - diluted	**1.76**	1.55	1.60	1.46	1.21	1.07	1.35	1.02
Net Earnings (Loss)	**839**	(45)	2,580	393	250	290	426	290
- per share - basic	**0.96**	(0.05)	2.81	0.43	0.27	0.31	0.46	0.31
- per share - diluted	**0.94**	(0.05)	2.77	0.42	0.27	0.31	0.46	0.31
Operating Earnings[(3)]	**655**	611	573	559	379	465	316	278
- per share - diluted	**0.73**	0.67	0.62	0.60	0.41	0.50	0.34	0.29
Cash Flow from Continuing Operations[(2)]	**1,512**	1,308	1,429	1,259	1,021	896	1,103	918
Net Earnings (Loss) from Continuing Operations	**786**	(125)	1,188	432	265	326	447	266
- per share - basic	**0.90**	(0.14)	1.29	0.47	0.29	0.35	0.49	0.28
- per share - diluted	**0.88**	(0.14)	1.28	0.46	0.28	0.35	0.48	0.28
Operating Earnings from Continuing Operations[(3)]	**623**	518	612	553	362	462	337	254
Revenues, Net of Royalties	**3,581**	2,661	4,208	2,320	2,552	2,730	2,639	2,190

(1) Per share amounts have been restated for the effect of the common share split approved in April, 2005.

(2) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are discussed under "Cash Flow" in this MD&A.

(3) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under Operating Earnings in this MD&A.

CASH FLOW

EnCana's 2005 second quarter cash flow was $1,572 million, an increase of $441 million from the same period in 2004. This increase reflects increased commodity prices in the second quarter of 2005 and lower realized hedge losses. EnCana's discontinued operations contributed $60 million to cash flow compared with $110 million from the same period in 2004.

EnCana's 2005 second quarter cash flow from continuing operations increased $491 million to $1,512 million compared with the same period in 2004 with significant items as follows:

- Natural gas sales volumes increased seven percent to 3,212 MMcf/d;
- Average North American natural gas prices, excluding financial hedges, were $6.25 per Mcf compared to $5.34 per Mcf in the same period of 2004, an increase of 17 percent;
- Average North American liquids prices, excluding financial hedges, were $31.80 per bbl in 2005 compared to $27.43 per bbl in the same period of 2004, an increase of 16 percent;
- Realized financial commodity hedge losses included in cash flow from continuing operations were $71 million after-tax in 2005 compared to $134 million after-tax for the same period in 2004; and
- The current income tax provision net of income tax on the sale of assets was $83 million in 2005, compared with $183 million in 2004.

EnCana's 2005 year-to-date cash flow was $2,985 million, an increase of $859 million from the same period in 2004. This increase reflects the net impact of the Company's overall two percent sales volume growth, increased prices for the first six months in 2005 and lower realized hedge losses. EnCana's discontinued operations contributed $165 million to cash flow, compared with $209 million in 2004.

EnCana's 2005 year-to-date cash flow from continuing operations increased $903 million, to $2,820 million compared with the same period in 2004 with significant items as follows:

- Natural gas sales volumes increased 12 percent to 3,179 MMcf/d;
- Average North American natural gas prices, excluding financial hedges, were $6.03 per Mcf compared to $5.30 per Mcf in the same period of 2004, an increase of 14 percent;
- Average North American liquids prices, excluding financial hedges, were $30.79 per bbl in 2005 compared to $26.42 per bbl in the same period of 2004, an increase of 17 percent;
- Realized financial commodity hedge losses included in cash flow from continuing operations were $81 million after-tax in 2005 compared to $194 million after-tax for the same period in 2004; and
- The current income tax provision net of income tax on the sale of assets was $308 million in 2005, compared with $408 million in 2004.

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

NET EARNINGS

EnCana's 2005 second quarter net earnings were $839 million compared with $250 million in the same period in 2004. EnCana's 2005 second quarter net earnings from continuing operations were $786 million, an increase of

$521 million compared with 2004. In addition to the items affecting second quarter cash flow from continuing operations as detailed previously, significant items are:

- Unrealized mark-to-market gains of $201 million after-tax in 2005 compared with a loss of $72 million in the same period in 2004; and
- A $38 million after-tax unrealized loss on Canadian issued U.S. dollar debt in 2005 compared with a $25 million loss in 2004.

EnCana's 2005 year-to-date net earnings were $794 million compared with $540 million in the same period in 2004. EnCana's year-to-date net earnings from continuing operations were $661 million, an increase of $70 million in 2005 compared with 2004. In addition to the items affecting cash flow from continuing operations as detailed previously, significant items are:

- Unrealized mark-to-market losses of $427 million after-tax in 2005 compared to $285 million in the same period in 2004;
- An increase in DD&A of $205 million as a result of increased sales volumes, the impact of the higher value of the Canadian dollar and higher DD&A rates resulting from the impacts of foreign exchange, the Tom Brown, Inc. ("TBI") acquisition in May 2004 and increased future development costs;
- Included in 2004 is a gain due to a change in tax rates of $109 million, with no comparable amount to-date in 2005; and
- A $53 million after-tax unrealized loss on Canadian issued U.S. dollar debt to-date in 2005 compared with a $57 million loss in 2004.

Reconciliation of Net Earnings from Continuing Operations from 2004 to 2005
($ millions)

2004 year-to-date net earnings from continuing operations	**$**	**591**
Upstream prices		488 [1]
Upstream volumes		309
Realized loss on financial contracts		164
Gain on disposition		(35)
Foreign exchange loss		(73)
Income tax		(158)
Upstream expenses		(158)
DD&A expenses		(205)
Unrealized fair value adjustment on financial contracts		(230)
Other		(32)
2005 year-to-date net earnings from continuing operations	**$**	**661**

[1] Excludes the effect of Upstream financial hedging.

OPERATING EARNINGS

Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures that show net earnings excluding non-operating items such as 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. Management believes these items reduce the comparability of the Company's underlying financial performance between periods. 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 five years. The following table has been prepared in order to provide investors with information that is more comparable between years.

Summary of Operating Earnings	Three months ended June 30			Six months ended June 30			Year Ended
($ millions)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004	2004
Net Earnings, as reported	**$ 839**	236%	$ 250	**$ 794**	47%	$ 540	$ 3,513
Deduct: Gain on discontinuance	**-**		-	**-**		-	(1,364)
Add: Unrealized mark-to-market accounting (gain) loss (after-tax)	**(222)**		104	**419**		356	165
Deduct: Unrealized foreign exchange loss (gain) on translation of Canadian issued U.S. dollar debt (after-tax)	**38**		25	**53**		57	(229)
Deduct: Future tax recovery due to tax rate reductions	**-**		-	**-**		(109)	(109)
Operating Earnings [(1)(3)]	**$ 655**	73%	$ 379	**$ 1,266**	50%	$ 844	$ 1,976
($ per Common Share - Diluted)							
Net Earnings, as reported	**$ 0.94**	248%	$ 0.27	**$ 0.88**	52%	$ 0.58	$ 3.75
Deduct: Gain on discontinuance	**-**		-	**-**		-	(1.46)
Add: Unrealized mark-to-market accounting (gain) loss (after-tax)	**(0.25)**		0.11	**0.47**		0.38	0.18
Deduct: Unrealized foreign exchange loss (gain) on translation of Canadian issued U.S. dollar debt (after-tax)	**0.04**		0.03	**0.06**		0.06	(0.24)
Deduct: Future tax recovery due to tax rate reductions	**-**		-	**-**		(0.12)	(0.12)
Operating Earnings [(1)(3)]	**$ 0.73**	78%	$ 0.41	**$ 1.41**	57%	$ 0.90	$ 2.11

Summary of Operating Earnings from Continuing Operations	Three months ended June 30			Six months ended June 30			Year Ended
($ millions)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004	2004
Net Earnings from Continuing Operations, as reported	**$ 786**	197%	$ 265	**$ 661**	12%	$ 591	$ 2,211
Add: Unrealized mark-to-market accounting (gain) loss (after-tax)	**(201)**		72	**427**		285	116
Deduct: Unrealized foreign exchange loss (gain) on translation of Canadian issued U.S. dollar debt (after-tax)	**38**		25	**53**		57	(229)
Deduct: Future tax recovery due to tax rate reductions	**-**		-	**-**		(109)	(109)
Operating Earnings from Continuing Operations [(2)(3)]	**$ 623**	72%	$ 362	**$ 1,141**	38%	$ 824	$ 1,989

(1) 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.

(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 June 30

($ millions)	2005				2004			
	Produced Gas	**Crude Oil and NGLs**	**Other**	**Total**	Produced Gas	Crude Oil and NGLs	Other	Total
Revenues, Net of Royalties	**$ 1,785**	**$ 384**	**$ 58**	**$ 2,227**	$ 1,387	$ 322	$ 54	$ 1,763
Expenses								
Production and mineral taxes	**83**	**14**	**-**	**97**	73	10	-	83
Transportation and selling	**112**	**14**	**-**	**126**	114	15	-	129
Operating	**170**	**78**	**48**	**296**	125	64	48	237
Operating Cash Flow	**$ 1,420**	**$ 278**	**$ 10**	**$ 1,708**	$ 1,075	$ 233	$ 6	$ 1,314
Depreciation, depletion and amortization				**648**				571
Upstream Income				**$ 1,060**				$ 743

Six months ended June 30

($ millions)	2005				2004			
	Produced Gas	**Crude Oil and NGLs**	**Other**	**Total**	Produced Gas	Crude Oil and NGLs	Other	Total
Revenues, Net of Royalties	**$ 3,482**	**$ 732**	**$ 119**	**$ 4,333**	$ 2,653	$ 635	$ 104	$ 3,392
Expenses								
Production and mineral taxes	**158**	**26**	**-**	**184**	119	18	-	137
Transportation and selling	**226**	**31**	**-**	**257**	220	36	-	256
Operating	**335**	**149**	**104**	**588**	246	137	95	478
Operating Cash Flow	**$ 2,763**	**$ 526**	**$ 15**	**$ 3,304**	$ 2,068	$ 444	$ 9	$ 2,521
Depreciation, depletion and amortization				**1,308**				1,074
Upstream Income				**$ 1,996**				$ 1,447

Three Months Ended June 30

Results from continuing operations for the quarter ended June 30, 2005 compared with the same quarter in 2004 reflect a three percent or 130 MMcfe/d increase in sales volumes. The increase in sales volumes is primarily attributable to organic growth from North American resource plays and the full quarter impact from the TBI acquisition in 2004. These increases were partially offset by non-core property dispositions in the latter half of 2004.

Revenues, net of royalties, reflect the increase in the quarter over quarter natural gas and crude oil benchmark prices (see the “Business Environment” section of this MD&A) offset by the realized hedging losses. The effect of realized commodity hedging losses for the three months ended June 30, 2005 was $112 million, or $0.30 per Mcfe compared to $172 million or $0.47 per Mcfe for the same period in 2004.

North American production and mineral taxes increased 17 percent in the second quarter of 2005 compared to the same period in 2004 primarily due to increased natural gas and crude oil prices, increased volumes in the United States including the 2004 acquisition of TBI properties, partially offset by a $4 million refund for a prior period overpayment. In addition, production and mineral taxes in 2004 in the U.S. include the impact of an adjustment to Colorado rates.

North American transportation and selling costs have remained relatively unchanged in the second quarter of 2005 compared with the same quarter in 2004. In 2005 costs have increased due to the marketing of gas volumes for several U.S. properties downstream of the wellhead which were marketed at the wellhead in 2004. In the second quarter of 2004 the U.S. operations included a one time charge of $21 million for the buyout of third party physical contracts.

For the three months ended June 30, 2005, operating expenses were $59 million higher, an increase of $0.14 per Mcfe to $0.66 per Mcfe compared to $0.52 per Mcfe for the same period in 2004. This increase is primarily due to an increase in the average U.S./Canadian dollar exchange rate during 2005, an increase in long-term compensation expenses due to the higher EnCana share price, rising costs as a result of increased industry activity and higher Canadian property taxes. Excluding the impact of foreign exchange, operating expenses in 2005 would have increased to $0.62 per Mcfe.

DD&A expense increased by $77 million for the quarter ended June 30, 2005 compared to the same quarter in 2004 primarily as a result of increased sales volumes, higher DD&A rates and the impact of the higher value of the Canadian dollar compared to the U.S. dollar applied to Canadian dollar denominated DD&A expense. On a continuing operations basis, excluding other activities, DD&A rates were $1.70 per Mcfe for the second quarter of 2005 compared to $1.51 per Mcfe for the same quarter of 2004. DD&A rates have increased in 2005 due to the impacts of foreign exchange, the TBI acquisition and increased future development costs.

Six Months Ended June 30

Results from continuing operations reflect a seven percent or 269 MMcfe/d increase in sales volumes for the six months ended June 30, 2005 compared with the same period in 2004. The increase in sales volumes is primarily attributable to organic growth from North American resource plays and the TBI acquisition in May and the Fort Worth property acquisition in December offset slightly by non-core property dispositions in 2004.

Revenues, net of royalties, reflect the increase in year-to-date natural gas and crude oil benchmark prices (see the “Business Environment” section of this MD&A) offset by the realized hedging losses. The effect of realized commodity hedging losses for the six months ended June 30, 2005 was $134 million, or $0.18 per Mcfe compared to $263 million or $0.38 per Mcfe for the same period in 2004.

North American production and mineral taxes increased 34 percent in the first six months of 2005 compared to the same period in 2004 primarily due to higher natural gas and crude oil prices, increased volumes in the United States offset slightly by a $4 million refund for a prior period overpayment. In addition, production and mineral taxes in 2004 include the impact of an adjustment to Colorado rates.

For the six months ended June 30, 2005, operating expenses excluding Other were $101 million higher, an increase of $0.10 per Mcfe to $0.65 per Mcfe compared to $0.55 per Mcfe for the same period in 2004. This increase is primarily due to an increase in the average U.S./Canadian dollar exchange rate during 2005, an increase in long-term compensation expenses due to the higher EnCana share price, rising costs as a result of increased industry activity and higher Canadian property taxes. Excluding the impact of foreign exchange, operating expenses in 2005 would have increased to $0.61 per Mcfe.

DD&A expense increased by $234 million for the first six months of 2005 compared to the first six months of 2004 primarily as a result of increased sales volumes, higher DD&A rates and the impact of the higher value of the Canadian dollar compared to the U.S. dollar applied to Canadian dollar denominated DD&A expense. On a continuing operations basis, excluding other activities, DD&A rates were $1.73 per Mcfe for the first six months of 2005 compared to $1.50 per Mcfe in the first six months of 2004. DD&A rates have increased in 2005 due to the impacts of foreign exchange, the TBI acquisition and increased future development costs.

Revenue Variances for the Second Quarter of 2005 Compared to the Second Quarter of 2004 from Continuing Operations

Three months ended June 30

($ millions)

	2004 Revenues, Net of Royalties	Revenue Variances in: Price[1]	Volume	2005 Revenues, Net of Royalties
Produced Gas				
Canada	$ 981	$ 217	$ (14)	$ 1,184
United States	406	61	134	601
Total Produced Gas	$ 1,387	$ 278	$ 120	$ 1,785
Crude Oil and NGLs				
Canada	$ 285	$ 77	$ (32)	$ 330
United States	37	15	2	54
Total Crude Oil and NGLs	$ 322	$ 92	$ (30)	$ 384

(1) Includes realized commodity hedging impacts.

The increase in sales prices accounts for approximately 80 percent of the change in revenues, net of royalties, for the second quarter of 2005 compared with the second quarter of 2004.

The revenue variances due to volumes in Canada for the second quarter of 2005 compared with the second quarter of 2004 were mainly due to the dispositions of mature conventional producing assets during 2004.

Revenue Variances for the First Six Months of 2005 Compared to the First Six Months of 2004 from Continuing Operations

Six months ended June 30

($ millions)

	2004 Revenues, Net of Royalties	Revenue Variances in: Price[1]	Volume	2005 Revenues, Net of Royalties
Produced Gas				
Canada	$ 1,917	$ 384	$ 16	$ 2,317
United States	736	94	335	1,165
Total Produced Gas	$ 2,653	$ 478	$ 351	$ 3,482
Crude Oil and NGLs				
Canada	$ 570	$ 119	$ (66)	$ 623
United States	65	20	24	109
Total Crude Oil and NGLs	$ 635	$ 139	$ (42)	$ 732

(1) Includes realized commodity hedging impacts.

The increase in sales prices accounts for approximately 67 percent of the change in revenues, net of royalties, for the first half of 2005 compared with the first half of 2004.

The crude oil and NGLs revenue variance due to volumes in Canada of $(66) million for the six months ended June 30, 2005 compared with the six months ended June 30, 2004 was mainly due to the dispositions of mature conventional oil producing assets during 2004.

Quarterly Sales Volumes	2005		2004				2003	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Produced Gas *(million cubic feet per day)*	**3,212**	3,146	3,087	3,096	3,001	2,684	2,662	2,518
Crude Oil *(barrels per day)*	**132,294**	130,826	132,061	142,506	144,347	142,669	151,644	149,582
NGLs *(barrels per day)*	**24,814**	26,358	27,409	27,167	26,340	23,208	22,827	23,288
Continuing Operations *(million cubic feet equivalent per day)* (1)	**4,155**	4,089	4,044	4,114	4,025	3,679	3,709	3,555
Discontinued Operations								
Ecuador *(barrels per day)*	**73,176**	72,487	77,876	74,846	78,303	80,982	77,352	39,807
United Kingdom *(barrels of oil equivalent per day)* (2)	**-**	-	13,927	20,222	26,728	22,755	18,400	6,979
Syncrude *(barrels per day)*	**-**	-	-	-	-	-	-	3,399
Discontinued Operations *(million cubic feet equivalent per day)* (1)	**439**	435	551	570	630	623	574	301
Total *(million cubic feet equivalent per day)* (1)	**4,594**	4,524	4,595	4,684	4,655	4,302	4,283	3,856

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.
(2) Includes natural gas and liquids (converted to BOE).

Sales Volumes	Three months ended June 30			Six months ended June 30		
	2005	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Produced Gas *(million cubic feet per day)*	**3,212**	7%	3,001	**3,179**	12%	2,843
Crude Oil *(barrels per day)*	**132,294**	-8%	144,347	**131,564**	-8%	143,508
NGLs *(barrels per day)*	**24,814**	-6%	26,340	**25,581**	3%	24,775
Continuing Operations *(million cubic feet equivalent per day)* (1)	**4,155**	3%	4,025	**4,122**	7%	3,853
Discontinued Operations						
Ecuador *(barrels per day)*	**73,176**	-7%	78,303	**72,833**	-9%	79,643
United Kingdom *(barrels of oil equivalent per day)* (2)	**-**	-100%	26,728	**-**	-100%	24,741
Discontinued Operations *(million cubic feet equivalent per day)* (1)	**439**	-30%	630	**437**	-30%	626
Total *(million cubic feet equivalent per day)* (1)	**4,594**	-1%	4,655	**4,559**	2%	4,479

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.
(2) Includes natural gas and liquids (converted to BOE).

Three Months Ended June 30

In the three months ended June 30, 2005, sales volumes from continuing operations were higher by three percent, or 130 MMcfe/d compared to the same quarter of 2004.

Canadian natural gas sales volumes during the second quarter of 2005 decreased approximately one percent or 26 MMcf/d from the comparable quarter in 2004. This decrease results mainly from the net divestiture of non-core properties during 2004 producing approximately 82 MMcf/d offset by successful resource play drilling programs at Cutbank Ridge in northeast British Columbia and shallow gas and coalbed methane (“CBM”) in southern Alberta. Natural gas sales volumes in the United States for the three months ended June 30, 2005 were higher by approximately 29 percent or 237 MMcf/d compared to the same period of 2004. This increase is primarily due to the TBI acquisition which added approximately 155 MMcf/d, the Fort Worth property acquisition in December 2004 and successful resource play drilling at Piceance and Jonah.

Second quarter 2005 liquids sales volumes from continuing operations declined by eight percent or 13,579 bbls/d when compared to the second quarter of 2004. The lower liquids sales volumes were mainly due to non-core property dispositions in the third quarter of 2004 which were producing approximately 13,000 bbls/d, offset by continued development at Pelican Lake as well as incremental NGLs production from the TBI acquisition. In addition, production at Foster Creek decreased by approximately 5,700 bbls/d in the second quarter of 2005 due to scheduled maintenance and work required to prepare for the 30,000 bbls/d facility expansion, of which 10,000 bbls/d are planned to come on production late in the fourth quarter of 2005.

Six Months Ended June 30

In the first six months of 2005, sales volumes from continuing operations were higher by seven percent, or 269 MMcfe/d compared to the first six months of 2004.

Canadian natural gas sales volumes during the first six months of 2005 increased approximately one percent or 26 MMcf/d from the comparable period in 2004. This increase results mainly from successful resource play drilling programs at Cutbank Ridge in northeast British Columbia, shallow gas and CBM in southern Alberta and gas storage withdrawals of 13 MMcf/d in the first six months of 2005. The growth in volumes was offset partially by the net divestiture of non-core properties which were producing approximately 89 MMcf/d during 2004. Natural gas sales volumes in the United States for the six months ended June 30, 2005 were higher by approximately 41 percent or 310 MMcf/d compared to the same period of 2004. This increase is primarily due to the TBI acquisition which added approximately 214 MMcf/d, the Fort Worth property acquisition in December 2004 and successful resource play drilling at Piceance and Jonah.

In the first six months of 2005, liquids sales volumes from continuing operations declined by seven percent or 11,138 bbls/d when compared to the first half of 2004. The lower liquids sales volumes were mainly due to the disposition of Petrovera and other non-core properties in the first and third quarters of 2004 respectively, partially offset by continued development at Pelican Lake as well as incremental NGLs production from the TBI acquisition.

Per Unit Results - Produced Gas

Three months ended June 30

	Canada			United States		
($ per thousand cubic feet)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Price	**$ 6.08**	17%	$ 5.20	**$ 6.60**	15%	$ 5.72
Expenses						
Production and mineral taxes	**0.10**	43%	0.07	**0.65**	-19%	0.80
Transportation and selling	**0.36**	3%	0.35	**0.42**	24%	0.34
Operating	**0.62**	27%	0.49	**0.50**	35%	0.37
Netback	**$ 5.00**	17%	$ 4.29	**$ 5.03**	19%	$ 4.21
Gas Sales Volumes *(MMcf per day)*	**2,151**	-1%	2,177	**1,061**	29%	824

Six months ended June 30

	Canada			United States		
($ per thousand cubic feet)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Price	**$ 5.89**	13%	$ 5.21	**$ 6.32**	13%	$ 5.57
Expenses						
Production and mineral taxes	**0.10**	43%	0.07	**0.63**	-6%	0.67
Transportation and selling	**0.37**	-5%	0.39	**0.44**	22%	0.36
Operating	**0.64**	23%	0.52	**0.48**	33%	0.36
Netback	**$ 4.78**	13%	$ 4.23	**$ 4.77**	14%	$ 4.18
Gas Sales Volumes *(MMcf per day)*	**2,115**	1%	2,089	**1,064**	41%	754

Three Months Ended June 30

Benchmark NYMEX natural gas prices for the second quarter of 2005 were higher by 12 percent compared with 2004. For the three months ended June 30, 2005, North American realized commodity hedging losses on natural gas were approximately $42 million or $0.14 per Mcf compared to losses of approximately $69 million or $0.25 per Mcf in the same period in 2004.

Natural gas per unit production and mineral taxes in the U.S. for the three months ended June 30, 2005 compared to the same period in 2004 decreased 19 percent or $0.15 per Mcf due to increased production from Texas properties which have lower production and mineral tax rates compared to the rates for Colorado and Wyoming production and a refund for a prior period overpayment. In addition, production and mineral taxes in 2004 include the impact of an adjustment to Colorado rates.

Natural gas per unit transportation and selling costs for the U.S. have increased 24 percent or $0.08 per Mcf for the three months ended June 30, 2005 compared to 2004, primarily as a result of marketing TBI gas volumes downstream of the wellhead in 2005.

Canadian natural gas per unit operating expenses for the second quarter of 2005 were 27 percent or $0.13 per Mcf higher compared to the same period of 2004 primarily due to the higher U.S./Canadian exchange rates, repairs and maintenance and property taxes. Increases in the U.S. natural gas per unit operating expenses of 35 percent or $0.13 per Mcf for the three months ended June 30, 2005 compared to the same period in 2004 were mainly a result of higher operating cost properties from the TBI acquisition. In addition, operating costs in both Canada and the U.S. were affected by higher long-term compensation expenses and rising costs as a result of increased industry activity during the second quarter of 2005.

Six Months Ended June 30

Benchmark NYMEX natural gas prices for the first half of 2005 were higher by 11 percent compared with 2004. For the six months ended June 30, 2005, North American realized commodity hedging gains on natural gas were approximately $9 million or $0.02 per Mcf compared to losses of approximately $89 million or $0.17 per Mcf in the same period in 2004.

Natural gas per unit production and mineral taxes in the U.S. for the six months ended June 30, 2005 compared to 2004 decreased six percent or $0.04 per Mcf due to a combination of lower production and mineral tax rates for Texas production compared to the rates for Colorado and Wyoming production and a refund for a prior period overpayment. In addition, production and mineral taxes in 2004 include the impact of an adjustment to Colorado rates.

Natural gas per unit transportation and selling costs for the U.S. have increased 22 percent or $0.08 per Mcf for the six months ended June 30, 2005 compared to 2004, primarily as a result of marketing TBI gas volumes downstream of the wellhead in 2005. Per unit transportation and selling costs in Canada have decreased five percent or $0.02 per Mcf for the six months ended June 30, 2005 compared to the same period in 2004 as a result of the expiration of long term transportation contracts offset partially by higher U.S./Canadian exchange rates.

Canadian natural gas per unit operating expenses for the first half of 2005 were 23 percent or $0.12 per Mcf higher compared to the same period of 2004 primarily due to the higher U.S./Canadian exchange rates, repairs and maintenance and property taxes. Increases in the U.S. natural gas per unit operating expenses of 33 percent or $0.12 per Mcf for the six months ended June 30, 2005 compared to the same period in 2004 were mainly a result of higher operating cost properties from the TBI acquisition. In addition, operating costs in both Canada and the U.S. were affected by higher long-term compensation expenses and rising costs as a result of increased industry activity during the first half of 2005.

Per Unit Results - Crude Oil North America

	Three months ended June 30			Six months ended June 30		
($ per barrel)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Price	**$ 29.83**	11%	$ 26.85	**$ 28.73**	11%	$ 25.79
Expenses						
Production and mineral taxes	**0.66**	89%	0.35	**0.59**	64%	0.36
Transportation and selling	**1.15**	-2%	1.17	**1.27**	-5%	1.34
Operating	**6.48**	34%	4.83	**6.26**	20%	5.22
Netback	**$ 21.54**	5%	$ 20.50	**$ 20.61**	9%	$ 18.87
Crude Oil Sales Volumes *(bbls per day)*	**132,294**	-8%	144,347	**131,564**	-8%	143,508

Three Months Ended June 30

Increases in the average crude oil price in the second quarter of 2005, excluding the impact of financial hedges, reflect the increase in the benchmark WTI which increased 39 percent in 2005 compared to the same quarter of 2004. This increase was partially offset by the increased WTI/Bow River crude oil price differential (up approximately 83 percent). North American realized commodity hedging losses on crude oil were approximately $70 million or $4.88 per bbl of liquids in the second quarter of 2005 compared to losses of approximately $102 million or $6.53 per bbl of liquids in the same period in 2004.

North American crude oil per unit production and mineral taxes increased by 89 percent or $0.31 per bbl for the three months ended June 30, 2005 compared to the same period in 2004 primarily due to higher prices and increased production from southern Alberta and Saskatchewan properties which are subject to freehold mineral tax and Saskatchewan resource tax, respectively.

North American crude oil per unit operating costs for the second quarter of 2005 have increased 34 percent or $1.65 per bbl compared to the same period in 2004 mainly due to the higher U.S./Canadian exchange rate, higher workovers, repairs and maintenance and long-term compensation expenses. In addition, the increased proportion of crude oil volumes from steam assisted gravity drainage ("SAGD") projects, which have higher operating costs compared to other properties, has resulted in an overall increase in crude oil operating costs.

Six Months Ended June 30

Increases in the average crude oil price in the first half of 2005, excluding the impact of financial hedges, reflect the increase in the benchmark WTI which increased 40 percent in 2005 compared to 2004. This increase was partially offset by the increased WTI/Bow River crude oil price differential (up approximately 93 percent). North American realized commodity hedging losses on crude oil were approximately $143 million or $5.03 per bbl of liquids in 2005 compared to losses of approximately $174 million or $5.67 per bbl of liquids in 2004.

North American crude oil per unit production and mineral taxes increased by 64 percent or $0.23 per bbl in the first six months of 2005 compared to the same period in 2004 primarily due to higher prices and increased production from southern Alberta and Saskatchewan properties which are subject to freehold mineral tax and Saskatchewan resource tax, respectively.

North American crude oil per unit operating costs for the first half of 2005 have increased 20 percent or $1.04 per bbl compared to the same period in 2004 mainly due to the higher U.S./Canadian exchange rate, higher workovers, repairs and maintenance and long-term compensation expenses. In addition, the increased proportion of crude oil volumes from SAGD projects, which have higher operating costs compared to other properties, has resulted in an overall increase in crude oil operating costs. This increase was partially offset by the sale of Petrovera in February 2004 which had higher operating costs relative to other properties.

Per Unit Results - NGLs

Three months ended June 30

	Canada			United States		
($ per barrel)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Price	**$ 39.55**	39%	$ 28.48	**$ 44.79**	36%	$ 32.93
Expenses						
Production and mineral taxes	**-**	-	-	**4.37**	11%	3.93
Transportation and selling	**0.39**	11%	0.35	**0.01**	-	-
Netback	**$ 39.16**	39%	$ 28.13	**$ 40.41**	39%	$ 29.00
NGLs Sales Volumes *(bbls per day)*	**11,719**	-14%	13,588	**13,095**	3%	12,752

Six months ended June 30

	Canada			United States		
($ per barrel)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Price	**$ 39.80**	43%	$ 27.87	**$ 42.76**	30%	$ 32.86
Expenses						
Production and mineral taxes	**-**	-	-	**4.28**	20%	3.58
Transportation and selling	**0.37**	6%	0.35	**0.01**	-	-
Netback	**$ 39.43**	43%	$ 27.52	**$ 38.47**	31%	$ 29.28
NGLs Sales Volumes *(bbls per day)*	**11,705**	-15%	13,780	**13,876**	26%	10,995

NGLs realized price changes generally correlate with changes in WTI oil prices. The strong WTI oil price in the second quarter and to-date in 2005 positively impacted NGLs prices.

U.S. NGLs per unit production and mineral taxes for the three months and six months ended June 30, 2005 compared to the same periods in 2004 increased 11 percent or $0.44 per bbl and 20 percent or $0.70 per bbl respectively. The higher production and mineral taxes in the United States were a result of the increase in NGLs prices.

MIDSTREAM & MARKET OPTIMIZATION OPERATIONS

Financial Results

Three months ended June 30

($ millions)	**2005**			2004		
	Midstream	**Market Optimization**	**Total**	Midstream	Market Optimization	Total
Revenues	**$ 169**	**$ 870**	**$ 1,039**	$ 172	$ 726	$ 898
Expenses						
Transportation and selling	**-**	**5**	**5**	-	8	8
Operating	**64**	**12**	**76**	56	13	69
Purchased product	**87**	**846**	**933**	118	704	822
Operating Cash Flow	**$ 18**	**$ 7**	**$ 25**	$ (2)	$ 1	$ (1)
Depreciation, depletion and amortization			**9**			45
Segment Income			**$ 16**			$ (46)

Six months ended June 30

($ millions)	**2005**			2004		
	Midstream	**Market Optimization**	**Total**	Midstream	Market Optimization	Total
Revenues	**$ 735**	**$ 1,831**	**$ 2,566**	$ 723	$ 1,594	$ 2,317
Expenses						
Transportation and selling	**-**	**10**	**10**	-	16	16
Operating	**137**	**22**	**159**	127	20	147
Purchased product	**515**	**1,781**	**2,296**	567	1,542	2,109
Operating Cash Flow	**$ 83**	**$ 18**	**$ 101**	$ 29	$ 16	$ 45
Depreciation, depletion and amortization			**18**			52
Segment Income			**$ 83**			$ (7)

Revenues in Midstream & Market Optimization operations increased 16 percent in the second quarter of 2005 compared with the same period in 2004 due primarily to increases in commodity prices. Operating cash flow increased by $26 million in this same period to $25 million due to improved results from gas storage operations activities and strong margins for NGLs.

Revenues increased 11 percent compared with 2004 on a year-to-date basis as a result of increased commodity prices. Year-to-date operating cash flow was $101 million, an increase of $56 million compared with 2004. Improved margins from gas storage optimization activities and NGLs contributed to most of this increase.

In 2004, the second quarter and year-to-date depreciation, depletion and amortization expenses were increased by approximately $35 million due to a writedown in the values of EnCana's equity investment interest in the Trasandino Pipeline in Argentina and Chile.

CORPORATE

	Three months ended June 30					Six months ended June 30				
($ millions)		**2005**	2005 vs 2004		2004		**2005**	2005 vs 2004		2004
Revenues	**$**	**315**	389%	$	(109)	**$**	**(657)**	-54%	$	(427)
Expenses										
Operating		**1**	133%		(3)		**(2)**	-60%		(5)
Depreciation, depletion and amortization		**18**	29%		14		**35**	17%		30
Segment Income	**$**	**296**	347%	$	(120)	**$**	**(690)**	-53%	$	(452)
Administrative		**66**	50%		44		**127**	37%		93
Interest, net		**101**	2%		99		**201**	13%		178
Accretion of asset retirement obligation		**9**	200%		3		**18**	100%		9
Foreign exchange loss		**119**	561%		18		**150**	95%		77
Stock-based compensation		**4**	0%		4		**8**	-11%		9
Gain on dispositions		**-**	100%		(1)		**-**	100%		(35)

Year-to-date 2005 corporate revenues include approximately $657 million in unrealized mark-to-market losses related to financial commodity contracts compared with $429 million during the same period of 2004. Other mark-to-market gains ($2 million) on derivative financial instruments related to interest and electricity consumption are recorded in interest, net and operating expenses, respectively.

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

	Three months ended June 30				Six months ended June 30			
($ millions)		**2005**		2004		**2005**		2004
Continuing Operations								
Natural Gas	**$**	**261**	$	(30)	**$**	**(574)**	$	(250)
Crude Oil		**54**		(79)		**(83)**		(179)
		315		(109)		**(657)**		(429)
Expenses		**1**		(1)		**(2)**		(4)
		314		(108)		**(655)**		(425)
Income Tax		**113**		(36)		**(228)**		(140)
	$	**201**	$	(72)	**$**	**(427)**	$	(285)

Price volatility has had a significant impact on the year-to-date accounting for our price risk management activities. On June 30, 2005 the forward price curve for the remainder of 2005 had increased from year end by 39 percent to $58.44/bbl for WTI and 15 percent to $7.35 Mcf for NYMEX gas.

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

Administrative expenses increased 50 percent in the second quarter and 37 percent for the six months ended June 30, 2005. The increase reflects the effect of the increased long-term compensation expenses that are tied to EnCana's share price and the change in the U.S./Canadian dollar exchange rate. On a year-to-year basis, administrative costs were approximately $0.17 per Mcfe compared with $0.13 per Mcfe in 2004.

The higher interest expense resulted primarily from the higher average outstanding debt level compared with the six month period to June 30, 2004 as a result of the TBI acquisition in the second quarter of 2004 offset by debt reductions from proceeds received from the sale of non-core assets. EnCana’s long-term debt decreased by $891 million to $6,851 at June 30, 2005 compared with $7,742 million at December 31, 2004. EnCana’s 2005 year-to-date weighted average interest rate on outstanding debt was 5.3 percent, up from a year-to-date average of approximately 4.9 percent in 2004 as a result of a reduction in the proportion of floating rate debt.

The foreign exchange loss of $150 million to-date in 2005 includes $65 million resulting from the change in the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada. Under Canadian GAAP, the Company is required to translate long-term debt issued from Canada and denominated in U.S. dollars into Canadian dollars at the period-end exchange rate. Resulting foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings.

INCOME TAX

The year-to-date effective tax rate was 25.3 percent compared with 10.0 percent in 2004. The 2005 effective tax rate is higher than 2004 primarily as a result of the reduction in 2004 of $109 million in future income taxes resulting from the reduction in the Alberta tax rate from 12.5 percent to 11.5 percent and Alberta’s retention of the resource allowance and non-deductible crown royalties regime until 2007. The 2005 income tax provision includes the net benefit of tax basis retained on dispositions of $68 million (2004: $103 million) as well as $228 million related to income tax on unrealized mark to market losses (2004: $140 million).

Included in net earnings for the six months ended June 30, 2005 is current tax expense of $899 million; $591 million of this relates to the sale of assets and has been shown as an investing activity in the Statement of Cash Flows. The balance of $308 million has been included in cash flow.

Further information regarding EnCana’s effective tax rate can be found in Note 6 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 subject to tax. There are a variety of items of this type, including:

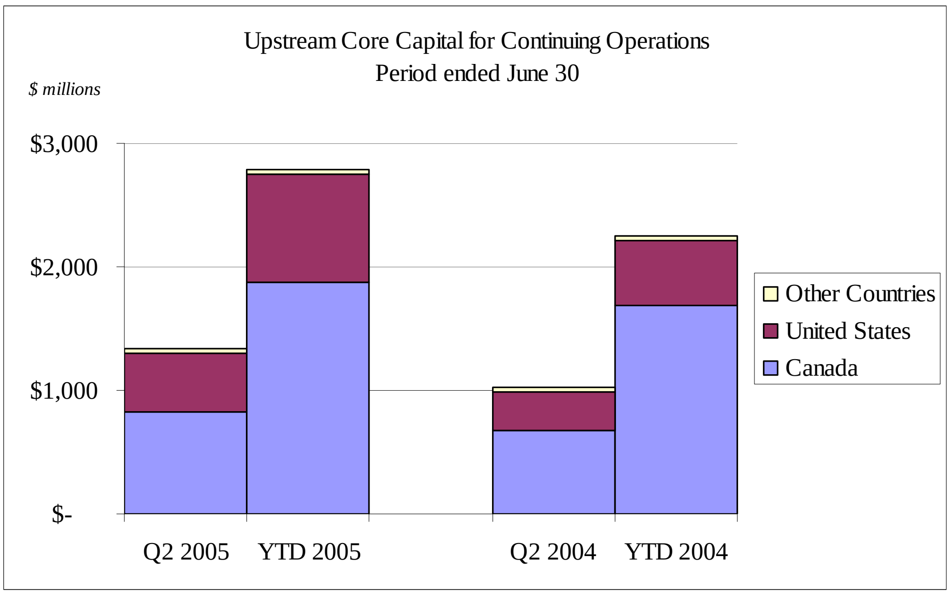
- The effects of asset dispositions where the tax values of the assets sold differ from their accounting value;
- Adjustments for the impact of legislative tax changes which have a prospective impact on future income tax obligations;
- The non-taxable half of Canadian capital gains (losses); and
- Items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

The operations of the Company are complex and related tax interpretations, regulations and legislation in the various jurisdictions that the Company and its subsidiaries operate in are continually changing. 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

	Three months ended June 30					Six months ended June 30				
($ millions)		**2005**	2005 vs 2004		2004		**2005**	2005 vs 2004		2004
Upstream	**$**	**1,321**	31%	$	1,005	**$**	**2,778**	24%	$	2,244
Midstream & Market Optimization		**96**	500%		16		**140**	460%		25
Corporate		**9**	-		9		**15**	-17%		18
Core Capital Expenditures	**$**	**1,426**	38%	$	1,030	**$**	**2,933**	28%	$	2,287
Acquisitions		**26**	-99%		2,340		**38**	-99%		2,607
Dispositions		**(2,406)**	2170%		(106)		**(2,459)**	266%		(672)
Discontinued Operations		**53**	-69%		172		**100**	-77%		439
Net Capital	**$**	**(901)**	-126%	$	3,436	**$**	**612**	-87%	$	4,661



UPSTREAM CAPITAL EXPENDITURES

The increase in Upstream capital expenditures in the second quarter and on a year-to-date basis in 2005 is the result of the impact of the increased drilling and development activities in the U.S. including the impact of inflationary costs and a higher average U.S./Canadian dollar exchange rate on Canadian dollar denominated expenditures, offset partially by lower drilling activity in Canada as a result of early spring break up due to warm weather and unseasonably wet weather in June. The change in the average U.S./Canadian dollar exchange rate resulted in an increase on Canadian dollar denominated core capital expenditures of approximately $136 million. Natural gas capital expenditures were primarily focused on continued development of the Company's key resource plays in Piceance, Jonah, East Texas and Fort Worth in the United States and Greater Sierra, Cutbank Ridge, shallow gas and CBM in Canada. Crude oil capital spending in 2005 was concentrated at Foster Creek and Pelican Lake in Alberta. The Company drilled 2,370 net wells in the first six months of 2005 compared to 2,667 net wells for the same period in 2004.

MIDSTREAM & MARKET OPTIMIZATION CAPITAL EXPENDITURES

Expenditures in the second quarter of 2005 and on a year-to-date basis were mostly focused on pre-construction activities underway for the Entrega pipeline in Colorado.

CORPORATE CAPITAL EXPENDITURES

Corporate capital expenditures relate primarily to spending on business information systems, leasehold improvements and furniture and office equipment.

ACQUISITIONS AND DISPOSITIONS

Acquisitions included the TBI acquisition in 2004.

Dispositions in 2005 include the sale of Gulf of Mexico assets and the sale of non-core Canadian conventional oil and gas assets. Dispositions in the first six months of 2004 include the sale of Petrovera and the sale of non-core Canadian conventional oil and gas assets.

DISCONTINUED OPERATIONS

Discontinued operations in the Interim Consolidated Financial Statements include Ecuador in 2005 and also includes the United Kingdom in 2004.

EnCana's 2005 second quarter net earnings from discontinued operations are $53 million compared to a net loss of $15 million in 2004 and include realized commodity losses of $22 million after-tax (2004: $43 million after-tax) and unrealized financial hedge gains of $21 million after-tax (2004: losses of $32 million after-tax).

EnCana's 2005 year-to-date net earnings from discontinued operations are $133 million compared to a net loss of $51 million in 2004 and include realized commodity hedge losses of $37 million after-tax (2004: $82 million after-tax) and unrealized financial hedge gains of $8 million after-tax (2004: losses of $71 million after-tax). Summary information is presented below. Additional information concerning EnCana's discontinued operations can be found in Note 3 to EnCana's Interim Consolidated Financial Statements.

ECUADOR

	Three months ended June 30			Six months ended June 30		
	2005	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Sales volumes						
Crude Oil *(barrels per day)*	**73,176**	-7%	78,303	**72,833**	-9%	79,643
($ millions)						
Net Earnings (loss) from Discontinued Operations	**$ 51**	492%	$ (13)	**$ 131**	398%	$ (44)
Capital Investment	**53**	-5%	56	**100**	-9%	110

Production volumes in the second quarter of 2005 averaged 73,662 bbls/d; down six percent from the same period in 2004. Sales volumes in the second quarter of 2005 decreased seven percent to average 73,176 bbls/d primarily due to declining production in Tarapoa and Block 15.

Production and mineral taxes were $17 million higher in the second quarter of 2005 compared to 2004 as a result of higher realized prices on the Tarapoa block sales volumes partially offset by lower Tarapoa sales volumes. The Company is required to pay a percentage of revenue from this block to the Ecuador government based on realized prices over a base price.

Production volumes for the first six months of 2005 averaged 74,673 bbls/d; down three percent from the same period in 2004. Sales volumes in the first six months of 2005 decreased nine percent to average 72,833 bbls/d primarily due to an underlift of 1,840 bbls/d in the first six months of 2005 compared to an overlift of 2,295 bbls/d in the same period in 2004.

Production and mineral taxes were $28 million higher in the first six months of 2005 compared to 2004 as a result of higher realized prices on the Tarapoa block sales volumes partially offset by lower Tarapoa sales volumes.

In accordance with Canadian GAAP, no DD&A expense is being recorded in 2005 on discontinued Ecuador operations. As a result, both second quarter and year-to-date 2005 earnings are higher than the comparable period in 2004.

Contingency information regarding certain disputed items with the Ecuadorian government relating to value-added tax ("VAT"), ownership of Block 15 and deductibility of interest is included in Note 3 to EnCana's Interim Consolidated Financial Statements.

UNITED KINGDOM

	Three months ended June 30		Six months ended June 30	
	2005	2004	**2005**	2004
Sales volumes				
Produced Gas *(million cubic feet per day)*	-	36	-	32
Crude Oil *(barrels per day)*	-	18,698	-	17,391
NGLs *(barrels per day)*	-	2,030	-	2,017
Total *(barrels of oil equivalent per day)*	-	26,728	-	24,741
($ millions)				
Net Earnings (loss) from Discontinued Operations	**$ 2**	$ (2)	**$ 2**	$ (7)
Capital Investment	-	116	-	329

In December 2004, a subsidiary of the Company completed the sale of its U.K. central North Sea assets, production and prospects for net cash consideration of approximately $2.1 billion, resulting in a gain on sale of approximately $1.4 billion.

LIQUIDITY AND CAPITAL RESOURCES

	Three months ended June 30			Six months ended June 30		
($ millions)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Net cash provided by (used in)						
Operating activities	**$ 872**	2%	$ 853	**$ 2,798**	25%	$ 2,235
Investing activities	**579**	116%	(3,587)	**(770)**	84%	(4,685)
Financing activities	**(1,568)**	-157%	2,743	**(2,307)**	-193%	2,486
Deduct: Foreign exchange gain on cash and cash equivalents held in foreign currency	**(1)**	-	-	**(2)**	-	-
(Decrease) increase in cash and cash equivalents	**(116)**	-1389%	9	**(277)**	-869%	36

EnCana's cash flow from continuing operations was $1,512 million in the second quarter of 2005, up $491 million from $1,021 million for the same period in 2004. On a year-to-date basis, cash flow from continuing operations was $2,820 million, an increase of $903 million from 2004. The increase in cash flow in 2005 was primarily due to increased revenues from higher commodity prices and the growth in sales volumes partially offset by increased expenses. Cash flow from continuing operations comprises the majority of EnCana's cash provided by operating activities.

Net cash of $579 million was generated by investing activities compared with a use of $3,587 million in the second quarter of 2004 due to net proceeds on the disposal of assets in the quarter more than offsetting capital expenditures. In addition, 2004 activities included the business combination with TBI. On a year-to-date basis, net cash used by investing activities was $770 million compared with $4,685 million in 2004.

Long-term debt plus the current portion of long-term debt decreased by $770 million to $7,160 million from the year-end total of $7,930 million. EnCana’s net debt adjusted for working capital was $7,620 million as at June 30, 2005 compared with $7,184 million at December 31, 2004. Working capital was a deficit of $769 million and included unrealized losses on mark-to-market accounting on commodity hedges of $620 million and income tax payable of $779 million. This compares to working capital of $558 million as at December 31, 2004.

On June 17, 2005 EnCana announced plans to seek written consent from Canadian noteholders for approval of amendments to permit the Company to redeem the following three issues of non-callable medium term notes: EnCana’s 8.5 percent notes due March 15, 2011, 5.95 percent notes due June 2, 2008, and 5.50/6.20 percent notes due June 23, 2028. The aggregate principal amount of these notes is C$200 million. On July 6, 2005 EnCana announced that it had received the consents, and has called for redemption of the 8.5 percent notes and the 5.50/6.20 percent notes at a total cost of C$128 million. EnCana has called a meeting for noteholders in early August to consider similar amendments to the remaining C$100 million of 5.95 percent notes.

Financial Ratios

	June 30 2005	December 31 2004
Net Debt to Capitalization	**36%**	33%
Net Debt to EBITDA[(1)]	**1.3**	1.4

(1) EBITDA is a non-GAAP measure that is defined as earnings from continuing operations before gain on disposition, income taxes, foreign exchange gains or losses, gains or losses, interest net, acccretion of asset retirement obligation, and depreciation, depletion, and amortization.

Net Debt to Capitalization and Net Debt to EBITDA are two ratios EnCana uses to steward the Company’s overall debt position as measures of the Company’s overall financial strength. Unrealized commodity hedge losses recorded in the first half of 2005 and the repurchase of shares through the normal course issuer bid have resulted in an increase in the debt to capitalization ratio.

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'.

As at June 30, 2005, the Company had available unused committed bank credit facilities in the amount of $3.1 billion.

OUTSTANDING SHARE DATA

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.

EnCana's shareholders approved the split of the Corporation's outstanding Common Shares on a two-for-one basis ("Share Split") at its Annual and Special Meeting held on April 27, 2005. Each shareholder received one additional common share for each common share he or she held on the record date for the Share Split of May 12, 2005.

Common Shares[(1)]

(millions)	**June 30 2005**	December 31 2004
Outstanding, beginning of year	**900.6**	921.2
Issued under option plans	**9.8**	19.4
Shares repurchased (Normal Course Issuer Bid)	**(44.7)**	(40.0)
Shares repurchased (Performance Share Unit Plan)	**(5.5)**	-
Common shares outstanding, end of period	**860.2**	900.6
Weighted average common shares outstanding - diluted	**900.7**	936.0

(1) The number of common shares outstanding prior to the 2 for 1 share split has been restated for comparison.

There were no Preferred Shares outstanding during these periods. Employees and directors have been granted options to purchase Common Shares under various plans. At June 30, 2005, 26.1 million options were outstanding of which 20.9 million are exercisable.

Long-term incentives granted to employees throughout EnCana include a reduced level of stock option grants that is supplemented by grants of Performance Share Units ("PSUs"). PSUs will not result in the issue of new Common Shares by the Company. Stock options granted in 2004 and 2005 have an associated Tandem Share Appreciation Right ("TSAR") and employees may elect to exercise either the stock option or the associated TSAR. TSAR exercises will result in either cash payments by the Company or issuance of Common Shares based upon the employee's choice at the time of exercise.

EnCana obtained regulatory approval under Canadian securities laws to purchase Common Shares under three consecutive Normal Course Issuer Bids which commenced in October 2002 and may continue until October 28, 2005. EnCana is entitled to purchase for cancellation up to approximately 92.2 million Common Shares under the current Bid. As of July 14, 2005 EnCana has purchased approximately 78 million Common Shares, leaving approximately 14 million Common Shares available for purchase through the expiry of the Bid on October 28, 2005. Shareholders may obtain a copy of the Bid documents without charge at www.sedar.com or by contacting investor.relations@encana.com

Normal Course Issuer Bid

	Share Purchases[1]	
(millions)	Six months ended June 30 2005	Year ended December 31 2004
Bid expired October 2004	-	11.0
Bid expiring October 2005	**44.7**	29.6
	44.7	40.6

(1) Transactions that occurred before the 2 for 1 share split have been restated for comparison.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

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

Included in the Company's long-term debt commitments of $6,851 million at June 30, 2005 are $1,172 million outstanding related to Banker's Acceptances and Commercial Paper loans that are supported by revolving credit facilities and term loan borrowings. The Company intends and expects that it will have the ability to extend the term of this debt on an ongoing basis. Further details regarding the Company's long-term debt are described in Note 7 to the Interim Consolidated Financial Statements.

As at June 30, 2005, EnCana remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 48 MMcf/d with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 158 Bcf at a weighted average price of $3.68 per Mcf. At June 30, 2005, these transactions had an unrealized loss of $349 million.

Contingency information regarding certain disputed items with the Ecuadorian government relating to VAT, ownership of Block 15 and deductibility of interest is included in Note 3 to EnCana's Interim Consolidated Financial Statements.

Variable Interest Entities ("VIE")

During the second quarter of 2005, certain assets previously determined to be a VIE were transferred to EnCana. At June 30, EnCana no longer holds an interest in a VIE.

Off-Balance Sheet Arrangements

The Company does not have any off-balance sheet arrangements that have or are reasonably likely to have an effect on its results of operations or financial condition.

Leases

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

Legal Proceedings Related to Discontinued Merchant Energy Operations

As previously described in the Company's Management Discussion and Analysis for the year ended December 31, 2004, 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.

The Company and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California and, along with other energy companies, are defendants in multiple other lawsuits filed in California State and District Court (many of which are class actions). WD is a defendant in a consolidated class action lawsuit filed in the United States District Court in New York. The Gallo complaint claims damages in excess of $30 million, before potential trebling under California laws.

The California lawsuits relate to sales of natural gas in California from 1999 to 2002 and 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 to artificially raise the price of natural gas through various means including the illegal sharing of price information through online trading, price indices and wash trading. The consolidated New York lawsuit claims that the defendants' alleged manipulation of natural gas price indices resulted in higher prices of 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 the Company as the remaining defendants. As is customary, the class actions do not specify the amount of damages claimed.

The Company and WD intend to vigorously defend against these 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

There have been no changes to EnCana's accounting principles and practices in 2005, nor have there been any material changes to EnCana's critical accounting estimates.

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

FINANCIAL RISKS

The Company 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 approved by senior management, and is subject to limits established by the Board of Directors. As a means of mitigating exposure to commodity price risk, the Company has entered into various financial instrument agreements. The Company's policy is not to use derivative financial instruments for speculative purposes. The details of these instruments, including any unrealized gains or losses, as of June 30, 2005, are disclosed in Note 12 to the Interim Consolidated Financial Statements.

The Company 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 associated with cash flows expected to be generated from budgeted capital programs and in other cases to the mitigation of price risks for specific assets and obligations.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by the Company are swaps, collars 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 entered into swaps which fix the AECO and NYMEX prices and collars 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, the Company 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 loss of $29 million.

The Company 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 $24 million.

As part of its gas storage optimization program, EnCana has entered into financial instruments and physical contracts at various locations and terms over the next 12 months to partially manage the price volatility of the corresponding physical transactions and inventories. The financial instruments used include futures, fixed for floating swaps and basis swaps.

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, three-way put spreads and put options.

The Company has a power purchase arrangement contract that expires in 2005. This contract was entered into as part of a cost management strategy.

Foreign Exchange

As a means of mitigating the exposure to fluctuations in the U.S. to Canadian exchange rate, the Company 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.

The Company 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. The Company has entered into interest rate swap transactions from time to time as a means of managing the fixed/floating rate debt portfolio mix.

Credit Risk

The Company 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 to counterparties of investment grade credit quality and transactions that are fully collateralized. A substantial portion of the Company's accounts receivable is with customers in the oil and gas industry.

OPERATIONAL RISK

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 the Company'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.

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

ENVIRONMENT, HEALTH, SAFETY AND SECURITY RISK

These risks are managed by executing policies and standards that comply with or exceed government regulations and industry standards. In addition, the Company 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 ensure that EnCana's personnel and assets are protected. 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.

Kyoto Protocol

The Kyoto protocol, ratified by the Canadian Federal Government in December 2002, came into force on February 16, 2005. The protocol commits Canada to reducing greenhouse gas emissions to six percent below 1990 levels over the period 2008 – 2012. The Federal Government released a framework outlining its Climate Change action plan on April 13, 2005. The plan as released contains few technical details regarding the implementation of the Government's greenhouse gas reduction strategy. The Climate Change Working Group of Canadian Association of Petroleum Producers continues to work with the Federal and Alberta governments to develop an approach for implementing targets and enabling greenhouse gas control legislation which protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

As the federal government has yet to finalize their detailed Kyoto compliance plan, EnCana is unable to predict the impact of the potential regulations upon its business; however, it is possible that the Company would face increases in operating costs in order to comply with greenhouse gas emissions legislation.

REPUTATIONAL RISK

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. The Company will also continue to develop its high quality in-situ oilsands resources.

The year-over-year storage surplus has the potential to put third quarter gas prices at risk. However, this may be offset by a warmer than normal summer or above-normal hurricane disruptions. The outlook for the balance of the year and beyond will be impacted by weather, timing of new supplies and economic activity.

Volatility in crude oil prices is expected to continue throughout 2005 as a result of market uncertainties over continued demand growth in China, the reliability of production from key producing countries, OPEC actions and the overall state of the world economies.

The Company expects its 2005 core capital investment program to be funded from cash flow.

Proceeds from the sales of non-core properties are expected to reduce debt and fund a share buyback program.

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.

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 within the meaning of the "safe harbour" provisions of the United States Private Securities Litigation Reform Act of 1995. 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 development and the timing thereof; projections relating to the volatility of crude oil prices in 2005 and the reasons therefor; the Company's projected capital investment levels for 2005 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 execution of share purchases under its Normal Course Issuer Bid; the Company's defence of lawsuits; projections and assumptions relating to capital expenditures; the impact of the Kyoto Accord on operating costs; projected tax rates and projected current taxes payable for 2005 and the adequacy of the Company's provision for taxes; the Company's plans to divest of its NGLs extraction business, natural gas storage business and Ecuador operations; and projections relating to the use of proceeds from the sale of non-core properties, including debt repayment and purchases under its Normal Course Issuer Bid. 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 oil and gas prices; 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, 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; its 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, including Ecuador; 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 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, Unbooked Resource Potential, Total Resource Portfolio and Total Resource Life

EnCana uses the terms resource play, estimated ultimate recovery, unbooked resource potential, total resource portfolio and total resource life. 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. Unbooked resource potential is a term used by EnCana to refer to the estimated quantities of hydrocarbons that may be added to proved reserves through the low-risk development of known resources within existing landholdings that meet the Company’s targeted economic thresholds. Total resource portfolio is the sum of proved reserves plus unbooked resource potential. Total resource life is calculated by dividing the total resource portfolio by annualized production as of a given date.

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 $0.81 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 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 June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
REVENUES, NET OF ROYALTIES					
Upstream	*(Note 2)*	**$ 2,227**	$ 1,763	**$ 4,333**	$ 3,392
Midstream & Market Optimization	*(Note 2)*	**1,039**	898	**2,566**	2,317
Corporate - Unrealized gain (loss) on risk management	*(Note 2)*	**315**	(109)	**(657)**	(429)
- Other	*(Note 2)*	**-**	-	**-**	2
		3,581	2,552	**6,242**	5,282
EXPENSES	*(Note 2)*				
Production and mineral taxes		**97**	83	**184**	137
Transportation and selling		**131**	137	**267**	272
Operating		**373**	303	**745**	620
Purchased product		**933**	822	**2,296**	2,109
Depreciation, depletion and amortization		**675**	630	**1,361**	1,156
Administrative		**66**	44	**127**	93
Interest, net		**101**	99	**201**	178
Accretion of asset retirement obligation	*(Note 8)*	**9**	3	**18**	9
Foreign exchange loss	*(Note 5)*	**119**	18	**150**	77
Stock-based compensation		**4**	4	**8**	9
Gain on divestitures	*(Note 4)*	**-**	(1)	**-**	(35)
		2,508	2,142	**5,357**	4,625
NET EARNINGS BEFORE INCOME TAX		**1,073**	410	**885**	657
Income tax expense	*(Note 6)*	**287**	145	**224**	66
NET EARNINGS FROM CONTINUING OPERATIONS		**786**	265	**661**	591
NET EARNINGS (LOSS) FROM DISCONTINUED OPERATIONS	*(Note 3)*	**53**	(15)	**133**	(51)
NET EARNINGS		**$ 839**	$ 250	**$ 794**	$ 540
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	*(Note 11)*				
Basic		**$ 0.90**	$ 0.29	**$ 0.75**	$ 0.64
Diluted		**$ 0.88**	$ 0.28	**$ 0.73**	$ 0.63
NET EARNINGS PER COMMON SHARE	*(Note 11)*				
Basic		**$ 0.96**	$ 0.27	**$ 0.90**	$ 0.59
Diluted		**$ 0.94**	$ 0.27	**$ 0.88**	$ 0.58

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(unaudited)*

($ millions)		Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
RETAINED EARNINGS, BEGINNING OF YEAR		**$ 7,935**	$ 5,276
Net Earnings		**794**	540
Dividends on Common Shares		**(110)**	(92)
Charges for Normal Course Issuer Bid	*(Note 9)*	**(1,124)**	(126)
Charges for Shares Repurchased and Held	*(Note 9)*	**(147)**	-
RETAINED EARNINGS, END OF PERIOD		**$ 7,348**	$ 5,598

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET *(unaudited)*

($ millions)		**As at June 30, 2005**	As at December 31, 2004
ASSETS			
Current Assets			
Cash and cash equivalents		**$ 325**	$ 602
Accounts receivable and accrued revenues		**2,140**	1,898
Risk management	*(Note 12)*	**160**	336
Inventories		**424**	513
Assets of discontinued operations	*(Note 3)*	**165**	156
		3,214	3,505
Property, Plant and Equipment, net	*(Note 2)*	**22,051**	23,140
Investments and Other Assets		**379**	334
Risk Management	*(Note 12)*	**106**	87
Assets of Discontinued Operations	*(Note 3)*	**1,735**	1,623
Goodwill		**2,488**	2,524
	(Note 2)	**$ 29,973**	$ 31,213
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 1,884**	$ 1,879
Income tax payable		**779**	359
Risk management	*(Note 12)*	**690**	241
Liabilities of discontinued operations	*(Note 3)*	**321**	280
Current portion of long-term debt	*(Note 7)*	**309**	188
		3,983	2,947
Long-Term Debt	*(Note 7)*	**6,851**	7,742
Other Liabilities		**86**	118
Risk Management	*(Note 12)*	**269**	192
Asset Retirement Obligation	*(Note 8)*	**640**	611
Liabilities of Discontinued Operations	*(Note 3)*	**144**	102
Future Income Taxes		**4,459**	5,193
		16,432	16,905
Shareholders' Equity			
Share capital	*(Note 9)*	**5,102**	5,299
Share options, net		**-**	10
Paid in surplus		**90**	28
Retained earnings		**7,348**	7,935
Foreign currency translation adjustment		**1,001**	1,036
		13,541	14,308
		$ 29,973	$ 31,213

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*

($ millions)		Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
OPERATING ACTIVITIES					
Net earnings from continuing operations		**$ 786**	$ 265	**$ 661**	$ 591
Depreciation, depletion and amortization		**675**	630	**1,361**	1,156
Future income taxes	*(Note 6)*	**(387)**	(38)	**(675)**	(342)
Cash tax on sale of assets	*(Note 4)*	**591**	-	**591**	-
Unrealized (gain) loss on risk management	*(Note 12)*	**(314)**	109	**655**	426
Unrealized foreign exchange loss		**105**	32	**123**	71
Accretion of asset retirement obligation	*(Note 8)*	**9**	3	**18**	9
Gain on divestitures	*(Note 4)*	**-**	(1)	**-**	(35)
Other		**47**	21	**86**	41
Cash flow from continuing operations		**1,512**	1,021	**2,820**	1,917
Cash flow from discontinued operations		**60**	110	**165**	209
Cash flow		**1,572**	1,131	**2,985**	2,126
Net change in other assets and liabilities		**(16)**	(41)	**(14)**	(46)
Net change in non-cash working capital from continuing operations		**(682)**	(254)	**(116)**	(15)
Net change in non-cash working capital from discontinued operations		**(2)**	17	**(57)**	170
		872	853	**2,798**	2,235
INVESTING ACTIVITIES					
Business combination with Tom Brown, Inc.		**-**	(2,335)	**-**	(2,335)
Capital expenditures	*(Note 2)*	**(1,452)**	(1,035)	**(2,971)**	(2,306)
Proceeds on disposal of assets	*(Note 4)*	**2,406**	110	**2,459**	463
Cash tax on sale of assets	*(Note 4)*	**(591)**	-	**(591)**	-
Net change in investments and other		**(27)**	(28)	**(8)**	(17)
Net change in non-cash working capital from continuing operations		**293**	(173)	**448**	(112)
Discontinued operations		**(50)**	(126)	**(107)**	(378)
		579	(3,587)	**(770)**	(4,685)
FINANCING ACTIVITIES					
Net repayment of revolving long-term debt		**(682)**	455	**(715)**	447
Issuance of long-term debt		**-**	2,761	**-**	2,761
Repayment of long-term debt		**-**	(454)	**(1)**	(549)
Issuance of common shares	*(Note 9)*	**83**	43	**184**	154
Purchase of common shares	*(Note 9)*	**(902)**	(12)	**(1,662)**	(230)
Dividends on common shares		**(66)**	(46)	**(110)**	(92)
Other		**(1)**	(4)	**(3)**	(5)
		(1,568)	2,743	**(2,307)**	2,486
DEDUCT: FOREIGN EXCHANGE GAIN ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		**(1)**	-	**(2)**	-
(DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS		**(116)**	9	**(277)**	36
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		**441**	140	**602**	113
CASH AND CASH EQUIVALENTS, END OF PERIOD		**$ 325**	$ 149	**$ 325**	$ 149

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, 2004. 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, 2004.

2. 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 Africa, South America, the Middle East and Greenland.

- **Midstream & Market Optimization** is conducted by the Midstream & Marketing division. Midstream includes natural gas storage, natural gas liquids processing and power generation. 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 Midstream & 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.

Midstream & Market Optimization purchases substantially all of the Company's North American Upstream production. 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 3.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. SEGMENTED INFORMATION (continued)

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

	Upstream		Midstream & Market Optimization	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 2,227**	$ 1,763	**$ 1,039**	$ 898
Expenses				
Production and mineral taxes	**97**	83	**-**	-
Transportation and selling	**126**	129	**5**	8
Operating	**296**	237	**76**	69
Purchased product	**-**	-	**933**	822
Depreciation, depletion and amortization	**648**	571	**9**	45
Segment Income	**$ 1,060**	$ 743	**$ 16**	$ (46)

	Corporate *		Consolidated	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 315**	$ (109)	**$ 3,581**	$ 2,552
Expenses				
Production and mineral taxes	**-**	-	**97**	83
Transportation and selling	**-**	-	**131**	137
Operating	**1**	(3)	**373**	303
Purchased product	**-**	-	**933**	822
Depreciation, depletion and amortization	**18**	14	**675**	630
Segment Income	**$ 296**	$ (120)	**1,372**	577
Administrative			**66**	44
Interest, net			**101**	99
Accretion of asset retirement obligation			**9**	3
Foreign exchange loss			**119**	18
Stock-based compensation			**4**	4
Gain on divestitures			**-**	(1)
			299	167
Net Earnings Before Income Tax			**1,073**	410
Income tax expense			**287**	145
Net Earnings From Continuing Operations			**$ 786**	$ 265

* For the three months ended June 30, the unrealized gain (loss) on risk management is recorded in the Consolidated Statement of Earnings as follows (see also Note 12):

	2005	2004
Revenues, Net of Royalites - Corporate	**$ 315**	$ (109)
Operating Expenses and Other - Corporate	**1**	(1)
Total Unrealized Gain (Loss) on Risk Management - Continuing Operations	**$ 314**	$ (108)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. SEGMENTED INFORMATION (continued)

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

Upstream	Canada		United States	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 1,514**	$ 1,266	**$ 655**	$ 443
Expenses				
Production and mineral taxes	**29**	18	**68**	65
Transportation and selling	**85**	84	**41**	45
Operating	**200**	161	**48**	28
Depreciation, depletion and amortization	**469**	435	**171**	117
Segment Income	**$ 731**	$ 568	**$ 327**	$ 188

	Other		Total Upstream	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 58**	$ 54	**$ 2,227**	$ 1,763
Expenses				
Production and mineral taxes	**-**	-	**97**	83
Transportation and selling	**-**	-	**126**	129
Operating	**48**	48	**296**	237
Depreciation, depletion and amortization	**8**	19	**648**	571
Segment Income	**$ 2**	$ (13)	**$ 1,060**	$ 743

Midstream & Market Optimization	Midstream		Market Optimization		Total Midstream & Market Optimization	
	2005	2004	**2005**	2004	**2005**	2004
Revenues	**$ 169**	$ 172	**$ 870**	$ 726	**$ 1,039**	$ 898
Expenses						
Transportation and selling	**-**	-	**5**	8	**5**	8
Operating	**64**	56	**12**	13	**76**	69
Purchased product	**87**	118	**846**	704	**933**	822
Depreciation, depletion and amortization	**9**	43	**-**	2	**9**	45
Segment Income	**$ 9**	$ (45)	**$ 7**	$ (1)	**$ 16**	$ (46)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. SEGMENTED INFORMATION (continued)

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

Produced Gas	Produced Gas					
	Canada		United States		Total	
	2005	2004	**2005**	2004	**2005**	2004
Revenues, Net of Royalties	**$ 1,184**	$ 981	**$ 601**	$ 406	**$ 1,785**	$ 1,387
Expenses						
Production and mineral taxes	**21**	13	**62**	60	**83**	73
Transportation and selling	**71**	69	**41**	45	**112**	114
Operating	**122**	97	**48**	28	**170**	125
Operating Cash Flow	**$ 970**	$ 802	**$ 450**	$ 273	**$ 1,420**	$ 1,075

Oil & NGLs	Oil & NGLs					
	Canada		United States		Total	
	2005	2004	**2005**	2004	**2005**	2004
Revenues, Net of Royalties	**$ 330**	$ 285	**$ 54**	$ 37	**$ 384**	$ 322
Expenses						
Production and mineral taxes	**8**	5	**6**	5	**14**	10
Transportation and selling	**14**	15	**-**	-	**14**	15
Operating	**78**	64	**-**	-	**78**	64
Operating Cash Flow	**$ 230**	$ 201	**$ 48**	$ 32	**$ 278**	$ 233

Other & Total Upstream	Other		Total Upstream	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 58**	$ 54	**$ 2,227**	$ 1,763
Expenses				
Production and mineral taxes	**-**	-	**97**	83
Transportation and selling	**-**	-	**126**	129
Operating	**48**	48	**296**	237
Operating Cash Flow	**$ 10**	$ 6	**$ 1,708**	$ 1,314

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. SEGMENTED INFORMATION (continued)

Results of Continuing Operations *(For the six months ended June 30)*

	Upstream		Midstream & Market Optimization	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 4,333**	$ 3,392	**$ 2,566**	$ 2,317
Expenses				
Production and mineral taxes	**184**	137	**-**	-
Transportation and selling	**257**	256	**10**	16
Operating	**588**	478	**159**	147
Purchased product	**-**	-	**2,296**	2,109
Depreciation, depletion and amortization	**1,308**	1,074	**18**	52
Segment Income	**$ 1,996**	$ 1,447	**$ 83**	$ (7)

	Corporate *		Consolidated	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ (657)**	$ (427)	**$ 6,242**	$ 5,282
Expenses				
Production and mineral taxes	**-**	-	**184**	137
Transportation and selling	**-**	-	**267**	272
Operating	**(2)**	(5)	**745**	620
Purchased product	**-**	-	**2,296**	2,109
Depreciation, depletion and amortization	**35**	30	**1,361**	1,156
Segment Income	**$ (690)**	$ (452)	**1,389**	988
Administrative			**127**	93
Interest, net			**201**	178
Accretion of asset retirement obligation			**18**	9
Foreign exchange loss			**150**	77
Stock-based compensation			**8**	9
Gain on divestitures			**-**	(35)
			504	331
Net Earnings Before Income Tax			**885**	657
Income tax expense			**224**	66
Net Earnings From Continuing Operations			**$ 661**	$ 591

* For the six months ended June 30, the unrealized loss on risk management is recorded in the Consolidated Statement of Earnings as follows (see also Note 12):

	2005	2004
Revenues, Net of Royalites - Corporate	**$ (657)**	$ (429)
Operating Expenses and Other - Corporate	**(2)**	(4)
Total Unrealized Loss on Risk Management - Continuing Operations	**$ (655)**	$ (425)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. SEGMENTED INFORMATION (continued)

Results of Continuing Operations *(For the six months ended June 30)*

Upstream	Canada		United States	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 2,940**	$ 2,487	**$ 1,274**	$ 801
Expenses				
Production and mineral taxes	**51**	38	**133**	99
Transportation and selling	**172**	186	**85**	70
Operating	**392**	335	**92**	48
Depreciation, depletion and amortization	**931**	851	**359**	199
Segment Income	**$ 1,394**	$ 1,077	**$ 605**	$ 385

	Other		Total Upstream	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 119**	$ 104	**$ 4,333**	$ 3,392
Expenses				
Production and mineral taxes	**-**	-	**184**	137
Transportation and selling	**-**	-	**257**	256
Operating	**104**	95	**588**	478
Depreciation, depletion and amortization	**18**	24	**1,308**	1,074
Segment Income	**$ (3)**	$ (15)	**$ 1,996**	$ 1,447

Midstream & Market Optimization	Midstream		Market Optimization		Total Midstream & Market Optimization	
	2005	2004	**2005**	2004	**2005**	2004
Revenues	**$ 735**	$ 723	**$ 1,831**	$ 1,594	**$ 2,566**	$ 2,317
Expenses						
Transportation and selling	**-**	-	**10**	16	**10**	16
Operating	**137**	127	**22**	20	**159**	147
Purchased product	**515**	567	**1,781**	1,542	**2,296**	2,109
Depreciation, depletion and amortization	**18**	50	**-**	2	**18**	52
Segment Income	**$ 65**	$ (21)	**$ 18**	$ 14	**$ 83**	$ (7)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. SEGMENTED INFORMATION (continued)

Upstream Geographic and Product Information (Continuing Operations) *(For the six months ended June 30)*

Produced Gas	Produced Gas					
	Canada		United States		Total	
	2005	2004	**2005**	2004	**2005**	2004
Revenues, Net of Royalties	**$ 2,317**	$ 1,917	**$ 1,165**	$ 736	**$ 3,482**	$ 2,653
Expenses						
Production and mineral taxes	**37**	28	**121**	91	**158**	119
Transportation and selling	**141**	150	**85**	70	**226**	220
Operating	**243**	198	**92**	48	**335**	246
Operating Cash Flow	**$ 1,896**	$ 1,541	**$ 867**	$ 527	**$ 2,763**	$ 2,068

Oil & NGLs	Oil & NGLs					
	Canada		United States		Total	
	2005	2004	**2005**	2004	**2005**	2004
Revenues, Net of Royalties	**$ 623**	$ 570	**$ 109**	$ 65	**$ 732**	$ 635
Expenses						
Production and mineral taxes	**14**	10	**12**	8	**26**	18
Transportation and selling	**31**	36	**-**	-	**31**	36
Operating	**149**	137	**-**	-	**149**	137
Operating Cash Flow	**$ 429**	$ 387	**$ 97**	$ 57	**$ 526**	$ 444

Other & Total Upstream	Other		Total Upstream	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 119**	$ 104	**$ 4,333**	$ 3,392
Expenses				
Production and mineral taxes	**-**	-	**184**	137
Transportation and selling	**-**	-	**257**	256
Operating	**104**	95	**588**	478
Operating Cash Flow	**$ 15**	$ 9	**$ 3,304**	$ 2,521

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. SEGMENTED INFORMATION (continued)

Capital Expenditures (Continuing Operations)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	**2005**	2004
Upstream				
Canada	**$ 850**	$ 675	**$ 1,894**	$ 1,703
United States	**481**	316	**893**	526
Other Countries	**16**	19	**29**	34
	1,347	1,010	**2,816**	2,263
Midstream & Market Optimization	**96**	16	**140**	25
Corporate	**9**	9	**15**	18
Total	**$ 1,452**	$ 1,035	**$ 2,971**	$ 2,306

Property, Plant and Equipment and Total Assets

		Property, Plant and Equipment As at		Total Assets As at	
		June 30, 2005	December 31, 2004	**June 30, 2005**	December 31, 2004
Upstream		**$ 20,918**	$ 22,097	**$ 25,395**	$ 26,118
Midstream & Market Optimization		**914**	804	**1,732**	1,904
Corporate		**219**	239	**946**	1,412
Assets of Discontinued Operations	*(Note 3)*			**1,900**	1,779
Total		**$ 22,051**	$ 23,140	**$ 29,973**	$ 31,213

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. DISCONTINUED OPERATIONS

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 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 December 1, 2004, the Company completed the sale of its 100 percent interest in EnCana (U.K.) Limited for net cash consideration of approximately $2.1 billion. EnCana's U.K. operations included crude oil and natural gas interests in the U.K. central North Sea including the Buzzard, Scott and Telford oil fields, as well as other satellite discoveries and exploration licenses. A gain on sale of approximately $1.4 billion was recorded. Accordingly, these operations have been accounted for as discontinued operations.

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 June 30					
	Ecuador		United Kingdom		Total	
	2005	2004	**2005**	2004	**2005**	2004
Revenues, Net of Royalties	**$ 241**	$ 111	**$ -**	$ 55	**$ 241**	$ 166
Expenses						
Production and mineral taxes	**30**	13	**-**	-	**30**	13
Transportation and selling	**16**	14	**-**	11	**16**	25
Operating	**34**	29	**-**	14	**34**	43
Depreciation, depletion and amortization	**-**	69	**-**	34	**-**	103
Interest, net	**-**	(1)	**-**	(2)	**-**	(3)
Accretion of asset retirement obligation	**1**	1	**-**	1	**1**	2
Foreign exchange loss (gain)	**1**	-	**(3)**	3	**(2)**	3
	82	125	**(3)**	61	**79**	186
Net Earnings (Loss) Before Income Tax	**159**	(14)	**3**	(6)	**162**	(20)
Income tax expense (recovery)	**108**	(1)	**1**	(4)	**109**	(5)
Net Earnings (Loss) From Discontinued Operations	**$ 51**	$ (13)	**$ 2**	$ (2)	**$ 53**	$ (15)

	For the six months ended June 30					
	Ecuador		United Kingdom		Total	
	2005	2004	**2005**	2004	**2005**	2004
Revenues, Net of Royalties *	**$ 432**	$ 190	**$ -**	$ 96	**$ 432**	$ 286
Expenses						
Production and mineral taxes	**52**	24	**-**	-	**52**	24
Transportation and selling	**31**	33	**-**	19	**31**	52
Operating	**62**	59	**-**	20	**62**	79
Depreciation, depletion and amortization	**-**	134	**-**	67	**-**	201
Interest, net	**-**	(1)	**-**	(2)	**-**	(3)
Accretion of asset retirement obligation	**1**	1	**-**	2	**1**	3
Foreign exchange loss (gain)	**1**	-	**(3)**	2	**(2)**	2
	147	250	**(3)**	108	**144**	358
Net Earnings (Loss) Before Income Tax	**285**	(60)	**3**	(12)	**288**	(72)
Income tax expense (recovery)	**154**	(16)	**1**	(5)	**155**	(21)
Net Earnings (Loss) From Discontinued Operations	**$ 131**	$ (44)	**$ 2**	$ (7)	**$ 133**	$ (51)

* Revenues, net of royalties in Ecuador include $55 million of realized losses (2004 - $100 million) and $11 million of unrealized gains (2004 - $84 million of losses) related to derivative financial instruments.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. DISCONTINUED OPERATIONS (continued)

Consolidated Balance Sheet

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

	As at						
	June 30, 2005			December 31, 2004			
	Ecuador	United Kingdom	Total	Ecuador	United Kingdom	Syncrude	Total
Assets							
Cash and cash equivalents	**$ 4**	**$ 6**	**$ 10**	$ 2	$ 12	$ -	$ 14
Accounts receivable and accrued revenues	**132**	**-**	**132**	111	13	-	124
Risk management	**-**	**-**	**-**	3	-	-	3
Inventories	**23**	**-**	**23**	15	-	-	15
	159	**6**	**165**	131	25	-	156
Property, plant and equipment, net	**1,391**	**-**	**1,391**	1,295	-	-	1,295
Investments and other assets	**344**	**-**	**344**	328	-	-	328
	$ 1,894	**$ 6**	**$ 1,900**	$ 1,754	$ 25	$ -	$ 1,779
Liabilities							
Accounts payable and accrued liabilities	**$ 103**	**$ 28**	**$ 131**	$ 61	$ 32	$ 3	$ 96
Income tax payable	**127**	**1**	**128**	101	-	-	101
Risk management	**61**	**-**	**61**	72	-	-	72
	291	**29**	**320**	234	32	3	269
Asset retirement obligation	**23**	**-**	**23**	22	-	-	22
Future income taxes	**121**	**1**	**122**	80	11	-	91
	435	**30**	**465**	336	43	3	382
Net Assets of Discontinued Operations	**$ 1,459**	**$ (24)**	**$ 1,435**	$ 1,418	$ (18)	$ (3)	$ 1,397

Contingencies

In Ecuador, a subsidiary of EnCana has a 40 percent non-operated economic interest in relation to Block 15 pursuant to a contract with a subsidiary of Occidental Petroleum Corporation. In its 2004 filings with Securities regulatory authorities, Occidental Petroleum Corporation indicated that its subsidiary had received formal notification from Petroecuador, the state oil company of Ecuador, initiating proceedings to determine if the subsidiary had violated the Hydrocarbons Law and its Participation Contract for Block 15 with Petroecuador and whether such violations constitute grounds for terminating the Participation Contract.

In its filings, Occidental Petroleum Corporation indicated that it believes it has complied with all material obligations under the Participation Contract and that any termination of the Participation Contract by Ecuador based upon these stated allegations would be unfounded and would constitute an unlawful expropriation under international treaties.

In addition to the above, the Company continues to proceed with its arbitration related to value-added tax ("VAT") owed to the Company and has been in discussions related to certain income tax matters related to interest deductibility and other matters in Ecuador.

4. DIVESTITURES

Total proceeds received on sale of assets and investments was $2,459 million (2004 - $463 million) as described below:

Upstream

In 2005, the Company has completed the disposition of mature conventional oil and natural gas assets for proceeds of $408 million (2004 - $419 million).

In May, 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.

Other

In March 2004, the Company sold its equity investment in a well servicing company for approximately $44 million, recording a pre-tax gain of $34 million.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. FOREIGN EXCHANGE LOSS

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
Unrealized Foreign Exchange Loss on Translation of U.S. Dollar Debt Issued in Canada	**$ 47**	$ 32	**$ 65**	$ 71
Other Foreign Exchange Losses (Gains)	**72**	(14)	**85**	6
	$ 119	$ 18	**$ 150**	$ 77

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
Current				
Canada	**$ 124**	$ 180	**$ 310**	$ 402
United States	**559**	7	**591**	15
Other	**(9)**	(4)	**(2)**	(9)
Total Current Tax	**674**	183	**899**	408
Future	**(387)**	(38)	**(675)**	(233)
Future Tax Rate Reductions	**-**	-	**-**	(109)
Total Future Tax	**(387)**	(38)	**(675)**	(342)
	$ 287	$ 145	**$ 224**	$ 66

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

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
Net Earnings Before Income Tax	**$ 1,073**	$ 410	**$ 885**	$ 657
Canadian Statutory Rate	**37.9%**	39.1%	**37.9%**	39.1%
Expected Income Tax	**406**	160	**335**	257
Effect on Taxes Resulting from:				
Non-deductible Canadian crown payments	**44**	51	**86**	103
Canadian resource allowance	**(42)**	(63)	**(90)**	(123)
Canadian resource allowance on unrealized risk management (gains) losses	**(5)**	2	**13**	19
Statutory and other rate differences	**(69)**	(17)	**(84)**	(30)
Effect of tax rate changes	**-**	-	**-**	(109)
Non-taxable capital losses	**11**	7	**16**	14
Previously unrecognized capital losses	**-**	2	**-**	15
Tax basis retained on dispositions	**(68)**	(23)	**(68)**	(103)
Large corporations tax	**-**	3	**4**	7
Other	**10**	23	**12**	16
	$ 287	$ 145	**$ 224**	$ 66
Effective Tax Rate	**26.7%**	35.4%	**25.3%**	10.0%

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

7. LONG-TERM DEBT

	As at June 30, 2005	As at December 31, 2004
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	**$ 1,172**	$ 1,515
Unsecured notes	**1,285**	1,309
	2,457	2,824
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	**-**	399
Unsecured notes and debentures	**4,640**	4,641
	4,640	5,040
Increase in Value of Debt Acquired*	**63**	66
Current Portion of Long-Term Debt	**(309)**	(188)
	$ 6,851	$ 7,742

* 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 22 years.

On June 17, 2005, EnCana announced its intention to seek the necessary approvals to redeem three series of unsecured notes with a total face value of C$200 million. Accordingly, these unsecured notes have been recorded in current portion of long-term debt.

8. 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 June 30, 2005	As at December 31, 2004
Asset Retirement Obligation, Beginning of Year	**$ 611**	$ 383
Liabilities Incurred	**48**	98
Liabilities Settled	**(10)**	(16)
Liabilities Disposed	**(22)**	(35)
Change in Estimated Future Cash Flows	**6**	124
Accretion Expense	**18**	22
Other	**(11)**	35
Asset Retirement Obligation, End of Period	**$ 640**	$ 611

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

9. SHARE CAPITAL

(millions)	June 30, 2005 Number	June 30, 2005 Amount	December 31, 2004 Number	December 31, 2004 Amount
Common Shares Outstanding, Beginning of Year	**900.6**	**$ 5,299**	921.2	$ 5,305
Shares Issued under Option Plans	**9.8**	**184**	19.4	281
Shares Repurchased	**(50.2)**	**(381)**	(40.0)	(287)
Common Shares Outstanding, End of Period	**860.2**	**$ 5,102**	900.6	$ 5,299

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 June 30, 2005, the Company purchased 50,211,198 Common Shares for total consideration of approximately $1,662 million. Of the amount paid, $381 million was charged to Share capital, $10 million was charged to Paid in surplus and $1,271 million was charged to Retained earnings. Included in the above are 5.5 million Common Shares which have been repurchased by a wholly owned Trust and are held for issuance upon vesting of units under EnCana's Performance Share Unit plan (see Note 10).

On October 26, 2004, the Company received regulatory approval for a new Normal Course Issuer Bid commencing October 29, 2004. Under this bid, the Company may purchase for cancellation up to 46,229,000 of its Common Shares, representing five percent of the approximately 924.58 million Common Shares outstanding as of the filing of the bid on October 22, 2004. On February 4, 2005, the Company received regulatory approval for an amendment to the Normal Course Issuer Bid which increases the number of shares available for purchase from five percent of the issued and outstanding Common Shares to ten percent of the public float of Common Shares (a total of approximately 92.2 million Common Shares). The current Normal Course Issuer Bid expires on October 28, 2005.

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 June 30, 2005. Information related to TSAR's is included in Note 10.

	Stock Options *(millions)*	**Weighted Average Exercise Price** *(C$)*
Outstanding, Beginning of Year	**36.2**	**23.15**
Exercised	**(9.8)**	**22.65**
Forfeited	**(0.3)**	**19.94**
Outstanding, End of Period	**26.1**	**23.37**
Exercisable, End of Period	**20.9**	**23.23**

	Outstanding Options			**Exercisable Options**	
Range of Exercise Price	Number of Options Outstanding *(millions)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *(C$)*	Number of Options Outstanding *(millions)*	Weighted Average Exercise Price *(C$)*
10.00 to 12.49	0.8	3.8	11.43	0.8	11.43
12.50 to 14.99	0.4	1.6	13.10	0.4	13.10
15.00 to 21.99	0.6	1.4	20.08	0.5	19.89
22.00 to 26.50	24.3	2.1	24.00	19.2	24.02
	26.1	2.1	23.37	20.9	23.23

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

9. SHARE CAPITAL (continued)

EnCana has recorded stock-based compensation expense in the Consolidated Statement of Earnings for stock options granted to employees and directors in 2003 using the fair-value method. Stock options granted in 2004 and 2005 have an associated Tandem Share Appreciation Right attached. Compensation expense has not been recorded in the Consolidated Statement of Earnings related to stock options granted prior to 2003. If the Company had applied the fair-value method to options granted prior to 2003, pro forma Net Earnings and Net Earnings per Common Share for the three months ended June 30, 2005 would be unchanged (three months ended 2004 - $241 million; $0.26 per common share - basic; $0.26 per common share - diluted). Pro forma Net Earnings and Net Earnings per Common Share for the six months ended June 30, 2005 would be unchanged (2004 - $522 million; $0.57 per common share - basic; $0.56 per common share diluted).

10. COMPENSATION PLANS

The tables below outline certain information related to EnCana's compensation plans at June 30, 2005. Additional information is contained in Note 16 of the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2004.

A) Pensions

The following table summarizes the net benefit plan expense:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	**2005**	2004
Current Service Cost	**$ 2**	$ 1	**$ 4**	$ 3
Interest Cost	**3**	3	**6**	6
Expected Return on Plan Assets	**(3)**	(3)	**(6)**	(6)
Amortization of Net Actuarial Loss	**-**	2	**1**	3
Amortization of Transitional Obligation	**1**	(1)	**-**	(2)
Amortization of Past Service Cost	**-**	1	**1**	1
Expense for Defined Contribution Plan	**5**	4	**10**	7
Net Benefit Plan Expense	**$ 8**	$ 7	**$ 16**	$ 12

EnCana previously disclosed in its annual audited Consolidated Financial Statements for the year ended December 31, 2004 that it expected to contribute $6 million to its defined benefit pension plans in 2005. The Company now anticipates that it will contribute $8 million to the defined benefit pension plans in 2005. At June 30, 2005, contributions of $4 million have been made.

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

The following table summarizes the information about SAR's at June 30, 2005:

	Outstanding SAR's	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**930,510**	**18.31**
Exercised	**(593,558)**	**15.55**
Forfeited	**(1,530)**	**23.14**
Outstanding, End of Period	**335,422**	**23.15**
Exercisable, End of Period	**335,422**	**23.15**
U.S. Dollar Denominated *(US$)*		
Outstanding, Beginning of Year	**771,860**	**14.40**
Exercised	**(258,774)**	**14.30**
Outstanding, End of Period	**513,086**	**14.45**
Exercisable, End of Period	**513,086**	**14.45**

To June 30, EnCana recorded compensation costs of $10 million related to the outstanding SAR's (2004 - $3 million).

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

10. COMPENSATION PLANS (continued)

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

The following table summarizes the information about Tandem SAR's at June 30, 2005:

	Outstanding TSAR's	Weighted Average Exercise Price
Canadian Dollar Denominated ***(C$)***		
Outstanding, Beginning of Year	1,735,000	27.77
Granted	6,876,612	38.56
Exercised	(112,730)	27.13
Forfeited	(149,500)	29.68
Outstanding, End of Period	8,349,382	36.61
Exercisable, End of Period	272,810	27.27

To June 30, EnCana recorded compensation costs of $31 million related to the outstanding TSAR's (2004 - nil).

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

The following table summarizes the information about DSU's at June 30, 2005:

	Outstanding DSU's	Weighted Average Exercise Price
Canadian Dollar Denominated ***(C$)***		
Outstanding, Beginning of Year	750,612	24.81
Granted, Directors	77,552	43.14
Units, in Lieu of Dividends	2,717	46.01
Outstanding, End of Period	830,881	26.59
Exercisable, End of Period	830,881	26.59

To June 30, EnCana recorded compensation costs of $13 million related to the outstanding DSU's (2004 - $5 million).

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

The following table summarizes the information about PSU's at June 30, 2005:

	Outstanding PSU's	Weighted Average Grant Price
Canadian Dollar Denominated ***(C$)***		
Outstanding, Beginning of Year	3,294,206	26.71
Granted	1,715,873	38.21
Forfeited	(166,293)	30.45
Outstanding, End of Period	4,843,786	30.65
Exercisable, End of Period	-	-
U.S. Dollar Denominated ***(US$)***		
Outstanding, Beginning of Year	449,230	20.56
Granted	387,924	30.95
Forfeited	(29,018)	26.80
Outstanding, End of Period	808,136	25.32
Exercisable, End of Period	-	-

To June 30, EnCana recorded compensation costs of $33 million related to the outstanding PSU's (2004 - $10 million).

At June 30, 2005, 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)

11. PER SHARE AMOUNTS

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

	Three Months Ended			Six Months Ended	
	March 31,	June 30,		June 30,	
(millions)	2005	**2005**	2004	**2005**	2004
Weighted Average Common Shares Outstanding - Basic	891.8	**872.0**	920.6	**881.8**	921.2
Effect of Dilutive Securities	17.2	**19.9**	10.4	**18.9**	12.4
Weighted Average Common Shares Outstanding - Diluted	909.0	**891.9**	931.0	**900.7**	933.6

The amounts above have been restated to reflect the effect of the common share split approved in April 2005.

12. 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 (Loss) Gain on Risk Management Activities

The following table summarizes the gains and losses on risk management activities:

	Realized			Unrealized		
	Q1	**Q2**	**YTD**	Q1	**Q2**	**YTD**
Revenues, Net of Royalites	$ (20)	**$ (114)**	**$ (134)**	$ (972)	**$ 315**	**$ (657)**
Operating Expenses and Other	5	**5**	**$ 10**	3	**(1)**	**$ 2**
Total (Loss) Gain on Risk Management - Continuing Operations	(15)	**(109)**	**(124)**	(969)	**314**	**(655)**
(Loss) Gain on Risk Management - Discontinued Operations	(23)	**(32)**	**(55)**	(20)	**31**	**11**
	$ (38)	**$ (141)**	**$ (179)**	$ (989)	**$ 345**	**$ (644)**

Amounts Recognized on Transition

As discussed in Note 2 to the annual audited Consolidated Financial Statements for the year ended December 31, 2004, 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. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indications and forecasts.

At June 30, 2005, a net unrealized gain remains to be recognized over the next four years as follows:

	Unrealized Gain (Loss)
2005	
Three months ended September 30, 2005	$ 9
Three months ended December 31, 2005	9
Total remaining to be recognized in 2005	$ 18
2006	$ 24
2007	15
2008	1
Total to be recognized in 2006 through to 2008	$ 40
Total to be recognized	$ 58
Total to be recognized - Continuing Operations	$ 59
Total to be recognized - Discontinued Operations	(1)
	$ 58

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

12. 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, 2005 to June 30, 2005:

	Transition Amounts	Fair Market Value	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	$ (72)	$ (189)	
Change in Fair Value of Contracts in Place at Beginning of Year	-	(678)	$ (678)
Fair Value of Contracts in Place at Transition Realized in 2005	14	(14)	-
Fair Value of Contracts Entered into Since Beginning of Year	-	34	34
Fair Value of Contracts Outstanding	$ (58)	$ (847)	$ (644)
Unamortized Premiums Paid on Collars and Options		93	
Fair Value of Contracts Outstanding and Premiums Paid, End of Period		$ (754)	
Amounts Allocated to Continuing Operations	$ (59)	$ (693)	$ (655)
Amounts Allocated to Discontinued Operations	1	(61)	11
	$ (58)	$ (754)	$ (644)

At June 30, 2005, the net deferred amounts recognized on transition and the risk management amounts are recorded in the Consolidated Balance Sheet as follows:

	As at June 30, 2005
Remaining Deferred Amounts Recognized on Transition	
Accounts receivable and accrued revenues	**$ 2**
Investments and other assets	**1**
Accounts payable and accrued liabilities	**32**
Other liabilities	**30**
Net Deferred Gain - Continuing Operations	**$ 59**
Net Deferred Loss - Discontinued Operations	**(1)**
	$ 58
Risk Management	
Current asset	**$ 160**
Long-term asset	**106**
Current liability	**690**
Long-term liability	**269**
Net Risk Management Liability - Continuing Operations	**$ (693)**
Net Risk Management Liability - Discontinued Operations	**(61)**
	$ (754)

A summary of all unrealized estimated fair value financial positions is as follows:	**As at June 30, 2005**
Commodity Price Risk	
Natural gas	**$ (489)**
Crude oil	**(225)**
Power	**3**
Interest Rate Risk	**18**
Total Fair Value Positions - Continuing Operations	**$ (693)**
Total Fair Value Positions - Discontinued Operations	**(61)**
	$ (754)

Information with respect to power and interest rate risk contracts in place at December 31, 2004 is disclosed in Note 17 to the Company's annual audited Consolidated Financial Statements. No significant new contracts have been entered into as at June 30, 2005.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

12. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Natural Gas

At June 30, 2005, the Company's gas risk management activities from financial contracts had an unrealized loss of $546 million and a fair market value position of $(489) million. The contracts were as follows:

	Notional Volumes *(MMcf/d)*	Term	Average Price		Fair Market Value
Sales Contracts					
Fixed Price Contracts					
NYMEX Fixed Price	770	2005	6.74	US$/Mcf	$ (71)
Colorado Interstate Gas (CIG)	114	2005	4.87	US$/Mcf	(32)
Other	110	2005	5.21	US$/Mcf	(33)
NYMEX Fixed Price	525	2006	5.66	US$/Mcf	(429)
Colorado Interstate Gas (CIG)	100	2006	4.44	US$/Mcf	(92)
Houston Ship Channel (HSC)	90	2006	5.08	US$/Mcf	(84)
Rockies	35	2006	4.45	US$/Mcf	(33)
Other	46	2006	4.69	US$/Mcf	(43)
Collars and Other Options					
Purchased NYMEX Put Options	1,059	2005	5.64	US$/Mcf	(33)
NYMEX 3-Way Call Spread	180	2005	5.00/6.69/7.69	US$/Mcf	(19)
Purchased NYMEX Put Options	243	2006	5.18	US$/Mcf	(17)
Basis Contracts					
Fixed NYMEX to AECO Basis	883	2005	(0.66)	US$/Mcf	52
Fixed NYMEX to Rockies Basis	257	2005	(0.48)	US$/Mcf	18
Other	469	2005	(0.50)	US$/Mcf	11
Fixed NYMEX to AECO Basis	703	2006	(0.65)	US$/Mcf	61
Fixed NYMEX to Rockies Basis	324	2006	(0.58)	US$/Mcf	27
Fixed NYMEX to CIG Basis	301	2006	(0.83)	US$/Mcf	9
Other	182	2006	(0.36)	US$/Mcf	8
Fixed Rockies to CIG Basis	12	2007	(0.10)	US$/Mcf	-
Fixed NYMEX to AECO Basis	355	2007-2008	(0.66)	US$/Mcf	41
Fixed NYMEX to Rockies Basis	350	2007-2008	(0.64)	US$/Mcf	58
Fixed NYMEX to CIG Basis	157	2007-2009	(0.75)	US$/Mcf	38
Purchase Contracts					
Fixed Price Contracts					
Waha Purchase	27	2005	5.90	US$/Mcf	5
Waha Purchase	23	2006	5.32	US$/Mcf	17
Basis Contracts					
Fixed NYMEX to Ventura	32	2005	(0.44)	US$/Mcf	-
					(541)
Other Financial Positions *					(5)
Total Unrealized Loss on Financial Contracts					(546)
Unamortized Premiums Paid on Options					57
Total Fair Value Positions					$ (489)

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

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

12. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Crude Oil

At June 30, 2005, the Company's oil risk management activities from financial contracts had an unrealized loss of $322 million and a fair market value position of $(286) million. The contracts were as follows:

	Notional Volumes *(bbl/d)*	Term	Average Price *(US$/bbl)*	Fair Market Value
Fixed WTI NYMEX Price	41,000	2005	28.41	$ (224)
Costless 3-Way Put Spread	9,000	2005	20.00/25.00/28.78	(48)
Unwind WTI NYMEX Fixed Price	(7,200)	2005	42.70	21
Purchased WTI NYMEX Call Options	(38,000)	2005	49.76	59
Purchased WTI NYMEX Put Options	35,000	2005	40.00	(12)
Fixed WTI NYMEX Price	15,000	2006	34.56	(128)
Unwind WTI NYMEX Fixed Price	(1,300)	2006	52.75	3
Purchased WTI NYMEX Call Options	(12,000)	2006	60.00	13
Purchased WTI NYMEX Put Options	22,000	2006	27.36	(7)
				(323)
Other Financial Positions *				1
Total Unrealized Loss on Financial Contracts				(322)
Unamortized Premiums Paid on Options				36
Total Fair Value Positions				$ (286)
Total Fair Value Positions - Continuing Operations				$ (225)
Total Fair Value Positions - Discontinued Operations				(61)
				$ (286)

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

13. RECLASSIFICATION

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2005.

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)	2005 Year-to-date	2005 Q2	2005 Q1	2004 Year	2004 Q4	2004 Q3	2004 Q2	2004 Q1
TOTAL CONSOLIDATED								
Cash Flow	**2,985**	**1,572**	1,413	4,980	1,491	1,363	1,131	995
Per share - Basic	**3.39**	**1.80**	1.58	5.41	1.62	1.48	1.23	1.08
- Diluted	**3.31**	**1.76**	1.55	5.32	1.60	1.46	1.21	1.07
Net Earnings (Loss)	**794**	**839**	(45)	3,513	2,580	393	250	290
Per share - Basic	**0.90**	**0.96**	(0.05)	3.82	2.81	0.43	0.27	0.31
- Diluted	**0.88**	**0.94**	(0.05)	3.75	2.77	0.42	0.27	0.31
Operating Earnings [(1)]	**1,266**	**655**	611	1,976	573	559	379	465
Per share - Diluted	**1.41**	**0.73**	0.67	2.11	0.62	0.60	0.41	0.50
CONTINUING OPERATIONS								
Cash Flow from Continuing Operations	**2,820**	**1,512**	1,308	4,605	1,429	1,259	1,021	896
Net Earnings (Loss) from Continuing Operations	**661**	**786**	(125)	2,211	1,188	432	265	326
Per share - Basic	**0.75**	**0.90**	(0.14)	2.40	1.29	0.47	0.29	0.35
- Diluted	**0.73**	**0.88**	(0.14)	2.36	1.28	0.46	0.28	0.35
Operating Earnings - Continuing Operations [(2)]	**1,141**	**623**	518	1,989	612	553	362	462
Foreign Exchange Rates (US$ per C$1)								
Average	**0.810**	**0.804**	0.815	0.768	0.820	0.765	0.736	0.759
Period end	**0.816**	**0.816**	0.827	0.831	0.831	0.791	0.746	0.763

(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 (restated for the effect of the share split)	2005 Year-to-date	2005 Q2	2005 Q1	2004 Year	2004 Q4	2004 Q3	2004 Q2	2004 Q1
Common Shares Outstanding *(millions)*								
Period end	**860.2**	**860.2**	881.7	900.6	900.6	924.0	922.0	919.6
Average - Basic	**881.8**	**872.0**	891.8	920.8	917.6	923.4	920.6	921.8
Average - Diluted	**900.7**	**891.9**	909.0	936.0	929.8	932.4	931.0	934.2
Price Range *($ per share)*								
TSX - C$								
High	**51.27**	**51.27**	44.28	35.01	35.01	30.30	29.87	29.64
Low	**32.55**	**39.05**	32.55	25.50	28.95	26.15	26.50	25.50
Close	**48.33**	**48.33**	42.72	34.20	34.20	29.18	28.81	28.35
NYSE - US$								
High	**41.56**	**41.56**	36.45	28.72	28.72	23.46	22.37	22.13
Low	**26.45**	**31.31**	26.45	19.03	23.05	19.98	19.03	19.18
Close	**39.59**	**39.59**	35.21	28.53	28.53	23.15	21.58	21.56
Share Volume Traded *(millions)*	**677.9**	**327.3**	350.6	1,056.1	326.7	229.5	242.3	257.6
Share Value Traded *(US$ millions weekly average)*	**874.1**	**878.8**	852.6	456.9	636.0	364.8	392.9	403.7

Financial Metrics	
Net Debt to Capitalization	**36%**
Net Debt to EBITDA	**1.3x**
Return on Capital Employed	**20%**
Return on Common Equity	**30%**

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics (continued)

Net Capital Investment *($ millions)*	**2005**	2004
Upstream		
Canada	**$ 1,871**	$ 1,684
United States	**878**	526
Frontier and International New Ventures	**29**	34
	2,778	2,244
Midstream & Market Optimization	**140**	25
Corporate	**15**	18
Core Capital from Continuing Operations	**2,933**	2,287
Acquisitions		
Upstream		
Property		
Canada	**23**	19
United States	**15**	-
Corporate		
Petrovera	**-**	253
Tom Brown, Inc. [1]	**-**	2,335
Dispositions		
Upstream		
Property		
Canada	**(402)**	(133)
United States	**(2,055)**	3
Corporate		
Petrovera	**-**	(541)
Midstream & Market Optimization		
Property	**-**	(1)
Corporate	**(2)**	-
Net Acquisition and Disposition activity from Continuing Operations	**(2,421)**	1,935
Discontinued Operations	**100**	439
Net Capital Investment	**$ 612**	$ 4,661

[1] Net cash consideration excluding debt acquired of $406 million.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties

Sales Volumes	**2005**			2004				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS								
Produced Gas *(MMcf/d)*								
Canada								
Production	**2,102**	**2,151**	2,052	2,105	2,106	2,138	2,177	2,000
Inventory withdrawal / (injection)	**13**	**-**	27	(6)	(26)	-	-	-
Canada Sales	**2,115**	**2,151**	2,079	2,099	2,080	2,138	2,177	2,000
United States	**1,064**	**1,061**	1,067	869	1,007	958	824	684
Total Produced Gas	**3,179**	**3,212**	3,146	2,968	3,087	3,096	3,001	2,684
Oil and Natural Gas Liquids *(bbls/d)*								
North America								
Light and Medium Oil	**50,149**	**50,020**	50,280	56,215	52,725	52,824	64,448	54,940
Heavy Oil	**81,415**	**82,274**	80,546	84,164	79,336	89,682	79,899	87,729
Natural Gas Liquids [1]								
Canada	**11,705**	**11,719**	11,692	13,452	13,452	12,804	13,588	13,971
United States	**13,876**	**13,095**	14,666	12,586	13,957	14,363	12,752	9,237
Total Oil and Natural Gas Liquids	**157,145**	**157,108**	157,184	166,417	159,470	169,673	170,687	165,877
Total Continuing Operations *(MMcfe/d)*	**4,122**	**4,155**	4,089	3,966	4,044	4,114	4,025	3,679
DISCONTINUED OPERATIONS								
Ecuador								
Production [2]	**74,673**	**73,662**	75,695	76,872	76,235	76,567	78,376	76,320
(Under) / over lifting	**(1,840)**	**(486)**	(3,208)	1,121	1,641	(1,721)	(73)	4,662
Ecuador Sales *(bbls/d)*	**72,833**	**73,176**	72,487	77,993	77,876	74,846	78,303	80,982
United Kingdom *(BOE/d)*	**-**	**-**	-	20,973	13,927	20,222	26,728	22,755
Total Discontinued Operations *(MMcfe/d)*	**437**	**439**	435	594	551	570	630	623
Total *(MMcfe/d)*	**4,559**	**4,594**	4,524	4,560	4,595	4,684	4,655	4,302

(1) Natural gas liquids include condensate volumes.

(2) 2005 includes approximately 28,385 bbls/day (2004 full year - 31,000 bbls/day) related to Block 15.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

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

	2005			2004				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS								
Produced Gas - Canada *($/Mcf)*								
Price	**5.89**	**6.08**	5.70	5.34	5.86	5.10	5.20	5.21
Production and mineral taxes	**0.10**	**0.10**	0.09	0.08	0.10	0.09	0.07	0.08
Transportation and selling	**0.37**	**0.36**	0.37	0.39	0.39	0.37	0.35	0.44
Operating	**0.64**	**0.62**	0.65	0.52	0.55	0.50	0.49	0.56
Netback	**4.78**	**5.00**	4.59	4.35	4.82	4.14	4.29	4.13
Produced Gas - United States *($/Mcf)*								
Price	**6.32**	**6.60**	6.04	5.79	6.53	5.36	5.72	5.39
Production and mineral taxes	**0.63**	**0.65**	0.62	0.65	0.69	0.57	0.80	0.51
Transportation and selling	**0.44**	**0.42**	0.46	0.31	0.27	0.26	0.34	0.39
Operating	**0.48**	**0.50**	0.45	0.37	0.41	0.36	0.37	0.33
Netback	**4.77**	**5.03**	4.51	4.46	5.16	4.17	4.21	4.16
Produced Gas - Total North America *($/Mcf)*								
Price	**6.03**	**6.25**	5.81	5.47	6.08	5.18	5.34	5.26
Production and mineral taxes	**0.28**	**0.28**	0.27	0.25	0.29	0.24	0.27	0.19
Transportation and selling	**0.39**	**0.38**	0.40	0.36	0.35	0.33	0.35	0.43
Operating	**0.58**	**0.58**	0.58	0.48	0.50	0.46	0.46	0.50
Netback	**4.78**	**5.01**	4.56	4.38	4.94	4.15	4.26	4.14
Natural Gas Liquids - Canada *($/bbl)*								
Price	**39.80**	**39.55**	40.04	31.43	36.73	33.46	28.48	27.27
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-
Transportation and selling	**0.37**	**0.39**	0.35	0.41	0.47	0.45	0.35	0.35
Netback	**39.43**	**39.16**	39.69	31.02	36.26	33.01	28.13	26.92
Natural Gas Liquids - United States *($/bbl)*								
Price	**42.76**	**44.79**	40.93	35.43	38.74	36.09	32.93	32.77
Production and mineral taxes	**4.28**	**4.37**	4.20	3.82	3.94	4.05	3.93	3.09
Transportation and selling	**0.01**	**0.01**	0.01	-	-	-	-	-
Netback	**38.47**	**40.41**	36.72	31.61	34.80	32.04	29.00	29.68
Natural Gas Liquids - Total North America *($/bbl)*								
Price	**41.41**	**42.32**	40.53	33.36	37.75	34.85	30.63	29.46
Production and mineral taxes	**2.32**	**2.31**	2.34	1.84	2.00	2.14	1.90	1.23
Transportation and selling	**0.17**	**0.19**	0.16	0.21	0.23	0.21	0.18	0.21
Netback	**38.92**	**39.82**	38.03	31.31	35.52	32.50	28.55	28.02
Crude Oil - Light and Medium - North America *($/bbl)*								
Price	**40.01**	**41.44**	38.57	34.67	39.57	37.40	32.43	29.92
Production and mineral taxes	**1.52**	**1.71**	1.32	0.96	1.38	0.85	0.79	0.86
Transportation and selling	**1.19**	**1.20**	1.19	1.01	1.04	1.08	0.76	1.19
Operating	**6.36**	**6.34**	6.38	5.85	6.41	6.49	4.84	5.87
Netback	**30.94**	**32.19**	29.68	26.85	30.74	28.98	26.04	22.00
Crude Oil - Heavy - North America *($/bbl)*								
Price	**21.78**	**22.77**	20.76	23.41	21.37	28.01	22.35	21.48
Production and mineral taxes	**0.03**	**0.02**	0.03	0.04	0.04	0.05	(0.01)	0.06
Transportation and selling	**1.32**	**1.13**	1.52	1.09	(0.57)	1.63	1.50	1.69
Operating	**6.21**	**6.57**	5.83	5.32	6.27	4.79	4.82	5.44
Netback	**14.22**	**15.05**	13.38	16.96	15.63	21.54	16.04	14.29
Crude Oil - Total North America *($/bbl)*								
Price	**28.73**	**29.83**	27.60	27.92	28.63	31.49	26.85	24.73
Production and mineral taxes	**0.59**	**0.66**	0.53	0.41	0.57	0.34	0.35	0.37
Transportation and selling	**1.27**	**1.15**	1.39	1.06	0.07	1.42	1.17	1.50
Operating	**6.26**	**6.48**	6.04	5.53	6.33	5.42	4.83	5.61
Netback	**20.61**	**21.54**	19.64	20.92	21.66	24.31	20.50	17.25

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

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

	2005			2004				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS (continued)								
Total Liquids - Canada *($/bbl)*								
Price	**29.60**	**30.58**	28.60	28.21	29.36	31.63	26.99	24.95
Production and mineral taxes	**0.54**	**0.61**	0.48	0.37	0.52	0.31	0.32	0.34
Transportation and selling	**1.20**	**1.09**	1.31	1.00	0.11	1.35	1.10	1.40
Operating	**5.76**	**5.96**	5.55	5.05	5.75	4.98	4.42	5.11
Netback	**22.10**	**22.92**	21.26	21.79	22.98	24.99	21.15	18.10
Total Liquids - North America *($/bbl)*								
Price	**30.79**	**31.80**	29.77	28.77	30.20	32.03	27.43	25.39
Production and mineral taxes	**0.88**	**0.92**	0.83	0.63	0.82	0.63	0.59	0.49
Transportation and selling	**1.09**	**1.00**	1.18	0.93	0.10	1.23	1.02	1.32
Operating	**5.24**	**5.46**	5.03	4.67	5.24	4.55	4.09	4.82
Netback	**23.58**	**24.42**	22.73	22.54	24.04	25.62	21.73	18.76
Total North America *($/Mcfe)*								
Price	**5.83**	**6.03**	5.62	5.30	5.83	5.22	5.15	4.98
Production and mineral taxes	**0.25**	**0.25**	0.24	0.21	0.25	0.21	0.22	0.16
Transportation and selling	**0.34**	**0.33**	0.36	0.31	0.27	0.30	0.30	0.37
Operating	**0.65**	**0.66**	0.64	0.55	0.59	0.53	0.52	0.58
Netback	**4.59**	**4.79**	4.38	4.23	4.72	4.18	4.11	3.87

Impact of Upstream Realized Financial Hedging

Natural Gas *($/Mcf)*	**0.02**	**(0.14)**	0.18	(0.22)	(0.37)	(0.15)	(0.25)	(0.08)
Liquids *($/bbl)*	**(5.03)**	**(4.88)**	(5.18)	(7.08)	(8.24)	(8.75)	(6.53)	(4.79)
Total *($/Mcfe)*	**(0.18)**	**(0.30)**	(0.06)	(0.46)	(0.61)	(0.48)	(0.47)	(0.27)

Average Royalty Rates
(excluding impact of realized financial hedging)

Produced Gas								
Canada	**11.5%**	**11.0%**	11.9%	12.5%	12.0%	12.2%	12.7%	13.3%
United States	**18.0%**	**17.9%**	18.1%	19.6%	19.8%	18.3%	21.1%	19.3%
Crude Oil								
Canada and United States	**8.9%**	**9.2%**	8.7%	9.0%	8.7%	8.8%	11.6%	9.4%
Natural Gas Liquids								
Canada	**14.7%**	**15.6%**	13.8%	15.7%	16.5%	18.5%	13.1%	14.8%
United States	**16.7%**	**12.7%**	20.0%	18.7%	21.4%	13.6%	20.7%	19.2%
Total North America	**13.0%**	**12.6%**	13.3%	13.7%	13.8%	13.2%	14.1%	13.7%

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

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

	2005			2004				
	Year-to-date	**Q2**	Q1	Year	Q4	Q3	Q2	Q1
DISCONTINUED OPERATIONS								
Crude Oil - Ecuador *($/bbl)*								
Price	**36.09**	**36.37**	35.80	28.68	29.97	33.47	27.78	23.82
Production and mineral taxes	**3.98**	**4.53**	3.42	2.13	2.73	2.62	1.84	1.37
Transportation and selling	**2.35**	**2.48**	2.21	2.12	1.57	2.36	1.92	2.63
Operating	**4.73**	**5.18**	4.26	4.39	5.02	4.35	4.14	4.04
Netback	**25.03**	**24.18**	25.91	20.04	20.65	24.14	19.88	15.78
Crude Oil - United Kingdom *($/bbl)*								
Price	**-**	**-**	-	36.92	46.19	40.88	34.68	31.11
Transportation and selling	**-**	**-**	-	2.06	2.17	2.44	1.85	1.94
Operating	**-**	**-**	-	6.75	5.00	9.98	7.84	3.86
Netback	**-**	**-**	-	28.11	39.02	28.46	24.99	25.31

Impact of Upstream Realized Financial Hedging - Crude Oil

Ecuador *($/bbl)*	**(4.19)**	**(4.90)**	(3.48)	(9.66)	(14.60)	(10.31)	(7.13)	(6.69)
United Kingdom *($/bbl)* [1]	**-**	**-**	-	(7.62)	(6.34)	(11.75)	(7.01)	(5.72)

Average Royalty Rates
(excluding impact of realized financial hedging)

Crude Oil								
Ecuador	**26.6%**	**26.3%**	26.9%	27.1%	27.8%	26.5%	26.5%	27.4%

[1] Excludes hedges unwound as a result of the United Kingdom disposition.

EnCana Corporation

Further information on ENCnaa Corporation is avaialbel on the company's Web site (www.encana.com) or by contacting:

Investor contacts:
EnCana Corporate Development
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