ENCANA

ENCANA EARNS $1.2 BILLION IN FIRST QUARTER OF 2003, $790 MILLION EXCLUDING GAINS, CASH FLOW APPROACHES $1.9 BILLION

Performance right on track as gas sales exceed 3 billion cubic feet per day

CALGARY, ALBERTA, (MAY 8, 2003) – EnCana Corporation (TSX & NYSE: ECA) earned $1.246 billion, or $2.57 per common share diluted, in the first quarter of 2003 and generated $1.852 billion of cash flow, or $3.80 per common share diluted. On a pro forma basis in the first quarter of 2002, EnCana earned $163 million, or 34 cents per common share diluted, and generated $779 million, or $1.61 per common share diluted, of cash flow.

First quarter earnings included a one-time, after-tax gain of approximately $263 million, or 54 cents per common share diluted, on the sale of EnCana's interests in two oil pipelines, plus an unrealized after-tax gain of approximately $193 million, or 40 cents per common share diluted, related to foreign exchange gains on the translation of EnCana's U.S. dollar debt. These gains, which had no impact on cash flow, totalled $456 million, or 94 cents per common share diluted. Excluding these two items, EnCana earned $790 million, or $1.63 per common share diluted, from continuing operations. Revenues, net of royalties and production taxes, in the first quarter were $4.158 billion, while core capital investment was $1.587 billion.

All references to 2002 production, sales and financial information in this quarterly report text and tables for EnCana are presented on a pro forma basis as if the merger of PanCanadian Energy Corporation ("PanCanadian" or "PCE") and Alberta Energy Company Ltd. ("AEC") had occurred at the beginning of 2002. All dollar figures are Canadian unless otherwise stated.

NATURAL GAS AND OIL SALES 10 PERCENT HIGHER IN PAST YEAR

First quarter daily conventional oil and gas sales increased 10 percent averaging 735,836 barrels of oil equivalent (BOE) compared to the pro forma conventional sales of 669,298 barrels of oil equivalent during the first quarter of 2002. Daily natural gas sales increased 11 percent to average 3,016 million cubic feet, which included an average of 141 million cubic feet per day of sales from EnCana's gas storage. First quarter natural gas production increased 12 percent over the same period in 2002. Conventional oil and natural gas liquids sales increased 8 percent to average 233,169 barrels per day, compared to pro forma sales of 215,298 barrels per day in the first quarter of 2002. EnCana drilled 1,329 net wells in the first quarter.

"EnCana is right on track, achieving record financial and operating performance as it embarks on its second year of operations. Strong growth in sales of conventional oil and natural gas combined with robust commodity prices produced exceptionally strong financial results," said Gwyn Morgan, EnCana's President & Chief Executive Officer. "With the outlook for a continuation of very strong gas pricing fundamentals, EnCana is extremely well positioned to capitalize on a production mix that is leveraged two-thirds to North American natural gas. The company's current gas field productive capacity is already in the range of its 2003 sales target of 3.0 billion to 3.1 billion cubic feet per day. "The success we achieved in our first year is continuing in 2003. As part of the company's strategic realignment, we completed the sale of our interests in the Express and Cold Lake pipeline systems and sold a 10 percent interest in Syncrude. The $2.7 billion of gross proceeds generated by these sales have fortified an already strong balance sheet. EnCana has the financial strength to fund industry-leading internal growth while maintaining flexibility to act opportunistically on value creating, tuck-in acquisitions in our core operating areas. We will also continue to compare these uses of capital with the value-creation potential of share buybacks under our Normal Course Issuer Bid," Morgan said.

STRONG WINTER DEMAND AND TIGHT NORTH AMERICA SUPPLY DRIVE FIRST QUARTER GAS PRICES HIGHER

In the first three months of 2003, a combination of cold weather across North America's large consuming regions and weakening North American natural gas production levels drove prices to two-year highs. In the first quarter, the average AECO index price was $7.92 per thousand cubic feet, up 137 percent from the first quarter of 2002. U.S. gas storage volumes are at record lows, while Canadian gas storage volumes are well below the five-year average. In 2002, U.S. supply fell about 4.7 percent from 2001, while Canadian supply was down approximately 3.5 percent in the same time period. Demands to refill storage, combined with normal summer weather, are expected to keep prices strong throughout 2003.

WORLD OIL PRICES EXCEPTIONALLY STRONG DUE TO SUPPLY UNCERTAINTY IN MIDDLE EAST AND VENEZUELA

During the first quarter, the average benchmark West Texas Intermediate crude oil price was US$33.80, up 56 percent over the same period last year. Although oil prices have retreated from these high levels, volatility is expected to continue due to the challenges of reintegrating Iraq production, political issues in Venezuela and Nigeria, OPEC compliance with production quotas and world economic uncertainty.

RISK MANAGEMENT PROGRAMS MITIGATE VOLATILITY

EnCana's risk management program is designed to partially mitigate the volatility associated with commodity prices, exchange rates and interest rates. As a means of managing the impact of commodity price volatility in its producing areas and to help provide greater certainty in cash flow generation for its high-return capital investment program, EnCana has entered into various fixed-price contracts for a portion of its forecast 2003 sales. With the high oil and gas prices experienced in the first quarter, EnCana's commodity price risk management measures, including financial and physical transactions, resulted in pre-tax revenue being lower by approximately $100 million, comprised of $122 million lower revenues on oil sales and $22 million of higher revenues from gas sales. The $22 million of higher gas revenues is comprised of $111 million of higher revenues from physical transactions and $89 million of lower revenues from commodity financial transactions. The $122 million of lower revenues from oil sales was associated with commodity financial transactions only.

Consolidated EnCana Highlights

FINANCIAL HIGHLIGHTS

(as at and for the three months ended March 31) *($ millions, except per share amounts)*	**EnCana Q1 2003 Actuals**	EnCana Q1 2002 Pro Forma[2]
REVENUES, NET OF ROYALTIES AND PRODUCTION TAXES	**4,158**	2,263
Cash Flow	**1,852**	779
Per common share – diluted	**3.80**	1.61
Net earnings		
From Continuing Operations excluding F/X gain (loss) on translation of US$ debt (after-tax)	**790**	156
Per common share – basic	**1.66**	0.33
Per common share – diluted	**1.63**	0.32
From foreign exchange gain (loss) on translation of US$ debt (after-tax)	**193**	(1)
Per common share – basic	**0.40**	–
Per common share – diluted	**0.40**	–
From Continuing Operations	**983**	155
Per common share – basic	**2.06**	0.33
Per common share – diluted	**2.03**	0.32
From Discontinued Operations	**263**	8
Per common share – basic	**0.55**	0.02
Per common share – diluted	**0.54**	0.02
Net earnings	**1,246**	163
Per common share – diluted[1]	**2.61**	0.34
Per common share – diluted	**2.57**	0.34
Core capital investment	**1,587**	1,296
Total assets	**29,410**	29,570
Long-term debt	**5,867**	6,938
Preferred securities	**567**	584
Shareholders' equity	**14,994**	13,101
Debt-to-capitalization ratio (adjusted for working capital & including preferred securities as debt)	**29%**	39%
Common shares		
Outstanding at March 31 (millions)	**480.6**	474.1
Weighted average diluted (millions)	**486.9**	483.6

[1] **Impact of including share options in earnings calculations**
If EnCana were to record compensation expense for outstanding stock options, earnings per common share – basic would have been $2.58 per common share, $0.03 per common share less, during the first quarter of 2003.

[2] **Important Notice: Readers are cautioned that comparisons to prior years' results are based on pro forma calculations and these pro forma results may not reflect all adjustments and reconciliations that may be required under Canadian generally accepted accounting principles. These pro forma results may not be indicative of the results that actually would have occurred or of the results that may be obtained in the future. Also, certain information provided for prior years has been reclassified to conform to the presentation adopted in 2002.**

(for the period ended March 31)	**Q1 2003 Actuals**	Q1 2002 Pro Forma	% Change
SALES			
Natural gas *(MMcf/d)*			
North America	**3,003**	2,713	+11
U.K	**13**	11	+18
Total natural gas	**3,016**	2,724	+11
Conventional oil and NGLs *(bbls/d)*			
North America	**179,795**	163,635	+10
Ecuador	**42,764**	38,774	+10
U.K.	**10,610**	12,889	–18
Total oil and NGLs *(bbls/d)**	**233,169**	215,298	+8
Total conventional sales *(BOE/d)**	**735,836**	669,298	+10
Prices, including hedging			
North American gas price *($/Mcf)*	**7.45**	3.43	+117
North American conventional oil price *($/bbl)*			
Light/medium	**32.53**	26.11	+25
Heavy	**22.97**	21.56	+7
Syncrude *($/bbl)*	**48.97**	34.86	+40
International crude oil *($/bbl)*			
Ecuador	**43.90**	22.07	+99
U.K.	**42.53**	30.85	+38
Natural gas liquids *($/bbl)*	**43.73**	22.72	+92
Total liquids *($/bbl)*	**34.04**	25.24	+35

* Excludes Syncrude which averaged 20,272 barrels per day in the first quarter of 2003, compared to 31,548 barrels per day in the first quarter of 2002.

EnCana targeting 10 percent per share internal sales growth in 2003

EnCana's 2003 total daily conventional oil and gas sales volumes are forecast to grow by an average of 10 percent per share from 2002 pro forma rates to between 740,000 and 797,000 barrels of oil equivalent, excluding Syncrude. That sales forecast is comprised of between 3 billion and 3.1 billion cubic feet of gas per day and 240,000 and 280,000 barrels of conventional oil and natural gas liquids per day.

ENCANA CORPORATE DEVELOPMENTS

EnCana completes sale of interests in two major oil pipelines and 10 percent share of Syncrude

During the first quarter of 2003, EnCana closed the sales of its indirect 100 percent ownership of the Express Pipeline System and its indirect 70 percent interest in the Cold Lake Pipeline System for a total consideration of approximately $1.6 billion, which included assumed debt of approximately $599 million. EnCana also sold a 10 percent share of the Syncrude project to Canadian Oil Sands Limited for approximately $1.07 billion. EnCana's remaining 3.75 percent share of Syncrude is considered a non-core asset.

Normal Course Issuer Bid purchases

To date, EnCana has purchased for cancellation 676,900 of its common shares at an average price of $45.89 per common share under the company's Normal Course Issuer Bid. Under the bid, EnCana may purchase for cancellation up to 23,843,565 of its common shares, representing 5 percent of the 476,871,300 common shares outstanding as at October 4, 2002.

Dividend

The board of directors of EnCana declared a quarterly dividend of 10 cents per share payable on June 30, 2003 to common shareholders of record as of June 13, 2003.

FINANCIAL STRENGTH

EnCana possesses one of the strongest financial positions among its upstream independent peer group. At March 31, 2003, the company's debt-to-capitalization ratio was 29:71 (preferred securities included as debt). EnCana's debt-to-EBIDTA multiple, on a trailing 12-month basis, was 0.9 times. First quarter core capital investment was $1,587 million. Corporate acquisitions were $179 million and net proceeds from asset and corporate dispositions were $2,034 million, resulting in negative net capital investment of $268 million. EnCana's operating costs on conventional oil and gas production averaged $4.20 per barrel of oil equivalent for the quarter.

EnCana maintains strong investment grade ratings from the major bond rating services: Dominion Bond Rating Service Limited, A(low), Moody's Investors Service, Baa1, and Standard and Poor's Ratings Services, A-. The company also has a $4 billion credit facility with a syndicate of major banks and lending institutions, of which more than $3 billion remains unutilized.

ENCANA OPERATIONAL HIGHLIGHTS

North America

First quarter gas and conventional liquids sales up 10 percent year-over-year

EnCana's North American gas and conventional oil and natural gas liquids sales continued to grow at double-digit rates in the first quarter, averaging 680,295 barrels of oil equivalent per day – a 10 percent increase over the pro forma average of 615,802 barrels of oil equivalent per day in the first quarter of 2002. Gas production increased 12 percent in the past year, averaging approximately 2.9 billion cubic feet per day. Conventional liquids production was up about 10 percent year-over-year, averaging approximately 180,000 barrels per day. The company also sold an average of 141 million cubic feet per day of gas from storage in the quarter. Gas production growth was led by increased production from the U.S. Rockies, Ferrier, Suffield and the Palliser block in Alberta and Greater Sierra in northeast British Columbia. Rising output from the company's two steam-assisted gravity drainage (SAGD) projects in northeast Alberta, combined with production increases at Suffield, raised the company's conventional oil production in the first quarter. In North America, EnCana drilled 1,317 net wells during the first quarter.

U.S. Rockies delivers tremendous growth in year-over-year gas sales

U.S. Rockies first quarter gas sales rose more than 80 percent to average 672 million cubic feet per day, compared to an average of 365 million cubic feet per day on a pro forma basis from the first quarter of 2002. Production growth in the U.S Rockies is primarily from the Jonah field in Wyoming and the Mamm Creek field in Colorado. EnCana has fixed the NYMEX price differential on 566 million cubic feet per day of forecast 2003 gas sales at an average basis of US$0.50 per thousand cubic feet, and an additional 392 million cubic feet per day of forecast gas sales for 2004 through 2007 at an average basis of US$0.45 per thousand cubic feet.

"This high growth region continues to deliver tremendous performance. With more than 1.6 million net undeveloped acres and the recent addition of gas transmission capacity out of the region on the Kern River pipeline expansion, we plan to continue to set the pace for gas growth in the U.S. Rockies, " said Randy Eresman, EnCana's Chief Operating Officer.

Winter drilling builds production volumes in northeast British Columbia

EnCana drilled 91 net wells in the Greater Sierra area of northeast British Columbia, where production in the first quarter averaged 158 million cubic feet per day, up 12 percent from pro forma production one year earlier. With the recent gathering system expansion, production is currently at about 210 million cubic feet per day in Greater Sierra.

"Our assembly line drilling methods enabled us to keep more than 30 rigs running through to spring break up, while reducing costs for each well drilled. This successful drilling season has resulted in continued strong production growth in our fastest growing Canadian region," Eresman said.

Canada's leading SAGD project delivering steady volumes

EnCana's largest SAGD thermal oilsands project at Foster Creek in northeast Alberta is currently producing at its design rate of approximately 20,000 barrels of oil per day. EnCana has started its 80-megawatt co-generation plant at Foster Creek, which is expected to lower the SAGD project's operating costs by an estimated $2 per barrel. The company continues to target operating costs in the range of $6 to $7 per barrel, assuming an AECO gas price of $5 per thousand cubic feet, when all facilities are fully operational. The power plant is generating about 45 megawatts of electricity for sale to the Alberta power grid.

Gulf of Mexico – successful appraisal drilling at Tahiti

Exploration success continues at the Tahiti prospect in the deep water Gulf of Mexico, where two successful appraisal wells have increased confidence that the field contains between 400 million and 500 million barrels of estimated recoverable oil. The appraisal program confirmed that the Tahiti reservoirs are well developed and correlate over a five-kilometer distance. One of the appraisal wells encountered more than 1,000 feet of net pay in high-quality sandstones, making it one of the thickest net pay accumulations in the history of the deep water Gulf of Mexico. EnCana holds a 25 percent interest in this ChevronTexaco-operated discovery.

East Coast of Canada – Deep Panuke

EnCana is conducting a thorough review of its Deep Panuke natural gas development project, examining ways to enhance project economics. Following a request by EnCana for an adjournment, the Canada-Nova Scotia Offshore Petroleum Board and the National Energy Board have agreed to suspend the development's regulatory review. EnCana plans to update the regulatory agencies by the end of 2003. To better evaluate the ultimate natural gas potential in the Deep Panuke area, EnCana has additional exploration planned for 2003.

EnCana closes sale of 10 percent interest in Syncrude

EnCana's share of Syncrude production during the first quarter of 2003 averaged 20,272 barrels per day. This lower quarterly volume reflects the completion of the sale, on February 28, 2003, of a 10 percent interest in Syncrude to Canadian Oil Sands Limited.

International

EnCana's first quarter international oil and natural gas liquids production averaged 63,680 barrels per day, but sales were reduced to 53,374 barrels per day primarily as a result of directing oil for line fill into Ecuador's OCP Pipeline, marking the beginning of a major new oil growth opportunity for EnCana and the South American nation. In the U.K., EnCana and its partners are finalizing work on the design and environmental statement for development of the Buzzard discovery, which is scheduled to start production in 2006.

Ecuador – first barrels flowing into OCP Pipeline tanks

First quarter production in Ecuador averaged 54,726 barrels of oil per day, up 9 percent from an average of 50,351 barrels per day on a pro forma basis one year earlier. While daily production has increased year-over-year, 2003 reported sales volumes exclude an average of 8,191 barrels per day during the first quarter which was delivered to line fill for the new OCP Pipeline.

Midstream & Marketing

EnCana's Midstream & Marketing division achieved first quarter operating cash flow from continuing operations of about $55 million.

Gas storage expands with first phase of Countess facility

EnCana plans to open the first 10 billion cubic feet of storage capacity this summer at its new Countess facility, located about 85 kilometres east of Calgary. Injections are planned during the summer, in preparation for winter withdrawals. The first phase of the Countess facility, which is intended to become a significant new component of EnCana's AECO Hub, is on time and on budget. Completion of the project, designed to take total Countess capacity to about 40 billion cubic feet, is expected by April 2005. In northern California, EnCana continues construction work on increasing the Wild Goose gas storage facility to 23 billion cubic feet of capacity by spring 2004, with further expansions to 29 billion cubic feet expected by spring 2005.

OCP Pipeline nears completion

Ecuador's OCP Pipeline is more than 95 percent complete, with producers having delivered more than 1 million barrels of oil into OCP's Amazonas Oil Terminal for use in commissioning the pipeline system. Commissioning of the system's pumping stations and receiving and shipping terminals is underway. First oil is expected to be shipped from the OCP marine terminal on the Pacific coast this summer.

"Ecuador is on the verge of achieving a major milestone in its journey towards economic stability with the pending completion of the OCP Pipeline. EnCana is proud to partner with the people of Ecuador in this milestone," said Bill Oliver, EnCana's President of Midstream & Marketing.

ENCANA CORPORATION

EnCana is one of the world's leading independent oil and gas companies with an enterprise value of approximately C$30 billion. EnCana is North America's largest independent natural gas producer and gas storage operator. Ninety percent of the company's assets are in four key North American growth platforms. EnCana is the largest producer and landholder in Western Canada and is a key player in Canada's emerging offshore East Coast basins. In the U.S., 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. The company has two key high potential international growth platforms: EnCana is the largest private sector oil producer in Ecuador and is the operator of a large oil discovery in the U.K. central North Sea. The company also conducts high upside potential New Ventures exploration in other parts of the world. EnCana is driven to be the industry's best-in-class benchmark in production cost, per-share growth and value creation for shareholders. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

ADVISORY – In the interests of providing EnCana shareholders and potential investors with information regarding EnCana, including management's assessment of EnCana's 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, EnCana's internal projections, expectations or beliefs concerning future operating results, and various components thereof; EnCana's ability to invest selectively and returns on such investments; drilling activity in North America in 2003; future economic performance; the production and growth potential of EnCana's various assets, including assets in the U.S. Rockies, Greater Sierra, offshore Canada's East Coast, the U.K. central North Sea, the Gulf of Mexico and Ecuador; the anticipated oil and natural gas prices for the remainder of 2003; the ability to achieve production and sales growth targets for 2003 and beyond (including per share sales growth); the sources and deployment of expected capital in 2003; the projected annual post-merger synergies in 2003; the anticipated completion of the different phases of the Countess gas storage project and the Wild Goose gas storage project in 2003 and beyond; EnCana's plans for its gas storage facilities; the timing of updates to regulators regarding progress on enhancements to the Deep Panuke project; projected gas storage capacity in 2004 and 2005; the success of future drilling prospects; potential exploration; the potential success of certain projects such as SAGD, Buzzard (including in 2006), coalbed methane, the OCP Pipeline, the Kern River pipeline, the Foster Creek co-generation plant and Syncrude and the expected rates of returns from such projects; the potential reduction of operating costs for SAGD; the potential capacity of the OCP Pipeline; the ability and timing of meeting EnCana's targeted transportation commitments on the OCP Pipeline; the proposed dates of drilling and production in the U.K. central North Sea; and the potential success of other exploratory wells in the Gulf of Mexico, offshore Canada's East Coast and the U.K. central North Sea.

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; imprecision of reserve estimates; 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 international war, hostilities, civil insurrection and instability affecting countries in which the company operates and international terrorist threats; the risk that the anticipated synergies to be realized by the merger of AEC and PanCanadian will not be realized; costs relating to the merger of AEC and PanCanadian being higher than anticipated 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 quarterly report are made as of the date of this quarterly report, and EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this quarterly report are expressly qualified by this cautionary statement.

Further information on EnCana Corporation is available on the company's Web site, www.encana.com, or by contacting:

FOR FURTHER INFORMATION:

Investor contact:

EnCana Corporate Development

Sheila McIntosh

Senior Vice-President, Investor Relations

(403) 645-2194

Greg Kist

Manager, Investor Relations

(403) 645-4737

Media contact:

Alan Boras

Manager, Media Relations

(403) 645-4747

SPECIAL NOTE REGARDING FORWARD-LOOKING INFORMATION

In the interest of providing EnCana Corporation ("EnCana" or the "Company") shareholders and potential investors with information regarding the Company, 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" 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: increases in the Company's crude oil, natural gas liquids and natural gas production in 2003 and beyond; expected growth in natural gas production and storage capacity in North America; expected growth in oil production in Ecuador, the U.K. central North Sea and the Gulf of Mexico; the search for new growth platforms in 2003; and sales in 2003; the impact of the Company's risk management program; proceeds which may be generated from the sale of the Company's remaining Syncrude share and gross-overriding royalty; the Company's capital investment levels for 2003 and the source of funding therefor; storage injection requirements for 2003; the impact of legal claims on the financial position and results of operations of the Company; the Company's oilsands strategy; average natural gas price improvements and crude oil price volatility in 2003; the results of inquiries by U.S. governmental agencies; the impact on AECO production area prices of pipeline capacity fluctuations; and future operating results and various components thereof.

Readers are cautioned not to place undue reliance on forward-looking information, as there can be no assurance that the plans, intentions or expectations upon which it is based will occur. By its nature, forward-looking information involves 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. Although the Company 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. Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in this MD&A include, but are not limited to: volatility of crude oil and natural gas prices, fluctuations in currency and interest rates, product supply and demand, market competition, risks inherent in the Company's North American and foreign oil and gas and midstream operations, risks inherent in the Company's marketing operations, imprecision of reserves and resource potential estimates, the Company's ability to replace and expand oil and gas reserves, the Company's ability to either generate sufficient cash flow from operations to meet its current and future obligations or obtain external sources of debt and equity capital, general economic and business conditions, the Company's ability to enter into or renew leases, the timing and costs of well and pipeline construction, the Company's ability to make capital investments and the amounts of capital investments, imprecision in estimating the timing, costs and levels of production and drilling, the results of exploration and development drilling, imprecision in estimates of future production capacity, the Company's ability to secure adequate product transportation, uncertainty in the amounts and timing of royalty payments, imprecision in estimates of product sales, changes in environmental and other regulations, political and economic conditions in the countries in which the Company operates including Ecuador, the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company operates and international terrorist threats, and such other risks and uncertainties described from time to time in the Company's reports and filings with the Canadian securities authorities and the U.S. Securities and Exchange Commission. Accordingly, the Company cautions that events or circumstances could cause actual results to differ materially from those predicted. Statements relating to "reserves" or "resources" 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. Readers are cautioned that the foregoing list of important factors is not exhaustive. Readers are further cautioned not to place undue reliance on forward-looking statements contained in this MD&A, which are made as of the date hereof, and the Company undertakes no obligation to update publicly or revise any forward-looking information, 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.

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 for the three months ended March 31, 2003 and March 31, 2002 and the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2002.

OVERVIEW

The 2002 comparative figures included in the unaudited interim Consolidated Financial Statements ("Consolidated Financial Statements") for the three months ended March 31, 2003 reflect the results of the Company prior to the April 5, 2002 merger with Alberta Energy Company Ltd. ("AEC"). As such, the amounts reported for the period ended March 31, 2002 do not include any results related to AEC's operations during that time period.

EnCana reports the results of its continuing operations under two main business segments: Upstream and Midstream & Marketing.

The Upstream segment includes the Company's exploration for and production of natural gas, natural gas liquids ("NGLs") and crude oil. The Company's Upstream operations primarily are located in Canada, the United States ("U.S."), Ecuador, and the United Kingdom ("U.K.") central North Sea. The Upstream segment's International New Ventures exploration includes the Company's activities in the Gulf of Mexico, the U.K. central North Sea, the Middle East, Africa, Australia and Latin America, as well as, the Canadian East Coast and the North American northern frontier.

The Midstream & Marketing segment is comprised of midstream operations, which include gas storage operations, natural gas liquids processing and power generation operations, as well as marketing activity under which the Company purchases and takes delivery of third party product and the delivery of product to customers under transportation arrangements not utilized for the Company's own production.

CONSOLIDATED FINANCIAL RESULTS

In the first quarter of 2003 EnCana's cash flow from continuing operations was $1,852 million, or $3.80 per Common Share-Diluted, an increase of 379 percent over $387 million, or $1.48 per Common Share-Diluted, in the first quarter of 2002. Net earnings from continuing operations were $983 million, or $2.03 per Common Share-Diluted, compared with $131 million, or $0.51 per Common Share-Diluted, in the corresponding period last year. Growth in the Company's sales volumes and significantly higher commodity prices were the primary factors contributing to these increases.

	Three Months Ended March 31	
Consolidated Financial Summary *($ millions, except per share amounts)*	2003	2002
Revenues, Net of Royalties and Production Taxes	**$ 4,158**	$ 1,061
Net Earnings from Continuing Operations	**983**	131
– per Common Share-Diluted	**2.03**	0.51
Net Earnings	**1,246**	133
– per Common Share-Diluted	**2.57**	0.51
Cash Flow from Continuing Operations	**1,852**	387
– per Common Share-Diluted	**3.80**	1.48
Cash Flow	**1,852**	389
– per Common Share-Diluted	**3.80**	1.49

In accordance with Canadian generally accepted accounting principles ("GAAP"), the Company is required to translate long-term debt 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 or, in the case of long-term debt held by self-sustaining foreign operations, in the foreign currency translation adjustment account included in Shareholders' Equity in the Consolidated Balance Sheet. In order to provide shareholders and potential investors with information clearly presenting the effect of the translation of the outstanding U.S. dollar debt on the Company's results, the following table has been prepared:

	2003		2002		
($ millions)	Q1	Q4	Q3	Q2	Q1**
Net Earnings from Continuing Operations, as reported	**$ 983**	$ 416	$ 184	$ 494	$ 131
Deduct: Foreign exchange gain/(loss) on translation of U.S. dollar debt (after-tax)*	**193**	10	(145)	163	(1)
Earnings from Continuing Operations, excluding foreign exchange on translation of U.S. dollar debt	**$ 790**	$ 406	$ 329	$ 331	$ 132
($ per Common Share - Diluted)					
Net Earnings from Continuing Operations per Common Share - Diluted, as reported	**$ 2.03**	$ 0.86	$ 0.38	$ 1.05	$ 0.51
Deduct: Foreign exchange gain/(loss) on translation of U.S. dollar debt (after-tax)*	**0.40**	0.02	(0.30)	0.35	–
Earnings from Continuing Operations, excluding foreign exchange on translation of U.S. dollar debt per Common Share - Diluted	**$ 1.63**	$ 0.84	$ 0.68	$ 0.70	$ 0.51

* As this is an unrealized gain/(loss), there is no impact on cash flow.

** Q1 2002 results exclude the results of AEC.

Earnings from Continuing Operations, excluding foreign exchange on the translation of U.S. dollar debt, and cash flow per share are not measures that have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this discussion and analysis in order to provide shareholders and potential investors with additional information regarding the Company's finances and results of operations.

ACQUISITIONS AND DIVESTITURES

Acquisitions

On January 31, 2003, the Company expanded its production and landholdings in Ecuador through the purchase of a corporation for net cash consideration of $179 million, subject to normal post-closing adjustments and expenses. This acquisition included interests in developed and undeveloped reserves in three blocks adjacent to Block 15, where the Company has an existing non-operated working interest.

Divestitures

On February 3, 2003, the Company announced that it had reached an agreement to sell a 10 percent interest in the Syncrude project. The sale of the 10 percent interest was completed on February 28, 2003 for net cash consideration of $1,026 million, subject to certain post-closing adjustments. There was no gain or loss recorded on the transaction. The Company also granted the purchaser an option to purchase, on similar terms prior to the end of 2003, its remaining 3.75 percent share and a gross-overriding royalty. If exercised, it is anticipated that the option would generate additional proceeds of approximately $417 million.

With the sale of its Syncrude interest, the Company intends to focus its oilsands strategy on developing its high quality bitumen resources, recovered through steam-assisted gravity drainage ("SAGD"), on 100 percent owned and operated lands at Foster Creek and Christina Lake.

Discontinued Operations

Midstream – Pipelines

The Company announced that it had closed the sale of its interests in the Cold Lake Pipeline System and Express Pipeline System on January 2, 2003 and January 9, 2003, respectively, for total consideration of approximately $1.6 billion, including the assumption of related long-term debt. An after-tax gain on sale of $263 million was recorded in relation to these transactions.

These pipeline sales were part of EnCana's strategic realignment to focus on its highest growth, highest return core assets. The proceeds were used for general corporate purposes, including debt reduction, prior to being re-deployed into other strategic initiatives.

The Midstream-Pipelines operations described above have been accounted for as discontinued operations as described in Note 4 to the Consolidated Financial Statements.

BUSINESS ENVIRONMENT

(average for the quarter)	Three Months Ended March 31 2003	2002
AECO Price *($ per thousand cubic feet)*	**$ 7.92**	$ 3.34
NYMEX Price *(US$ per million British thermal unit)*	**6.59**	2.32
WTI *(US$ per barrel)*	**33.80**	21.63
WTI/Bow River Differential *(US$ per barrel)*	**7.58**	5.22
WTI/Oriente Differential (Ecuador) *(US$ per barrel)*	**5.02**	3.95
U.S./Canadian Dollar Exchange Rate *(US$)*	**0.662**	0.627

Natural gas prices in the first quarter of 2003 were significantly higher than prices in the same period last year. The average AECO index price was $7.92 per thousand cubic feet, up 137 percent from the first three months of 2002. The NYMEX average price was also higher, up 184 percent from the first quarter of 2002, to US$6.59 per million British thermal unit. The increased prices were, in part, the result of lower industry production and levels of gas in storage combined with colder weather in the first three months of 2003 compared with the same period of 2002.

At an average of US$33.80 per barrel during the first three months of 2003, the benchmark West Texas Intermediate ("WTI") crude oil price was up 56 percent over the same period last year. Uncertainty related to the war in Iraq and reduced Venezuelan production contributed to the rise in world oil prices.

Relative to the first quarter of last year, the differential between heavy and light crude oil prices widened in the first quarter of 2003. Both the WTI/Bow River differential and the WTI/Oriente differential were wider in comparison to the first three months of last year. The increase in the differentials was primarily due to the substantially higher average WTI price, which was up US$12.17 per barrel over the first quarter of 2002. The impact of the high WTI price was offset somewhat by the short supply of heavy crude oil to the U.S. resulting primarily from the oil workers strike in Venezuela.

The Canadian dollar showed strength during the first quarter of 2003. The U.S./Canadian dollar exchange rate averaged US$0.662 in the first three months of 2003, an improvement over an average rate of US$0.627 during the same period last year. The strengthening of the Canadian dollar was primarily the result of favorable news with respect to the Canadian economy and a widening spread between Canadian and U.S. interest rates.

RESULTS OF OPERATIONS

Upstream

Three Months Ended March 31

	2003					2002				
($ millions)	**Produced Gas & NGLs**	**Conventional Crude Oil**	**Syncrude**	**Non-Producing**	**Total**	Produced Gas & NGLs	Conventional Crude Oil	Syncrude	Non-Producing	Total
Revenues										
Gross revenue	**$ 2,258**	**$ 613**	**$ 91**	**$ 45**	**$ 3,007**	$ 398	$ 240	$ –	$ 16	$ 654
Royalties and production taxes	**368**	**131**	**1**	**–**	**500**	35	33	–	–	68
Revenues, net of royalties and production taxes	**1,890**	**482**	**90**	**45**	**2,507**	363	207	–	16	586
Expenses										
Transportation and selling	**118**	**44**	**1**	**–**	**163**	33	11	–	–	44
Operating	**150**	**128**	**43**	**53**	**374**	49	55	–	6	110
Depreciation, depletion and amortization	**509**	**209**	**7**	**2**	**727**	136	64	–	3	203
Upstream Income	**$ 1,113**	**$ 101**	**$ 39**	**$ (10)**	**$ 1,243**	$ 145	$ 77	$ –	$ 7	$ 229

Sales Volumes	Three Months Ended March 31	
	2003**	2002
Produced Gas *(million cubic feet per day)*	**3,016**	1,085
Crude Oil *(barrels per day)*	**203,116**	100,375
NGLs *(barrels per day)*	**30,053**	16,486
Syncrude *(barrels per day)*	**20,272**	–
Total *(barrels of oil equivalent per day)**	**756,108**	297,694

* Natural gas converted to barrel of oil equivalent at 6 thousand cubic feet = 1 barrel of oil equivalent

** Includes volumes related to the merger with AEC

Revenue Variances for 2003 Compared to 2002 *($ millions)*	Three Months Ended March 31		
	Price	Volume	Total
Produced Gas and NGLs	$ 1,157	$ 703	$ 1,860
Conventional Crude Oil	127	246	373
Syncrude	–	91	91
Total Gross Revenue*	$ 1,284	$ 1,040	$ 2,324

* Excludes gross revenue from Non-Producing Operations

Consolidated Upstream Results

The Company reports its segmented financial results showing revenues prior to all royalty payments, both cash and in-kind, consistent with Canadian disclosure practices for the oil and gas industry. Upstream gross revenue for the first quarter of 2003 was $3,007 million, $2,353 million, or 360 percent, higher than gross revenue of $654 million in the first quarter of 2002. The increase reflected the benefit of the growth in sales volumes stemming from the merger with AEC, acquisitions in the U.S. Rockies in the second and third quarters of 2002, expansion of the Company's SAGD projects and continued development in both Canada and the U.S. Rockies, combined with higher first quarter 2003 commodity prices.

Royalties and production taxes in the first quarter of 2003 were 16 percent of gross revenue, excluding the impact of hedging, compared with 11 percent in the same period last year. The increased rate reflects the addition of AEC's production base in April 2002 that is predominantly in areas subject to crown royalties, thereby decreasing the Company's relative proportion of production attributable to fee land where primarily mineral taxes are payable.

Transportation and selling costs increased to $163 million from $44 million in the first quarter of 2002, primarily as a result of higher sales volumes in the first three months of 2003. For the purpose of the revenue discussions below, these costs have been netted against gross revenue in calculating the per unit realized prices for each commodity.

Upstream conventional oil and natural gas operating expenses were $278 million in the quarter, up $174 million from the corresponding period last year. Additional production, resulting from the merger with AEC, the Company's acquisitions in the U.S. Rockies, the expansion of the SAGD projects, and continued development in both Canada and the U.S. Rockies, were the primary factors contributing to the increase. On a per unit basis, conventional oil and natural gas operating expenses, excluding cost recoveries, were $4.20 per barrel of oil equivalent, compared with $3.88 per barrel of oil equivalent in the first three months of 2002. The higher unit operating expenses primarily reflected increased maintenance, power and fuel costs combined with an increased production weighting from higher operating cost properties.

Depreciation, depletion and amortization ("DD&A") charges amounted to $727 million in the first three months of 2003 compared with $203 million in the same period last year. On a barrel of oil equivalent basis, DD&A charges were $10.68 per barrel, up 41 percent from $7.58 per barrel in the first quarter of 2002. The higher costs in the first quarter of 2003 reflect the added charges associated with the addition of the AEC assets in April 2002, which were recorded at their fair value as part of the allocation of the purchase price, and an increase in the Company's 2003 consolidated DD&A rate. The Company performs periodic reviews of its DD&A rates in order to ensure that the rates remain appropriate given changes in the depletable assets and reserves bases.

Produced Gas and NGLs

Per-Unit Results – Produced Gas and NGLs

Three Months Ended March 31	Produced Gas – Canada		Produced Gas – U.S.		NGLs	
	2003	2002	**2003**	2002	**2003**	2002
	($ per thousand cubic feet)		*($ per thousand cubic feet)*		*($ per barrel)*	
Price, net of transportation and selling	**$ 7.85**	$ 3.24	**$ 7.55**	$ 3.76	**$ 43.73**	$ 20.06
Royalties	**1.00**	0.30	**2.23**	1.10	**9.21**	1.00
Operating expenses	**0.63**	0.46	**0.25**	0.77	**–**	–
Netback excluding hedging	**6.22**	2.48	**5.07**	1.89	**34.52**	19.06
Financial Hedge	**(0.65)**	0.32	**0.80**	–	**–**	–
Netback including hedging	**$ 5.57**	$ 2.80	**$ 5.87**	$ 1.89	**$ 34.52**	$ 19.06

In the first quarter of 2003, gross revenue from the sales of produced gas and NGLs was $2,258 million, an increase of $1,860 million, or 467 percent, over the corresponding period last year. Increased sales volumes and higher natural gas and NGLs commodity prices were contributing factors to the increase in gross revenue. Gross natural gas revenue in the first quarter of 2003 included a net loss of $89 million from financial currency and commodity hedging activities. This compared with a net gain of $29 million on financial transactions in the same period last year. In addition, a gain in physical hedging activity for 2003 of $111 million has been included in the unit price net of transportation and selling.

Produced gas sales volumes in the first quarter of 2003 averaged 3,016 million cubic feet per day, up 178 percent from sales of 1,085 million cubic feet per day in the same quarter last year. NGLs sales volumes of 30,053 barrels per day compared with sales volumes of 16,486 barrels per day in the corresponding period of 2002. The increased sales volumes in the first three months of 2003 were the result of added volumes from the April 2002 merger with AEC, the Company's acquisitions in the U.S. Rockies region, drilling successes at Jonah, Mamm Creek and Ferrier and continued development at Suffield, the Palliser Block and Greater Sierra.

The benefit of the Company's growth in natural gas and NGLs sales volumes was augmented by stronger commodity prices. Realized natural gas sales prices in Canada averaged $7.85 per thousand cubic feet, excluding a financial hedging loss of $0.65 per thousand cubic feet, during the first three months of 2003, a 142 percent increase over an average price of $3.24 per thousand cubic feet, which excluded a financial hedging gain of $0.32 per thousand cubic feet, in the same period of 2002. The realized price for natural gas in the U.S. was also higher at $7.55 per thousand cubic feet, excluding a financial hedging gain of $0.80 per thousand cubic feet, an increase of 101 percent over $3.76 per thousand cubic feet in the first quarter last year. The average NGLs price for the first quarter of 2003 was $43.73 per barrel, up 118 percent from $20.06 per barrel in the first quarter last year.

In the first three months of 2003, produced gas operating expenses in Canada, net of operating recoveries, were $0.63 per thousand cubic feet, which compared with $0.46 per thousand cubic feet in the same period last year. Higher Canadian operating costs resulted from increased maintenance and electrical costs, higher processing fees and increased production from higher operating cost properties.

Produced gas operating expenses in the U.S., net of operating recoveries, averaged $0.25 per thousand cubic feet in the first quarter of 2003, an improvement over costs of $0.77 per thousand cubic feet in the same quarter of 2002. Unit operating costs in the U.S. benefited from the addition of lower operating cost properties at Jonah and Mamm Creek acquired as part of the merger with AEC.

Conventional Crude Oil

Per-Unit Results - Conventional Oil

Three Months Ended March 31	North America		Ecuador		United Kingdom	
($ per barrel)	**2003**	2002	**2003**	2002	**2003**	2002
Price, net of transportation and selling	**$ 35.61**	$ 25.38	**$ 43.90**	$ –	**$ 42.53**	$ 31.15
Royalties	**4.72**	4.08	**17.12**	–	**–**	–
Operating expenses	**7.59**	6.46	**5.63**	–	**4.41**	2.83
Netback excluding hedging	**23.30**	14.84	**21.15**	–	**38.12**	28.32
Financial Hedge	**(8.83)**	(0.91)	**–**	–	**–**	(0.30)
Netback including hedging	**$ 14.47**	$ 13.93	**$ 21.15**	$ –	**$ 38.12**	$ 28.02

Gross revenue from the sale of conventional crude oil was $613 million in the first quarter of 2003, an increase of $373 million, or 155 percent, over the same quarter last year. The improvement in gross revenue was the result of growth in sales volumes combined with higher world oil prices. Conventional crude oil gross revenue in the quarter was reduced by a loss of approximately $120 million resulting from financial commodity and currency hedging. This compared with a loss of $8 million in the first three months of 2002.

In the first three months of 2003, North America conventional crude oil sales were up 70 percent, averaging 150,882 barrels per day, compared with sales of 88,656 barrels per day in the same period of 2002. The increase in sales volumes was the result of the inclusion of merger related volumes, continued development at Suffield, commencement of commercial production at Christina Lake and the ramping up of production at Foster Creek. The Company's realized price from North America conventional crude oil averaged $35.61 per barrel, excluding a financial hedging loss of $8.83 per barrel, in the quarter, an improvement over an average price of $25.38 per barrel, excluding a financial hedging loss of $0.91 per barrel, in the first quarter of 2002.

Unit operating costs for North America conventional crude oil averaged $7.59 per barrel, up from $6.46 per barrel in the first quarter of 2002. The higher unit operating expenses for the quarter were due to increased production from the SAGD projects at Foster Creek and Christina Lake, higher maintenance costs and higher fuel and electricity costs resulting from the rise in natural gas prices.

Crude oil production in Ecuador averaged 54,726 barrels per day during the quarter. Of this production, 8,191 barrels per day was transferred to the Oleoducto de Crudos Pesados ("OCP") pipeline for use by OCP in asset commissioning, while 3,771 barrels per day were underlifted due to timing of shipments. Sales of Ecuador crude oil were 42,764 barrels per day at a realized price of $43.90 per barrel which compared to sales of 49,934 barrels per day at an average realized price of $35.38 per barrel in the fourth quarter of 2002. Unit operating costs were $5.63 per barrel in the first quarter, an improvement over costs of $6.04 per barrel in the last quarter of 2002 primarily due to cost control initiatives. The Ecuador region was added to the Company's upstream operations as part of the April 2002 merger with AEC.

In the first quarter of 2003, sales of U.K. crude oil averaged 9,470 barrels per day, a decline from sales of 11,719 barrels per day in the same quarter last year, but an improvement from sales of 6,868 barrels per day in the last quarter of 2002 and consistent with 2002 annualized sales of 9,733 barrels per day. The decline in U.K. sales volumes was offset by a considerable improvement in the average realized price, which was $42.53 per barrel compared with $31.15 per barrel in the first quarter of 2002. Unit operating costs related to U.K. crude oil production in the first quarter were $4.41 per barrel, up from $2.83 per barrel in the corresponding period last year primarily as a result of lower sales volumes.

Syncrude

As a result of the merger, EnCana added Syncrude oil production to its upstream operating results. In the first three months of 2003, Syncrude sales added $91 million to upstream gross revenue with sales volumes averaging 20,272 barrels per day. This compared with $135 million in gross revenue in the fourth quarter of 2002. The reduction in gross revenue reflects the impact of the sale during the period of the Company's 10 percent interest in Syncrude. Syncrude gross revenue in the quarter was reduced by approximately $5 million ($2.83 per barrel) as the result of a loss related to commodity price hedging.

Syncrude operating costs in the first quarter were $43 million, or $23.75 per barrel, which compared to $52 million, or $16.31 per barrel, in the fourth quarter of last year. Unit operating costs were higher in the quarter due to extensive maintenance and reduced production.

As previously discussed, on February 28, 2003, the Company sold a 10 percent interest in the Syncrude project and has granted the purchaser an option to purchase the remaining 3.75 percent interest and a gross-overriding royalty prior to the end of 2003. Further details regarding this sale are included in Note 2 to the Consolidated Financial Statements.

Midstream & Marketing

Financial Results*

Three Months Ended March 31 *($ millions)*	Midstream		Marketing		Total	
	2003	2002	**2003**	2002	**2003**	2002
Gross Revenue	$ **481**	$ 73	$ **1,170**	$ 406	$ **1,651**	$ 479
Expenses						
Transportation and selling	**–**	–	**27**	5	**27**	5
Operating	**120**	55	**22**	6	**142**	61
Purchased product	**308**	–	**1,119**	380	**1,427**	380
Depreciation, depletion and amortization	**7**	4	**1**	1	**8**	5
	$ **46**	$ 14	$ **1**	$ 14	$ **47**	$ 28

* Results of the Midstream & Marketing segment exclude financial results related to discontinued operations as described in Note 4 to the Consolidated Financial Statements.

Gross revenue from continuing midstream operations increased to $481 million compared with gross revenue of $73 million in first quarter of 2002. The increase reflected the addition of the AEC midstream assets, which primarily include gas storage activities and natural gas processing, to the Company's existing midstream segment. The midstream operations revenue was also positively impacted by the upward trend of natural gas and NGLs commodity prices experienced in the first quarter of 2003.

Marketing Financial Results On a product basis

Three Months Ended March 31 *($ millions)*	Gas		Crude Oil & NGLs		Total	
	2003	2002	**2003**	2002	**2003**	2002
Gross Revenue	$ **688**	$ 121	$ **482**	$ 285	$ **1,170**	$ 406
Expenses						
Transportation and selling	**4**	–	**23**	5	**27**	5
Operating	**18**	2	**4**	4	**22**	6
Purchased product	**670**	105	**449**	275	**1,119**	380
	$ **(4)**	$ 14	$ **6**	$ 1	$ **2**	$ 15

In the first quarter of 2003, gross revenue from the Company's marketing activities totalled $1,170 million, up from $406 million in the same period last year. The increase largely reflected the volumes added as a result of the merger with AEC and the higher commodity prices experienced across the energy industry in the first quarter of 2003.

Corporate

Administrative expenses for the quarter totalled $56 million compared with $17 million in the first quarter of 2002. The higher expenses resulted from increases in compensation costs, office facilities charges and information technology costs and were primarily attributable to the increased size of the Company. On a per unit basis, administrative costs were $0.82 per barrel of oil equivalent compared with $0.63 per barrel of oil equivalent in the first three months last year and unchanged from the full year 2002.

Net interest expense of $86 million was up from $27 million in the first quarter of 2002. The higher net interest expense resulted primarily from the additional interest expense associated with higher average debt outstanding during the quarter.

A total foreign exchange gain of $294 million was recorded in the first quarter of 2003. This compared with a gain of $10 million in the corresponding period of last year. The majority of the foreign exchange impact resulted from the translation of U.S. dollar denominated debt into Canadian dollars at the period-end exchange rate. Any exchange gains and losses resulting from this translation are recorded in earnings in the period they arise.

The provision for income tax increased $367 million over the first quarter of 2002 to $449 million largely as a result of higher operating income. The effective tax rate for the quarter was 31 percent, down from 38 percent in the first quarter last year. The reduction reflects the recognition of available capital losses offsetting unrealized capital gains of $245 million recorded in the quarter on the revaluation of debt denominated in U.S. dollars.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow from continuing operations of $1,852 million in the first three months of 2003 was up $1,465 million from $387 million in the same period last year. The increased cash flow from continuing operations was primarily the result of higher revenues resulting from the Company's growth in sales volumes and stronger commodity prices.

EnCana's net debt, including preferred securities, was $5,886 million at March 31, 2003 compared with $7,568 million at December 31, 2002. This decrease reflected the repayment of $438 million in short-term debt and the $1,345 million in revolving credit and term loan borrowings. The repayment of debt was funded by proceeds from the Company's dispositions of its 10 percent interest in Syncrude and its interests in the Cold Lake and Express Pipeline Systems. The strengthening of the Canadian dollar relative to the U.S. dollar, which resulted in an unrealized gain of $245 million on the translation of U.S. dollar debt, also contributed to the lower level of debt at March 31, 2003.

Net debt to capitalization, including all preferred securities as debt, was 29 percent, down from 36 percent at December 31, 2002. Net debt was 1.1 times the trailing 12-month cash flow at the end of the quarter. As at March 31, 2003, the Company had available unused bank credit facilities in the amount of $3,307 million.

At March 31, 2003, the Company had $2,588 million in goodwill recorded on its Consolidated Balance Sheet, which compared to $2,886 million in goodwill at December 31, 2002. The reduction in goodwill reflected adjustments related to the sale of the Company's 10 percent interest in Syncrude.

At December 31, 2002, the Company had $457 million in preferred securities of a subsidiary recorded as a liability on its balance sheet. These preferred securities are unsecured junior subordinated debentures and were recorded as a liability of the Company following the merger with AEC. On January 1, 2003, these preferred securities became the direct obligation of EnCana as a result of the amalgamation of the Company with AEC and accordingly are now recorded under the shareholders' equity section of the Consolidated Balance Sheet.

In October 2002, the Company received regulatory approval to make a Normal Course Issuer Bid. Under the bid, EnCana may purchase for cancellation up to 23,843,565 of its Common Shares, representing five percent of the approximately 476,871,300 Common Shares then outstanding. Purchases under the program must terminate on October 21, 2003 or on such earlier date as the Company may complete its purchases pursuant to the Notice of Intention filed with the Toronto Stock Exchange. As of April 30, 2003, the Company had purchased for cancellation 676,900 Common Shares at an average price of $45.89 per Common Share under this program. No purchases were made under this program prior to March 31, 2003.

Capital Expenditures

The Company's consolidated capital expenditures were $1,587 million, up $1,106 million from the first quarter of 2002. The majority of expenditures in both periods were directed towards natural gas exploration and development in North America. The Company's capital investment for the quarter was funded by cash flow of $1,852 million and proceeds received on the dispositions of the Company's 10 percent interest in Syncrude and its interests in the Cold Lake and Express Pipeline Systems.

The following table provides a summary of the Company's capital spending, excluding dispositions and corporate acquisitions, on a divisional basis.

	Three Months Ended March 31	
Capital Expenditures *($ millions)*	**2003**	2002
Upstream		
Canada	**$ 1,129**	$ 348
United States	**227**	87
Ecuador	**110**	–
U.K.	**24**	39
Other Countries	**25**	3
Total Upstream	**1,515**	477
Midstream & Marketing	**54**	1
Corporate	**18**	3
Total	**$ 1,587**	$ 481

Upstream Capital Expenditures

Upstream capital expenditures totalled $1,515 million in the first quarter of 2003, an increase of $1,038 million over the same period last year. The majority of expenditures related to the Company's North American properties, with spending in Canada directed primarily towards exploration and development of natural gas properties at Suffield and the Palliser Block in Alberta and Greater Sierra in northeast British Columbia. Capital expenditures in the United States focused primarily on natural gas exploration and development at Jonah and Mamm Creek.

Midstream & Marketing Capital Expenditures

In the first quarter of 2003, capital spending of $54 million was up $53 million from the same quarter last year. Expenditures related primarily to ongoing improvements to midstream facilities, the construction of the Countess gas storage facility and the expansion of the Wild Goose storage facility.

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 as outlined in the December 31, 2002 audited Consolidated Financial Statements and MD&A. There were no material changes as of March 31, 2003.

Discontinued Merchant Energy Operations

In response to the previously disclosed subpoena from the U.S. Commodity Futures Trading Commission ("CFTC") requiring the Company to produce documents and other information in connection with that agency's investigation relating to, among other things, inaccurate reporting of natural gas and power trading information by employees of a number of energy trading firms, including former employees of the Company's discontinued Houston-based merchant energy operation, to energy industry publications that compile and report index prices, the Company has been cooperating fully with the CFTC and carrying out an internal investigation. The Company has also cooperated fully in responding to the previously disclosed requests by U.S. governmental agencies respecting so called "round trip" trading. While no assurance can be provided, based on information currently available to the Company, the Company believes that none of these inquiries by U.S. governmental agencies is likely to result in a material adverse effect upon the Company.

An action has been filed by E. & J. Gallo Winery, in the United States District Court, Eastern District of California, against the Company and its wholly owned U.S. marketing subsidiary alleging that they engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California laws to artificially raise the price of natural gas through various means including online trading, price indexes and wash trading, and claiming damages in excess of US$30 million, before potential trebling under California laws. The Company intends to vigorously defend against this claim.

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. These exposures are managed through the use of various derivative instruments and contracts, which are governed under formal policies approved by the Board of Directors, and are subject to limits established by the Board of Directors.

This risk management program is designed to enhance shareholder value by mitigating the volatility associated with commodity prices, exchange rates and interest rates and enhancing the probability of achieving corporate performance targets.

As a means of managing commodity price volatility in its producing areas and to ensure greater certainty in cash flow generation for its capital program, the Company has entered into various financial agreements and physical contracts. These transactions fixed the oil and natural gas prices for a portion of its future production.

Natural Gas

EnCana entered into fixed price AECO and NYMEX swaps and AECO and NYMEX collars as a means of protecting corporate cash flow to ensure sufficient funds for capital expenditure programs. To protect against weakening production area prices EnCana has entered into AECO and U.S. Rockies basis transactions. AECO production area prices may be negatively impacted as large amounts of contracted capacity on pipelines moving gas to downstream markets come up for renewal over the next several years. To manage exposure to transportation capacity on the Alliance Pipeline, the Company has entered into fixed price purchase and sale contracts.

Crude Oil

The Company has managed the WTI NYMEX price for a portion of its oil production with fixed price swaps and costless collars.

Gas Storage Optimization

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

The following table summarizes the unrecognized gains/(losses) on the Company's risk management activities at March 31, 2003:

	Contract Maturity			
($ millions)	2003	2004	2005 and beyond	Total
Natural Gas	$ (99)	$ 101	$ 96	**$ 98**
Crude Oil	(94)	(87)	–	**(181)**
Gas Storage Optimization	7	–	–	**7**
Power	(2)	–	(1)	**(3)**
Foreign Currency Risk	(6)	(9)	–	**(15)**
Interest Rate Risk	17	23	18	**58**
Total	$ (177)	$ 28	$ 113	**$ (36)**

Further details regarding the above risk management activities can be found in Note 10 to the Consolidated Financial Statements.

OUTLOOK

During 2003, EnCana will continue to focus on growing its natural gas production and storage capacity in North America and crude oil production in Ecuador to deliver anticipated strong near term growth while building the U.K. central North Sea and the Gulf of Mexico oil growth platforms for expected medium and longer term value creation. The Company will also continue its efforts to expand its medium and long-term growth prospects by searching for new growth platforms through new ventures exploration.

The Company's 2003 forecast for produced gas sales remains at between 3.0 and 3.1 billion cubic feet per day. Conventional oil and natural gas liquids sales volumes continue to be forecast at between 240,000 and 280,000 barrels per day.

The Company continues to expect average natural gas prices in 2003 to be higher than 2002 levels. Strong storage injection requirements in 2003 combined with reduced U.S. and Canadian supply have tightened the balance between supply and demand resulting in higher average natural gas prices in 2003.

Volatility in crude oil prices is expected to continue in 2003 as a result of market uncertainties over the reintegration of Iraqi production, political issues in Venezuela and Nigeria, OPEC compliance with production quotas, and the overall health of the world economies.

The Company currently expects 2003 capital investment in core programs to be approximately $5 billion before acquisitions and dispositions, which the Company anticipates will be funded from cash flow.

May 7, 2003

EnCana Corporation

CONSOLIDATED STATEMENT OF EARNINGS

For the three months ended March 31, 2003

(unaudited) ($ millions, except per share amounts)		Three Months Ended March 31 2003	2002
REVENUES, NET OF ROYALTIES AND PRODUCTION TAXES	*(Note 3)*	**$ 4,158**	$ 1,061
EXPENSES	*(Note 3)*		
Transportation and selling		**190**	49
Operating		**516**	171
Purchased product		**1,427**	380
Administrative		**56**	17
Interest, net		**86**	27
Foreign exchange (gain)	*(Note 5)*	**(294)**	(10)
Depreciation, depletion and amortization		**745**	214
		2,726	848
NET EARNINGS BEFORE THE UNDERNOTED		**1,432**	213
Income tax expense	*(Note 6)*	**449**	82
NET EARNINGS FROM CONTINUING OPERATIONS		**983**	131
NET EARNINGS FROM DISCONTINUED OPERATIONS	*(Note 4)*	**263**	2
NET EARNINGS		**$ 1,246**	$ 133
DISTRIBUTIONS ON PREFERRED SECURITIES, NET OF TAX		**(6)**	–
NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS		**$ 1,252**	$ 133
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	*(Note 9)*		
Basic		**$ 2.06**	$ 0.51
Diluted		**$ 2.03**	$ 0.51
NET EARNINGS PER COMMON SHARE	*(Note 9)*		
Basic		**$ 2.61**	$ 0.52
Diluted		**$ 2.57**	$ 0.51

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(unaudited) ($ millions)	Three Months Ended March 31 2003	2002
RETAINED EARNINGS, BEGINNING OF YEAR	**$ 4,684**	$ 3,630
Net Earnings	**1,246**	133
Dividends on Common Shares and Other Distributions, net of tax	**(42)**	(25)
RETAINED EARNINGS, END OF PERIOD	**$ 5,888**	$ 3,738

See accompanying Notes to Consolidated Financial Statements.

EnCana Corporation

CONSOLIDATED BALANCE SHEET

For the three months ended March 31, 2003

(unaudited) ($ millions)		**As at Mar. 31, 2003**	As at Dec. 31, 2002
ASSETS			
Current Assets			
Cash and cash equivalents		**$ 273**	$ 212
Accounts receivable and accrued revenue		**2,303**	2,052
Income tax receivable		**48**	–
Inventories		**467**	543
Assets of discontinued operations		**–**	1,482
		3,091	4,289
Capital Assets, net	*(Note 3)*	**23,271**	23,770
Investments and Other Assets		**460**	377
Goodwill		**2,588**	2,886
	(Note 3)	**$ 29,410**	$ 31,322
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 2,443**	$ 2,390
Income tax payable		**–**	14
Liabilities of discontinued operations		**–**	825
Short-term debt		**–**	438
Current portion of long-term debt	*(Note 7)*	**100**	212
		2,543	3,879
Long-Term Debt	*(Note 7)*	**5,867**	7,395
Deferred Credits and Other Liabilities		**583**	585
Future Income Taxes		**5,423**	5,212
Preferred Securities of Subsidiary		**–**	457
		14,416	17,528
Shareholders' Equity			
Preferred securities		**567**	126
Share capital	*(Note 8)*	**8,776**	8,732
Share options, net		**119**	133
Paid in surplus		**75**	61
Retained earnings		**5,888**	4,684
Foreign currency translation adjustment		**(431)**	58
		14,994	13,794
		$ 29,410	$ 31,322

See accompanying Notes to Consolidated Financial Statements.

EnCana Corporation

CONSOLIDATED STATEMENT OF CASH FLOWS

For the three months ended March 31, 2003

(unaudited) ($ millions)		Three Months Ended March 31 2003	2002
OPERATING ACTIVITIES			
Net earnings from continuing operations		$ 983	$ 131
Depreciation, depletion and amortization		745	214
Future income taxes	*(Note 6)*	414	42
Other		(290)	–
Cash flow from continuing operations		1,852	387
Cash flow from discontinued operations		–	2
Cash flow		1,852	389
Net change in other assets and liabilities		(6)	(26)
Net change in non-cash working capital from continuing operations		54	(242)
Net change in non-cash working capital from discontinued operations		–	53
		1,900	174
INVESTING ACTIVITIES			
Capital expenditures	*(Note 3)*	(1,587)	(481)
Proceeds on disposal of capital assets		10	3
Corporate (acquisitions) and dispositions	*(Note 2)*	847	–
Equity investments		(66)	–
Net change in investments and other		(34)	(17)
Net change in non-cash working capital from continuing operations		(203)	(31)
Discontinued operations		998	–
		(35)	(526)
FINANCING ACTIVITIES			
Repayment of short-term debt		(438)	–
Repayment of long-term debt		(1,345)	(80)
Issuance of common shares	*(Note 8)*	44	18
Dividends on common shares		(48)	(25)
Payments to preferred securities holders		(8)	–
Net change in non-cash working capital from continuing operations		(5)	(3)
Other		(1)	–
		(1,801)	(90)
DEDUCT: FOREIGN EXCHANGE LOSS ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		3	2
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		61	(444)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR		212	963
CASH AND CASH EQUIVALENTS, END OF PERIOD		$ 273	$ 519

See accompanying Notes to Consolidated Financial Statements.

NOTE 1 BASIS 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, production and marketing of natural gas, natural gas liquids and crude oil, as well as natural gas storage operations, natural gas liquids processing and power generation operations.

The interim Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as the annual audited Consolidated Financial Statements for the year ended December 31, 2002. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements. The interim Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2002.

NOTE 2 CORPORATE (ACQUISITIONS) AND DISPOSITIONS

	March 31	
($ millions)	**2003**	2002
Acquisitions	**$ (179)**	$ –
Dispositions	**1,026**	–
	$ 847	$ –

On January 31, 2003, the Company acquired the Ecuadorian interests of Vintage Petroleum Inc. for net cash consideration of $179 million (US$116 million). The purchase was accounted for using the purchase method with the results reflected in the consolidated results of EnCana from the date of acquisition. The acquisition was accounted for as follows:

($ millions)	
Working Capital	**$ 2**
Capital Assets	**$ 194**
Future Income Taxes	**(17)**
	$ 179

On February 28, 2003, the Company completed the sale of its 10 percent interest in the Syncrude Joint Venture to Canadian Oil Sands Limited for net cash consideration of $1,026 million. There was no gain or loss on this sale. The Company has also granted Canadian Oil Sands Limited an option to purchase its remaining 3.75 percent working interest in the Syncrude Joint Venture and a gross-overriding royalty interest for cash proceeds of $417 million.

NOTE 3 SEGMENTED INFORMATION

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

- Upstream includes the Company's exploration for and production of natural gas, natural gas liquids and crude oil. The Company's Upstream operations are located in Canada, the United States, the U.K. central North Sea, Ecuador and International New Ventures exploration activity in the Gulf of Mexico, the U.K. central North Sea, the Middle East, Africa, Australia, Latin America, as well as, the Canadian East Coast and the North American northern frontier.
- Midstream & Marketing includes gas storage operations, natural gas liquids processing and power generation operations, as well as, marketing 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.

The Company reports its segmented financial results showing revenue prior to all royalty payments, both cash and in kind, consistent with Canadian disclosure practices for the oil and gas industry.

Operations that have been discontinued are disclosed in Note 4.

SEGMENTED INFORMATION (continued)

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

	Upstream		Midstream & Marketing	
($ millions)	**2003**	2002	**2003**	2002
Revenues				
Gross revenue	**$ 3,007**	$ 654	**$ 1,651**	$ 479
Royalties and production taxes	**500**	68	**–**	–
Revenues, net of royalties and production taxes	**2,507**	586	**1,651**	479
Expenses				
Transportation and selling	**163**	44	**27**	5
Operating	**374**	110	**142**	61
Purchased product	**–**	–	**1,427**	380
Depreciation, depletion and amortization	**727**	203	**8**	5
Segment Income	**$ 1,243**	$ 229	**$ 47**	$ 28

	Corporate		Consolidated	
	2003	2002	**2003**	2002
Revenues				
Gross revenue	**$ –**	$ (4)	**$ 4,658**	$ 1,129
Royalties and production taxes	**–**	–	**500**	68
Revenues, net of royalties and production taxes	**–**	(4)	**4,158**	1,061
Expenses				
Transportation and selling	**–**	–	**190**	49
Operating	**–**	–	**516**	171
Purchased product	**–**	–	**1,427**	380
Depreciation, depletion and amortization	**10**	6	**745**	214
Segment Income	**(10)**	(10)	**1,280**	247
Administrative	**56**	17	**56**	17
Interest, net	**86**	27	**86**	27
Foreign exchange (gain)	**(294)**	(10)	**(294)**	(10)
	(152)	34	**(152)**	34
Net Earnings Before Income Tax	**142**	(44)	**1,432**	213
Income tax expense	**449**	82	**449**	82
Net Earnings from Continuing Operations	**$ (307)**	$ (126)	**$ 983**	$ 131

SEGMENTED INFORMATION (continued)

Geographic and Product Information *(For the three months ended March 31)*

UPSTREAM *($ millions)*	Produced Gas and NGLs							
	Canada		U.S. Rockies		Conventional Crude Oil		Syncrude	
	2003	2002	**2003**	2002	**2003**	2002	**2003**	2002
Revenues								
Gross revenue	**$ 1,667**	358	**$ 571**	$ 32	**$ 395**	$ 204	**$ 91**	$ –
Royalties and production taxes	**224**	28	**144**	7	**65**	33	**1**	–
Revenues, net of royalties and production taxes	**1,453**	330	**427**	25	**330**	171	**90**	–
Expenses								
Transportation and selling	**92**	31	**23**	–	**31**	8	**1**	–
Operating	**135**	44	**15**	5	**102**	52	**43**	–
Depreciation, depletion and amortization	**402**	117	**100**	17	**147**	56	**7**	–
Segment Income	**$ 824**	138	**$ 289**	$ 3	**$ 50**	$ 55	**$ 39**	$ –

	Ecuador		U.K. North Sea		Non-Producing		Total Upstream	
	2003	2002	**2003**	2002	**2003**	2002	**2003**	2002
Revenues								
Gross revenue	**$ 179**	–	**$ 49**	$ 44	**$ 45**	$ 16	**$ 3,007**	$ 654
Royalties and production taxes	**66**	–	**–**	–	**–**	–	**500**	68
Revenues, net of royalties and production taxes	**113**	–	**49**	44	**45**	16	**2,507**	586
Expenses								
Transportation and selling	**10**	–	**6**	5	**–**	–	**163**	44
Operating	**22**	–	**4**	3	**53**	6	**374**	110
Depreciation, depletion and amortization	**35**	–	**34**	10	**2**	3	**727**	203
Segment Income	**$ 46**	–	**$ 5**	$ 26	**$ (10)**	$ 7	**$ 1,243**	$ 229

MIDSTREAM & MARKETING *($ millions)*	Midstream		Marketing		Total Midstream & Marketing	
	2003	2002	**2003**	2002	**2003**	2002
Revenues						
Gross revenue	**$ 481**	$ 73	**$ 1,170**	$ 406	**$ 1,651**	$ 479
Expenses						
Transportation and selling	**–**	–	**27**	5	**27**	5
Operating	**120**	55	**22**	6	**142**	61
Purchased product	**308**	–	**1,119**	380	**1,427**	380
Depreciation, depletion and amortization	**7**	4	**1**	1	**8**	5
Segment Income	**$ 46**	$ 14	**$ 1**	$ 14	**$ 47**	$ 28

SEGMENTED INFORMATION (continued)

Capital Expenditures

	March 31	
($ millions)	**2003**	2002
Upstream		
Canada	**$ 1,129**	$ 348
United States	**227**	87
Ecuador	**110**	–
United Kingdom	**24**	39
Other Countries	**25**	3
Midstream & Marketing	**54**	1
Corporate	**18**	3
Total	**$ 1,587**	$ 481

Capital and Total Assets

	Capital Assets		Total Assets	
	As at		As at	
($ millions)	**Mar.31, 2003**	Dec. 31, 2002	**Mar. 31, 2003**	Dec. 31, 2002
Upstream	**$ 22,292**	$ 22,836	**$ 26,681**	$ 27,132
Midstream & Marketing	**774**	742	**2,314**	2,216
Corporate	**205**	192	**415**	492
Assets of Discontinued Operations	**–**	–	**–**	1,482
Total	**$ 23,271**	$ 23,770	**$ 29,410**	$ 31,322

NOTE 4 DISCONTINUED OPERATIONS

On April 24, 2002, the Company adopted formal plans to exit from the Houston-based merchant energy operation, which was included in the Midstream & Marketing segment. Accordingly, these operations have been accounted for as discontinued operations. The wind-down of these operations was substantially completed at December 31, 2002.

On July 9, 2002, the Company announced that it planned to sell its 70 percent equity investment in the Cold Lake Pipeline System and its 100 percent interest in the Express Pipeline System. Both crude oil pipeline systems were acquired in the business combination with Alberta Energy Company Ltd. on April 5, 2002. Accordingly, these operations have been accounted for as discontinued operations. On January 2, 2003 and January 9, 2003, the Company completed the sale of its interest in the Cold Lake Pipeline System and Express Pipeline System for total consideration of approximately $1.6 billion, including assumption of related long-term debt, and recorded an after-tax gain on sale of $263 million.

The following table presents the effect of the discontinued operations on the Consolidated Financial Statements:

Consolidated Statement of Earnings

	For the three months ended March 31	
($ millions)	**2003**	2002*
Revenues	**$ –**	$ 746
Expenses		
Operating	**–**	–
Purchased product	**–**	733
Administrative	**–**	10
(Gain) on discontinuance	**(343)**	–
	(343)	743
Net Earnings Before Income Tax	**343**	3
Income tax expense	**80**	1
Net Earnings from Discontinued Operations	**$ 263**	$ 2

* The above table does not include any financial information for the three months ended March 31, 2002 related to Midstream - Pipelines as EnCana did not, at that time, own the pipelines which have been discontinued.

NOTE 5 FOREIGN EXCHANGE (GAIN)

	March 31	
($ millions)	**2003**	2002
Unrealized foreign exchange (gain) on translation of U.S. dollar debt	**$ (245)**	$ (2)
Other foreign exchange (gains)	**(49)**	(8)
	$ (294)	$ (10)

NOTE 6 INCOME TAXES

($ millions)	March 31 2003	2002
Provision for Income Taxes		
Current		
Canada	**$ 23**	$ 37
United States	**–**	–
Ecuador	**12**	–
United Kingdom	**–**	3
	35	40
Future	**414**	42
	$ 449	$ 82

NOTE 7 LONG-TERM DEBT

($ millions)		**As at Mar. 31, 2003**	As at Dec. 31, 2002
Canadian Dollar Denominated Debt			
Revolving credit and term loan borrowings		**$ 333**	1,388
Unsecured notes and debentures		**1,825**	1,825
		2,158	3,213
U.S. Dollar Denominated Debt			
U.S. revolving credit and term loan borrowings		**469**	696
U.S. unsecured notes and debentures		**3,251**	3,608
		3,720	4,304
Increase in Value of Debt Acquired	*(Note A)*	**89**	90
Current Portion of Long-term Debt		**(100)**	(212)
		$ 5,867	$ 7,395

A) Increase in Value of Debt Acquired

Certain of the notes and debentures of the Company were acquired in the business combination with Alberta Energy Company Ltd. on April 5, 2002 and were accounted for at their fair value at the date of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 24 years.

NOTE 8 SHARE CAPITAL

	March 31, 2003		December 31, 2002	
($ millions)	**Number**	**Amount**	Number	Amount
Common Shares Outstanding, Beginning of Year	**478.9**	**$ 8,732**	254.9	$ 196
Shares Issued to AEC Shareholders	**–**	**–**	218.5	8,397
Shares Issued under Option Plans	**1.7**	**44**	5.5	139
Common Shares Outstanding, End of Period	**480.6**	**$ 8,776**	478.9	$ 8,732

The Company has a stock-based compensation plan ("EnCana plan") that allows employees to purchase common shares of the Company. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted under the plan are generally fully exercisable after three years and expire five years after the grant date. Options granted under previous EnCana and Canadian Pacific Limited replacement plans expire 10 years from the date the options were granted.

The following tables summarize the information about options to purchase common shares at March 31, 2003:

	Stock Options *(millions)*	**Weighted Average Exercise Price** *($)*
Outstanding, Beginning of Year	**29.6**	**39.74**
Granted under EnCana Plan	**0.3**	**48.00**
Exercised	**(1.7)**	**25.80**
Forfeited	**(0.5)**	**46.46**
Outstanding, End of Period	**27.7**	**40.57**
Exercisable, End of Period	**15.9**	**35.00**

	Outstanding Options			**Exercisable Options**	
Range of Exercise Price *($)*	Number of Options Outstanding *(millions)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *($)*	Number of Options Outstanding *(millions)*	Weighted Average Exercise Price *($)*
13.50 to 19.99	2.7	1.2	18.88	2.7	18.88
20.00 to 24.99	1.8	2.1	22.24	1.8	22.24
25.00 to 29.99	2.9	2.1	26.57	2.9	26.57
30.00 to 43.99	1.7	2.9	38.76	1.5	38.25
44.00 to 53.00	18.6	3.9	47.91	7.0	47.43
	27.7	3.0	40.57	15.9	35.00

NOTE 8 SHARE CAPITAL (continued)

The Company does not record compensation expense in the Consolidated Financial Statements for share options granted to employees and directors. If the fair-value method had been used, the Company's Net Earnings and Net Earnings per Common Share would approximate the following pro forma amounts:

	March 31	
($ millions, except per share amounts)	**2003**	2002
Compensation Costs	**13**	5
Net Earnings		
As reported	**1,246**	133
Pro forma	**1,233**	128
Net Earnings per Common Share		
Basic		
As reported	**2.61**	0.52
Pro forma	**2.58**	0.50
Diluted		
As reported	**2.57**	0.51
Pro forma	**2.55**	0.49

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option-pricing model with weighted average assumptions for grants as follows:

	March 31	
	2003	2002
Weighted Average Fair Value of Options Granted	**$ 13.05**	$ 11.94
Risk Free Interest Rate	**4.19%**	4.46%
Expected Lives (years)	**3.00**	3.00
Expected Volatility	**0.33**	0.35
Annual Dividend per Share	**$ 0.40**	$ 0.40

NOTE 9 PER SHARE AMOUNTS

The following table summarizes the common shares used in calculating net earnings per common share.

	March 31	
(millions)	**2003**	2002
Weighted Average Common Shares Outstanding – Basic	**479.9**	255.3
Effect of Dilutive Securities	**7.0**	5.7
Weighted Average Common Shares Outstanding – Diluted	**486.9**	261.0

NOTE 10 FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Unrecognized gains (losses) on risk management activities are as follows:

($ millions)		As at March 31, 2003
Commodity Price Risk	(Note A)	
Natural gas		$ 98
Crude oil		(181)
Gas storage optimization		7
Power		(3)
Foreign Currency Risk		(15)
Interest Rate Risk		58
		$ (36)

Information with respect to foreign currency risk and interest rate risk contracts in place at December 31, 2002, is disclosed in Note 19 to the Company's annual audited Consolidated Financial Statements. No significant new contracts have been entered into as at March 31, 2003.

A) Commodity Price Risk

Natural Gas

At March 31, 2003, the fair value of financial instruments that related to the corporate gas risk management activities was $63 million. The contracts were as follows:

	Notional Volumes *(MMcf/d)*	Financial/ Physical	Term	Price		Unrecognized Gain/(Loss) *(Cdn$ millions)*
Sales Contracts						
Fixed AECO price	352	Financial	2003-2004	6.26	Cdn$/mcf	$ (55)
Fixed AECO price	6	Physical	2003	5.88	Cdn$/mcf	(1)
Fixed AECO price	74	Financial	2003-2004	2.96	US$/mmbtu	(110)
Fixed AECO price	10	Physical	2003	3.34	US$/mmbtu	(5)
AECO Collars	71	Financial	2004	5.34-7.52	Cdn$/mcf	3
Nymex Fixed Price	110	Financial	2003-2004	3.97	US$/mmbtu	(106)
Alliance Pipeline Mitigation	32	Financial	2003	3.92	US$/mmbtu	(16)
Fixed Nymex to AECO basis	243	Financial	2003-2007	(0.51)	US$/mmbtu	62
Fixed Nymex to Rockies basis	158	Financial	2003-2007	(0.45)	US$/mmbtu	117
Fixed Nymex to Rockies basis	214	Physical	2003-2007	(0.48)	US$/mmbtu	148
Nymex Collars	47	Physical	2003-2007	2.08-4.52	US$/mmbtu	(11)
Purchase Contracts						
Alliance Pipeline Mitigation	35	Physical	2003	3.24	Cdn$/mcf	33
Fuel	10	Physical	2003	5.15	Cdn$/mcf	4
						63
Gas Marketing Financial Activities						12
Gas Marketing Physical Activities						23
						$ 98

The fair value of the financial instruments that related to the gas marketing activities was an unrecognized gain of $12 million. These activities are part of the ongoing operations of the Company's proprietary production management and the financial transactions are directly related to physical sales. The corresponding physical transactions have an unrecognized gain of $23 million.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Crude Oil

As at March 31, 2003, the Company's corporate oil risk management activities had an unrecognized loss of $181 million. The contracts were as follows:

	Notional Volumes *(bbl/d)*	Term	Average Price *(US$/bbl)*	Unrecognized Gain/(Loss) *(Cdn$ millions)*
Fixed WTI NYMEX Price	85,000	2003	25.28	$ (77)
Fixed WTI NYMEX Price	62,500	2004	23.13	(53)
Collars on WTI NYMEX	40,000	2003	21.95–29.00	(16)
Collars on WTI NYMEX	62,500	2004	20.00–25.69	(35)
				$ (181)

Gas Storage Optimization

As part of the Company's gas storage optimization program, the Company has entered into financial instruments at various locations and terms over the next 12 months to manage the price volatility of the corresponding physical transactions and inventory.

As at March 31, 2003, the unrecognized gain on financial instruments was $10 million, which was as follows:

	Notional Volumes *(bcf)*	Price *(US$/mcf)*	Unrecognized Gain/(Loss) *(Cdn$ millions)*
Purchases	153.5	5.27	$ (15)
Sales	165.4	5.38	25
			10
Physical Contracts			(3)
			$ 7

The net unrecognized gain of $7 million does not reflect unrealized gains on physical inventory in storage.

Natural Gas Liquids

As at December 31, 2002, Kinetic Resources USA Inc, a partnership in which the Company holds a 75 percent interest, had sold call options and held various fixed price purchase and sale contracts which had since expired.

Power

As part of the business combination with AEC, the Company acquired two electricity contracts. These contracts were originally entered into as part of an electricity cost management strategy. At March 31, 2003, the unrecognized loss on these contracts was $3 million.

NOTE 11 RECLASSIFICATION

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2003.

Financial Statistics

(C$ millions, except per share amounts)	**2003**	2002		
	Q1	Q4	Q3	Q2
Cash Flow	**1,852**	1,472	1,022	938
Per share – Basic	**3.86**	3.08	2.14	2.03
– Diluted	**3.80**	3.03	2.12	2.00
Net Earnings	**1,246**	429	204	458
Per share – Basic	**2.61**	0.90	0.43	0.99
– Diluted	**2.57**	0.88	0.42	0.97
Net Earnings from Continuing Operations	**983**	416	184	494
Per share – Basic	**2.06**	0.87	0.38	1.07
– Diluted	**2.03**	0.86	0.38	1.05
Earnings from Continuing Operations, excluding foreign exchange translation of U.S. dollar debt (after tax) *	**790**	406	329	331
Per share – Diluted	**1.63**	0.84	0.68	0.70

Shares	**2003**	2002		
	Q1	Q4	Q3	Q2
Common Shares Outstanding *(millions)*				
Average	**479.9**	477.9	476.8	461.1
Average Diluted	**486.9**	485.2	482.2	470.0
Price range *($ per share)*				
TSE – C$				
High	**49.55**	49.75	48.25	50.25
Low	**46.06**	41.75	38.05	43.62
Close	**47.75**	48.78	48.00	46.70
NYSE – US$				
High	**33.39**	32.10	31.35	32.20
Low	**29.92**	26.45	24.08	28.50
Close	**32.36**	31.10	30.10	30.60
Share volume traded *(millions)*	**110.2**	122.3	105.5	113.2
Share value traded *($ millions weekly average)*	**402.9**	418.3	366.3	412.6
Ratios				
Debt to Capitalization	**29%**	36%	39%	39%
Return on Capital Employed	**13.0%**			
Return on Common Equity	**17.4%**			

* The Company is required to translate long-term debt denominated in U.S. dollars into Canadian dollars at the period-end exchange rate with any resulting adjustments recorded in the Consolidated Statement of Earnings.

Financial Statistics *(continued)*

Net Capital Investment *($ millions)*	**2003**	Pro Forma 2002
Upstream		
Conventional – Canada	**$ 1,062**	$ 834
Conventional – U.S.	**210**	242
Syncrude	**61**	40
Ecuador	**110**	69
United Kingdom	**24**	39
Other	**25**	(4)
Property Acquisitions	**23**	60
Dispositions	**(1,036)**	(38)
Net Upstream	**479**	1,242
Midstream & Marketing		
Capital Expenditures	**54**	8
Dispositions	**–**	–
Net Midstream & Marketing	**54**	8
Corporate	**18**	8
Corporate Acquisitions	**179**	–
Net Capital Investment - Continuing Operations	**730**	1,258
Discontinued Operations	**(998)**	2
Total Net Capital Investment	**$ (268)**	$ 1,260

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS

(unaudited) For the Period Ended March 31, 2003

Pro Forma Operating Statistics

Sales Volumes		**2003**	2002			
		Q1	Q4	Q3	Q2	Q1*
Produced Gas *(MMcf/d)*						
Canada		**2,331**	2,375	2,129	2,144	2,348
United States		**672**	654	550	428	365
United Kingdom		**13**	8	9	8	11
		3,016	3,037	2,688	2,580	2,724
Oil and Natural Gas Liquids *(bbls/d)*						
North America						
Conventional Light and Medium Oil		**60,246**	62,369	65,345	66,807	70,914
Conventional Heavy Oil		**90,636**	86,019	80,797	76,233	68,846
Natural Gas Liquids						
Canada		**19,162**	19,121	16,225	16,796	17,448
United States		**9,751**	11,558	6,702	7,115	6,427
Total North America Conventional		**179,795**	179,067	169,069	166,951	163,635
Syncrude		**20,272**	34,261	36,039	24,295	31,548
Total North America		**200,067**	213,328	205,108	191,246	195,183
Ecuador	**	**42,764**	49,934	55,579	59,864	38,774
United Kingdom		**10,610**	7,786	9,538	11,966	12,889
Total Oil and Natural Gas Liquids		**253,441**	271,048	270,225	263,076	246,846
Total *(boe/d)*		**756,108**	777,215	718,225	693,104	700,846

* Q1 2002 volumes have been presented on a pro forma basis.

** Crude oil production in Ecuador averaged 54,726 bbls/d during Q1 2003. Of this production, 8,191 bbls/d was transferred to the OCP pipeline for use by OCP in asset commissioning and 3,771 bbls/d was underlifted resulting in sales of 42,764 bbls/d.

Operating Statistics

Per-unit Results	**2003**	2002		
	Q1	Q4	Q3	Q2
Produced Gas - Canada *($/Mcf)*				
Price, net of transportation and selling	**7.85**	5.17	3.24	4.23
Royalties	**1.00**	0.77	0.39	0.65
Operating expenses	**0.63**	0.59	0.58	0.54
Netback excluding hedge	**6.22**	3.81	2.27	3.04
Financial Hedge	**(0.65)**	(0.08)	0.29	(0.12)
Netback including hedge	**5.57**	3.73	2.56	2.92
Produced Gas - United States *(C$/Mcf)*				
Price, net of transportation and selling	**7.55**	4.74	3.16	3.56
Royalties	**2.23**	1.42	0.99	0.98
Operating expenses	**0.25**	0.28	0.34	0.38
Netback excluding hedge	**5.07**	3.04	1.83	2.20
Financial Hedge	**0.80**	0.42	0.57	0.06
Netback including hedge	**5.87**	3.46	2.40	2.26
Conventional Light and Medium Oil *($/bbl)*				
Price, net of transportation and selling	**41.36**	36.36	36.01	35.35
Royalties	**5.82**	4.81	4.56	4.36
Operating expenses	**7.68**	7.16	6.58	7.25
Netback excluding hedge	**27.86**	24.39	24.87	23.74
Financial Hedge	**(8.83)**	(1.26)	(0.89)	(1.59)
Netback including hedge	**19.03**	23.13	23.98	22.15
Conventional Heavy Oil *($/bbl)*				
Price, net of transportation and selling	**31.80**	25.81	29.44	26.85
Royalties	**3.99**	3.43	3.67	3.09
Operating expenses	**7.52**	5.64	6.71	5.87
Netback excluding hedge	**20.29**	16.74	19.06	17.89
Financial Hedge	**(8.83)**	(1.18)	(0.89)	(0.76)
Netback including hedge	**11.46**	15.56	18.17	17.13
Total Conventional Oil *($/bbl)*				
Price, net of transportation and selling	**35.61**	30.26	32.38	30.82
Royalties	**4.72**	4.01	4.07	3.68
Operating expenses	**7.59**	6.28	6.66	6.51
Netback excluding hedge	**23.30**	19.97	21.65	20.63
Financial Hedge	**(8.83)**	(1.22)	(0.89)	(1.15)
Netback including hedge	**14.47**	18.75	20.76	19.48
Natural Gas Liquids *($/bbl)*				
Price, net of transportation and selling	**43.73**	36.15	31.18	29.92
Royalties	**9.21**	5.95	4.62	4.69
Netback	**34.52**	30.20	26.56	25.23
Syncrude *($/bbl)*				
Price, net of transportation and selling	**51.80**	43.23	43.73	40.51
Gross overriding royalty and other revenue	**0.42**	0.11	0.17	0.16
Royalties	**0.52**	0.43	0.43	0.42
Operating expenses	**23.75**	16.31	13.38	30.47
Netback excluding hedge	**27.95**	26.60	30.09	9.78
Financial Hedge	**(2.83)**	(0.94)	(1.19)	(0.42)
Netback including hedge	**25.12**	25.66	28.90	9.36
Ecuador Oil *($/bbl)*				
Price, net of transportation and selling	**43.90**	35.38	33.59	31.67
Royalties	**17.12**	12.29	12.51	10.76
Operating expenses	**5.63**	6.04	4.60	5.70
Netback excluding hedge	**21.15**	17.05	16.48	15.21
Financial Hedge	**–**	–	–	(0.04)
Netback including hedge	**21.15**	17.05	16.48	15.17
United Kingdom Oil *($/bbl)*				
Price, net of transportation and selling	**42.53**	37.99	39.30	37.78
Operating expenses	**4.41**	11.10	5.71	3.12
Netback	**38.12**	26.89	33.59	34.66

ENCANA CORPORATION

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