EnCana Corporation

FIRST QUARTER INTERIM REPORT

For the period ended

March 31, 2004



ENCANA'S FIRST QUARTER OPERATING EARNINGS REACH US\$465 MILLION, NET EARNINGS WERE US\$290 MILLION, CASH FLOW NEARS US\$1 BILLION

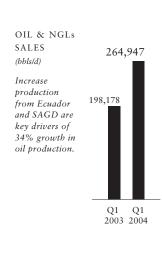
Oil and natural gas sales up 14 percent to 717,000 barrels of oil equivalent per day

CALGARY, ALBERTA, (APRIL 28, 2004) – EnCana Corporation's (TSX & NYSE: ECA) first quarter 2004 operating earnings were US\$465 million, or \$1.00 per share diluted, down 9 percent from \$510 million in the first quarter of 2003 due largely to lower realized natural gas and oil prices. First quarter cash flow was \$995 million, or \$2.13 per share diluted. Sales of oil, natural gas and natural gas liquids (NGLs) increased 14 percent in the first quarter to 717,000 barrels of oil equivalent (BOE) per day.

"Our first quarter 2004 operational performance is firmly on plan and our financial results remain solid. Continued strong gas production growth from resource plays in Western Canada and the U.S. Rockies, plus strong oil production increases from Ecuador and our steam-assisted gravity drainage projects in northeast Alberta, is anchoring our sustained growth and value creation," said Gwyn Morgan, EnCana's President & Chief Executive Officer.

EnCana's first quarter operating earnings exclude the after-tax impacts of foreign exchange on translation of U.S. dollar denominated debt issued in Canada, mark-tomarket unrealized losses related to financial derivatives and the impact of tax changes recently enacted in Alberta. After these accounting adjustments, net earnings in the first quarter were \$290 million, or 62 cents per share diluted. First quarter earnings were reduced by \$252 million, after-tax, as a result of the adoption of the new accounting standard governing hedging relationships. The depreciation of the Canadian dollar versus the U.S. dollar since December 31, 2003 resulted in a further reduction in earnings of \$32 million, after-tax, on translation of U.S. dollar denominated debt issued in Canada. The effect of recent Alberta income tax changes increased earnings by \$109 million.





First quarter cash flow of \$995 million includes a cash tax provision of \$232 million, which is consistent with the company's 2004 guidance. All figures are in U.S. dollars unless otherwise noted.

CHANGE IN ACCOUNTING POLICY FOR UNREALIZED HEDGING LOSSES IMPACTS EARNINGS

On January 1, 2004, EnCana was required to adopt the new accounting standard governing hedging activities. In addition to the first quarter impact, EnCana expects that this new standard will continue to result in greater volatility in its reported net earnings. Implementation of this accounting standard resulted in the company recording an unrealized after-tax mark-to-market loss of \$252 million in the quarter on the portfolio of its financial derivatives, commonly known as financial price hedges. A complete discussion of the impact of this new accounting standard is contained in Notes 2 and 13 of the unaudited first quarter consolidated financial statements.

GAS PRODUCTION UP 10 PERCENT IN PAST YEAR; OIL AND NGLS SALES UP 34 PERCENT

EnCana's first quarter natural gas sales were 2.7 billion cubic feet per day, up 5 percent compared with the first quarter of 2003 when 120 million cubic feet per day of previously produced gas was withdrawn from storage. Gas production was up 10 percent during the period compared to the same period in 2003. Oil and NGLs sales grew 34 percent to 265,000 barrels per day. Operating costs were \$3.53 per BOE, which was slightly higher than forecast due primarily to the effect of the weaker U.S. dollar on non-U.S. operating costs and colder weather. For the full year, the company expects operating costs to be in its forecast range of between \$3.30 and \$3.50 per BOE. The first quarter capital program was \$1.5 billion. Net divestitures of about \$300 million reduced investment to \$1.2 billion of net capital.

"Effective field execution and cooperative winter weather allowed the company to complete its entire winter drilling program, a substantial improvement over the previous winter, which was hampered by a late start and an early break-up. EnCana drilled 1,619 net wells during the first quarter, about one-third of its full year estimate of 5,000 wells. Production volumes in April have averaged near the high end of our 2004 sales guidance range," Morgan said.



GAS SALES (MMcf/d) 2,712 2,589 Production increases 10% excluding the impact of produced gas sales from storage in the first quarter of 2003.

Q1 Q1 2003 2004 EnCana continues to focus its North American asset base on low production cost, lowdecline-rate resource plays that have long-term predictable reserve and production growth potential. The U.S. Rockies is EnCana's fastest growing region and, with the anticipated acquisition of Tom Brown, Inc., the company's U.S. production is expected to be about 1 billion cubic feet equivalent per day, representing close to one-quarter of total production. The combination of Tom Brown's resource plays and the planned sale of some of EnCana's non-resource play conventional production is expected to increase resource play production to about three-quarters of total North American production by year-end, up from about two-thirds.

"We continue to add to our strong portfolio of predictable, steady-growth resource plays. Over the past 18 months, we added about 500,000 net acres – containing huge undeveloped gas potential – with our Cutbank Ridge land acquisition, expanded our pursuit of coalbed methane resources on our expansive fee title lands east of Calgary and now plan to add about 2 million net acres containing major undeveloped resource potential through the Tom Brown purchase. Given EnCana U.S.A.'s track record on similar properties in the U.S. Rockies, such as Mamm Creek in Colorado and Jonah in Wyoming, we are confident that there is substantial growth potential residing in these early-life resource plays," Morgan said.

2004 GUIDANCE CONFIRMED, CONVENTIONAL PRODUCTION DIVESTITURE PROGRAM STEPPED UP

EnCana is on track to meet its 2004 sales guidance of between 690,000 and 735,000 BOE per day, comprised of between 2.7 billion and 2.85 billion cubic feet of natural gas per day and between 240,000 and 260,000 barrels of oil and NGLs per day. Upon the anticipated successful completion of the acquisition of Tom Brown, production is expected to increase by about 325 million cubic feet equivalent per day. As a second step in EnCana's advancement of its resource play strategy, the company plans, over the next 12 months, to sell conventional assets currently producing between 40,000 and 60,000 BOE per day for estimated proceeds of \$1 billion to \$1.5 billion. The net impact of these transactions is expected to be accretive to production, cash flow and earnings in 2004 and beyond.

RISK MANAGEMENT STRATEGY

EnCana employs a consistent market risk mitigation strategy that is expected to be approximately revenue neutral over the long term. This volatility reduction strategy is intended to result in greater predictability of cash flow and returns on capital investment. The corporation's basic strategy is to hedge up to 50 percent of current year and up to 25 percent of the following year's projected sales. In addition, the company enters into longer term basis and pricing hedges specifically for the purpose of protecting against high U.S. Rockies gas price basis differentials. EnCana has about 47 percent of projected 2004 gas sales, after royalties, hedged at an average effective NYMEX price of about \$5.25 per thousand cubic feet. About half of EnCana's projected 2004 oil sales are hedged with swaps or subject to costless collars between \$20 and \$26 per barrel of WTI. The detailed risk management positions at March 31, 2004 are presented in Note 13 to the unaudited first quarter consolidated financial statements for the financial contracts and in management's discussion and analysis for the physical contracts. In the first quarter, EnCana's financial commodity and currency risk management measures resulted in gross revenue being lower by approximately \$150 million, comprised of \$130 million on oil sales and \$20 million on gas sales.

ENCANA'S REALIZED NATURAL GAS PRICES DOWN SLIGHTLY, REALIZED OIL PRICES DOWN

EnCana's first quarter realized North American natural gas prices were down about 4 percent from the first quarter of 2003 to \$5.26 per thousand cubic feet. Realized oil and NGLs prices were down about 6 percent from the first quarter of 2003 to \$25.23 per barrel. Canadian heavy oil price differentials widened to average \$9.03 per barrel compared to \$7.58 per barrel one year earlier. Ecuadorian NAPO blend, shipped on the new OCP Pipeline, experienced a wider price differential from WTI in the first quarter of 2004, averaging \$11.65 per barrel, compared to \$8.06 per barrel at year-end 2003. OCP began full operations in the fourth quarter of 2003.

FINANCIAL HIGHLIGHTS

US\$ and U.S. protocols

Consolidated EnCana Highlights	Q1	Q1	%
(as at and for the period ended March 31) (US\$ millions, except per share amounts)	2004	2003	Change
REVENUES, NET OF ROYALTIES	2,850	2,743	+4
Cash flow	995	1,221	-19
Per share – basic	2.16	2.54	-15
Per share – diluted	2.13	2.52	-15
Operating EBITDA*	1,305	1,273	+3
Cash tax	232	20	n/a
EARNINGS			
Net earnings from continuing operations	290	650	-55
Per share – basic	0.63	1.35	-53
Per share – diluted	0.62	1.34	-54
Add back:			
Mark-to-market impact (after-tax)	252	-	n/a
Add back:	22	(1.10)	100
Foreign exchange translation of U.S. dollar debt issued in Canada (after-tax)	32	(140)	-123
Less:	(109)		
Tax rate change	(109)	-	n/a
Operating earnings	465	510	-9
Per share – basic	1.01	1.06	-5
Per share – diluted	1.00	1.05	-5
Net capital investment – continuing operations	1,225	1,120	+9
Total assets	24,808		
Long-term debt	6,031		
Shareholders' equity	11,372		
Net debt-to-capitalization ratio	37%		
COMMON SHARES (millions)			
Outstanding at March 31	459.8	480.6	_4
Weighted average (diluted)	467.1	484.3	-4

* Operating EBITDA is net earnings from continuing operations before interest, income taxes, depreciation, depletion and amortization (DD&A), accretion of asset retirement obligation, foreign exchange loss (gain), gain on disposition and unrealized loss on risk management (\$376 million, before tax).

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

Consolidated EnCana Highlights

(for the period ended Mar. 31) (After royalties)	Q1 2004	Q1 2003	% Change
Natural gas (MMcf/d)			
Production	2,712	2,469	+10
Produced gas withdrawn from storage		120	n/a
Total natural gas sales (MMcf/d)	2,712	2,589	+5
Oil and NGLs sales (bbls/d)			
North America	165,877	156,295	+6
International	99,070	41,883	+137
Total oil and NGLs sales (bbls/d)	264,947	198,178	+34
Total sales (BOE/d)	716,947	629,678	+14

Resource play growth exceeds 25 percent across EnCana's portfolio

In North America, development capital continues to be focused on turning resource play potential into production. First quarter oil and gas production from EnCana's key North American resource plays has increased more than 25 percent since the first quarter of 2003. This is comprised of increases in gas production at Mamm Creek in Colorado, Greater Sierra in northeast B.C., and Canadian Plains shallow gas on legacy Suffield and Palliser Blocks and increases in oilsands production at Foster Creek in northeast Alberta.

GROWTH FROM KEY NORTH AMERICAN RESOURCE PLAYS

		Dai	ly Production			Net We	ls Drilled
	2004		2003			2004	2003
	Q1	Q4	Q3	Q2	Q1	Q1	Full year
Natural gas (MMcf/d)							
Jonah	394	389	376	356	375	11	59
Mamm Creek	191	175	126	112	86	66	259
Canadian Plains shallow gas	593	586	564	548	536	536	2,404
Coalbed methane	10	7	3	3	2	81	267
Greater Sierra	216	175	144	136	118	135	199
Cutbank Ridge	22	6	2	2	2	17	20
Oil (Mbbls/d)							
Foster Creek	28	26	22	20	19	4	8
Pelican Lake	15	15	16	17	15	29	134

CORPORATE DEVELOPMENTS

Dividend \$0.10 per share

EnCana's board of directors has declared a quarterly dividend of \$0.10 per share payable on June 30, 2004 to common shareholders of record as of June 15, 2004.

Normal Course Issuer Bid purchases

To date in 2004, EnCana has purchased for cancellation 5.5 million of its shares at an average price of C\$55.37 per share under its current Normal Course Issuer Bid. The company had 459.8 million shares outstanding at March 31, 2004.

FINANCIAL STRENGTH

EnCana maintains a strong balance sheet. At March 31, 2004 the company's net debt-to-capitalization ratio was 37:63. EnCana's net debt-to-EBITDA multiple, on a trailing 12-month basis, was 1.6 times.

At March 31, 2004, on a pro forma basis with the Tom Brown acquisition and the planned divestitures of Canadian non-core conventional production, EnCana's estimated net debt-to-capitalization would be 41 percent and net debt-to-EBITDA would be 1.9 times. EnCana expects to refinance its \$3 billion bridge financing through the proceeds from the anticipated divestitures, future cash flow, and accessing the capital and bank markets through approximately \$5 billion of existing and unused debt shelf registration statements and bank credit facilities.

In the first quarter of 2004, EnCana invested \$1,538 million of capital, net divestitures were \$313 million, resulting in net capital investment of \$1,225 million. EnCana expects its book tax rate, on a normalized basis, to be between 26 and 31 percent for 2004, compared to the previous guidance of between 34 and 36 percent, primarily as a result of Alberta tax changes and the effects of asset dispositions.

NOTES REGARDING U.S. DOLLAR REPORTING AND NON-GAAP MEASURES

NOTE 1. EnCana financial results in U.S. dollars and operating results according to U.S. protocols

Starting with year-end 2003, EnCana is reporting its financial results in U.S. dollars and its reserves and production 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-royalties basis. There is no change to the physical volumes produced and sold or to the actual reserves as a result of adopting U.S. protocols. However, readers should note that the change results in a general lowering of reported numbers for EnCana's sales volumes and impacts the percentage changes year over year. For example, under previous Canadian protocols, if EnCana produced and sold 100 barrels of oil at the wellhead, it reported sales of 100 barrels. Under the new U.S. protocol, royalties paid to the Crown, state or mineral rights owners are deducted before sales volumes are reported. For example, under U.S. protocols, if EnCana would report sales of 80 barrels of oil.

NOTE 2. Non-GAAP measures

This news release contains references to cash flow, operating EBITDA (net earnings from continuing operations before interest, income taxes, DD&A, accretion of asset retirement obligation, foreign exchange loss (gain), gain on disposition and unrealized loss on risk management), EBITDA and operating earnings, and the related basic and diluted per common share amounts as applicable, which are not measures that have any standardized meaning prescribed by Canadian GAAP and 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 press release in order to provide shareholders and potential investors with additional information regarding EnCana's liquidity and its ability to generate funds to finance its operations.

EnCana Corporation

With an enterprise value of approximately \$25 billion, EnCana is one of the world's leading independent oil and gas companies and North America's largest independent natural gas producer and gas storage operator. Ninety percent of the company's assets are located in North America. EnCana is the largest producer and landholder in Western Canada and is a key player in Canada's emerging offshore East Coast basins. Through its U.S. subsidiaries, EnCana is one of the largest gas explorers and producers in the Rocky Mountain states and has a strong position in the deep water Gulf of Mexico. International subsidiaries operate two key high potential international growth regions: Ecuador, where it is the largest private sector oil producer, and the U.K. where it is the operator of a large oil discovery. EnCana and its subsidiaries also conduct high upside potential new ventures exploration in other parts of the world. EnCana is driven to be the industry's high performance benchmark in production cost, pershare growth and value creation for shareholders. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

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

Natural gas volumes that have been converted to barrels of oil equivalent (BOEs) have been converted on the basis of six thousand cubic feet (mcf) to one barrel (bbl). BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent equivalency at the well head.

EnCana Corporation resource descriptions

EnCana uses the terms resource play, estimated ultimate recovery and resource potential. Resource play is a term used by EnCana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate. As used by EnCana, estimated ultimate recovery (EUR) has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom. Resource potential is a term used by EnCana to refer to the estimated quantities of hydrocarbons that may be added to proved reserves over a specified period of time from a specified resource play or plays.

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 news release 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 news release include, but are not limited to: future economic performance (including per share growth); anticipated life of proved reserves; anticipated success of resource plays; the anticipated proportion of total North American resource play production; potential success of such projects as SAGD, coalbed methane, Ecuador, Deep Panuke, Buzzard, Cutbank Ridge, Greater Sierra, Mamm Creek, Jonah and Entrega; the anticipated completion, timing and capacity of the Entrega Pipeline; the anticipated resource potential associated with Tom Brown, Inc. (TBI); the anticipated successful completion of the TBI acquisition; the potential impact of the TBI acquisition on EnCana's production, cash flow, earnings and financial benchmarks; the anticipated sources of refinancing for that acquisition and anticipated divestitures; anticipated risk mitigation strategies and the effect of such strategies; potential demand for gas; anticipated production in 2004 and beyond (including U.S. production); anticipated volatility in reported net earnings; anticipated book tax rate; anticipated drilling; potential capital expenditures and investment; anticipated coalbed methane development in 2004 and beyond; potential oil and gas sales in 2004 and beyond, anticipated costs; 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 or probable 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; 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 news release are made as of the date of this news release, 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 news release are expressly qualified by this cautionary statement.

NOTE REGARDING FORWARD-LOOKING STATEMENTS

ADVISORY - In the interest of providing EnCana Corporation ("EnCana" or the "Company") shareholders and potential investors with information regarding the Company and its subsidiaries, certain statements throughout this Management's Discussion and Analysis ("MD&A") constitute forward-looking statements within the meaning 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: production and sales estimates for crude oil, natural gas and NGLs for 2004; the production and growth potential, including the Company's plans therefor, with respect to EnCana's various assets and initiatives, including assets and initiatives in North America, Ecuador, the U.K. central North Sea, the Gulf of Mexico and potential new ventures exploration growth platforms; potential dispositions of assets in 2004; the Company's projected capital investment levels for 2004 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; the impact of the Kyoto Accord and similar initiatives in the U.S.A. on operating costs; the Company's projected ability to extend its debt program on an ongoing basis; projected volatility of crude oil prices in 2004 and the impact which weather, the timing of new production and economic activity levels may have on commodity prices in 2004; projected tax rates and projected current taxes payable for 2004 and the impact of future unrealized foreign exchange gains and losses thereon and the adequacy of the Company's provision for taxes; the impact of the AEUB ruling on 2004 natural gas production and projected increased capital as a result of the potential acquisition of Tom Brown, Inc.; the anticipated satisfaction of conditions and the projected closing date for the Tom Brown, Inc. acquisition; the Company's plans for Tom Brown, Inc. following the proposed acquisition, including potential natural gas production increases expected therefrom; and the timing for repairs to the SOTE Pipeline. 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

recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved or probable reserves; 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; 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 brought 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 forwardlooking 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.

NOTE REGARDING OIL AND GAS INFORMATION

ADVISORY – In this MD&A, certain natural gas volumes have been converted to barrels of oil equivalent (BOEs) on the basis of six thousand cubic feet (mcf) to one barrel (bbl). BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent equivalency at the well head.

Natural gas volumes are sold based on heat content or in millions of British Thermal Units ("MMBtu") but physically measured in thousands of cubic feet. The heat content varies by production region. For example, Alberta's heat content is approximately 1.20 MMBtu and the U.S. Rockies is approximately 1.11 MMBtu. The average heat content per cubic foot of EnCana's natural gas is approximately 1,040 Btu or a conversion ratio of 1 mcf = 1.040 MMBtu.

NOTE REGARDING NON-GAAP MEASURES

ADVISORY - 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 from Continuing Operations per share-basic, Cash Flow from Continuing Operations per share-diluted, Cash Flow per share-basic and Cash Flow per sharediluted, Operating Earnings, Earnings Before Interest, Taxes, Depreciation Depletion and Amortization ("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.

MANAGEMENT'S DISCUSSION AND 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 March 31, 2004 and the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2003. The Interim Consolidated Financial Statements and comparative information have been prepared in accordance with Canadian GAAP in the currency of the United States (except where indicated as being in another currency). This MD&A is dated April 27, 2004

OVERVIEW

SUMMARY OF KEY EVENTS

This MD&A discusses the operations and key events that have impacted the 2004 first quarter results compared to the same period in 2003. The significant items are:

- Upstream sales volumes increased by 14 percent offset partially by lower realized prices resulting in Upstream revenue increasing by \$158 million, or 10 percent. See the "Consolidated Upstream Results", "Produced Gas and NGLs" and "Crude Oil" sections under "Results of Operations" in this MD&A for further analysis.
- Higher reported Canadian operating expenses and capital expenditures were significantly contributed to by the higher average value of the Canadian dollar which increased \$0.10, or 15 percent, from the first quarter of 2003 to the first quarter of 2004. See the "Consolidated Upstream Results", "Produced Gas and NGLs", "Crude Oil" and "Corporate" sections under "Results of Operations" as well as the "Capital Expenditures" section under "Liquidity and Capital Resources" in this MD&A for further analysis.
- Adoption of mark-to-market accounting on January 1, 2004 for derivative instruments resulted in unrealized mark-to-market accounting losses of \$376 million (\$252 million after tax). See "Accounting Policies and Estimates" and "Risk Management" in this MD&A for further analysis.
- Current income tax increased to \$232 million from \$20 million. See the "Corporate" section under "Results of Operations" in this MD&A for further detail.
- An unrealized after-tax loss on Canadian issued U.S. dollar debt of \$32 million for the first quarter of 2004 compared to an after-tax gain of \$140 million in the same period for 2003. See the "Corporate" section under "Results of Operations" in this MD&A for further detail.

See "Operating Earnings" and "Cash Flow from Continuing Operations and Current Income Tax" sections under "Consolidated Financial Results" for an eight quarter summary of the effects of unrealized gains/losses on translation of Canadian issued U.S. dollar debt, current income taxes as well as the impact of the adoption of mark-to-market accounting as of January 1, 2004 and resulting unrealized losses on the current quarter.

U.S. DOLLAR AND U.S. PROTOCOL REPORTING

The Interim Consolidated Financial Statements, including all comparative figures, have been presented in United States dollars ("U.S. dollars"). In this MD&A, all references to \$\$ are to the U.S. dollar. References to C\$ are to the Canadian dollar.

In this MD&A, production and sales volumes are presented on an after royalties basis consistent with U.S. protocol reporting.

Impacts on results due to the change in the U.S./Canadian dollar exchange rate in prior periods have been significant when analyzing specific components of the Canadian business segments contained in the Interim Consolidated Financial Statements.

- The increase in the average U.S./Canadian dollar exchange rate for the first quarter of 2004 compared to the average U.S./Canadian dollar exchange rate for the first quarter in 2003 adversely affected the reported U.S. dollar costs for operating expenses, capital expenditures, administrative expenses and depreciation, depletion and amortization ("DD&A") expenses denominated in Canadian dollars;
- Since commodity prices received are based on U.S. dollars, or on Canadian dollar prices which are closely tied to the U.S. dollar, revenues for the Company were relatively unaffected by the exchange rate changes;
- The weaker quarter end U.S./Canadian dollar exchange rate compared to the 2003 year-end U.S./Canadian dollar exchange rate resulted in unrealized losses on U.S. dollar denominated long-term debt issued in Canada.

BUSINESS SEGMENTS

EnCana reports the results of its continuing operations under two main business segments: Upstream and Midstream & Marketing. Upstream includes the Company's exploration for, as well as development and production of, natural gas, natural gas liquids ("NGLs"), crude oil and other related activities. Upstream operations are divided into producing and other activities. Natural gas and NGLs are produced in Canada, the United States, and the U.K. central North Sea. Crude oil is principally produced in Canada, Ecuador and the U.K. central North Sea. International New Ventures Exploration is mainly focused on exploration opportunities in Africa, South America and the Middle East and is included under Other activities. Other activities also include third party processing, gas gathering and electrical cogeneration associated with producing activities. The Midstream & Marketing segment includes natural gas storage operations, NGLs processing, power generating operations and marketing activities. These marketing activities include the sale and delivery of produced product and the purchase of third party product primarily for the optimization of the Midstream assets as well as the optimization of transportation arrangements not fully utilized for the Company's own production.

BUSINESS ENVIRONMENT

Commodity Price and Foreign Exchange Benchmarks	Three Mo	nths Ended I	March 31	Year Ended
(average for the period)	2004	2004 vs 2003	2003	2003
AECO Price (C\$ per thousand cubic feet)	\$ 6.60	-17%	\$ 7.92	\$ 6.70
NYMEX Price (\$ per million British thermal units)	5.69	-14%	6.59	5.39
AECO/NYMEX Basis Differential (\$ per million British thermal units)	0.69	-50%	1.38	0.65
WTI (\$ per barrel)	35.25	4%	33.80	30.99
Dated Brent (\$ per barrel)	31.95	1%	31.52	28.84
WTI/Bow River Differential (\$ per barrel)	9.03	19%	7.58	8.01
WTI/OCP NAPO Differential (Ecuador) (\$ per barrel) (1)	11.65	-	-	8.06
WTI/Oriente Differential (Ecuador) (\$ per barrel)	7.70	52%	5.06	5.59
U.S./Canadian Dollar Period End Exchange Rate	0.763	12%	0.681	0.774
U.S./Canadian Dollar Average Exchange Rate	0.759	15%	0.662	0.716

(1) The WTI/OCP NAPO Differential was posted as of September 2003.

Quarterly Commodity Price and Foreign Exchange Benchmarks

	2004		20	03			2002	
(average for the period)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
AECO Price								
(C\$ per thousand cubic feet)	6.60	\$ 5.59	\$ 6.29	\$ 6.99	\$ 7.92	\$ 5.25	\$ 3.25	\$ 4.42
NYMEX Price								
(\$ per million British thermal units)	5.69	4.58	4.97	5.41	6.59	3.98	3.18	3.40
AECO/NYMEX Basis Differentia	1							
(\$ per million British thermal units)	0.69	0.37	0.38	0.47	1.38	0.63	1.09	0.57
WTI (\$ per barrel)	35.25	31.16	30.21	28.91	33.80	28.23	28.25	26.27
Dated Brent (\$ per barrel)	31.95	29.41	28.41	26.03	31.52	26.78	26.95	25.04
WTI/Bow River Differential								
(\$ per barrel)	9.03	9.77	8.12	6.58	7.58	7.66	5.38	5.43
WTI/OCP NAPO Differential								
(Ecuador) (\$ per barrel) (1)	11.65	8.17	7.75	_	_	_	_	-
WTI/Oriente Differential								
(Ecuador) (\$ per barrel)	7.70	5.63	5.34	6.32	5.06	4.92	4.35	3.78
U.S./Canadian Dollar Period								
End Exchange Rate	0.763	0.774	0.741	0.738	0.681	0.633	0.631	0.659
U.S./Canadian Dollar Average								
Exchange Rate	0.759	0.760	0.725	0.715	0.662	0.637	0.640	0.643

(1) The WTI/OCP NAPO Differential was posted as of September 2003 therefore Q3 2003 represents September only.

Natural Gas

Concerns that North American natural gas production may be declining, continued concerns over natural gas inventories and the influence of the price of crude oil continued to result in historically high average New York Mercantile Exchange ("NYMEX") gas prices. Lower NYMEX and AECO average gas prices in the first quarter of 2004, compared to the corresponding period in 2003, were primarily due to higher U.S. natural gas storage levels compared to the prior year. As of March 31, 2004, the U.S. Department of Energy reported that U.S. natural gas inventories are 49 percent higher than the corresponding period in 2003 but 7 percent lower than the five year average. The improved AECO/NYMEX basis differential in the first quarter of 2004 compared to the first quarter of 2003 can be attributed to a stronger Canadian dollar and lower transportation differentials for the marginal sales volumes transported from Alberta to Eastern Canada.

Percentage of Natural Gas Volumes Benchmark Price Exposure

(annual approximate percentage)	2004 (1)	2003
Fixed Prices – Hedges	47%	47%
Downstream/NYMEX Price	41%	39%
Long-term Fixed/Other	7%	5%
AECO Price	5%	9%
(1) Based on estimated 2004 sales volumes as of March 31, 2004 excluding Tom Brown, Inc.		

Crude Oil

The benchmark West Texas Intermediate ("WTI") crude oil price has remained strong when comparing first quarter 2004 to the comparable period in 2003 due to uncertainty over supply/demand imbalances, strong Asian demand, the slow return of Iraqi oil production and OPEC's production management initiatives.

The Canadian WTI/Bow River heavy oil differential widened in the first quarter of 2004 compared to the first quarter of 2003 primarily due to the higher price for WTI as well as wider U.S. Gulf Coast light to heavy product differentials. As a percentage of WTI, Bow River's average sales price for the first quarter of 2004 was 74 percent of WTI as compared to 78 percent in the first quarter of 2003.

In September 2003, the OCP Pipeline in Ecuador became operational resulting in the creation of a new Ecuadorian crude called NAPO blend. The Company currently transports nearly all of its Ecuadorian production through this pipeline. The NAPO blend is a heavier crude than Oriente resulting in a wider differential to WTI. The first quarter 2004 over first quarter 2003 increase in the Oriente differential is primarily related to the increase in the WTI price as well as wider U.S. Gulf Coast light to heavy product differentials.

U.S./Canadian Dollar Exchange Rates

The first quarter 2004 over first quarter 2003 average U.S./Canadian dollar exchange rate increase was primarily the result of the economic slowdown in the U.S., continuing differences between Canadian and U.S. interest rates and the U.S. current account deficit. The \$0.01 reduction in the first quarter period end exchange rate compared to the year ended December 31, 2003 resulted in an unrealized loss on the U.S. denominated debt issued in Canada of approximately \$39 million before tax.

CONSOLIDATED FINANCIAL RESULTS

Consolidated Financial Summary	Three Mor	ths Ended I	March 31	Year Ended
(\$ millions, except per share amounts)	2004 (1)	2004 vs 2003	2003	2003
Revenues, Net of Royalties	\$ 2,850	4%	\$ 2,743	\$10,216
Net Earnings from Continuing Operations	290	-55%	650	2,167
– per share – basic	0.63	-53%	1.35	4.57
– per share – diluted	0.62	-54%	1.34	4.52
Net Earnings	290	-65%	837	2,360
– per share – basic	0.63	-64%	1.74	4.98
– per share – diluted	0.62	-64%	1.73	4.92
Cash Flow from Continuing Operations	995	-16%	1,191	4,420
– per share – basic	2.16	-13%	2.48	9.32
– per share – diluted	2.13	-13%	2.46	9.21
Cash Flow	995	-19%	1,221	4,459
– per share – basic	2.16	-15%	2.54	9.41
– per share – diluted	2.13	-15%	2.52	9.30

(1) Revenues, Net of Royalties includes unrealized losses on financial derivative instruments of \$379 million.

Quarterly Summary

	2004 (1)		20	03			2002	
(\$ millions, except per share amounts)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Revenues, Net of Royalties	\$ 2,850	\$ 2,850	\$ 2,291	\$ 2,332	\$ 2,743	\$ 2,116	\$ 1,780	\$ 1,693
Net Earnings from								
Continuing Operations	290	426	286	805	650	248	79	318
– per share – basic	0.63	0.92	0.60	1.67	1.35	0.52	0.17	0.69
- per share - diluted	0.62	0.91	0.60	1.66	1.34	0.51	0.16	0.68
Net Earnings	290	426	290	807	837	282	136	303
– per share – basic	0.63	0.92	0.61	1.68	1.74	0.59	0.29	0.66
- per share - diluted	0.62	0.91	0.61	1.67	1.73	0.58	0.28	0.65
Cash Flow from								
Continuing Operations	995	1,217	973	1,039	1,191	874	583	569
– per share – basic	2.16	2.63	2.06	2.16	2.48	1.83	1.22	1.23
- per share - diluted	2.13	2.61	2.04	2.14	2.46	1.81	1.21	1.22
Cash Flow	995	1,254	977	1,007	1,221	935	651	591
– per share – basic	2.16	2.71	2.06	2.10	2.54	1.96	1.37	1.28
- per share - diluted	2.13	2.69	2.04	2.08	2.52	1.94	1.35	1.26

(1) Revenues, Net of Royalties includes unrealized losses on financial derivative instruments of \$379 million.

EnCana's cash flow from continuing operations decreased \$196 million in the first quarter of 2004 compared to the same period in 2003 primarily due to the provision for current income tax of \$232 million and an increase in operating expenses offset partially by the 14 percent increase in barrel of oil equivalent per day sales volumes. Cash flow is a non-GAAP measure but is commonly used in the oil and gas industry to assist management, investors and analysts to measure the Company's ability to finance its capital programs and meet its credit obligations.

Comparison of net earnings for the first quarter of 2004 to the first quarter of 2003:

- Upstream revenue increased by \$158 million, or 10 percent. This increase reflected higher sales volumes of 14 percent on a daily barrel of oil equivalent basis, offset by realized (excluding hedge) weighted average prices, net of royalties which were lower by \$0.23 per thousand cubic feet of natural gas and \$1.77 per barrel of crude oil. Realized commodity hedging losses in 2004 were \$150 million compared to \$138 million in 2003.
- Unrealized mark-to-market losses of \$376 million (\$252 million after tax) are included in the 2004 Consolidated Statement of Earnings with no comparable amount in 2003. As of January 1, 2004, the Company adopted the amendments made to the accounting standard for Hedging Relationships. The Company has entered into various financial instrument agreements which do not qualify as a hedge or were not designated as a hedge for accounting purposes. See Notes 2 and 13 to the Interim Consolidated Financial Statements.
- Increased operating expenses were primarily the result of the increase in sales volumes and the impact of the higher U.S./Canadian dollar exchange rate on Canadian denominated expenditures.
- An unrealized after-tax loss on the U.S. dollar denominated debt issued in Canada of \$32 million, or \$0.07 per share diluted, is included in 2004 compared to an after tax gain of \$140 million, or \$0.29 per share diluted, in the same period for 2003. The loss on the foreign exchange translation of U.S. denominated debt issued in Canada resulted from the decrease in the value of the Canadian dollar relative to the U.S. dollar from the December 31, 2003 year end rate of \$0.774 to the March 31, 2004 quarter end rate of \$0.763.
- A gain on disposal of an investment of \$34 million is included in 2004.
- A gain of \$109 million, or \$0.23 per share diluted, which reduces future income taxes resulting from Alberta corporate tax changes which were approved by the Provincial Legislature on March 31, 2004. Gains or losses on tax rate changes are recorded in the Consolidated Statement of Earnings and are included as an adjustment to Future Income Taxes in the Consolidated Balance Sheet.
- Inclusion of \$187 million in net earnings from discontinued operations in 2003.

Impacts on results due to the change in the U.S./Canadian dollar exchange rate have been significant when analyzing specific components contained in the Interim Consolidated Financial Statements. For every 100 dollars denominated in Canadian currency spent on capital projects, operating expenses and administrative expenses, the Company incurred additional costs, as reported in U.S. dollars, of approximately \$9.70 based on the increase in the average U.S./Canadian dollar exchange rate in the first quarter of 2004 to \$0.759 compared to the first quarter of 2003 of \$0.662. Revenues for the Company were relatively unaffected by the increased 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.

OPERATING EARNINGS

Operating earnings 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 gain/loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates. The following table has been prepared in order to provide shareholders and potential investors with information clearly presenting the effect on the Company's results of mark-to-market accounting for derivative financial instruments, the translation of the outstanding U.S. dollar debt issued in Canada and the effect of the reduction in the Canadian and Alberta tax rates. Management believes items such as unrealized mark-to-market gains/losses on derivative financial instruments, foreign exchange gains/losses and tax rate reductions distorts results and reduces the comparability of the Company's underlying financial performance between periods. The majority of the unrealized gains/losses on U.S. dollar debt issued in Canada relate to debt with maturity dates in excess of 5 years.

	2004		200	03			2002	
(\$ millions)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Net Earnings from Continuing Operations, as reported Add: Unrealized mark-to-market accounting loss	\$ 290	\$ 426	\$ 286	\$ 805	\$ 650	\$ 248	\$ 79	\$ 318
(after-tax) ⁽²⁾ Add: Unrealized foreign exchange loss (gain) on translation of Canadian issued U.S. dollar	252	_	_	-	_	-	_	-
debt (after-tax) Add: Future tax (recovery) expense due to tax	32	(113)	(12)	(168)	(140)	(6)	100	(113)
rate reductions	(109)	3	-	(362)	-	(3)	9	(26)
Operating Earnings ⁽¹⁾⁽³⁾	\$ 465	\$ 316	\$ 274	\$ 275	\$ 510	\$ 239	\$ 188	\$ 179
<i>\$ per Common Share – Diluted)</i> Net Earnings from Continuing Operations, as reported Add: Unrealized mark-to-market accounting loss	0.62	\$ 0.91	\$ 0.60	\$ 1.66	\$ 1.34	\$ 0.51	\$ 0.16	\$ 0.68
(after-tax) ⁽²⁾ Add: Unrealized foreign exchange loss (gain) on translation of Canadian issued U.S. dollar	0.54	_	_	_	_	-	_	-
debt (after-tax) Add: Future tax (recovery) expense due to tax	0.07	(0.24)	(0.03)	(0.35)	(0.29)	(0.01)	0.21	(0.24)
rate reductions	(0.23)	0.01	-	(0.75)	-	(0.01)	0.02	(0.06)

(1) Operating earnings 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 gain/loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.

(2) The Company adopted mark-to-market accounting on derivative financial instruments prospectively January 1, 2004.

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

CASH FLOW FROM CONTINUING OPERATIONS AND CURRENT INCOME TAX

As mentioned previously in this MD&A, the change in cash flow from continuing operations was primarily the result of the change in provision for current income tax. The following table has been prepared to disclose the quarterly cash flow from continuing operations and current tax provisions.

	2004		200	3			2002	
(\$ millions)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Cash Flow from Continuing Operations	995	1,217	973	1,039	1,191	874	583	569
Current Income Tax (1)	232	(73)	51	(54)	20	(107)	16	28

(1) Amount deducted (added) in determining Cash Flow from Continuing Operations.

QUARTERLY SALES VOLUMES SUMMARY

Sales volumes have increased 14 percent on a barrel of oil equivalent basis when comparing first quarter 2004 to the same period in 2003. The quarterly operating earnings and cash flow profile amounts disclosed earlier in this MD&A are closely correlated to commodity prices as well as the quarterly sales volume profile in the following table.

	2004			20	003			2002	
(After Royalties)	Q1	2004 Q1 vs 2003 Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Produced Gas Sales <i>(millions of cubic feet per day)</i> Crude Oil and Natural Gas Liquids	2,712	5%	2,682	2,525	2,469	2,589	2,584	2,340	2,243
(barrels per day) ⁽¹⁾	264,947	34%	266,890	218,490	205,908	198,178	202,044	198,303	201,735
Total (BOE per day) ⁽²⁾	716,947	14%	713,890	639,323	617,408	629,678	632,711	588,303	575,568

(1) NGLs include condensate volumes.

(2) Natural gas converted to barrels of oil equivalent at 6 thousand cubic feet = 1 barrel of oil equivalent.

ACQUISITIONS AND DIVESTITURES

On April 15, 2004, the Company announced that a wholly owned subsidiary was making a public tender offer to acquire all of the issued and outstanding shares of Tom Brown, Inc. ("TBI"), a publicly traded exploration and production company with operations in the United States and Canada, for total consideration, including debt, of approximately \$2.7 billion. This transaction is subject to certain conditions, including stockholders tendering more than 50 percent of the outstanding shares and regulatory approvals. It is anticipated that these conditions will be met and that the transaction will close later in the second quarter. Following closing, TBI will be merged with the wholly owned subsidiary with the result that all TBI shares will be owned, indirectly, by EnCana. The acquisition is expected to add production of approximately 325 million cubic feet per day of natural gas equivalent.

In February 2004, an EnCana U.K. subsidiary completed the purchase of an additional 13.5 percent and 20.2 percent interest in the Scott and Telford fields, respectively, for net cash consideration of approximately \$126 million. As a result of this acquisition and the initial ownership interest held, the EnCana U.K. subsidiary now holds a 41 percent interest in the Scott field and a 54.3 percent interest in the Telford field.

In February 2004, the Company sold its 53.3 percent partnership interest in Petrovera Resources ("Petrovera") for net cash consideration of approximately \$288 million including working capital adjustments. To facilitate this transaction, the Company purchased the 46.7 percent interest of its partner and then sold the 100 percent interest in Petrovera for approximately \$541 million including working capital adjustments. There was no gain or loss recorded on this sale. The Company's share of Petrovera's 2003 production was approximately 20,000 barrels of oil equivalent per day of primarily heavy crude oil. The use of the proceeds from this divestiture is discussed in the "Liquidity and Capital Resources" section of this MD&A.

RESULTS OF OPERATIONS

UPSTREAM OPERATIONS

				20	04							2	003		
(Three Months Ended March 31)	Produce Gas & NGL	ζ	(Crude Oil		Other	Total	ŀ	Produced Gas & NGLs	5	C	rude Oil		Other	Total
Revenues, Net of Royalties	\$ 1,34	4	\$	414	\$	50	\$ 1,808		\$ 1,280)	\$	337	\$	33	\$ 1,650
Expenses															
Production and mineral taxes	s 4	9		16		-	65		33	3		17		-	50
Transportation and selling	11	2		42		-	154		78	3		29		-	107
Operating	12	1		109		47	277		97	7		85		37	219
Depreciation, depletion															
and amortization	38)		216		5	601	_	320)		138		1	459
Upstream Income	\$ 68	2	\$	31	\$	(2)	\$ 711		\$ 752	2	\$	68	\$	(5)	\$ 815
(1) NGLs results include Condensate.															
 (1) NGLs results include Condensate. Revenue Variances for 2004 Co (Three Months Ended March 31) 	mpared	to 2	003	3 (\$ mil	llions,) (1)			Price	1	Volu	me		Other	Total
Revenue Variances for 2004 Co (Three Months Ended March 31)	mpared	to 2	.003	3 (\$ mil	llions,) (1)		5		5		me 74	s	Other –	\$ Total
Revenue Variances for 2004 Co	mpared	to 2	003	3 (\$ mil	llions,) (1)	ę	5	Price (10) (40)					Other _ _	\$
Revenue Variances for 2004 Co (Three Months Ended March 31) Produced Gas and NGLs	mpared	to 2	.003	3 (\$ mil	llions,) (1)		5	(10)			74		Other _ _ 17	\$ 64
Revenue Variances for 2004 Co (Three Months Ended March 31) Produced Gas and NGLs Crude Oil		to 2	.003	3 (\$ mit	llions,) (1)	-	5	(10)		1	74		-	\$ 64 77

Financial Results (\$ millions)

	200)4			200)3			2002	
(After Royalties)	Corporate Guidance ⁽⁴	Q1	2004 Q1 vs 2003 Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Produced Gas (millions	of cubic feet per day)									
Canada										
Production Inventory withdrawal /		2,000	4%	2,008	1,914	1,899	1,922	1,943	1,959	1,980
(injection)		-			-	-	120	117	(51)	(90
Canada Sales	2,010 - 2,120	2,000	-2%	2,008	1,914	1,899	2,042	2,060	1,908	1,890
United States	675 - 715	684	28%	654	604	558	534	516	423	345
United Kingdom	15	28	115%	20	7	12	13	8	9	8
	2,700 - 2,850	2,712	5%	2,682	2,525	2,469	2,589	2,584	2,340	2,243
Oil and Natural Gas L	iquids (barrels per day)	(1)								
Canada	147,000 - 157,000	156,640	6%	164,859	163,179	149,292	148,147	148,196	142,856	140,512
United States	9,000 - 11,000	9,237	13%	9,612	9,691	10,376	8,148	10,162	6,146	6,467
Ecuador										
Production		76,320	91%	72,731	54,582	36,754	39,893	34,856	37,447	37,702
Transferred to OCP Pipeline ⁽²	2)	-	-	-	(4,919)	(2,039)	(5,941)	-	_	_
Over / (under) lifting		4,662	_	4,621	(9,856)	2,506	(2,679)	1,044	2,316	5,088
Ecuador Sales	68,000 - 74,000	80,982	159%	77,352	39,807	37,221	31,273	35,900	39,763	42,790
United Kingdom	16,000 - 18,000	18,088	70%	15,067	5,813	9,019	10,610	7,786	9,538	11,966
	240,000 - 260,000	264,947	34%	266,890	218,490	205,908	198,178	202,044	198,303	201,735
Total (BOE per day) ⁽³⁾	690,000 - 735,000	716,947	14%	713,890	639,323	617,408	629,678	632,711	588,303	575,568

(1) NGLs results include Condensate.

(2) Crude oil production in Ecuador transferred to the OCP Pipeline for use by OCP in asset commissioning.

(3) Natural gas converted to barrels of oil equivalent at 6 thousand cubic feet = 1 barrel of oil equivalent.

(4) Represents a full year of operations and excludes the potential acquisition of Tom Brown, Inc. of 312 to 320 million cubic feet of gas equivalent per day. Also excludes anticipated additional divestitures of oil and gas of between 40,000 to 60,000 BOE per day.

Consolidated Upstream Results

Upstream revenues, net of royalties increased approximately 10 percent, or \$158 million, in the first quarter of 2004 compared to the first quarter of 2003 primarily due to increases in crude oil sales volumes in Ecuador and the U.K. as well as higher natural gas sales volumes in the U.S. Rockies, offset partially by lower overall average realized commodity prices. Realized (before hedge) weighted average prices, net of royalties are lower by \$0.23 per thousand cubic feet of natural gas and \$1.77 per barrel of crude oil. Realized commodity and currency hedging losses in 2004 were \$150 million, or \$2.29 per barrel of oil equivalent, compared to \$138 million, or \$2.43 per barrel of oil equivalent, in 2003.

Higher production and mineral taxes in the first quarter of 2004 compared to the same period in 2003 were primarily the result of a prior year adjustment to mineral tax expense in Canada in 2003 and increased natural gas sales volumes in the U.S. Rockies.

Increases in transportation and selling costs in the first quarter comparison between 2004 and 2003 were primarily due to the increased natural gas sales volumes from the U.S. Rockies, higher exported volumes from Canada to the United States, higher crude oil sales volumes in Ecuador and the impact of the higher U.S./Canadian dollar exchange rate. Higher costs also reflect the Company's obligation to transport 108,000 barrels of oil per day on the OCP Pipeline as a result of the Ecuadorian government's decision to transport its royalty volumes on the SOTE Pipeline. A portion of this additional cost was offset during the quarter as the SOTE Pipeline operations were impacted by landslides resulting in the Ecuadorian government transporting its royalty volumes on the OCP Pipeline during repairs. Repairs to the SOTE Pipeline are expected to be completed in April 2004.

Upstream operating costs in the first quarter of 2004, excluding costs related to Other activities, increased approximately \$48 million or 26 percent over the first quarter of 2003. Higher crude oil and natural gas sales volumes and the increase in the U.S./Canadian dollar exchange rate were the primary reasons for the increased costs. Operating expenses excluding Other activities were \$3.53 per barrel of oil equivalent for the first quarter of 2004 up from \$3.24 per barrel of oil equivalent in the first quarter of 2003 with the higher average U.S./Canadian dollar exchange rate being the primary reason for the increase.

DD&A expense increased 31 percent, or \$142 million, compared to the first quarter of 2003 primarily as a result of the higher sales volumes and the increase in the U.S./Canadian dollar exchange rate. On a barrel of oil equivalent basis, excluding Other activities, DD&A rates were \$9.14 per barrel of oil equivalent for the first quarter of 2004 compared to \$8.08 per barrel of oil equivalent in the same period for 2003. The increased DD&A rate in the first quarter in 2004 primarily reflects the effect of the increase in the U.S./Canadian dollar exchange rate on the Canadian DD&A expense.

Other activities added \$50 million in revenues and \$47 million in operating expenses in the first quarter of 2004 and include activities that do not result directly in the production of oil and gas. These activities include revenue from third party processing, gas gathering and cogeneration of electricity and steam.

Produced Gas and NGLs (1)

Financial Results (\$ millions)

			Canada			U	United States			U	nited Kingdo	m	
(Three Months Ended March 31)		2004	2004 vs 2003		2003	2004	2004 vs 2003	2003		2004	2004 vs 2003		2003
Revenues, Net of Royalties	\$	971	1%	\$	963	\$ 358	15%	\$ 311	\$	15	150%	\$	6
Expenses													
Production and mineral taxes		15	275%		4	34	17%	29		-	-		-
Transportation and selling		82	34%		61	25	67%	15		5	150%		2
Operating		101	16%		87	20	100%	10		-	-		-
Depreciation, depletion and amortization		298	17%		254	82	24%	66		-	-		-
Segment Income	\$	475		\$	557	\$ 197		\$ 191	\$	10		\$	4
Gas Sales Volumes (million cubic feet per day) ⁽²⁾	2	2,000	-2%		2,042	684	28%	534		28	115%		13
NGL Sales Volumes (barrels per day)	13	8,971	-9%	1	5,291	9,237	16%	7,943	2	,005	76%		1,140

(1) NGLs results includes Condensate.

(2) 2003 first quarter results include 120 million cubic feet of gas per day of inventory withdrawals.

Revenues, net of royalties in the first quarter from sales of Canadian produced gas were relatively unchanged compared to the same period in 2003. Reduced Canadian sales of produced gas and NGLs as well as lower benchmark price impacts were more than offset by lower realized losses on hedging activities. Higher revenues, net of royalties in the U.S. and the U.K. were primarily the result of increased sales volumes and higher realized average prices. Total natural gas revenues in the first quarter of 2004 were reduced by a realized loss of \$20 million, or \$0.08 per thousand cubic feet, due to financial currency and commodity hedging activities, compared to a realized loss of \$59 million, or \$0.25 per thousand cubic feet, in the same period of 2003.

Canadian gas production was 2,000 million cubic feet per day, 78 million cubic feet per day higher in the first quarter compared to production of 1,922 million cubic feet per day during the first three months of 2003. Total Canadian produced gas sales were lower in the first three months of 2004 compared to the first quarter of 2003 primarily due to 120 million cubic feet per day of inventory withdrawals in the first quarter of 2003, shut-in natural gas production resulting from the gas over bitumen issue on the Primrose Block and the sale of the Company's interest in Petrovera offset partially by increased production from successful capital programs. Gas sales from the U.S. rose 150 million cubic feet per day when comparing first quarter 2004 to first quarter 2003 due to drilling successes, strategic acquisitions in 2003 and increased production from development in the Jonah and Mamm Creek fields. The higher volumes in the U.K. are the result of the additional acquired interests in the Scott and Telford fields in the central North Sea.

rer Omt Results – Froduced Gas (\$ per thous		Produc – Ca				Produc – U	ed G J.S.	las		Produc – U		as
(Three Months Ended March 31)		2004		2003		2004		2003		2004		2003
Price, net of royalties	\$	5.21	\$	5.53	\$	5.39	\$	5.32	\$	4.75	\$	3.21
Expenses												
Production and mineral taxes		0.08		0.02		0.51		0.57		-		-
Transportation and selling		0.44		0.33		0.39		0.32		1.83		1.90
Operating		0.56		0.48		0.33		0.20		-		-
Netback ⁽¹⁾	\$	4.13	\$	4.70	\$	4.16	\$	4.23	\$	2.92	\$	1.31
(1) Excludes realized commodity and currency hedge a	activities.											
Per Unit Results – NGLs (1) (\$ per barrel)		NO	C			NCI		C		NCI		7
		NGLs -	Can			NGLs	- U.			NGLs	– U.	
(Three Months Ended March 31)		2004		2003	_	2004		2003	_	2004		2003
Price, net of royalties	\$	27.27	\$	27.31	\$	32.77	\$	32.18	\$	22.29	\$	24.33
Expenses												
Production and mineral taxes		-		-		3.09		1.55		-		-
Transportation and selling		0.35		-		-		-		1.75		-

Per Unit Results – Produced Gas (\$ per thousand cubic feet)

(1) NGLs results includes Condensate.

Netback

Average realized price, net of royalties, excluding hedges, for natural gas produced in the U.S. and Canada have remained relatively flat when comparing the first quarter of 2004 to the same period in 2003. Lower price differentials between North American producing basins and NYMEX tended to offset a lower NYMEX price in the first quarter of 2004 compared to 2003, realizing a higher price for the Company's U.S. production. Average realized price, net of royalties for NGLs remained relatively unchanged in the first quarter of 2004 compared to the same period in 2003.

\$ 27.31

\$ 29.68

\$ 30.63

\$ 20.54

\$ 24.33

\$ 26.92

Per unit production and mineral taxes expense for produced gas in Canada increased primarily as a result of prior year adjustments related to mineral tax expenses in the first quarter of 2003. Per unit production and mineral taxes in the U.S. Rockies were lower in the first quarter of 2004 compared to the first quarter of 2003 due to higher production from properties which attract lower production tax rates.

Canadian produced natural gas per unit transportation and selling costs were higher primarily as a result of the increased U.S./Canadian exchange rate and higher average distances to sales markets from production facilities. The increase in the U.S. produced natural gas per unit transportation and selling costs were primarily the result of higher transportation rates.

Per unit operating expenses for Canadian produced gas reflect the impact of the increased U.S./Canadian dollar exchange rate and higher costs as a result of extremely cold weather experienced in the first quarter of 2004. Operating expense per unit in the U.S. increased \$0.13 for the first three months in 2004 over the first quarter of 2003 as a result of increased weighting of production from higher operating cost properties.

Crude Oil

Financial Results (\$ millions)

		Ν	orth Americ	a				Ecuador				Uı	nited Kingdo	om	
(Three Months Ended March 31)		2004	2004 vs 2003		2003		2004	2004 vs 2003		2003		2004	2004 vs 2003		2003
Revenues, Net of Royalties	\$	250	12%	\$	224	\$	126	45%	\$	87	\$	38	46%		\$26
Expenses															
Production and mineral taxes		5	-		5		11	-8%		12		-	-		-
Transportation and selling		20	-		20		19	171%		7		3	50%		2
Operating		73	9%		67		30	100%		15		6	100%		3
Depreciation, depletion and amortization		118	27%		93		65	183%		23		33	50%		22
Segment Income	\$	34		\$	39	\$	1		\$	30	\$	(4)		\$	(1
Crude Oil Sales Volumes (barrels per day)	14	2,669	7%	13	3,061	8	0,982	159%	31	1,273	16	,083	70%	9	9,470

In the first quarter of 2004, North American total crude oil revenues, net of royalties were higher than the first three months in 2003 primarily as a result of a 7 percent increase in crude oil volumes. Lower average realized prices in Ecuador as a result of an increased share of currency and commodity hedge losses, were more than offset by increased crude oil sales volumes following the commencement of operations on the OCP Pipeline and resulted in an overall increase of 45 percent in revenue, net of royalties. The increase in the U.K revenues, net of royalties was due to increased crude oil sales volumes resulting from the purchased interests in the Scott and Telford fields in the central North Sea offset partially by lower average realized prices as a result of an increased share of currency and commodity hedge losses. Total crude oil revenues were reduced by a realized loss of approximately \$130 million, or \$5.96 per barrel of crude oil, resulting from financial commodity and currency hedging. This compares with a realized loss of \$79 million, or \$5.08 per barrel of crude oil, in the first three months of 2003.

The increase in North American crude oil sales volumes is primarily the result of continued development of heavy oil fields at Foster Creek and Suffield offset partially by the sale of the Company's interest in Petrovera. Crude oil sales from Ecuador increased 49,709 barrels per day in the first quarter of 2004 compared to the same period in 2003 due to the completion and commencement of shipments on the OCP Pipeline in September 2003.

Per Unit Results – Crude Oil (\$ per barrel)

	North 2	America	Ecu	ador	United I	Kingdom
(Three Months Ended March 31)	2004	2003	2004	2003	2004	2003
Price, net of royalties	\$ 24.73	\$ 25.34	\$ 23.82	\$ 30.86	\$ 31.11	\$ 30.61
Expenses						
Production and mineral taxes	0.37	0.43	1.37	4.27	-	-
Transportation and selling	1.50	1.72	2.63	2.35	1.94	2.45
Operating	5.61	5.70	4.04	5.09	3.86	2.92
Netback ⁽¹⁾	\$ 17.25	\$ 17.49	\$ 15.78	\$ 19.15	\$ 25.31	\$ 25.24

(1) Excludes realized commodity and currency hedge activities.

Overall average realized crude oil prices, including the impact of financial hedges, in the first quarter of 2004 decreased approximately 12 percent over the same period of 2003. Higher benchmark WTI crude oil prices of 4 percent were more than offset by increased crude oil price differentials and a higher proportionate share of heavier blend oils in the product mix.

North American per unit production and mineral taxes decreased primarily as a result of increased weighting from properties that are not subject to production and mineral taxes. Per unit production and mineral taxes in Ecuador decreased \$2.90 per barrel, or 68 percent, in the first quarter of 2004 over the first quarter of 2003. This is due to lower realized prices for Tarapoa volumes offset by the increased weighting of production from the Tarapoa Block in the first quarter of 2004 compared to the same period in 2003. The Company is required to pay the Ecuadorian government a percentage of revenue from this block based on realized prices over a base price.

First quarter per unit transportation and selling costs in North America were lower by \$0.22 per barrel, or 13 percent, over the comparable period in 2003. Increases in transportation and selling costs due to the higher U.S./Canadian dollar exchange rate were more than offset by lower transportation costs in the first quarter of 2004 compared to the same period in 2003. This is primarily due to a change in the method of allocating transportation between the Upstream and Midstream & Marketing segments which was revised during the third quarter of 2003. Compared to the first quarter of 2003, higher per unit transportation and selling costs in Ecuador reflect the higher unit costs on the OCP Pipeline in 2004 compared to the SOTE pipeline system resulting from the ship or pay obligations on the system requiring the Company to pay for a prescribed amount of capacity at a fixed rate.

North American per unit operating expenses for crude oil decreased as a result of the sale of Petrovera and improved lower cost production techniques partially offset by the increased U.S./Canadian exchange rate. In Ecuador, a significant portion of operating expenses are fixed, resulting in lower per unit operating expenses as sales volumes increased in the first three months of 2004 compared to the same period in 2003.

MIDSTREAM & MARKETING OPERATIONS

Financial Results (\$ millions)

		Midstream			Marketing				Total		
(Three Months Ended March 31)	 2004	2004 vs 2003	2003	2004	2004 vs 2003	2003		2004	2004 vs 2003		2003
Revenues	\$ 551	73%	\$ 318	\$ 868	12%	\$ 775	\$ 1	,419	30%	\$ 1	1,093
Expenses											
Transportation and selling	-	-	-	8	-56%	18		8	-56%		18
Operating	71	-10%	79	7	-53%	15		78	-17%		94
Purchased product	449	120%	204	838	13%	741	1	,287	36%		945
Depreciation, depletion and amortization	7	75%	4	-	-100%	1		7	40%		5
	\$ 24	-23%	\$ 31	\$ 15	_	\$ _	\$	39	26%	\$	31

Revenues and purchased product expense in Midstream & Marketing operations increased in the first quarter compared to the same period in 2003 due primarily to a significant increase in the volume of optimization activity in the Midstream gas storage business unit associated with increased capacity from new and expanded facilities. This activity involves the purchase and sale of third party gas to capture storage value relating to storage capacity not leased to third party customers.

Marketing Financial Results on a Product Basis (\$ millions)

5	G	as		Cı	ude Oil	and I	NGLs	 Tot	al	
(Three Months Ended March 31)	2004		2003		2004		2003	 2004		2003
Revenues	\$ 497	\$	455	\$	371	\$	320	\$ 868	\$	775
Expenses										
Transportation and selling	-		3		8		15	8		18
Operating	3		13		4		2	7		15
Purchased product	490		444		348		297	838		741
Depreciation, depletion and amortization	-		1		-			-		1
	\$ 4	\$	(6)	\$	11	\$	6	\$ 15	\$	-

EnCana's Marketing operations include marketing activities to optimize the value from the Company's proprietary production, the purchase of third party product primarily for the optimization of midstream assets and optimization of transportation commitments not fully utilized for the Company's own production. The increase in first quarter 2004 revenues and corresponding purchased product expense relates to ongoing efforts to optimize the Company's growing proprietary production profile.

CORPORATE

Three Months Ended March 31)	2004	2004 vs 2003	2003
Revenue, Net of Royalties	\$ (377)	_	\$ _
Expenses			
Operating	(2)	-	-
Depreciation, depletion and amortization	16	129%	7
Administration	49	32%	37
Interest, net	79	23%	64
Accretion of asset retirement obligation	7	40%	5
Foreign exchange loss (gain)	58	-128%	(210)
Stock-based compensation	5	-	-
Gain on disposition	(34)	-	_
Income tax (recovery) expense	(95)	-132%	293

Net unrealized mark-to-market losses of \$376 million on derivative instruments are recorded in the applicable accounts to which the contract relates. Corporate revenue, net of royalties includes unrealized mark-to-market losses of \$379 million related to commodity contracts offset partially by other revenue of \$2 million.

Operating expenses include mark-to-market gains for derivative instruments on power consumption contracts.

Depreciation, depletion and amortization include provisions for corporate assets such as computer equipment, office furniture and leasehold improvements. The increase in expense is the result of higher capital spending in prior periods on corporate capital items and the impact of the change in the U.S./Canadian dollar exchange rate.

The increase in administrative expense in the first quarter for 2004 compared to the same period in 2003 reflects the effect of the change in the U.S./Canadian dollar exchange rate, higher governance costs as well as increased long-term compensation expenses. Administrative costs were lower by \$0.04 per barrel of oil equivalent, at \$0.75 per barrel of oil equivalent, for the first quarter of 2004 compared with \$0.79 per barrel of oil equivalent for the fourth quarter in 2003.

The higher net interest expense resulted primarily from the higher average outstanding debt level in the first quarter of 2004 versus first quarter of 2003 and the impact of the change in the U.S./Canadian dollar exchange rate.

The majority of the unrealized foreign exchange loss of \$58 million resulted from the change in the U.S./Canadian dollar period end exchange rate between December 31, 2003 and March 31, 2004 applied to U.S. dollar denominated debt issued in Canada. The unrealized foreign exchange loss, before tax, on U.S. dollar denominated debt issued in Canada for the first three months of 2004 was \$39 million compared to an unrealized before tax gain of \$178 million for the first three months of 2003. Under Canadian GAAP, the Company is required to translate long-term debt issued in 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.

In March 2004, the Company sold its 31 percent equity investment in a well servicing company and as a result realized a \$34 million gain. The proceeds from the sale were used to repay bank and commercial paper indebtedness.

The effective tax rate for the first quarter of 2004 was a recovery of 49 percent compared to a charge of 31 percent for the same period in 2003 as disclosed in Note 7 to the Interim Consolidated Financial Statements. The reduction in the effective tax rate when compared to expected tax rates and the Company's published guidance was principally impacted by two items. The first was a \$109 million reduction in future income taxes resulting from a reduction in the Alberta corporate tax rate from 12.5 percent to 11.5 percent effective April 1, 2004 and changes to transitional measures related to the phase out of the resource allowance for provincial tax purposes. This measure was substantively enacted on March 31, 2004. The second reflects a \$67 million reduction in future income taxes resulting from the first quarter disposition of the Company's interest in Petrovera.

EnCana's effective tax rate in any particular reporting period is a function of the relationship between the amount of net earnings before income taxes for the period and the magnitude of the items representing "permanent differences" that are excluded from the calculation of income for the period that will be subject to tax. There are a variety of items of this type, including:

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

Given the nature and scale of EnCana's activities, it is difficult to forecast the magnitude and timing of these types of items.

After reflecting the adjustments to future income taxes referred to above, the Company is reducing the range of its expected 2004 effective tax rate to between 26 and 31 percent. These rates may be impacted by the effect of future unrealized foreign exchange gains or losses in respect of the revaluation of debt denominated in U.S. dollars.

Current income tax expense for the first quarter of 2004 was \$232 million compared to \$20 million for the same period in 2003. Cash taxes were expected to increase significantly in 2004 when compared to the prior year as the effects of the merger were reflected in the Company's tax position for 2003. On an annualized basis, the current income tax charge for 2004 is in line with guidance for the year and the Company continues to expect that the current tax expense for 2004 will be within the previous guidance range of \$675 million to \$820 million. Current income tax expense was abnormally low in the comparable period in 2003 in large part as a result of the merger with Alberta Energy Company Ltd. ("AEC").

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.

LIQUIDITY AND CAPITAL RESOURCES

EnCana's cash flow from continuing operations was \$995 million for the first three months of 2004 down \$196 million, or 16 percent, compared to the same period last year. The decrease in cash flow was primarily due to the provision for current tax of \$232 million and increase in the U.S./Canadian dollar exchange rate partially offset by increased revenues from the growth in sales volumes.

EnCana's net debt, adjusted for working capital, was \$6,599 million as at March 31, 2004 compared with \$5,931 million at December 31, 2003. Working capital was a deficit of \$568 million at March 31, 2004 and included unrealized losses on mark-to-market accounting on derivatives of \$349 million and a current tax provision of \$232 million. This compares to a working capital surplus of \$157 million as at December 31, 2003. Cash flow together with proceeds from the disposition of the Company's interest in Petrovera, were used for the purchase of shares under the Company's Normal Course Issuer Bid and capital expenditures. As a result of these activities, long-term debt plus the current portion of long-term debt decreased \$155 million in the quarter compared to the 2003 year end.

In March 2004, an indirect wholly owned subsidiary, EnCana Holdings Finance Corp., filed a shelf prospectus whereby it may issue from time to time up to \$2 billion of debt securities. Debt securities issued under this shelf prospectus will be unconditionally guaranteed by EnCana Corporation. No amounts have been drawn under this shelf prospectus.

In February 2004, the Company announced that the dividend on its outstanding common shares for the quarter would be paid in U.S. dollars in the amount of \$0.10 per share. Previously, the Company paid quarterly dividends on its outstanding common shares in Canadian dollars at C\$0.10 per share.

Net debt to capitalization was 37 percent, up from 34 percent at December 31, 2003. Management calculates this ratio for internal purposes to manage the Company's overall debt position and for credit analysts who use it to measure a company's liquidity.

As at March 31, 2004, the Company had available unused committed bank credit facilities in the amount of \$1,569 million.

In October 2003, EnCana received approval from the Toronto Stock Exchange to continue to purchase, for cancellation, common shares under a Normal Course Issuer Bid. Under the bid, EnCana is entitled to purchase for cancellation up to 23.2 million of its common shares over a 12-month period ending October 21, 2004. In the first three months of 2004, EnCana purchased for cancellation approximately 5.2 million of its shares at an average price of C\$55.36 per share under its current Normal Course Issuer Bid, slightly more than share option exercises. As of March 31, 2004, under the terms of this bid, the Company had purchased for cancellation approximately 8.8 million common shares at an average price of C\$51.42 per share.

On March 23, 2004, the Company redeemed all of its Coupon Reset Subordinated Term Securities, Series A ("Term Securities") which had an aggregate principal amount of approximately C\$126 million. The redemption price of the Term Securities was the principal amount plus accrued and unpaid interest to the redemption date.

GOODWILL

At March 31, 2004, the Company had \$1,884 million in goodwill (December 31, 2003 – \$1,911 million) recorded on its Consolidated Balance Sheet as a result of the merger with AEC. There were no transactions creating additional goodwill during this three month period. The decrease in goodwill results from the change in the period end rates to convert Canadian dollars to U.S. dollars.

CAPITAL EXPENDITURES

Capital Investment (\$ millions)

Corporate	2004		20	003				2	002		
		Q4	Q3	Q2	Q1		Q4		Q3		Q2
	\$ 1,028	\$ 911	\$ 901	\$ 679	\$ 707	\$	490	\$	230	\$	450
	210	342	280	196	150		211		559		351
	54	93	65	34	73		61		61		46
	213	178	19	10	16		17		26		15
	15	15	15	31	17		75		17		23
\$ 3,700 - \$ 4,000	\$ 1,520	\$ 1,539	\$ 1,280	\$ 950	\$ 963	\$	854	\$	893	\$	885
\$ 145	(2) 9	69	58	113	36		22		14		10
	9	69	7	19	12		24		12		5
\$ 3,845 - \$ 4,145	\$ 1,538	\$ 1,677	\$ 1,345	\$ 1,082	\$ 1,011	\$	900	\$	919	\$	900
	253	-	91	-	116		-		-		-
\$ (365) (566)	(296)	-	(12)	(7)		(181)		(85)		(155)
\$ 3,480 - \$ 3,780	\$ 1,225	\$ 1,381	\$ 1,436	\$ 1,070	\$ 1,120	\$	719	\$	834	\$	745
	Guidance (1 \$ 3,700 - \$ 4,000 \$ 145 \$ 3,845 - \$ 4,145 \$ (365	$\begin{array}{c c} \hline Corporate \\ \hline Guidance ^{(1)} & Q1 \\ \hline \\ & & & Q1 \\ \hline \\ & & & Q1 \\ \hline \\ & & & & Q1 \\ \hline \\ & & & & & & \\ \hline \\ & & & & & & \\ \hline \\ & & & &$	Corporate Guidance (1) Q1 Q4 \$ 1,028 \$ 911 210 342 54 93 213 178 15 15 \$ 3,700 - \$ 4,000 \$ 1,520 \$ 145 ⁽²⁾ 9 9 69 9 69 \$ 3,845 - \$ 4,145 \$ 1,538 \$ (365) (566)	$\begin{array}{c cccc} \hline & & & & & & & & & & & & & & & & & & $	$\begin{array}{c ccccc} \hline Corporate \\ \hline Guidance (1) \\ \hline Q1 \\ \hline Q4 \\ Q3 \\ Q2 \\ \hline Q4 \\ Q3 \\ Q4 \\ Q4$	$\begin{array}{c ccccccccccccccccccccccccccccccccccc$	Corporate Guidance (1) Q1 Q4 Q3 Q2 Q1 \$ 1,028 \$ 911 \$ 901 \$ 679 \$ 707 \$ 210 342 280 196 150 54 93 65 34 73 213 178 19 10 16 15 15 15 31 17 \$ 3,700 - \$ 4,000 \$ 1,520 \$ 1,539 \$ 1,280 \$ 950 \$ 963 \$ $$ 145^{(2)}$ 9 69 58 113 36 \$ \$ $$ 3,845 - $ 4,145$ \$ 1,538 \$ 1,677 \$ 1,345 \$ 1,082 \$ 1,011 \$ $$ 3,845 - $ 4,145$ \$ 1,538 $$ (365)$ (296) - (12) (7)	Corporate Guidance (1) Q1 Q4 Q3 Q2 Q1 Q4 \$ 1,028 \$ 911 \$ 901 \$ 679 \$ 707 \$ 490 210 342 280 196 150 211 54 93 65 34 73 61 213 178 19 10 16 17 15 15 15 31 17 75 \$ 3,700 - \$ 4,000 \$ 1,520 \$ 1,539 \$ 1,280 \$ 950 \$ 963 \$ 854 \$ 145 ⁽²⁾ 9 69 58 113 36 22 9 69 7 19 12 24 \$ 3,845 - \$ 4,145 \$ 1,538 \$ 1,677 \$ 1,345 \$ 1,082 \$ 1,011 \$ 900 253 - 91 - 116 - \$ (365) (566) (296) - (12) (7) (181)	Guidance (1) Q1 Q4 Q3 Q2 Q1 Q4 \$ 1,028 \$ 911 \$ 901 \$ 679 \$ 707 \$ 490 \$ 210 342 280 196 150 211 54 93 65 34 73 61 213 178 19 10 16 17 15 15 15 31 17 75 \$ 3,700 - \$ 4,000 \$ 1,520 \$ 1,539 \$ 1,280 \$ 950 \$ 963 \$ 854 \$ \$ 145 ⁽²⁾ 9 69 58 113 36 22 24 \$ 3,845 - \$ 4,145 \$ 1,538 \$ 1,677 \$ 1,345 \$ 1,082 \$ 1,011 \$ 900 \$ \$ 3,845 - \$ 4,145 \$ 1,538 \$ 1,677 \$ 1,345 \$ 1,082 \$ 1,011 \$ 900 \$ \$ 253 - 91 - 116 - - \$ (365) (566) (296) - (12) (7) (181)	Corporate Guidance (1) Q1 Q4 Q3 Q2 Q1 Q4 Q3 \$ 1,028 \$ 911 \$ 901 \$ 679 \$ 707 \$ 490 \$ 230 210 342 280 196 150 211 559 54 93 65 34 73 61 61 213 178 19 10 16 17 26 15 15 15 31 17 75 17 \$ 3,700 - \$ 4,000 \$ 1,520 \$ 1,539 \$ 1,280 \$ 950 \$ 963 \$ 854 \$ 893 \$ 145 ⁽²⁾ 9 69 58 113 36 22 14 9 69 7 19 12 24 12 \$ 3,845 - \$ 4,145 \$ 1,538 \$ 1,677 \$ 1,345 \$ 1,082 \$ 1,011 \$ 900 \$ 919 253 - 91 - 116 - - \$ (365) (566) (Guidance (1)Q1Q4Q3Q2Q1Q4Q3 $\begin{pmatrix} \$ 1,028 \\ 210 \\ 342 \\ 210 \\ 54 \\ 93 \\ 65 \\ 54 \\ 93 \\ 65 \\ 34 \\ 73 \\ 61 \\ 61 \\ 61 \\ 61 \\ 61 \\ 72 \\ 61 \\ 61 \\ 61 \\ 75 \\ 75 \\ 75 \\ 75 \\ 75 \\ 75 \\ 75 \\ 7$

(1) Represents a full year of operations. Excludes potential acquisition of Tom Brown, Inc. of \$2,700 million and additional anticipated capital spending of \$160 million as well as additional potential divestitures anticipated of between \$1,000 million and \$1,500 million.

(2) Corporate Guidance is combined for Midstream & Marketing and Corporate.

(3) Represents Corporate acquisitions only. Property acquisitions are included in capital expenditures above.

The Company's capital expenditures increased \$527 million for the first three months in 2004 compared to the first quarter of 2003 as a result of higher levels of operating activity, increased property acquisitions and the impact of the higher U.S./Canadian dollar exchange rate. The Company's capital investment was funded by cash flow in excess of amounts paid for purchases under the Normal Course Issuer Bid, proceeds received on the disposition of the Petrovera interest as well as debt.

Upstream Capital Expenditures

Upstream capital expenditures in the first three months of 2004 were higher by 58 percent, or \$557 million, over the comparable period in 2003. Increased capital spending includes the purchase of an additional 13.5 percent and 20.2 percent ownership in both the Scott and Telford fields respectively in the U.K. central North Sea, increased drilling and development activities and the impact of the increased average U.S./Canadian dollar exchange rate on Canadian dollar denominated expenditures. Capital spending was primarily focused on North American properties with spending in Canada directed mostly at natural gas and oil exploration and development of properties on the Suffield and Palliser Blocks in southeast Alberta, as well as Greater Sierra and Cutbank Ridge in northeast British Columbia and Pelican Lake in northeast Alberta. The majority of capital expenditures in the United States were directed towards drilling in the Mamm Creek and Jonah areas.

Midstream & Marketing Capital Expenditures

Expenditures in the first three months of 2004 related primarily to ongoing improvements to midstream facilities. Capital spending in the first quarter of 2003 included amounts for the Countess and Wild Goose gas storage facilities as well as other midstream assets.

Corporate Capital Expenditures

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

Acquisitions and Divestitures

Acquisitions and divestitures in the first quarter of 2004 primarily reflect the purchase of the 46.7 percent interest from the Company's partner in Petrovera and the subsequent disposition of the 100 percent interest.

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. As at March 31, 2004, there were 459.8 million outstanding Common Shares compared to 460.6 million as at December 31, 2003. There were no Preferred Shares outstanding during these periods. Employees and directors have been granted options to purchase Common Shares under various plans. During the first quarter of 2004, approximately 4.4 million common shares were issued under the terms of these plans. These plans and outstanding balances are disclosed in Note 10 to the Interim Consolidated Financial Statements.

As discussed previously in the Liquidity and Capital Resources section of this MD&A, the Company has repurchased for cancellation, in the first three months of 2004, approximately 5.2 million common shares at an average price of C\$55.36 under a Normal Course Issuer Bid that was approved by the Toronto Stock Exchange in October 2003.

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. In addition, the Company has made commitments related to the risk mitigation program. See Note 13 of the Interim Consolidated Financial Statements for the financial transactions and the Risk Management section of this MD&A for the physical contracts. No significant changes to the commitments, other than the tender offer to purchase Tom Brown, Inc. as disclosed in the Acquisitions and Divestitures section of this MD&A, have occurred in the first quarter of 2004 when compared to the December 31, 2003, year end Consolidated Financial Statements.

As at March 31, 2004, the Company had \$1,781 million outstanding related to Banker's Acceptances, Commercial Paper and LIBOR 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 8 to the Interim Consolidated Financial Statements.

As at March 31, 2004, EnCana had entered into long-term, fixed price, physical contracts with a current delivery of approximately 69 million cubic feet per day with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 193 billion cubic feet at a weighted average price of \$3.54 per thousand cubic feet. At March 31, 2004, these transactions had an unrealized loss of \$149 million.

LEGAL PROCEEDINGS RELATED TO DISCONTINUED MERCHANT ENERGY OPERATIONS

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. The investigation related to alleged inaccurate reporting of natural gas trading information during 2000 and 2001 by former employees of WD's now discontinued Houston-based merchant energy trading operation to energy industry publications that compiled and reported index prices. All Houston-based merchant energy trading operations were discontinued following the merger with AEC in 2002. Under the terms of the settlement, 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 several other lawsuits in California (many of which are class actions) and three class action lawsuits filed in the United States District Court in New York. Several of the California class action lawsuits were transferred by the Judicial Panel on Multidistrict Litigation on a consolidated basis to the Nevada District Court and the New York lawsuits were consolidated in New York District Court by the plaintiff's application. The California lawsuits relate to sales of natural gas in California from 1999 to the present 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 New York lawsuits claim 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. The Gallo complaint claims damages in excess of \$30 million, before potential trebling under California laws. 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

CHANGES IN ACCOUNTING PRINCIPLES AND PRACTICES

Hedging Relationships

On January 1, 2004, the Company adopted the amendments made to the accounting standard for Hedging Relationships. Derivative instruments outstanding at January 1, 2004, that did not qualify as a hedge or were not designated as a hedge, were recorded using the mark-to-market accounting method whereby their fair value was recorded on the Consolidated Balance Sheet. The impact on the Company's Consolidated Financial Statements at January 1, 2004 was an increase in assets of \$145 million, an increase in liabilities of \$380 million and a net deferred loss of \$235 million. These amounts are taken into net earnings as the contracts expire. A portion of these net losses (\$137 million) were recognized in earnings at March 31, 2004. The timing of recognition of the remaining net losses of \$98 million is described in Note 2 of the Interim Consolidated Financial Statements.

Changes in the fair value from January 1, 2004 to March 31, 2004 for these contracts, as well as all other outstanding hedge contracts, were marked-to-market and a \$376 million loss (\$252 million after-tax) was recognized in net earnings at March 31, 2004. All unrealized losses on derivative instruments, as at March 31, 2004, are disclosed in Note 13 of the Consolidated Financial Statements. The unrealized losses of \$474 million include the remaining unrealized losses of \$98 million recorded at January 1, 2004, plus the \$376 million unrecognized losses recorded at March 31, 2004.

Derivative instruments are discussed further in the Risk Management section of the MD&A.

RISK MANAGEMENT

EnCana's results are impacted by external market risks associated with fluctuations in commodity prices, foreign exchange rates and interest rates in addition to credit, operational and safety and environmental risks. The Company partially mitigates its exposure to market 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.

COMMODITY PRICES

As a means of mitigating exposure to commodity price volatility, the Company has entered into various financial instrument agreements as disclosed in Note 13 of the Interim Consolidated Financial Statements and physical contracts as detailed in the natural gas section of this MD&A.

Derivative financial instruments are used by the Company to help manage its exposure to market risks related to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

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 market price risk associated with cash flows expected to be generated from budgeted capital programs and in other cases to the mitigation of market 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 typically entered into with major financial institutions, integrated energy companies or commodities trading institutions. Realized gains or losses from these derivative financial instruments are recognized in oil and gas revenues at the time the related production occurs. On January 1, 2004, the Company adopted AcG-13 of the CICA and uses the mark-to-market accounting method as described earlier in this MD&A under Hedging Relationships. Under the mark-to-market accounting method, unrealized gains or losses resulting from differences between the contracted commodity price and the period end forward curve commodity price are also recognized in revenues.

NATURAL GAS

The Company has entered into swaps which fix the AECO and NYMEX prices and collars 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 financial and physical contracts to fix the AECO and Rockies price differential which is based on the NYMEX price.

The financial contracts are disclosed in Note 13 of the Interim Consolidated Financial Statements. The physical contracts are as follows:

	Notional Volume (MMcf/d)	Term	Price (US\$ per Mcf)	Unrecog Gain	gnized /(Loss)
Fixed Price Contracts					
Sales Contract					
NYMEX Collars	50	2004	2.46 - 4.90		(16)
NYMEX Collars	50	2005	2.46 - 4.90		(18)
NYMEX Collars	46	2006 - 2007	2.46 - 4.90		(22)
Basis Contracts					
Sales Contract					
Fixed NYMEX to Rockies Basis	423	2004	(0.501)		26
Fixed NYMEX to San Juan Basis	50	2004	(0.637)		1
Fixed NYMEX to Rockies Basis	403	2005	(0.476)		28
Fixed NYMEX to San Juan Basis	50	2005	(0.637)		1
Fixed NYMEX to Rockies Basis	211	2006 - 2007	(0.495)		23
Fixed NYMEX to San Juan Basis	42	2006	(0.637)		_
					23
Gas Marketing Physical Positions					12
				\$	35

CRUDE OIL

The Company has partially mitigated its exposure to the WTI NYMEX price for a portion of its oil production with fixed price swaps, costless collars and 3-way put spreads. As part of the crude oil marketing activities, the Company partially mitigated its exposure to the risk around crude oil inventory and third party margins through the use of futures, options and collars.

GAS STORAGE OPTIMIZATION

As part of its gas storage optimization program, the Company has entered into financial instruments and physical contracts at various locations and terms over the next 10 months to manage the price volatility of the corresponding physical transactions and inventories. The financial instruments used include futures, fixed for floating swaps and basis swaps.

KYOTO PROTOCOL

The risks associated with the Kyoto Accord and similar initiatives in the U.S.A. remain unchanged as discussed in the 2003 year end MD&A.

ALBERTA ENERGY AND UTILITIES BOARD ("AEUB") RULING

The Company's production volumes, primarily from the Primrose Block in northeast Alberta, were affected by an AEUB decision, in September 2003, to shut-in natural gas production that put at risk the recovery of bitumen resources in the area. The impact of this decision caused the Company's first quarter natural gas production in the region to decline by approximately 12 million cubic feet per day when compared to the first quarter of 2003. The future impact of this decision is not known at this time but is not expected to be material.

OUTLOOK

During 2004, EnCana plans to focus on development of its North American resource plays to grow natural gas and crude oil production as well as crude oil production from Ecuador. Medium term growth is also expected to come from development of the Company's Gulf of Mexico oil, Canadian East Coast gas, and U.K. central North Sea oil growth platforms. The Company also plans to continue its efforts to expand its longer-term growth prospects through focused International New Ventures exploration.

The Company expects its 2004 capital investment program, before acquisitions or dispositions, of between \$3,845 million and \$4,145 million, to be funded from cash flow, proceeds from divestitures of non-core assets and long-term debt. In addition, incremental capital as a result of the potential acquisition of TBI, is expected to be approximately \$160 million. The Company has also increased its guidance for anticipated dispositions from \$365 million to between \$1,365 million and \$1,865 million for 2004 based on the successful acquisition of TBI.

	Three Months Ended March 31,
Full Year 2004 (2)	2004
2,010 - 2,120	2,000
675 - 715	684
15	28
2,700 - 2,850	2,712
147,000 - 157,000	156,640
9,000 - 11,000	9,237
68,000 - 74,000	80,982
16,000 - 18,000	18,088
240,000 - 260,000	264,947
690,000 – 735,000	716,947
	2,010 - 2,120 $675 - 715$ 15 $2,700 - 2,850$ $147,000 - 157,000$ $9,000 - 11,000$ $68,000 - 74,000$ $16,000 - 18,000$ $240,000 - 260,000$

(1) Natural gas converted to barrels of oil equivalent at 6 thousand cubic feet = 1 barrel of oil equivalent.

(2) Excludes volumes from potential acquisition of Tom Brown, Inc. Incremental production, should the Company acquire Tom Brown, Inc., for 2004 is expected to be between 312 to 320 million cubic feet equivalent per day of natural gas from the date of acquisition.

(3) Excludes reduced volumes anticipated from additional potential divestitures of 40,000 to 60,000 BOE/d.

As of March 31, 2004, overall natural gas storage inventories in North America are higher than the same period in 2003 but continue to be below the five year average. Reduced natural gas production, commodity demand and uncertainty surrounding the ability of producers to maintain inventory levels have resulted in continued higher historical average natural gas prices. The outlook for 2004 and beyond will be principally impacted by weather, timing of new production and economic activity.

Volatility in crude oil prices is expected to continue in 2004 as a result of market uncertainties over the reintegration of Iraqi production, lower than expected inventory levels in the U.S., OPEC compliance with production quotas, increased demand from Asian countries and the overall state of the world economies.

The Company has reduced the range of its expected 2004 effective tax rate to between 26 and 31 percent. These rates may be impacted by the effect of future unrealized foreign exchange gains or losses in respect of the revaluation of debt denominated in U.S. dollars. The Company continues to expect that the current tax expense for 2004 will be within the previous guidance range of \$675 million to \$820 million.

April 27, 2004

CONSOLIDATED STATEMENT OF EARNINGS (unaudited)

For the period ended March 31

		 Mar	ch 31	
		 Three Mo	nths Ende	d
(US\$ millions, except per share amounts)		2004		2003
REVENUES, NET OF ROYALTIES	(Notes 4, 13)	\$ 2,850	\$	2,743
EXPENSES	(Note 4)			
Production and mineral taxes		65		50
Transportation and selling		162		125
Operating		353		313
Purchased product		1,287		945
Depreciation, depletion and amortization		624		471
Administrative		49		37
Interest, net		79		64
Accretion of asset retirement obligation	(Note 9)	7		5
Foreign exchange loss (gain)	(Note 6)	58		(210
Stock-based compensation		5		-
Gain on disposition	(Note 3)	 (34)		-
		 2,655		1,800
NET EARNINGS BEFORE INCOME TAX		195		943
Income tax (recovery) expense	(Note 7)	(95)		293
NET EARNINGS FROM CONTINUING OPERA Net earnings from discontinued	TIONS	 290		650
OPERATIONS	(Note 5)	-		187
NET EARNINGS		\$ 290	\$	837
NET EARNINGS FROM CONTINUING OPERA	TIONS			
PER COMMON SHARE	(Note 12)			
Basic	. /	\$ 0.63	\$	1.35
Diluted		\$ 0.62	\$	1.34
NET EARNINGS PER COMMON SHARE	(Note 12)			
Basic		\$ 0.63	\$	1.74
Diluted		\$ 0.62	\$	1.73

CONSOLIDATED STATEMENT OF RETAINED EARNINGS (unaudited)

			Three Mor	nths Ende	Ended		
(US\$ millions)			2004		2003		
RETAINED EARNINGS, BEGINNING OF YEAR							
As previously reported		\$	5,276	\$	3,457		
Retroactive adjustment for changes in accounting policies			-		66		
As restated			5,276		3,523		
Net Earnings			290		837		
Dividends on Common Shares			(46)		(33)		
Charges for Normal Course Issuer Bid	(Note 10)		(120)		-		
RETAINED EARNINGS, END OF PERIOD		\$	5,400	\$	4,327		
See accompanying Notes to Consolidated Financial Statements.							

CONSOLIDATED BALANCE SHEET (unaudited)

(US\$ millions)		As at March 31, 2004	De	As at cember 31, 2003
ASSETS				
Current Assets				
Cash and cash equivalents		\$ 250	\$	148
Accounts receivable and accrued revenues		1,722		1,367
Risk management	(Note 13)	39		-
Inventories		 273		573
		2,284		2,088
Property, Plant and Equipment, net	(Note 4)	19,991		19,545
Investments and Other Assets		563		566
Risk Management	(Note 13)	86		-
Property, Plant and Equipment, net Investments and Other Assets Risk Management Goodwill IABILITIES AND SHAREHOLDERS' EQUITY Current Liabilities Accounts payable and accrued liabilities Risk management Income tax payable Current portion of long-term debt Long-Term Debt Other Liabilities		 1,884		1,911
	(Note 4)	\$ 24,808	\$	24,110
LIABILITIES AND SHAREHOLDERS' EQUITY Current Liabilities				
Accounts payable and accrued liabilities		\$ 1,886	\$	1,579
Risk management	(Note 13)	559		-
Income tax payable		218		65
Current portion of long-term debt	(Note 8)	 189		287
		2,852		1,931
Long-Term Debt	(Note 8)	6,031		6,088
Other Liabilities		95		21
Risk Management	(Note 13)	40		-
Asset Retirement Obligation	(Note 9)	441		430
Future Income Taxes		 3,977		4,362
		13,436		12,832
Shareholders' Equity				
Share capital	(Note 10)	5,343		5,305
Share options, net		30		55
Paid in surplus		26		18
Retained earnings		5,400		5,276
Foreign currency translation adjustment		 573		624
		 11,372		11,278
		\$ 24,808	\$	24,110
See accompanying Notes to Consolidated Financial Statements.				

CONSOLIDATED STATEMENT OF CASH FLOWS (unaudited)

For the period	
ended March 31	

		March 31 Three Months Ended					
(US\$ millions)			2004		2003		
OPERATING ACTIVITIES							
		\$	290	\$	650		
		·	624	•	471		
Future income taxes	(Note 7)		(327)		273		
Unrealized loss on risk management	(Note 13)		376		-		
Unrealized foreign exchange loss (gain)	(Note 6)		39		(178		
Accretion of asset retirement obligation	(Note 9)		7				
Gain on disposition	(Note 3)		(34)		-		
Other			20		(30		
Cash flow from continuing operations			995		1,191		
			_		30		
-			995		1,221		
			(5)				
0	16		467		(3 5(
			107		11		
ivet enange in non-easir working capital from discontinued operati	0115						
			1,457		1,279		
INVESTING ACTIVITIES							
Capital expenditures	(Note 4)		(1,538)		(1,011		
Proceeds on disposal of property, plant and equipment			25		7		
Dispositions (acquisitions)	(Note 3)		288		(116		
Equity investments	(Note 3)		44		(43		
Net change in investments and other			(2)		(23		
Net change in non-cash working capital from continuing operation	15		85		(134		
Discontinued operations			_		1,289		
			(1,098)		(33		
FINANCING ACTIVITIES							
Repayment of long-term debt			(103)		(892		
Issuance of common shares	(Note 10)		111		29		
Purchase of common shares	(Note 10)		(218)		-		
Dividends on common shares			(46)		(33		
Other			(1)		(1		
Net change in non-cash working capital from continuing operation	15		-		(4		
Discontinued operations			-		(282		
			(257)		(1,183		
DEDIICT: FORFIGN EXCHANCE LOSS ON CASH 4	ND						
RATING ACTIVITIES et earnings from continuing operations spreciation, depletion and amortization ture income taxes (Note 7) urealized loss on risk management (Note 13) realized foreign exchange loss (gain) (Note 6) crretion of asset retirement obligation (Note 9) in on disposition (Note 3) ther ash flow from continuing operations ash flow from continuing operations ash flow from discontinued operations ash flow et change in other assets and liabilities et change in non-cash working capital from continuing operations et change in non-cash working capital from discontinued operations et change in non-cash working capital from discontinued operations et change in non-cash working capital from discontinued operations et change in non-cash working capital from continuing operations et change in non-cash working capital from continuing operations et change in non-cash working capital from continuing operations solution (Note 3) uity investments (Note 3) et change in investments and other et change in non-cash working capital from continuing operations scontinued operations ANCING ACTIVITIES payment of long-term debt suance of common shares (Note 10) widends on common shares (Note 10) widends o					ź		
INCREASE IN CASH AND CASH EQUIVALENTS			102		61		
-	YEAR		148		116		
CASH AND CASH EQUIVALENTS, END OF PERIOD	D	\$	250	\$	177		

	NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)	
	For the period ended March 31, 2004	
	(All amounts in US\$ millions unless otherwise specified)	
NOTE 1	BASIS OF PRESENTATION	
	(the "Company"), and are presented in accordance with Canadian generally accepted accounting p Company is in the business of exploration for, and production and marketing of, natural gas, natu	principles. The ral gas liquids
	methods of computation as the annual audited Consolidated Financial Statements for the year end 31, 2003, except as noted below. The disclosures provided below are incremental to those included w audited Consolidated Financial Statements. The interim Consolidated Financial Statements show	ded December rith the annual ild be read in
NOTE 2	CHANGE IN ACCOUNTING POLICIES AND PRACTICES	
	 "Hedging Relationships", and EIC 128, "Accounting for Trading, Speculative or Non Trading Derival Instruments". Derivative instruments that do not qualify as a hedge under AcG - 13, or are not d hedge, are recorded in the Consolidated Balance Sheet as either an asset or liability with change recognized in net earnings. The Company has elected not to designate any of its price risk manager in place at March 31, 2004 as accounting hedges under AcG - 13 and, accordingly, will account for hedging derivatives using the mark-to-market accounting method. The impact on the Company's Financial Statements at January 1, 2004 resulted in the recognition of risk management assets with of \$145 million, risk management liabilities with a fair value of \$380 million and a net deferred loss o which will be recognized into net earnings as the contracts expire. At March 31, 2004, it is estim the following 12 months, \$169 million (\$118 million, net of tax) will be reclassified into net earnings as unrealized to be recognized in the earnings as unrealized	ative Financial esignated as a s in fair value nent activities all these non- Consolidated th a fair value f \$235 million ated that over sings from net
	over the years 2004 to 2008:	Unrealized
	All arounts in USS millions unless otherwise specified) ASIS OF PRESENTATION The interim Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries 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, natural gas liquids rocessing and power generation perations. The interim Consolidated Financial Statements have been prepared following the same accounting policies and sethods of computation as the annual audited Consolidated Financial Statements for the year ended December 1, 2003, except as noted below. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements and the notes thereto for the year ended becember 31, 2003. HANGE IN ACCOUNTING POLICIES AND PRACTICES Medging Relationships M January 1, 2004, the Company adopted the amendments made to Accounting Guideline 13 ("AcG - 1.3") Hedging Relationships M January 1, 2004 as accounting bedges under AcG - 13 and, accordingly, will account for all these non- deging derivative instruments that do not qualify as a hedge under AcG - 13, or are not designated as a dege, are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value cognized in net earnings. The Company has the contracts expire. At March 31, 2004, the Company has the contracts expire. At March 31, 2004, are recorded in the recognized in to recognized in the recognized in not et arrnings as	
	2004 Quarter 2	\$ (54)
	Quarter 3	(51)
	Quarter 4	
	Total remaining to be recognized in 2004	\$ (169)
	2005 Overter 1	¢
	Quarter 1 Quarter 2	
	Quarter 3	
	Quarter 4	9
	Total to be recognized in 2005	\$ 31
	2006	24
	2007	
		\$ (78)

	At March 31, 2004, the remaining net deferred loss totalled \$98 million of which \$211 million was recorded in Accounts receivable and accrued revenues, \$2 million in Investments and Other Assets, \$40 million in Accounts payable and accrued liabilities and \$75 million in Other Liabilities.
NOTE 3	DISPOSITIONS (ACQUISITIONS)
	In March 2004, the Company sold its investment in a well servicing company for approximately \$44 million, recording a gain on sale of \$34 million.
	On February 18, 2004, the Company sold its 53.3 percent interest in Petrovera Resources ("Petrovera") for approximately \$288 million, including working capital adjustments. In order to facilitate the transaction, EnCana purchased the 46.7 percent interest of its partner for approximately \$253 million, including working capital adjustments, and then sold the 100 percent interest in Petrovera for a total of approximately \$541 million, including working capital adjustments. There was no gain or loss recorded on this sale.
	On January 31, 2003, the Company acquired the Ecuadorian interests of Vintage Petroleum Inc. ("Vintage") for net cash consideration of \$116 million. This purchase was accounted for using the purchase method with the results reflected in the consolidated results of EnCana from the date of acquisition.
	Other dispositions of discontinued operations are disclosed in Note 5.
NOTE 4	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, natural gas liquids and crude oil and other related activities. The majority of the Company's Upstream operations are located in Canada, the United States, the United Kingdom and Ecuador. International new venture exploration is mainly focused on opportunities in Africa, South America and the Middle East.
	• Midstream & Marketing includes natural gas storage operations, natural gas liquids processing and power generation operations, as well as marketing activities. These marketing activities include the sale and delivery of produced product and the purchasing of third party product primarily for the optimization of midstream assets, as well as the optimization of transportation arrangements not fully utilized for the Company's own production.
	• 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 & Marketing purchases 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 5.

		Upst	ream			Midstı Marl	ream & keting	
		2004		2003	2004			2003
Revenues, Net of Royalties	\$	1,808	\$	1,650	\$ 1,419		\$	1,093
Expenses								
Production and mineral taxes		65		50		-		
Transportation and selling		154		107		8		1
Operating		277		219		78		9
Purchased product		-		-	1	,287		94
Depreciation, depletion and amortization		601		459		7		
Segment Income	\$	711	\$	815	\$	39	\$	3
	_	Corp	oorate	:		Conso	olidate	ed
		2004		2003		2004		200
Revenues, Net of Royalties	\$	(377)	\$	-	\$ 2	2,850	\$ 2	2,74
Expenses								
Production and mineral taxes		-		-		65		5
Transportation and selling		-		-		162		12
Operating		(2)		-		353		31
Purchased product		-		-	1	,287		94
Depreciation, depletion and amortization		16		7		624		47
Segment Income	\$	(391)	\$	(7)		359		83
Administrative	_					49		3
Interest, net						79		6
Accretion of asset retirement obligation						7		
Foreign exchange loss (gain)						58		(21
Stock-based compensation						5		
Gain on disposition						(34)		
						164		(10
Net Earnings Before Income Tax						195		94
Income tax (recovery) expense						(95)		29
Net Earnings from Continuing Operations					\$	290	\$	65

Geographic and Product Information	l (For th	e th	ree mon	ths e	ended M	larch	31)									
UPSTREAM									North		erica					
				Produced Gas and NGLs												
				Canada		United States				Crude Oil						
					2004		2003	_	2004		2003		2004		2003	
Revenues, Net of Royalties				\$	971	\$	963	\$	358	\$	311	\$	250	\$	224	
Expenses													_		_	
Production and mineral taxes					15		4		34		29		5		5	
Transportation and selling					82		61		25		15		20		20	
Operating					101		87		20		10		73		67	
Depreciation, depletion and amortizat	ion				298		254		82		66		118		93	
Segment Income			\$	475	\$	557	\$	197	\$	191	\$	34	\$	39		
	Ecuador				U.K. North Sea		Sea		Other			Total Upst			tream	
	2004		2003		2004		2003		2004		2003	2004		2003		
Revenues, Net of Royalties \$	126	\$	87	\$	53	\$	32	\$	50	\$	33	\$	1,808	\$ 3	1,650	
Production and mineral taxes	11		12		_		_		_		_		65		50	
Transportation and selling	19		7		8		4		_		_		154		107	
Operating	30		15		6		3		47		37		277		219	
Depreciation, depletion																
and amortization	65		23		33		22		5		1		601		459	
Segment Income \$	1	\$	30	\$	6	\$	3	\$	(2)	\$	(5)	\$	711	\$	815	
					Mids	strea	m		Marke	eting	*	Τ	otal Mi & Mai			
					2004		2003		2004		2003		2004		2003	
Revenues				\$	551	\$	318	\$	868	\$	775	\$	1,419	\$	1,093	
Expenses																
Transportation and selling					-		-		8		18		8		18	
Operating					71		79		7		15		78		94	
Purchased product					449		204		838		741		1,287		945	
Depreciation, depletion and amortizat	ion				7		4		-		1		7		5	
Segment Income				\$	24	\$	31	\$	15	\$	-	\$	39	\$	31	

waphic and Product Informatic 0

* Includes transportation cost optimization activity under which the Company purchases and takes delivery of product from others and delivers product to customers under transportation arrangements not utilized for the Company's own production.

	Three Months Ended March 31				2004		2003
	Upstream						
	Canada			s	1,028	\$	707
	United States			Ŷ	210	Ψ	150
	Ecuador				54		73
	United Kingdom				213		16
	Other Countries				15		17
	other countries						
	Midsterran & Marketing				1,520 9		963
	Midstream & Marketing				9		36 12
	Corporate						
	Total			\$	1,538	\$	1,011
	Property, Plant and Equipment and Total Assets						
			y, Plant and		T-+-1	A	
		Equ	uipment			Assets	
			As at			As at	
		March 31, 2004	December 31, 2003	March 20	31, 004	Decem	ber 31 2003
	Upstream	\$ 18,991	\$18,532	\$22,3	50	\$2	21,742
	Midstream & Marketing	777	784	1,5			1,879
	Corporate	223	229		07		489
	I		\$ 10 515	\$24,8	208	\$ 2	24,110
	Total	\$ 19,991	\$19.545				
NOTE 5	Total DISCONTINUED OPERATIONS On February 28, 2003, the Company completed the Venture ("Syncrude") to Canadian Oil Sands Limited On July 10, 2003, the Company completed the sale of	for net cash c of the remainin	onsideration of ong 3.75 percent	g interest in C\$1,026 mil	the Sy lion (\$0	rncrude 690 mi e and a	e Join Illion gros
NOTE 5	DISCONTINUED OPERATIONS On February 28, 2003, the Company completed the Venture ("Syncrude") to Canadian Oil Sands Limited On July 10, 2003, the Company completed the sale of overriding royalty for net cash consideration of C\$427 On January 2, 2003 and January 9, 2003, the Compa	sale of its 10 for net cash c of the remainin 7 million (\$309 ny completed	percent workin onsideration of 6 ng 3.75 percent i 9 million). There the sales of its in	g interest in C\$1,026 mil interest in Sy was no gain terests in the	the Sy lion (\$0 or loss Cold I	ncrude 690 mi e and a s on thi Lake Pi	e Join Illion gros is sale pelin
NOTE 5	DISCONTINUED OPERATIONS On February 28, 2003, the Company completed the Venture ("Syncrude") to Canadian Oil Sands Limited On July 10, 2003, the Company completed the sale o overriding royalty for net cash consideration of C\$423	e sale of its 10 for net cash c of the remainin 7 million (\$309 ny completed eration of app	percent workin onsideration of ng 3.75 percent i 9 million). There the sales of its in roximately C\$1.	g interest in C\$1,026 mil interest in Sy was no gain terests in the 6 billion (\$1	the Sy lion (\$0 or loss Cold I I billion	ncrude 690 mi e and a s on thi Lake Pi n), incl	e Joir Illion gros is sale pelin ludin
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NOTE 5	 DISCONTINUED OPERATIONS On February 28, 2003, the Company completed the Venture ("Syncrude") to Canadian Oil Sands Limited On July 10, 2003, the Company completed the sale of overriding royalty for net cash consideration of C\$422. On January 2, 2003 and January 9, 2003, the Company System and Express Pipeline System for total consideration of related long-term debt by the purchat (\$169 million). As all discontinued operations have either been dispot there are no remaining assets or liabilities on the Consoli 	e sale of its 10 for net cash c of the remainin 7 million (\$309 ny completed eration of app ser, and recor sed of or wind consolidated B	percent workin onsideration of (ng 3.75 percent i 9 million). There the sales of its in roximately C\$1. ded an after-tax l up has been con alance Sheet. T	g interest in C\$1,026 mil interest in Sy was no gain terests in the .6 billion (\$1 gain on sale npleted by D he following	the Sy lion (\$ or loss Cold I t billion e of CS	ncrude 690 mi e and a s on thi Lake Pi n), incl \$263 n ber 31,	e Join Illion) gros is sale pelind luding nillion 2003
NOTE 5	 DISCONTINUED OPERATIONS On February 28, 2003, the Company completed the Venture ("Syncrude") to Canadian Oil Sands Limited On July 10, 2003, the Company completed the sale overriding royalty for net cash consideration of C\$423. On January 2, 2003 and January 9, 2003, the Company System and Express Pipeline System for total consideration of related long-term debt by the purchat (\$169 million). As all discontinued operations have either been dispot there are no remaining assets or liabilities on the Consolidated Statement of Earnings 	e sale of its 10 for net cash c of the remainin 7 million (\$309 ny completed eration of app ser, and recor sed of or wind consolidated B	percent workin onsideration of 0 ng 3.75 percent i 9 million). There the sales of its in roximately C\$1. ded an after-tax l up has been con alance Sheet. T ent of Earnings f	g interest in C\$1,026 mil interest in Sy was no gain terests in the .6 billion (\$1 gain on sale npleted by D he following for 2003: Mid	the Sy lion (\$6 or loss Cold I t billion e of CS Decemb g table	ncrude 690 mi e and a s on thi Lake Pi n), incl \$263 n ber 31,	e Join Illion) gross jes sale pelinu uding nillior 2003 tts the
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NOTE 5	 DISCONTINUED OPERATIONS On February 28, 2003, the Company completed the Venture ("Syncrude") to Canadian Oil Sands Limited On July 10, 2003, the Company completed the sale overriding royalty for net cash consideration of C\$42. On January 2, 2003 and January 9, 2003, the Company System and Express Pipeline System for total consideration of related long-term debt by the purchat (\$169 million). As all discontinued operations have either been dispot there are no remaining assets or liabilities on the Consolidated Statement of Earnings For the three months ended March 31, 2003 Revenues, Net of Royalties Expenses Transportation and selling 	e sale of its 10 for net cash c of the remainin 7 million (\$309 ny completed eration of app ser, and recor sed of or wind consolidated B	percent workin onsideration of (ng 3.75 percent i 9 million). There the sales of its in roximately C\$1. ded an after-tax l up has been con salance Sheet. The ent of Earnings f	g interest in C\$1,026 millinterest in Sy was no gain terests in the .6 billion (\$1 gain on sale npleted by E he following for 2003: $\frac{Mid}{60}$	the Sy lion (\$6 or loss Cold I t billion e of CS Decemb g table	ncrude 690 mi e and a s on thi Lake Pi n), incl \$263 n \$263 n presen	e Join Illion) gross gross gelin luding nillion 2003 uts th Tota 60
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NOTE 5	 DISCONTINUED OPERATIONS On February 28, 2003, the Company completed the Venture ("Syncrude") to Canadian Oil Sands Limited On July 10, 2003, the Company completed the sale overriding royalty for net cash consideration of C\$423. On January 2, 2003 and January 9, 2003, the Company System and Express Pipeline System for total consider assumption of related long-term debt by the purchat (\$169 million). As all discontinued operations have either been dispot there are no remaining assets or liabilities on the Consolidated Statement of Earnings For the three months ended March 31, 2003 Revenues, Net of Royalties Expenses Transportation and selling Operating Depreciation, depletion and amortization Gain on discontinuance 	e sale of its 10 for net cash c of the remainin 7 million (\$309 ny completed eration of app ser, and recor sed of or wind consolidated B	percent workin onsideration of (ng 3.75 percent i 9 million). There the sales of its in roximately C\$1. ded an after-tax l up has been con salance Sheet. The ent of Earnings f	g interest in C\$1,026 mili interest in Sy was no gain terests in the .6 billion (\$1 gain on sale npleted by D he following for 2003: Mid crude - Pi 60 \$ 1 28 5 - 34	the Sy lion (\$6 or loss Cold I t billion e of CS Decemb g table dstream ipelines 	ncrude 690 mi e and a s on thi Lake Pi n), incl \$263 n ber 31, presen	e Join Illion) gross is sale pelin- luding nillion 2003 its the Construction 60 22 23 24 20 24 20 24 24 24 24 24 24 24 24 24 24 24 24 24
NOTE 5	 DISCONTINUED OPERATIONS On February 28, 2003, the Company completed the Venture ("Syncrude") to Canadian Oil Sands Limited On July 10, 2003, the Company completed the sale of overriding royalty for net cash consideration of C\$42. On January 2, 2003 and January 9, 2003, the Compan System and Express Pipeline System for total consider assumption of related long-term debt by the purchat (\$169 million). As all discontinued operations have either been dispot there are no remaining assets or liabilities on the Consolidated Statement of Earnings For the three months ended March 31, 2003 Revenues, Net of Royalties Expenses Transportation and selling Operating Depreciation, depletion and amortization Gain on discontinuance Net Earnings Before Income Tax 	e sale of its 10 for net cash c of the remainin 7 million (\$309 ny completed eration of app ser, and recor sed of or wind consolidated B	percent workin onsideration of (ng 3.75 percent i 9 million). There the sales of its in roximately C\$1. ded an after-tax l up has been con salance Sheet. The ent of Earnings f	g interest in C\$1,026 millinterest in Sy was no gain terests in the 6 billion (\$1 gain on sale mpleted by D he following for 2003: Mid crude $-Pi$ 60 \$ 1 28 5 - 34 26	the Sy lion (\$0 ncrude or loss Cold I t billion e of CS Decemb g table dstream ipelines - - - (220) (220)	ncrude 690 mi e and a s on thi Lake Pi n), incl \$263 n ber 31, presen	e Join Illion) gross is sale pelin ludin nillion 2003 tts th Tota 60 22 (22 (18) 240

Three Months Ended March 31 2004 Unrealized Foreign Exchange Loss (Gain) on Translation of U.S. Dollar Debt Issued in Canada \$ 39 Realized Foreign Exchange Losses (Gains) 19 \$ 58 NOTE 7 INCOME TAXES 1 Three Months Ended March 31 2004 Current 2004 Canada \$ 205 United States 8 Ecuador 19 232 Future Future tax rate reductions * (109)	20 \$ (1 (\$ (2 20 \$
U.S. Dollar Debt Issued in Canada \$ 39 Realized Foreign Exchange Losses (Gains) 19 \$ 58 NOTE 7 INCOME TAXES The provision for income taxes is as follows: Three Months Ended March 31 2004 Current 2004 Canada \$ 205 United States 8 Ecuador 19 Future (218)	(\$ (2
Realized Foreign Exchange Losses (Gains) 19 § 58 NOTE 7 INCOME TAXES The provision for income taxes is as follows: 2004 Current 2004 Current 2005 United States 8 Ecuador 19 232 Future	(\$ (2
NOTE 7 INCOME TAXES The provision for income taxes is as follows: Three Months Ended March 31 2004 Current 2004 Current 8 Loada \$ 205 United States 8 Ecuador 19 232 Future	\$ (2
NOTE 7 INCOME TAXES The provision for income taxes is as follows: <u>Three Months Ended March 31</u> 2004 Current Canada \$ 205 United States 8 Ecuador 19 232 Future (218)	20
The provision for income taxes is as follows: 2004 <i>Three Months Ended March 31</i> 2004 Current Canada \$ 205 United States 8 Ecuador 19 232 Future (218)	
The provision for income taxes is as follows: 2004 <i>Three Months Ended March 31</i> 2004 Current Canada \$ 205 United States 8 Ecuador 19 232 Future (218)	
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Future 232 (218) (218)	
Future (218)	
Enture tay rate reductions * (109)	2
ruture tax rate reductions (109)	
\$ (95)	\$ 2
* On March 31, 2004, the Alberta government substantively enacted the income tax rate reduction previously announced in Februar	
The following table reconciles income taxes calculated at the Canadian statutory rate with the actual inc	come tax
Three Months Ended March 31 2004	20
Net Earnings Before Income Tax \$ 195	\$ 9
Canadian Statutory Rate 39.1%	41.0
Expected Income Taxes 76	3
Effect on Taxes Resulting from:	0
Non-deductible Canadian crown payments 52	
Canadian resource allowance (57)	(1
Canadian resource allowance on unrealized risk management losses 21	
Statutory rate differences (9)	(
Effect of tax rate changes (109)	
Non-taxable capital gains 7	(
Previously unrecognized capital losses 13	(
Tax recovery on dispositions (80)	
Large corporations tax 4	
Other (13)	
\$ (95)	\$ 2
Effective Tax Rate (48.7%)	31.1

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NOTE 8	LONG-TERM DEBT		
		As at	As at
		March 31, 2004	December 31, 2003
	Canadian Dollar Denominated Debt		
	Revolving credit and term loan borrowings	\$ 1,387	\$ 1,425
	Unsecured notes and debentures Preferred securities	1,316 153	1,335 252
		2,856	3,012
	U.S. Dollar Denominated Debt	2,830	5,012
	Revolving credit and term loan borrowings	421	417
	Unsecured notes and debentures	2,713	2,713
	Preferred securities	150	150
		3,284	3,280
	Increase in Value of Debt Acquired *	80	83
	Current Portion of Long-Term Debt	(189)	(287)
		\$ 6,031	\$ 6,088
	* Certain of the notes and debentures of the Company were acquired in the busine 2002 and were accounted for at their fair value at the date of acquisition. The di	ifference between the fair value and the prir	
	debt is being amortized over the remaining life of the outstanding debt acquired,	approximately 27 years.	
NOTE	ACCET RETURNET OBLICATION		
NOTE 9	ASSET RETIREMENT OBLIGATION		
	The following table presents the reconciliation of the beginning and associated with the retirement of oil and gas properties:	l ending aggregate carrying amount	of the obligation
	associated with the retrement of on and gas properties.	March 31,	December 31,
		2004	2003
	Asset Retirement Obligation, Beginning of Year Liabilities Incurred	\$ 430 25	\$ 309
	Liabilities Settled	(4)	64 (23)
	Liabilities Disposed	(12)	()
	Accretion Expense	7	19
	Change in Estimate	1	-
	Other	(6)	61
	Asset Retirement Obligation, End of Period	\$ 441	\$ 430

NOTE 10

SHARE CAPITAL

SHARE CAPITAL	March	March 31, 2004		r 31, 2003
(millions)	Number	Amount	Number	Amount
Common Shares Outstanding, Beginning of Year	460.6	\$ 5,305	478.9	\$ 5,511
Shares Issued under Option Plans	4.4	111	5.5	114
Shares Repurchased	(5.2)	(73)	(23.8)	(320)
Common Shares Outstanding, End of Period	459.8	\$ 5,343	460.6	\$ 5,305

During the quarter, the Company purchased, for cancellation, 5,190,000 Common Shares for total consideration of approximately C\$287 million (\$218 million). Of the amount paid this quarter, C\$95 million (\$73 million) was charged to share capital, C\$34 million (\$25 million) was charged to paid in surplus and C\$158 million (\$120 million) was charged to retained earnings.

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 previous successor and/or related company replacement plans expire ten years from the date the options were granted.

The following tables summarize the information about options to purchase Common Shares at March 31, 2004:

				Stock Options (millions)	Weighted Average Exercise Price (C\$)
Outstanding, Beginning of Year				28.8	43.13
Exercised				(4.4)	33.24
Forfeited				(0.2)	47.19
Outstanding, End of Period				24.2	43.93
Exercisable, End of Period				11.3	41.14
	C	outstanding Option	ons	Exercisabl	e Options
		Weighted			
	Number of	Average	Weighted	Number of	Weighted
	Options	Remaining	Average	Options	Average
	Outstanding	Contractual	Exercise	Outstanding	Exercise

Range of Exercise Price (C\$)	Outstanding (millions)	Contractual Life <i>(years)</i>	Exercise Price (C\$)	Outstanding (millions)	Exercise Price (C\$)
13.50 to 19.99	0.6	0.6	18.55	0.6	18.55
20.00 to 24.99	1.0	1.1	22.49	1.0	22.49
25.00 to 29.99	1.2	1.0	26.31	1.2	26.31
30.00 to 43.99	0.8	1.6	39.16	0.7	38.61
44.00 to 53.00	20.6	3.4	47.96	7.8	47.71
	24.2	2.4	43.93	11.3	41.14

The Company 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. 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 March 31, 2004 would have been \$281 million; \$0.61 per common share – basic; \$0.60 per common share – diluted (2003 – \$829 million; \$1.73 per common share – basic; \$1.71 per common share – diluted).

			March 200
	Weighted Average Fair Value of Options Granted (C\$)		\$ 13.0
	Risk Free Interest Rate		4.19
	Expected Lives (years)		3.0
	Expected Volatility Annual Dividend per Share (C\$)		0.3 \$ 0.4
NOTE 11	COMPENSATION PLANS		
NOTE II	The tables below outline certain information related to the Com Additional information is contained in Note 16 of the Company's a		
	<i>A) Defined Benefit Pension Plans</i> The following table summarizes the net defined benefit plan exp	ense:	
	Three Months Ended March 31	2004	20
	Current Service Cost	\$ 2	\$
	Interest Cost	3	
	Expected Return on Plan Assets	(3)	
	-		
	Amortization of Net Actuarial Loss	-	
	Expense for Defined Contribution Plan	- 3	
		its defined benefit pension plans in 20	004. As
	 Expense for Defined Contribution Plan Net Defined Benefit Plan Expense The Company previously disclosed in its annual audited Conso December 31, 2003 that it expected to contribute \$6 million to March 31, 2004, no contributions have been made. The Compa 	lidated Financial Statements for the y its defined benefit pension plans in 20	004. As
	Expense for Defined Contribution Plan Net Defined Benefit Plan Expense The Company previously disclosed in its annual audited Conso December 31, 2003 that it expected to contribute \$6 million to March 31, 2004, no contributions have been made. The Compa to fund its defined benefit pension plans in 2004.	blidated Financial Statements for the y its defined benefit pension plans in 20 any presently anticipates contributing	004. As
	 Expense for Defined Contribution Plan Net Defined Benefit Plan Expense The Company previously disclosed in its annual audited Conso December 31, 2003 that it expected to contribute \$6 million to March 31, 2004, no contributions have been made. The Compa to fund its defined benefit pension plans in 2004. B) Share Appreciation Rights ("SAR's") 	blidated Financial Statements for the y its defined benefit pension plans in 20 any presently anticipates contributing	004. As \$6 millio Weigh
	 Expense for Defined Contribution Plan Net Defined Benefit Plan Expense The Company previously disclosed in its annual audited Conso December 31, 2003 that it expected to contribute \$6 million to March 31, 2004, no contributions have been made. The Compa to fund its defined benefit pension plans in 2004. B) Share Appreciation Rights ("SAR's") 	blidated Financial Statements for the y its defined benefit pension plans in 20 any presently anticipates contributing March 31, 2004: Outstanding	004. As \$6 millio Weigh Avera Exerc
	 Expense for Defined Contribution Plan Net Defined Benefit Plan Expense The Company previously disclosed in its annual audited Conso December 31, 2003 that it expected to contribute \$6 million to March 31, 2004, no contributions have been made. The Compa to fund its defined benefit pension plans in 2004. B) Share Appreciation Rights ("SAR's") The following table summarizes the information about SAR's at 	blidated Financial Statements for the y its defined benefit pension plans in 20 any presently anticipates contributing March 31, 2004:	004. As \$6 millio Weigh Avera Exerc
	 Expense for Defined Contribution Plan Net Defined Benefit Plan Expense The Company previously disclosed in its annual audited Conso December 31, 2003 that it expected to contribute \$6 million to March 31, 2004, no contributions have been made. The Compa to fund its defined benefit pension plans in 2004. B) Share Appreciation Rights ("SAR's") The following table summarizes the information about SAR's at 	blidated Financial Statements for the y its defined benefit pension plans in 20 any presently anticipates contributing March 31, 2004: Outstanding SAR's	004. As \$6 millid Weigh Avera Exerc Price
	 Expense for Defined Contribution Plan Net Defined Benefit Plan Expense The Company previously disclosed in its annual audited Conso December 31, 2003 that it expected to contribute \$6 million to March 31, 2004, no contributions have been made. The Compa to fund its defined benefit pension plans in 2004. B) Share Appreciation Rights ("SAR's") The following table summarizes the information about SAR's at 	blidated Financial Statements for the y its defined benefit pension plans in 20 any presently anticipates contributing March 31, 2004: Outstanding	004. As \$6 millid Weigh Avera Exerc Price 35.
	 Expense for Defined Contribution Plan Net Defined Benefit Plan Expense The Company previously disclosed in its annual audited Conso December 31, 2003 that it expected to contribute \$6 million to March 31, 2004, no contributions have been made. The Compa to fund its defined benefit pension plans in 2004. <i>B) Share Appreciation Rights ("SAR's")</i> The following table summarizes the information about SAR's at Canadian Dollar Denominated (C\$) Outstanding, Beginning of Year 	blidated Financial Statements for the y its defined benefit pension plans in 20 any presently anticipates contributing March 31, 2004: Outstanding SAR's 1,175,070	004. As \$6 milli Weigh Avera Exerc Price 35. 35.
	 Expense for Defined Contribution Plan Net Defined Benefit Plan Expense The Company previously disclosed in its annual audited Conso December 31, 2003 that it expected to contribute \$6 million to March 31, 2004, no contributions have been made. The Compa to fund its defined benefit pension plans in 2004. B) Share Appreciation Rights ("SAR's") The following table summarizes the information about SAR's at Canadian Dollar Denominated (C\$) Outstanding, Beginning of Year Exercised 	Didated Financial Statements for the y its defined benefit pension plans in 20 any presently anticipates contributing March 31, 2004: Outstanding SAR's 1,175,070 (372,828)	004. As \$6 millid Weigh Avera Exerc Price 35. 35. 36.
	 Expense for Defined Contribution Plan Net Defined Benefit Plan Expense The Company previously disclosed in its annual audited Conso December 31, 2003 that it expected to contribute \$6 million to March 31, 2004, no contributions have been made. The Compa to fund its defined benefit pension plans in 2004. <i>B) Share Appreciation Rights ("SAR's")</i> The following table summarizes the information about SAR's at Canadian Dollar Denominated (C\$) Outstanding, Beginning of Year Exercised Outstanding, End of Period 	Didated Financial Statements for the y its defined benefit pension plans in 20 any presently anticipates contributing March 31, 2004: Outstanding SAR's 1,175,070 (372,828) 802,242	004. As \$6 millid Weigh Avera Exerc Price 35. 35. 36.
	 Expense for Defined Contribution Plan Net Defined Benefit Plan Expense The Company previously disclosed in its annual audited Conso December 31, 2003 that it expected to contribute \$6 million to March 31, 2004, no contributions have been made. The Compa to fund its defined benefit pension plans in 2004. <i>B) Share Appreciation Rights ("SAR's")</i> The following table summarizes the information about SAR's at Canadian Dollar Denominated (<i>C\$</i>) Outstanding, Beginning of Year Exercised Outstanding, End of Period Exercisable, End of Period 	Didated Financial Statements for the y its defined benefit pension plans in 20 any presently anticipates contributing March 31, 2004: Outstanding SAR's 1,175,070 (372,828) 802,242 802,242 753,417	004. As \$6 millid Weigh Avera Exerc Price 35. 35. 36. 36. 28.
	 Expense for Defined Contribution Plan Net Defined Benefit Plan Expense The Company previously disclosed in its annual audited Conso December 31, 2003 that it expected to contribute \$6 million to March 31, 2004, no contributions have been made. The Compa to fund its defined benefit pension plans in 2004. <i>B) Share Appreciation Rights ("SAR's")</i> The following table summarizes the information about SAR's at Canadian Dollar Denominated (<i>C\$</i>) Outstanding, Beginning of Year Exercised Outstanding, End of Period Exercisable, End of Period U.S. Dollar Denominated (<i>US\$</i>) 	Didated Financial Statements for the y its defined benefit pension plans in 20 any presently anticipates contributing March 31, 2004:	004. As
	 Expense for Defined Contribution Plan Net Defined Benefit Plan Expense The Company previously disclosed in its annual audited Conso December 31, 2003 that it expected to contribute \$6 million to March 31, 2004, no contributions have been made. The Compa to fund its defined benefit pension plans in 2004. <i>B) Share Appreciation Rights ("SAR's")</i> The following table summarizes the information about SAR's at Canadian Dollar Denominated (C\$) Outstanding, Beginning of Year Exercised Outstanding, End of Period Exercisable, End of Period U.S. Dollar Denominated (US\$) Outstanding, Beginning of Year 	Didated Financial Statements for the y its defined benefit pension plans in 20 any presently anticipates contributing March 31, 2004: Outstanding SAR's 1,175,070 (372,828) 802,242 802,242 753,417	004. As \$6 millio Weigh Avera Exerc Price 35. 36. 36. 36. 28.

		Outstanding Tandem SAR's	Weighte Averag Exercis Price (C
	Canadian Dollar Denominated (C\$)		
	Outstanding, Beginning of Year Granted	206,900	53.0
	Outstanding, End of Period	206,900	53.0
	Exercisable, End of Period		
	<i>C) Deferred Share Units ("DSU's")</i> The following table summarizes the information about DSU's at March 31, 2004:		
		Outstanding DSU's	Weighte Averag Exercis Price (C
	Canadian Dollar Denominated (C\$)		
	Outstanding, Beginning of Year	319,250	48.6
	Granted, Directors	24,347	51.4
	Granted, Senior Executives	557	56.6
	Outstanding, End of Period Exercisable, End of Period	<u>344,154</u> 80,830	48.8
	D) Performance Share Units ("PSU's") The following table summarizes the information about PSU's at March 31, 2004:		
			Weight
		Outstanding PSU's	Averag Exerci Price (
	Canadian Dollar Denominated (C\$)		
	Outstanding, Beginning of Year	126,283	46.5
	Granted Outstanding, End of Period	1,664,911	53.9
	Exercisable, End of Period	1,791,194	53.4
	U.S. Dollar Denominated (US\$)		
	Outstanding, Beginning of Year	-	
	Granted	247,960	41.1
	Outstanding, End of Period	247,960	41.1
	Exercisable, End of Period	_	
OTE 12	PER SHARE AMOUNTS		
	The following table summarizes the Common Shares used in calculating Net Earning	s per Common S	hare:
		As at N	March 31
	(millions)	2004	200
	Weighted Average Common Shares Outstanding – Basic	460.9	479
	Effect of Dilutive Securities	6.2	4
	Weighted Average Common Shares Outstanding - Diluted	467.1	484

NOTE 13

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

As discussed in Note 2, on January 1, 2004, the fair value of all outstanding financial instruments that are not considered accounting hedges was recorded on the Consolidated Balance Sheet with an offsetting net deferred loss amount. The deferred loss is recognized into net earnings over the life of the associated contracts. Changes in fair value after that time are recorded on the Consolidated Balance Sheet with the 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.

The following table presents a reconciliation of the change in the unrealized amounts from January 1, 2004 to March 31, 2004:

		Ai	eferred mounts ognized nsition	ark-To- Market	 Total ealized 1/(Loss)
Fair Value of Contracts, January 1, 2004	(Note 2)	\$	235	\$ (235)	\$ _
Change in Fair Value of Contracts Still					
Outstanding at March 31, 2004			-	(316)	(316)
Fair Value of Contracts Realized During the Period			(137)	137	-
Fair Value of Contracts Entered into During the Period			-	(60)	(60)
Fair Value of Contracts Outstanding, End of Period		\$	98	\$ (474)	\$ (376)

The total realized loss recognized in net earnings for three months ended March 31, 2004 was \$145 million (\$99 million, net of tax).

At March 31, 2004, the net deferred amounts recognized on transition and the risk management amounts are recorded on the Consolidated Balance Sheet as follows:

	As at
	March 31, 2004
Deferred Amounts Recognized on Transition:	
Accounts receivable and accrued revenues	\$ 211
Investments and other assets	2
Accounts payable and accrued liabilities	40
Other liabilities	75
Total Net Deferred Loss	\$ 98
Risk Management	
Current asset	\$ 39
Long-term asset	86
Current liability	559
Long-term liability	40
Total Net Risk Management Liability	\$ (474)

A summary of all unrealized estimated fair value financial positions is as follows:

	March 31, 2004
Commodity Price Risk	
Natural gas	\$ (147)
Crude oil	(369)
Power	5
Foreign Currency Risk	(1)
Interest Rate Risk	38
	\$ (474)

As at

Information with respect to power, foreign currency risk and interest rate risk contracts in place at December 31, 2003 is disclosed in Note 17 to the Company's annual audited Consolidated Financial Statements. No significant new contracts have been entered into as at March 31, 2004.

Natural Gas

At March 31, 2004, the Company's gas risk management activities for financial contracts had an unrealized loss of \$147 million. The contracts were as follows:

	Notional Volumes (MMcf/d)	Term	Price		ealized n/(Loss
Fixed Price Contracts					
Sales Contracts					
Fixed AECO price	452	2004	6.20	C\$/Mcf	\$ (59
NYMEX Fixed price	712	2004	5.03	US\$/Mcf	(183
Chicago Fixed price	40	2004	5.41	US\$/Mcf	(7
AECO Collars	71	2004	5.34-7.52	C\$/Mcf	(4
Basis Contracts					
Sales Contracts					
Fixed NYMEX to AECO basis	352	2004	(0.55)	US\$/Mcf	24
Fixed NYMEX to Rockies basis	277	2004	(0.49)	US\$/Mcf	18
Fixed NYMEX to San Juan basis	64	2004	(0.63)	US\$/Mcf	1
Fixed Rockies to CIG basis	50	2004	(0.10)	US\$/Mcf	-
Fixed NYMEX to AECO basis	877	2005	(0.66)	US\$/Mcf	24
Fixed NYMEX to Rockies basis	258	2005	(0.48)	US\$/Mcf	17
Fixed NYMEX to San Juan basis	75	2005	(0.63)	US\$/Mcf	1
Fixed NYMEX to CIG basis	25	2005	(0.87)	US\$/Mcf	(2
Fixed Rockies to CIG basis	50	2005	(0.10)	US\$/Mcf	-
Fixed NYMEX to AECO basis	402	2006-2008	(0.65)	US\$/Mcf	18
Fixed NYMEX to Rockies basis	162	2006-2008	(0.56)	US\$/Mcf	16
Fixed NYMEX to San Juan basis	62	2006	(0.63)	US\$/Mcf	1
Fixed NYMEX to CIG basis	125	2006	(0.87)	US\$/Mcf	(6
Fixed Rockies to CIG basis	31	2006-2007	(0.10)	US\$/Mcf	(1
Purchase Contracts					
Fixed NYMEX to AECO basis	38	2004	(0.73)	US\$/Mcf	 (1
Gas Storage Financial Positions					(143 (10
Gas Marketing Financial Positions (1)					6
U					\$ (147
(1) The gas marketing activities are part of the daily ong	going operations of the	Company's propriet	ary production m	anagement.	\$ (

		Notional Volumes (bbl/d)	Term	Average Price (US\$/bbl)	Unrealize Gain/(Los
	Fixed WTI NYMEX Price Collars on WTI NYMEX	62,500 62,500	2004 2004	23.13 20.00–25.69	\$ (18 (13
	Fixed WTI NYMEX Price	45,000	2004	28.41	(13)
	3-way Put Spread	10,000	2005	20.00/25.00/28.78	(1
	Crude Oil Marketing Financial Position	as ⁽¹⁾			(36
	(1) The crude oil marketing activities are part of	f the daily ongoing operations of	of the Company's I	proprietary production manage	\$ (36
NOTE 14	SUBSEQUENT EVENT				
	On April 15, 2004, the Company an and outstanding common shares of To operations in the United States and 0 assumption of debt of approximately	om Brown, Inc., a public Canada, for total cash c	cly traded expl consideration of	oration and production of approximately \$2.3 b	company with oillion plus th
NOTE 15	RECLASSIFICATION Certain information provided for pr	rior periods has been r	eclassified to	conform to the present	ation adopte
	in 2004.	nor perious has been r		contorni to the present	ation adopte

SUPPLEMENTAL FINANCIAL INFORMATION (unaudited)

Financial Statistics						
	2004			2003		
(US\$ millions, except per share amounts)	Q1	Year	Q4	Q3	Q2	Q1
Cash Flow	995	4,459	1,254	977	1,007	1,221
Per share – Basic	2.16	9.41	2.71	2.06	2.10	2.54
– Diluted	2.13	9.30	2.69	2.04	2.08	2.52
Net Earnings	290	2,360	426	290	807	837
Per share – Basic	0.63	4.98	0.92	0.61	1.68	1.74
– Diluted	0.62	4.92	0.91	0.61	1.67	1.73
Net Earnings from Continuing Operations	290	2,167	426	286	805	650
Per share – Basic	0.63	4.57	0.92	0.60	1.67	1.35
– Diluted	0.62	4.52	0.91	0.60	1.66	1.34
Operating Earnings *	465	1,375	316	274	275	510
Per share – Diluted	1.00	2.87	0.68	0.57	0.56	1.05
Foreign Exchange Rates (US\$ per C\$1)						
Average	0.759	0.716	0.760	0.725	0.715	0.662
Period end	0.763	0.774	0.774	0.741	0.738	0.681

* Operating Earnings is a non-GAAP measure defined as Net Earnings from Continuing Operations excluding 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.

	2004			2003		
Common Shares Information	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding (millions)						
Period end	459.8	460.6	460.6	465.0	479.9	480.6
Average – Basic	460.9	474.1	462.3	473.4	480.6	479.9
Average – Diluted	467.1	479.7	465.9	477.9	484.4	484.3
Price Range (\$ per share)						
TSX – C\$						
High	59.27	53.55	52.25	52.79	53.55	50.00
Low	51.00	44.60	44.60	47.49	45.26	45.74
Close	56.69	51.00	51.00	48.90	51.70	47.75
NYSE – US\$						
High	44.25	40.08	40.08	38.34	39.63	33.50
Low	38.36	29.91	33.46	34.00	30.45	29.91
Close	43.12	39.44	39.44	36.38	38.37	32.36
Share Volume Traded (millions)	128.8	476.4	141.1	117.9	107.2	110.2
Share Value Traded (US\$ millions weekly average)	403.7	317.6	397.3	321.5	289.9	266.7
Financial Metrics						
Debt to Capitalization	37%					
Debt to EBITDA	1.6x					
Return on Capital Employed	13%					
Return on Common Equity	17%					

SUPPLEMENTAL FINANCIAL INFORMATION (unaudited)		
Financial Statistics (continued)		
Net Capital Investment (US\$ millions)	2004	2003
Upstream		
Canada	\$ 1,014	\$ 703
United States	210	139
Ecuador	54	73
United Kingdom	93	16
Other Countries	15	17
	1,386	948
Midstream & Marketing	9	21
Corporate	9	12
Core Capital	1,404	981
Acquisitions		
Upstream		
Property		
Canada	14	4
United States	-	11
United Kingdom	120	-
Midstream & Marketing	-	15
Corporate	253	116
Dispositions		
Upstream		
Property		
Canada	(24)	(7)
United States	(1)	-
Corporate	(541)	
Net Capital Investment – Continuing Operations	1,225	1,120
Discontinued Operations	-	(1,289)
Total Net Capital Investment	\$ 1,225	\$ (169)

<i>Operating Statistics – After Royalties</i>	2004			2003		
Sales Volumes	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas (MMcf/d)						
Canada						
Production	2,000	1,935	2,008	1,914	1,899	1,922
Inventory withdrawal		30	-	-	-	120
Canada Sales	2,000	1,965	2,008	1,914	1,899	2,042
United States	684	588	654	604	558	534
United Kingdom	28	13	20	7	12	13
	2,712	2,566	2,682	2,525	2,469	2,589
Oil and Natural Gas Liquids (bbls/d)						
North America						
Light and Medium Oil	54,940	54,459	56,585	54,597	52,733	53,890
Heavy Oil	87,729	87,867	95,059	94,985	82,001	79,171
Natural Gas Liquids*						
Canada	13,971	14,278	13,348	13,758	14,740	15,291
United States	9,237	9,291	9,479	9,530	10,194	7,943
Total North America	165,877	165,895	174,471	172,870	159,668	156,295
Ecuador						
Production	76,320	51,089	72,731	54,582	36,754	39,893
Transferred to OCP Pipeline**	-	(3,213)	-	(4,919)	(2,039)	(5,941)
Over / (under) lifting	4,662	(1,355)	4,621	(9,856)	2,506	(2,679)
Ecuador Sales	80,982	46,521	77,352	39,807	37,221	31,273
United Kingdom	18,088	10,128	15,067	5,813	9,019	10,610
Total Oil and Natural Gas Liquids	264,947	222,544	266,890	218,490	205,908	198,178
Total (BOE/d)	716,947	650,211	713,890	639,323	617,408	629,678

* Natural gas liquids include condensate volumes.

** Crude oil production in Ecuador transferred to the OCP Pipeline for use by OCP in asset commissioning.

Operating Statistics – After Royalties (continued)	2004			2003		
Per-unit Results (excluding impact of financial hedging)	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas – Canada (US\$/Mcf)						
Price, net of royalties	5.21	4.87	4.41	4.61	4.92	5.53
Production and mineral taxes	0.08	0.07	0.10	0.08	0.08	0.02
Transportation and selling	0.44	0.38	0.44	0.40	0.35	0.33
Operating expenses	0.56	0.48	0.45	0.50	0.47	0.48
Netback	4.13	3.94	3.42	3.63	4.02	4.70
Produced Gas – United States (US\$/Mcf)						
Price, net of royalties	5.39	4.88	4.71	4.82	4.74	5.32
Production and mineral taxes	0.51	0.47	0.42	0.46	0.46	0.57
Transportation and selling	0.39	0.40	0.51	0.39	0.36	0.32
Operating expenses	0.33	0.28	0.29	0.33	0.31	0.20
Netback	4.16	3.73	3.49	3.64	3.61	4.23
Produced Gas – Total North America (US\$/Mcf)						
Price, net of royalties	5.26	4.87	4.49	4.66	4.88	5.49
Production and mineral taxes	0.19	0.16	0.18	0.17	0.17	0.14
Transportation and selling	0.43	0.39	0.46	0.40	0.35	0.33
Operating expenses	0.50	0.43	0.41	0.46	0.43	0.42
Netback	4.14	3.89	3.44	3.63	3.93	4.60
Light and Medium Oil – North America (US\$/bbl)						
Price, net of royalties	29.92	26.61	25.53	24.31	27.43	29.34
Production and mineral taxes	0.86	0.29	0.73	(1.35)	0.71	1.08
Transportation and selling	1.19	1.42	1.33	0.71	1.73	1.95
Operating expenses	5.87	6.00	6.28	5.93	6.07	5.68
Netback	22.00	18.90	17.19	19.02	18.92	20.63
Heavy Oil - North America (US\$/bbl)						
Price, net of royalties	21.48	19.61	18.43	17.93	20.07	22.62
Production and mineral taxes	0.06	(0.03)	0.09	(0.49)	0.34	(0.02)
Transportation and selling	1.69	1.24	1.54	0.58	1.37	1.56
Operating expenses	5.44	5.67	4.95	5.93	6.18	5.70
Netback	14.29	12.73	11.85	11.91	12.18	15.38
Total Crude Oil – North America (US\$/bbl)						
Price, net of royalties	24.73	22.29	21.08	20.26	22.95	25.34
Production and mineral taxes	0.37	0.09	0.33	(0.80)	0.49	0.43
Transportation and selling	1.50	1.31	1.46	0.63	1.51	1.72
Operating expenses	5.61	5.80	5.45	5.93	6.13	5.70
Netback	17.25	15.09	13.84	14.50	14.82	17.49

Operating Statistics – After Royalties (continued)	2004			2003		
Per-unit Results (excluding impact of financial hedging) (continued)	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids – Canada (US\$/bbl)						
Price, net of royalties	27.27	24.26	25.13	23.52	21.02	27.31
Production and mineral taxes	_	-	_	_	_	-
Transportation and selling	0.35	0.17	0.13	0.58	_	_
Netback	26.92	24.09	25.00	22.94	21.02	27.31
Natural Gas Liquids – United States (US\$/bbl)						
Price, net of royalties	32.77	26.97	26.68	25.50	24.64	32.18
Production and mineral taxes	3.09	2.03	2.69	2.64	1.21	1.55
Transportation and selling	_	-	-	_	-	-
Netback	29.68	24.94	23.99	22.86	23.43	30.63
Natural Gas Liquids – Total North America (US\$/bbl)						
Price, net of royalties	29.46	25.33	25.77	24.33	22.50	28.98
Production and mineral taxes	1.23	0.80	1.12	1.08	0.50	0.53
Transportation and selling	0.21	0.10	0.08	0.35	-	-
Netback	28.02	24.43	24.57	22.90	22.00	28.45
Total Liquids – Canada (US\$/bbl)						
Price, net of royalties	24.95	22.47	21.41	20.54	22.76	25.55
Production and mineral taxes	0.34	0.08	0.30	(0.73)	0.44	0.38
Transportation and selling	1.40	1.21	1.36	0.62	1.36	1.54
Operating expenses	5.11	5.27	5.01	5.43	5.53	5.11
Netback	18.10	15.91	14.74	15.22	15.43	18.52
Ecuador Oil (US\$/bbl)						
Price, net of royalties	23.82	24.21	23.57	22.13	22.31	30.86
Production and mineral taxes	1.37	1.47	1.06	0.45	1.11	4.27
Transportation and selling	2.63	2.56	2.81	2.36	2.41	2.35
Operating expenses	4.04	4.84	4.62	4.33	5.63	5.09
Netback	15.78	15.34	15.08	14.99	13.16	19.15
United Kingdom Oil (US\$/bbl)						
Price, net of royalties	31.11	28.11	27.05	27.92	27.17	30.61
Transportation and selling	1.94	1.97	1.70	1.98	1.86	2.45
Operating expenses	3.86	5.09	6.23	6.55	4.69	2.92
Netback	25.31	21.05	19.12	19.39	20.62	25.24
Total Liquids – All Countries (US\$/bbl)						
Price, net of royalties	25.23	23.25	22.51	21.22	22.93	26.89
Production and mineral taxes	0.73	0.45	0.59	(0.35)	0.58	1.02
Transportation and selling	1.76	1.47	1.74	0.95	1.51	1.64
Operating expenses	4.49	4.93	4.75	5.01	5.22	4.77
Netback	18.25	16.40	15.43	15.61	15.62	19.46

Operating Statistics – After Royalties (continued)	2004			2003		
Impact of Financial Hedging	Q1	Year	Q4	Q3	Q2	Q1
Natural gas (\$/Mcf)	(0.08)	(0.10)	0.16	(0.06)	(0.25)	(0.25)
Liquids (\$/bbl)	(5.39)	(2.54)	(2.15)	(2.18)	(1.61)	(4.45)
Total (\$/BOE)	(2.29)	(1.25)	(0.22)	(0.99)	(1.55)	(2.43)
	2004			2003		
Average Royalty Rates (excluding impact of financial hedging)	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas						
Canada	13.3%	12.9%	12.2%	12.9%	14.2%	12.4%
United States	19.3%	20.0%	19.5%	20.2%	20.1%	20.5%
Crude Oil						
Canada and United States	9.4%	10.3%	9.7%	9.0%	10.7%	11.8%
Ecuador	27.4%	25.6%	25.4%	25.7%	24.9%	26.9%
Natural Gas Liquids						
Canada	14.8%	17.5%	14.7%	16.6%	18.0%	20.2%
United States	19.2%	17.6%	17.5%	17.0%	17.3%	18.5%
Total Upstream	15.2%	14.5%	14.4%	14.2%	15.1%	14.4%

ENCANA CORPORATION



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