ENCANA CORP
Form 40-F
March 08, 2004

U.S. SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 40-F

(Check One)

o Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934

or

þ Annual report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2003

Commission file number 1-15226

EnCana Corporation

(Exact name of registrant as specified in its charter)

Canada	1311	Not applicable
(Province or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number (if applicable))*	*(I.R.S. Employer Identification Number (if applicable))*

1800 855 2nd Street, S.W., P.O. Box 2850, Calgary, Alberta, Canada T2P 2S5
(403) 645-2000

(Address and Telephone Number of Registrant s Principal Executive Offices)

CT Corporation System, 111 8th Avenue, New York, NY 10011
(212) 894-8940

(Name, Address (Including Zip Code) and Telephone Number (Including Area Code) of Agent For Service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	Name of each exchange on which registered
Common Shares	New York Stock Exchange
Preferred Securities	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act. None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act. Debt Securities

For annual reports, indicate by check mark the information filed with this Form:

þ Annual Information Form þ Audited Annual Financial Statements

Indicate the number of outstanding shares of each of the issuer s classes of capital or common stock as of the close of the period covered by the annual report: 460,063,418

Indicate by check mark whether the registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the Exchange Act). If Yes is marked, indicate the file number assigned to the registrant in connection with such rule.

Yes o No þ

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports); and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

The Annual Report on Form 40-F shall be incorporated by reference into, or as an exhibit to, as applicable, each of the registrant s Registration Statements under the Securities Act of 1933: Form S-8 (File Nos. 333-13956 and 333-85598) and Form F-9 (File No. 333-98087).

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FORM 40-F

Principal Documents

The following documents have been filed as part of this Annual Report on Form 40-F, beginning on the following page:

(a) Annual Information Form for the fiscal year ended December 31, 2003;

(b) Management s Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2003; and

(c) Consolidated Financial Statements for the fiscal year ended December 31, 2003 *(Note 20 to the Consolidated Financial Statements relates to United States Accounting Principles and Reporting (U.S. GAAP)).*

ANNUAL INFORMATION FORM

February 25, 2004

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INTRODUCTORY INFORMATION

EnCana Corporation (EnCana or the Corporation) was formed through the business combination (the Merger), on April 5, 2002, of Alberta Energy Company Ltd. (AEC) and PanCanadian Energy Corporation (PanCanadian). The Merger was accomplished through an arrangement in respect of AEC under the *Business Corporations Act* (Alberta) and certain corporate changes for PanCanadian. Pursuant to the Merger, PanCanadian indirectly acquired all of the outstanding common shares of AEC in consideration for common shares issued by PanCanadian. PanCanadian s name was also changed to EnCana Corporation and its board of directors and senior management were reconstituted. Following completion of the Merger, AEC remained in existence, as an indirect wholly owned subsidiary of EnCana. On January 1, 2003, AEC and another subsidiary were amalgamated with EnCana. As a result of these transactions, the former PanCanadian and the former AEC continue as one corporation known as EnCana Corporation.

In this annual information form, unless otherwise specified or the context otherwise requires, reference to EnCana or to the Corporation includes reference to subsidiaries of and partnership interests held by EnCana Corporation and its subsidiaries. Any reference to EnCana or the Corporation for periods prior to the Merger are to EnCana s founding companies, PanCanadian and AEC, and their subsidiaries and partnership interests.

Unless otherwise indicated, all financial information included and incorporated by reference in this annual information form is determined using Canadian generally accepted accounting principles (Canadian GAAP), which differs from generally accepted accounting principles in the United States (U.S. GAAP). The notes to EnCana s audited consolidated financial statements contain a discussion of the principal differences between EnCana s financial results calculated under Canadian GAAP and under U.S. GAAP.

In accordance with Canadian GAAP, the consolidated financial statements of EnCana include the results of PanCanadian prior to the Merger and do not include any results related to AEC s operations prior to the Merger. Accordingly, unless otherwise indicated, all financial information contained in this annual information form for 2002 and prior periods does not reflect any results of AEC prior to the Merger. Unless otherwise indicated, other statistical information and operational results are presented on the same basis.

Unless otherwise specified, all dollar amounts are expressed in United States dollars, all references to dollars or $ are to United States dollars and all references to C$ are to Canadian dollars. For the financial years ended prior to December 31, 2003, all audited consolidated financial statements of EnCana were expressed in Canadian dollars. For purposes of expressing in United States dollars amounts that were previously expressed in Canadian dollars, the relevant amounts have been translated into United States dollars in the manner discussed in Note 2 to EnCana s audited consolidated financial statements for the year ended December 31, 2003. Capital expenditures budgeted for 2004 which are expected to be incurred in Canada have been translated into United States dollars using a rate of $0.73 United States dollars per one Canadian dollar.

NOTE REGARDING FORWARD-LOOKING STATEMENTS

This annual information form contains certain 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 similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this annual information form include, but are not limited to, statements with respect to: capital investment levels and the allocation thereof, drilling plans and the timing and location thereof, production levels and the timing of achieving such levels, pipeline capacity, reserve estimates, the timing of completion of the Ekwan pipeline, the timing of completion of the Wild Goose Storage Facility expansion, the timing of completion of the Countess Storage Facility and the use of its capacity, the use of facilities related to the Hythe Gas Storage Facility and the timing thereof, the future impact of the Alberta Energy and Utilities Board s September 2003 shut-in order, storage capacity, the level of expenditures for compliance with environmental regulations, site restoration costs including abandonment and reclamation costs, the timing and completion of acquisitions, the timing and completion of the Starks Storage facility, net cash flows, geographical expansion, the amount and use of steam power generated by the Foster Creek cogeneration facility, recovery improvement in the Weyburn oil field, plans for seismic surveys, the netback price received by EnCana, projected increases in oil shipment volumes through the OCP pipeline and the forward-looking statements identified in the Corporation s Management s Discussion and Analysis for the year ended December 31, 2003, which is incorporated into this annual information form by reference.

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 things contemplated by the forward-looking statements will not occur. 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. 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 annual information form include, but are not limited to: volatility of oil and natural gas prices, fluctuations in currency and interest rates, product supply and demand, market competition, risks inherent in EnCana s North American and foreign oil and natural gas and midstream operations, risks of war, hostilities, civil insurrection and instability affecting countries in which EnCana and its subsidiaries operate and terrorist threats, risks inherent in EnCana s and its subsidiaries marketing operations, including credit risk, imprecision of reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved reserves, EnCana s and its subsidiaries ability to replace and expand oil and natural gas reserves, EnCana s ability to generate sufficient cash flow from operations to meet its current and future obligations, EnCana s ability to access external sources of debt and equity capital, general economic and business conditions, EnCana s ability to enter into or renew leases, the timing and costs of gas storage facility, well and pipeline construction, EnCana 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, development and drilling, imprecision in estimates of future production capacity, EnCana s and its subsidiaries 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, risks associated with existing and potential future lawsuits and regulatory actions against EnCana and its subsidiaries, political and economic conditions in the countries in which EnCana and its subsidiaries operate including Ecuador, the risk that the anticipated synergies to be realized by the Merger will not be realized, difficulty in obtaining necessary regulatory approvals and such other risks and uncertainties described from time to time in EnCana s reports and filings with the Canadian securities authorities and the United States Securities and Exchange Commission (the SEC). Statements relating to reserves are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the 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.

The forward-looking statements contained in this annual information form are made as of the date hereof and EnCana undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this annual information form are expressly qualified by this cautionary statement.

NOTE REGARDING RESERVES DATA AND OTHER OIL AND GAS INFORMATION

In 2003, the securities regulatory authorities in Canada (other than Quebec) adopted National Instrument 51-101 (NI 51-101), which imposes new oil and gas disclosure standards for Canadian public companies engaged in oil and gas activities. NI 51-101 and its companion policy specifically contemplate the granting of exemptions from some of the disclosure standards prescribed by NI 51-101 to companies that are active in the United States (U.S.) capital markets, to permit the substitution of the standards required by the SEC in order to provide for comparability of oil and gas disclosure with that provided by U.S. and other international issuers. EnCana has obtained an exemption from Canadian securities regulatory authorities to permit it to provide disclosure in accordance with the relevant legal requirements of the SEC. Accordingly, the reserves data and other oil and gas information included or incorporated by reference in this annual information form is disclosed in accordance with U.S. disclosure requirements and practices. Such information, as well as the information that EnCana discloses in the future in reliance on the exemption, may differ from the corresponding information prepared in accordance with NI 51-101 standards.

The primary differences between the U.S. requirements and the NI 51-101 requirements are that (i) the U.S. standards require disclosure only of proved reserves, whereas NI 51-101 requires disclosure of proved and probable reserves, and (ii) the U.S. standards require that the reserves and related future net revenue be estimated under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made, whereas NI 51-101 requires disclosure of proved reserves and the related future net revenue estimated using constant prices and costs as at the last day of the financial year, and of proved and probable reserves and related future net revenue using forecast prices and costs. The definitions of proved reserves also differ, but according to the Canadian Oil and Gas Evaluation Handbook (the reference source for the definition of proved reserves under NI 51-101), differences in the estimated proved reserve quantities based on constant prices should not be material. EnCana concurs with this assessment.

EnCana has disclosed proved reserve quantities, using the standards contained in U.S. Regulation S-X, and the standardized measure of discounted future net cash flows relating to proved oil and gas reserves determined in accordance with United States Statement of Financial Accounting Standards No. 69 Disclosures About Oil and Gas Producing Activities (FAS 69).

Under U.S. disclosure standards, reserves and production information is disclosed on a net basis (after royalties). Unless otherwise indicated, the reserves and production information contained in this annual information form is shown on that basis.

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

CORPORATE STRUCTURE

Name and Incorporation

As described under Introductory Information , EnCana Corporation was formed through the Merger involving AEC and PanCanadian. EnCana is incorporated under the *Canada Business Corporations Act* (CBCA).

AEC was incorporated on September 18, 1973 under *The Companies Act* (Alberta) and was continued under the *Business Corporations Act* (Alberta) on September 30, 1986.

PanCanadian was incorporated under the CBCA on June 26, 2001 in order to participate in the reorganization of Canadian Pacific Limited (CPL) by way of a plan of arrangement whereby, effective October 1, 2001, CPL distributed to its common shareholders all of the shares of five public companies holding the assets of CPL s five primary operating subsidiaries, including PanCanadian. The holders of common shares of PanCanadian Petroleum Limited exchanged their shares for common shares of PanCanadian. At the conclusion of the CPL reorganization, PanCanadian Petroleum Limited became a wholly owned subsidiary of PanCanadian. PanCanadian Petroleum Limited and PanCanadian were amalgamated on January 1, 2002 and continued under the name PanCanadian Energy Corporation . On completion of the Merger with AEC on April 5, 2002, PanCanadian s name was changed to EnCana Corporation .

Prior to the CPL reorganization, PanCanadian Petroleum Limited was a public corporation, approximately 85 percent of which was held by CPL and 15 percent by the public. Originally established by CPL in 1958 as Canadian Pacific Oil and Gas Limited, PanCanadian Petroleum Limited began its operations using the fee title lands that the Government of Canada had transferred to CPL as part of CPL s building of the national railway across Canada. PanCanadian Petroleum Limited resulted from the amalgamation, under the laws of Canada, on December 31, 1971, of PanCanadian Petroleum Limited (incorporated as Central Leduc Oils Limited in 1947) and Canadian Pacific Oil and Gas Limited (incorporated in 1958). PanCanadian Petroleum Limited was continued under the CBCA on April 9, 1980.

The executive and registered office of EnCana is located at 1800, 855 2nd Street S.W., Calgary, Alberta, Canada T2P 2S5.

Intercorporate Relationships

The following table presents the name, the percentage of voting securities owned and the jurisdiction of incorporation, continuance or formation of EnCana s principal subsidiaries and partnerships with total assets that exceed 10 percent of the total consolidated assets of EnCana or revenues that exceed 10 percent of the total consolidated revenues of EnCana as at and for the year ended December 31, 2003:

Subsidiaries & Partnerships	Percentage Owned[(1)]	Jurisdiction of Incorporation, Continuance or Formation
EnCana Oil & Gas Partnership	100	Alberta
EnCana Midstream & Marketing	100	Alberta
EnCana West Ltd.	100	Alberta
Alenco Inc.	100	Delaware
EnCana Oil & Gas (USA) Inc.	100	Delaware
McMurry Oil Company	100	Wyoming
EnCana Marketing (USA) Inc.	100	Delaware

Notes:

(1) Includes indirect ownership.

The above table does not include all of the subsidiaries and partnerships of EnCana. The assets and revenues of unnamed subsidiaries and partnerships in the aggregate did not exceed 20 percent of the total consolidated assets or total consolidated revenues of EnCana as at and for the year ended December 31, 2003.

GENERAL DEVELOPMENT OF THE BUSINESS

EnCana is one of the world s leading independent crude oil and natural gas exploration and production companies, based on landholdings and production at December 31, 2003. EnCana s key landholdings are in western Canada, the U.S. Rocky Mountains, Ecuador, the United Kingdom (U.K.) central North Sea, offshore Canada s East Coast and the Gulf of Mexico. EnCana explores for, produces and markets natural gas, crude oil and natural gas liquids (NGLs) in Canada and the U.S. EnCana is also engaged in exploration and production activities internationally including production from Ecuador and the U.K. central North Sea. EnCana has interests in midstream operations and assets, including natural gas storage, NGLs gathering and processing facilities, power plants and pipelines.

Upon completion of the Merger on April 5, 2002, EnCana s business was organized into four operating divisions: Onshore North America, Offshore & International Operations, Offshore & New Ventures Exploration, and Midstream & Marketing. During 2003, EnCana reorganized its operations, and now operates under two main divisions: (i) Upstream; and (ii) Midstream & Marketing. The following describes the significant transactions and events in the last three years in the businesses that are now conducted in those divisions.

UPSTREAM

The Upstream division manages EnCana s exploration, development and production of natural gas, NGLs and crude oil and other related activities. The majority of EnCana s Upstream operations are located in Canada, the U.S., Ecuador and the U.K. central North Sea. International new ventures exploration is mainly focused on opportunities in Africa, South America and the Middle East.

Canada

EnCana s Canadian Upstream operations are divided into two regions Canadian Plains and Canadian Foothills & Frontier.

Canadian Plains Region

The Canadian Plains region of western Canada encompasses EnCana s natural gas production activities in southern Alberta and Saskatchewan as well as the Corporation s crude oil projects in northeast Alberta, southern Alberta and Saskatchewan and coalbed methane (CBM) projects in southern Alberta.

EnCana pursues natural gas in shallow and deep horizons and has had several discoveries over the last three years. EnCana is also involved in crude oil development projects including steam-assisted gravity drainage (SAGD) operations at Foster Creek and Christina Lake in northeast Alberta. Commercial production commenced at Foster Creek in the fourth quarter of 2001. In 2003, the Corporation completed an expansion of the Foster Creek project to increase production beyond its original design capacity. At the end of 2003, EnCana completed the third phase of a planned seven phase carbon dioxide (CO_2) miscible flood development at Weyburn, Saskatchewan. There are now 32 patterns, or well groupings, on stream out of a planned total of 75 patterns.

Exploration for CBM natural gas derived from coal seams over the last three years has led to the development of a number of CBM pilot projects located on the Palliser Block of southern Alberta. In the last half of 2003, EnCana expanded its CBM development by drilling approximately 200 wells on the Palliser Block.

In February 2003, EnCana sold a 10 percent interest in the Syncrude Joint Venture (Syncrude) to Canadian Oil Sands Limited (COS) for net cash consideration of approximately $690 million (C$1.0 billion). In July 2003, COS acquired EnCana s remaining 3.75 percent interest in Syncrude and an overriding royalty for net cash consideration of approximately $309 million (C$427 million), bringing the total net cash consideration from the sales to approximately $1.0 billion (C$1.5 billion). Both of these transactions are subject to post-closing adjustments.

In February 2004, EnCana sold its 53.3 percent interest in Petrovera Resources (Petrovera) for approximately $285 million (C$374 million), before working capital adjustments. Petrovera is an Alberta partnership that produces heavy oil in western Canada. EnCana s share of Petrovera s net production averaged approximately 17,500 barrels per day of crude oil in 2003.

Canadian Foothills & Frontier Region

The Canadian Foothills & Frontier region includes EnCana s natural gas and crude oil exploration, development and production activities in northern Alberta and British Columbia. It also includes EnCana s exploration and development activities offshore the East Coast of Canada and in the Northwest Territories.

In 2003, EnCana completed the acquisition of approximately 500,000 net acres of prospective natural gas development lands in Cutbank Ridge, which is located in the foothills of British Columbia and Alberta. In September 2003, EnCana purchased a majority interest in 39 parcels of land totalling roughly 350,000 net acres for approximately $270 million (C$369 million). The Corporation had previously acquired about 150,000 net acres through purchases and land swaps with other companies and Crown land sales, resulting in the total landholding of approximately 500,000 net acres.

The Corporation has developed a large land position offshore the East Coast of Canada. Since the Deep Panuke natural gas discovery in 1999, EnCana has conducted an active exploration program, on its own and with partners. In February 2003, EnCana requested an adjournment of the regulatory approval process for offshore development at Deep Panuke. In December 2003, following the drilling of two successful exploration wells, Margaree and MarCoh, EnCana initiated work on a new plan for a potential offshore development at Deep Panuke.

United States

EnCana s interests in the U.S. are primarily located in the U.S. Rockies, north Texas, the Gulf of Mexico and Alaska. The development of the U.S. as a core area began in June 2000, when EnCana Oil & Gas (USA) Inc., an indirect wholly owned subsidiary of EnCana, acquired all of the shares of McMurry Oil Company and other private interests (McMurry) for total consideration of approximately $778 million, including the assumption of debt. McMurry s principal producing properties are in the Jonah natural gas field located in the Green River Basin of southwest Wyoming.

In February 2001, EnCana Oil & Gas (USA) Inc., through a wholly owned subsidiary, acquired all of the shares of Ballard Petroleum LLC (Ballard) for net cash consideration of approximately $220 million. Ballard s principal producing properties are in the Mamm Creek natural gas field located in the Piceance Basin of northwest Colorado.

As a result of the McMurry acquisition in June 2000, and a consolidation of some of EnCana s U.S. subsidiaries in December 2000, EnCana Oil & Gas (USA) Inc. indirectly owned all of the partnership interests in Jonah Gas Gathering Corporation, a Wyoming general partnership which owned the Jonah Gas Gathering System. In September 2001, EnCana Oil & Gas (USA) Inc. s indirect interest in Jonah Gas Gathering Corporation was sold for proceeds of approximately $360 million.

In May 2002, wholly owned subsidiaries of EnCana Oil & Gas (USA) Inc. acquired natural gas and associated NGLs production, reserves and acreage from subsidiaries of El Paso Corporation (El Paso) for approximately $275 million. The principal producing properties acquired from the El Paso subsidiaries are located in the Piceance Basin of northwest Colorado.

In July 2002, EnCana Oil & Gas (USA) Inc. acquired natural gas and associated NGLs production, reserves and acreage from a subsidiary of The Williams Companies (Williams) for approximately $350 million. The principal producing properties acquired from the Williams subsidiary are located in the Jonah natural gas field in southwest Wyoming.

In July 2003, EnCana Oil & Gas (USA) Inc. acquired the common shares of Savannah Energy Inc. (Savannah) for net cash consideration of approximately $91 million. This acquisition included interests in developed and undeveloped reserves, natural gas and associated NGLs production, and acreage located in north Texas.

In October 2003, EnCana Oil & Gas (USA) Inc. acquired natural gas and associated NGLs production, reserves and acreage from Mesa Hydrocarbons LLC (Mesa) for net cash consideration of approximately $100 million. The principal producing properties acquired from Mesa are in the Piceance Basin of northwest Colorado.

Also in October 2003, EnCana Energy Resources Inc., an indirect wholly owned subsidiary of EnCana, divested crude oil, natural gas and associated NGLs production, reserves, acreage and facilities located primarily in Montana for net cash consideration of approximately $85 million.

In the Gulf of Mexico, a subsidiary of EnCana participated in the Llano oil discovery in 1998. In October 2003, this non-operated interest in the Llano discovery was exchanged for additional interests in the Scott and Telford fields in the U.K. central North Sea, which were received by another subsidiary of EnCana.

EnCana has been increasing its landholdings in the Gulf of Mexico through lease sales, farm-ins, exchanges and acquisitions. Several exploration wells have been drilled over the last three years, including a 25 percent non-operated interest in a significant crude oil discovery at Tahiti in 2002. A deepwater discovery in the Gulf of Mexico at Sturgis was announced in October 2003 in which EnCana holds a 25 percent non-operated interest.

Ecuador

EnCana entered Ecuador in 1999 through the acquisition of Pacalta Resources Ltd. for total consideration of approximately $703 million, and is involved in crude oil exploration, development and production primarily in the Oriente Basin. In the fourth quarter of 2000, EnCana farmed-in to a 40 percent non-operated interest in Block 15 in the Oriente Basin. The Corporation further increased its activity in Ecuador in January 2003 through an acquisition of additional reserves and production from Vintage Petroleum, Inc. (Vintage) for net cash consideration of approximately $116 million.

In November 2003, EnCana divested its interest in Block 27 in the Oriente Basin for net cash consideration of approximately $14 million.

EnCana is part of a consortium that completed construction of the Oleoducto de Crudos Pesados (OCP) pipeline in Ecuador in August 2003. The pipeline was fully commissioned in November 2003 and has a capacity of 450,000 barrels per day. EnCana has an indirect 36.3 percent equity interest in OCP and a 15-year shipping commitment of approximately 108,000 barrels per day.

United Kingdom

In January 2000, EnCana completed the purchase of 13.5 percent and 20.2 percent interests in the Scott and Telford crude oil fields, respectively, in the U.K. central North Sea, for net cash consideration of approximately $177 million. In October 2003, through the Llano exchange referred to above, EnCana acquired an additional 14.0 percent interest in each of the Scott and Telford fields. The Corporation also assumed operatorship of the Scott and Telford fields. In early 2004, EnCana completed the purchase of additional 13.5 percent and 20.2 percent interests in the Scott and Telford fields, respectively, for net cash consideration of approximately $126 million. EnCana now holds 41.0 percent of the Scott field and 54.3 percent of the Telford field.

In the spring of 2001, the Corporation made a significant crude oil discovery in the U.K. central North Sea at Buzzard. In November 2003, the U.K. Department of Trade and Industry approved the development plan for Buzzard.

International New Ventures Exploration

EnCana invests a small portion (less than 5 percent) of its capital in high potential exploration beyond its core geographic areas, primarily in Africa, South America and the Middle East.

MIDSTREAM & MARKETING

EnCana s midstream activities are primarily comprised of natural gas storage operations, NGLs processing and power generation operations.

EnCana continues to pursue expansions of its North American continental natural gas storage network with the expansion of the Wild Goose storage facility in northern California and the completion of the first phase of the Countess storage facility east of Calgary. The Wild Goose expansion is scheduled for completion in April 2004. The first phase of the new Countess facility came online in October 2003.

Also in October 2003, EnCana Gas Storage Inc., an indirect wholly owned subsidiary of EnCana, announced that it is planning to build a new, high-deliverability natural gas storage facility in southwest Louisiana. This planned facility is known as the Starks project and the first phase of the facility is anticipated to be fully in-service by the third quarter of 2005.

In December 2001, EnCana sold its 100 percent interest in Alberta Oilsands Pipeline Ltd., owner of the Alberta Oilsands Pipelines System, for approximately $137 million (C$218 million).

In January 2003, EnCana completed the sale of its indirect 70 percent interest in the Cold Lake Pipeline System (Cold Lake) for approximately $270 million (C$425 million). The Corporation has retained crude oil transportation capacity on the pipeline for its production through its existing long-term contracts. EnCana also completed the sale of its indirect 100 percent interest in the Express Pipeline System (Express) in January 2003 for approximately $778 million (C$1.2 billion), which included the assumption of approximately $385 million (C$600 million) in debt by the purchaser. EnCana has retained crude oil transportation capacity on the system through its existing long-term contracts.

EnCana s marketing activities include the sale and delivery of produced product and the purchase of third party product, primarily for the optimization of midstream assets as well as the optimization of transportation arrangements not fully utilized for the Corporation s own production. EnCana s production of NGLs in western Canada is marketed through Kinetic Resources (LPG), an Alberta partnership in which EnCana has an indirect 75 percent interest, and Kinetic Resources (U.S.A.), a Michigan partnership in which EnCana has an indirect 75 percent interest (collectively, Kinetic). EnCana crude oil marketing supplies a limited number of third parties with marketing services for a fee.

All Houston-based merchant energy trading operations were discontinued following the Merger in 2002.

NARRATIVE DESCRIPTION OF THE BUSINESS

EnCana s business is conducted in two main divisions: (i) Upstream; and (ii) Midstream & Marketing.

UPSTREAM

The majority of EnCana s Upstream operations are located in Canada, the U.S., Ecuador and the U.K. central North Sea. International new ventures exploration is mainly focused on opportunities in Africa, South America and the Middle East.

As at December 31, 2003, EnCana had net proved reserves of approximately 957 million barrels of crude oil and NGLs and 8.4 trillion cubic feet of natural gas, as estimated by independent qualified reserves evaluators. Proved developed reserves comprise approximately 61 percent of total net proved reserves. See Reserves and Other Oil and Gas Information .

In the following discussion, comparative production information for 2002 is presented on the basis of combining the results of PanCanadian and AEC for the period prior to the Merger.

Canada

Western Canada is EnCana s principal foundation, largely from its industry leading land position of approximately 25.1 million gross acres (approximately 21.5 million net acres, of which approximately 15.1 million net acres are undeveloped). The mineral rights on approximately one quarter of this land is acreage owned in fee title by EnCana, which means that production is subject to a mineral tax that is generally less than the Crown royalty imposed on production from land where the government owns the mineral rights.

Canadian Plains Region

The Canadian Plains region encompasses EnCana s natural gas production activities in southern Alberta and Saskatchewan as well as the Corporation s crude oil development projects, including thermal recovery projects at Foster Creek and Christina Lake using SAGD technology and a CO_2 miscible flood project at Weyburn. The region also includes EnCana s CBM projects in southern Alberta.

EnCana s 2004 capital investment in core programs for natural gas projects in the Canadian Plains region is budgeted to be approximately $860 million, with approximately $20 million directed to exploration and approximately $840 million to development. EnCana anticipates drilling approximately 3,450 gross natural gas wells (3,300 net wells) in this region in 2004. Capital investment in 2004 for crude oil projects is budgeted to be approximately $390 million, primarily directed towards development projects, including approximately $180 million for SAGD projects, and the drilling of approximately 570 gross oil wells (560 net wells).

The following describes EnCana s major producing areas or activities in the Canadian Plains region.

Suffield

At December 31, 2003, EnCana held an average 99 percent interest in the petroleum and natural gas rights to approximately 1.1 million gross acres (approximately 1.1 million net acres, of which approximately 223,000 net acres are undeveloped) in the productive Upper Cretaceous shallow natural gas horizons and deeper formations in the Suffield area in southeast Alberta.

The Suffield area is largely made up of the Suffield Block. Operations on the Suffield Block are carried out by EnCana in cooperation with the Canadian military according to guidelines established under agreements with the Government of Canada. At December 31, 2003, there were 6,514 gross producing shallow natural gas wells (6,497 net wells). There were also 66 gross natural gas wells (66 net wells) producing from deeper formations. EnCana s 2003 net production on the Suffield Block averaged 230 million cubic feet per day of dry, sweet natural gas (193 million cubic feet per day in 2002).

EnCana operates and holds a 100 percent interest in properties along the west side of the Suffield Block which produce heavy oil. At December 31, 2003, there were 861 gross producing oil wells (856 net wells), of which 551 gross wells (551 net wells) were horizontal wells. In 2003, EnCana s Suffield area net crude oil production averaged 26,945 barrels per day (22,834 barrels per day in 2002).

Brooks

At December 31, 2003, EnCana held an average 96 percent interest in the petroleum and natural gas rights to approximately 1.1 million gross acres (approximately 1.0 million net acres, of which approximately 134,000 net acres are undeveloped) in the Brooks area of southern Alberta, located east of Calgary. EnCana had interests in 7,886 gross producing natural gas wells (7,541 net wells) and 459 gross producing oil wells (449 net wells) at December 31, 2003. EnCana s net production in 2003 averaged 434 million cubic feet per day of natural gas and 15,295 barrels per day of crude oil and NGLs (429 million cubic feet per day of natural gas and 16,253 barrels per day of crude oil and NGLs in 2002).

Calgary

At December 31, 2003, EnCana held an average 94 percent interest in the petroleum and natural gas rights to approximately 1.3 million gross acres (approximately 1.2 million net acres, of which approximately 295,000 net acres are undeveloped) in the Calgary area. EnCana had interests in 2,573 gross producing natural gas wells (2,406 net wells) and 230 gross producing oil wells (183 net wells) at December 31, 2003. Average net production for 2003 in this area was 329 million cubic feet per day of natural gas and 7,342 barrels per day of crude oil and NGLs (345 million cubic feet per day of natural gas and 8,019 barrels per day of crude oil and NGLs in 2002).

Foster Creek

EnCana holds surface access rights for petroleum, natural gas and oilsands exploration, development and transportation from areas within the Primrose Block (Cold Lake Air Weapons Range) which were granted by the Government of Canada. EnCana has acquired, and has certain rights to acquire, oilsands leases wherever deposits of crude oil bitumen are identified within the areas for which petroleum and natural gas lease rights are held. EnCana is currently operating a 100 percent owned thermal oil recovery project in the Foster Creek area of the Primrose Block using SAGD technology. In 2003, EnCana s net production averaged 21,823 barrels per day of crude oil (13,026 barrels per day in 2002). Construction of the Phase I Expansion of the Foster Creek project was completed in the third quarter of 2003. The Phase I Expansion is designed to increase 2004 net production to an expected average rate of approximately 28,000 barrels per day of crude oil.

In 2003, EnCana completed the construction and commenced commercial operation of an 80 megawatt, natural gas-fired cogeneration facility in conjunction with its SAGD operation at Foster Creek. The facility reached its full capacity of 80 megawatts in the fourth quarter of 2003. The steam generated by the facility is being used within the SAGD operation and the power generated is being sold into the Alberta Power Pool grid.

Christina Lake

EnCana completed construction of a 100 percent owned thermal crude oil recovery pilot project at Christina Lake using SAGD technology, and commenced production at the end of the third quarter of 2002. Net production was approximately 3,806 barrels of crude oil per day in 2003 (307 barrels per day in 2002).

Thermal Recovery Research and Development

EnCana continues to research and develop technologies to increase recovery and decrease the costs of extracting crude oil bitumen from oilsands.

One focus area is to reduce the reliance on steam in crude oil bitumen production. To this end, EnCana is piloting two technologies using solvents as part of the extraction process. The Solvent Aided Process (SAP) mixes a small amount of solvent with steam to enhance recovery, while the Vapex process uses solvent in place of steam. After piloting SAP at Senlac, Saskatchewan in 2002, EnCana began construction of a pilot operation at Christina Lake in 2003. SAP testing at Christina Lake is expected to begin in the second quarter of 2004. The Vapex pilot commenced testing at Foster Creek in 2002, with additional research planned for 2004. Another focus area is artificial lift where EnCana is pursuing pump designs that are anticipated to enable the Corporation to implement low pressure SAGD and decrease facility capital costs. In 2003, EnCana successfully field-tested certain downhole pumps under existing SAGD operating conditions, allowing for further development of technology.

Weyburn

EnCana has a 62 percent working interest (50 percent economic interest) in the Weyburn crude oil field in southwest Saskatchewan. EnCana is the operator and expects to improve ultimate recovery in the enhanced oil recovery area with a CO_2 miscible flood project. EnCana s net production from Weyburn in 2003 averaged 10,846 barrels of crude oil per day (10,549 barrels per day in 2002).

Coalbed Methane

EnCana is expanding CBM development on its 100 percent owned fee title lands in southern Alberta. During 2003, the Corporation drilled approximately 270 wells, increasing production from the commercial demonstration project to approximately 10 million cubic feet per day. In 2004, EnCana plans to drill approximately 300 wells, which is expected to increase CBM production to approximately 30 million cubic feet per day by year end.

Canadian Foothills & Frontier Region

The major producing areas of the Canadian Foothills & Frontier region include Greater Sierra in northeast British Columbia, Sexsmith/Hythe/Saddle Hills in northwest Alberta, and the Primrose Block and Pelican Lake in northeast Alberta. The region also encompasses EnCana s recent Cutbank Ridge land acquisition spanning the British Columbia-Alberta border, as well as exploration and development activities offshore the East Coast of Canada and in the Northwest Territories.

EnCana s 2004 capital investment in core programs for natural gas projects in the Canadian Foothills & Frontier region is budgeted to be approximately $990 million, with approximately $110 million directed to exploration and approximately $880 million to development. EnCana plans to drill approximately 620 gross natural gas wells (590 net wells) and approximately 100 gross crude oil wells (95 net wells) in this region in 2004. Capital investment for crude oil projects is budgeted to be approximately $100 million, primarily directed towards development projects.

Greater Sierra

In the Greater Sierra area of northeast British Columbia, at December 31, 2003, EnCana held an average 86 percent interest in the petroleum and natural gas rights to approximately 3.2 million gross acres (approximately 2.8 million net acres, of which approximately 2.4 million net acres are undeveloped). EnCana held an average 96 percent interest in 13 production facilities in the area that were capable of processing approximately 320 million cubic feet per day of natural gas as at December 31, 2003. EnCana is currently in the process of constructing the $43 million Ekwan pipeline in northeast British Columbia which will transport natural gas to Alberta. The pipeline will extend approximately 80 kilometres with a capacity of approximately 400 million cubic feet per day. Completion of the pipeline is expected in the second quarter of 2004. EnCana had interests in 503 gross producing natural gas wells (440 net wells) at December 31, 2003. EnCana s net production in 2003 averaged 143 million cubic feet per day of natural gas and 607 barrels per day of NGLs (110 million cubic feet per day of natural gas and 524 barrels per day of NGLs in 2002).

Sexsmith/Hythe/Saddle Hills

In the Sexsmith/Hythe/Saddle Hills area in northwest Alberta, at December 31, 2003, EnCana held an average 80 percent interest in the petroleum and natural gas rights to approximately 529,000 gross acres (approximately 423,000 net acres, of which approximately 248,000 net acres are undeveloped). EnCana had interests in 296 gross natural gas wells (239 net wells) and 100 gross oil wells (67 net wells) that were producing at December 31, 2003. EnCana s net production in 2003 averaged 114 million cubic feet per day of natural gas and 2,990 barrels per day of crude oil and NGLs (99 million cubic feet per day of natural gas and 3,113 barrels per day of crude oil and NGLs in 2002).

EnCana operates and has a 62 percent interest in a 210 million cubic feet per day sour natural gas and liquids processing plant and an 85 percent interest in a 50 million cubic feet per day sweet natural gas plant in the Sexsmith area. EnCana owns 100 percent of and operates the Hythe sour natural gas plant, which has a capacity of approximately 170 million cubic feet per day. The Hythe and Sexsmith sour natural gas plants are interconnected by pipeline to provide greater operating efficiencies. EnCana also owns and operates a 240-kilometre natural gas gathering system in the area.

Primrose Block

At December 31, 2003, EnCana held an average 97 percent interest in the petroleum and natural gas rights to approximately 868,000 gross acres (approximately 842,000 net acres, of which approximately 541,000 net acres are undeveloped) on the Primrose Block in northeast Alberta. At December 31, 2003, EnCana had interests in 533 gross natural gas wells (511 net wells) that were producing. In 2003, EnCana s net production from Primrose averaged 174 million cubic feet per day of natural gas (187 million cubic feet per day in 2002), the majority of which is processed through 100 percent controlled and operated compression facilities. EnCana s 2003 production volumes, primarily from the Primrose Block, were affected by an Alberta Energy and Utilities Board decision, in September 2003, to shut-in natural gas production that may put at risk the recovery of bitumen resources in the area. The decision resulted in EnCana s annualized natural gas production in the region declining by approximately three million cubic feet per day. The future impact of this decision is not known at this time but EnCana does not expect it to be material.

Pelican Lake

At December 31, 2003, EnCana held a 100 percent interest in approximately 224,000 gross acres (approximately 224,000 net acres, of which approximately 167,000 net acres are undeveloped) of crude oil bitumen rights at Pelican Lake in north-central Alberta. EnCana also holds a 38 percent interest in a 110-kilometre, 20-inch diameter crude oil pipeline which connects the Pelican Lake area to a major pipeline that transports crude oil from northern Alberta to crude oil markets. EnCana s net production in 2003 from this area averaged 15,944 barrels per day of crude oil (13,739 barrels per day in 2002) from interests in 460 gross oil wells (453 net wells) that were producing at December 31, 2003.

Cutbank Ridge

In September 2003, EnCana completed the acquisition of approximately 500,000 net acres of prospective natural gas development lands in the Canadian Rocky Mountain foothills. The lands in this new resource play called Cutbank Ridge are located approximately 50 kilometres southwest of Dawson Creek, British Columbia. In September 2003, EnCana purchased a majority interest in 39 parcels of land totalling roughly 350,000 net acres for approximately $270 million (C$369 million). The Corporation had previously acquired about 150,000 net acres through purchases and land swaps with other companies and Crown land sales, resulting in the total landholding of approximately 500,000 net acres in the area. In 2003, EnCana drilled 19 net natural gas wells at Cutbank Ridge which produced approximately 14 million cubic feet per day of natural gas in December 2003. In 2004, EnCana plans to drill approximately 40 net natural gas wells at Cutbank Ridge.

East Coast of Canada

Offshore Nova Scotia on the East Coast of Canada, EnCana has a 100 percent working interest in the Deep Panuke natural gas discovery approximately 250 kilometres off the coast of Nova Scotia in approximately 40 metres of water. Infrastructure in this relatively under-explored basin will require expansion, the cost of which must be borne at least partly by the Deep Panuke project. In February 2003, EnCana requested an adjournment of the regulatory approval process in order to pursue further steps to improve the project s economics. In December 2003, following the drilling of two successful exploration wells, Margaree (100 percent operated interest) and MarCoh (24.5 percent operated interest), EnCana initiated work on a new plan for a potential offshore development at Deep Panuke.

In 2002, the Corporation participated in the drilling of the Annapolis well offshore Nova Scotia, which encountered approximately 30 metres of net natural gas pay over several zones. Further plans to assess the potential of this discovery are under development. EnCana has a 26 percent non-operated interest in the discovery.

At December 31, 2003, EnCana held an interest in approximately 4.4 million gross acres (approximately 3.0 million net acres) of exploration lands offshore Nova Scotia. The Corporation also held an interest in approximately 4.3 million gross acres (approximately 2.8 million net acres) of exploration lands located offshore Newfoundland and Labrador at December 31, 2003. EnCana operates 19 of its 25 exploration licenses in these areas and has an average working interest of approximately 66 percent.

Northwest Territories

EnCana has an approximate 37 percent interest in two exploration blocks comprising approximately 529,000 gross acres (approximately 198,000 net acres) in the Mackenzie Delta region of Canada s Northwest Territories. The Corporation is planning to drill one exploration well in the first half of 2004.

The Corporation has an approximate 60 percent working interest in two exploration blocks comprising approximately 388,000 gross acres (approximately 233,000 net acres) in the Norman Wells area of the Northwest Territories. EnCana is planning to drill one exploration well in the first half of 2004.

United States

EnCana s operations in the U.S. Rockies area are currently focused on exploiting deep, tight, long-life natural gas formations primarily in the Jonah sweet natural gas field located in the Green River Basin of southwest Wyoming and the Mamm Creek natural gas field located in the Piceance Basin of northwest Colorado. EnCana s U.S. operations also include interests in north Texas, the Gulf of Mexico and Alaska, as well as various natural gas gathering and processing assets.

EnCana s 2004 capital investment in core programs for natural gas projects in the U.S. is budgeted at approximately $820 million, with approximately $90 million directed to exploration and approximately $730 million to development, and includes the drilling of approximately 535 gross natural gas wells (500 net wells). Capital investment for crude oil projects is budgeted to be approximately $100 million, primarily directed to exploration projects.

<u>Jonah</u>

At Jonah in southwest Wyoming, EnCana held an average 75 percent interest in the petroleum and natural gas rights to approximately 77,000 gross acres (approximately 58,000 net acres, of which approximately 48,000 net acres are undeveloped) and had interests in 327 gross natural gas wells (287 net wells) that were producing at December 31, 2003. EnCana s net production in 2003 averaged 374 million cubic feet per day of natural gas and 3,348 barrels per day of NGLs (275 million cubic feet per day of natural gas and 2,788 barrels per day of NGLs in 2002).

<u>Mamm Creek</u>

At Mamm Creek in northwest Colorado, EnCana held an average 96 percent interest in the petroleum and natural gas rights to approximately 176,000 gross acres (approximately 168,000 net acres, of which approximately 113,000 net acres are undeveloped) and had interests in 601 gross natural gas wells (591 net wells) that were producing at December 31, 2003. EnCana s net production in 2003 averaged 125 million cubic feet per day of natural gas and 1,013 barrels per day of NGLs (56 million cubic feet per day of natural gas and 389 barrels per day of NGLs in 2002).

In October 2003, EnCana Oil & Gas (USA) Inc. acquired natural gas and associated NGLs production, reserves and acreage from Mesa for net cash consideration of approximately $100 million. The principal producing properties acquired from Mesa are in the Piceance Basin of northwest Colorado.

<u>North Texas</u>

In north Texas, EnCana held an average 77 percent interest in the petroleum and natural gas rights to approximately 95,000 gross acres (approximately 73,000 net acres, of which approximately 59,000 net acres are undeveloped) and had interests in 163 gross natural gas wells (159 net wells) that were producing at December 31, 2003. EnCana s net production in 2003 averaged seven million cubic feet per day of natural gas and 218 barrels per day of NGLs.

In July 2003, EnCana Oil & Gas (USA) Inc. acquired the common shares of Savannah for net cash consideration of approximately $91 million. This acquisition included interests in developed and undeveloped reserves, natural gas and associated NGLs production, and acreage located in north Texas.

<u>Gulf of Mexico</u>

EnCana owns a 25 percent non-operated interest in the Tahiti crude oil discovery, located in the deep water Green Canyon Block 640. Four appraisal wells were drilled in the first half of 2003 to evaluate this discovery.

In October 2003, a subsidiary of EnCana exchanged its 22.5 percent non-operated interest in the Llano crude oil discovery in the Gulf of Mexico for additional interests in the Scott and Telford fields in the U.K. central North Sea, which were received by another subsidiary of EnCana. Also in October 2003, a deepwater discovery in the Gulf of Mexico at Sturgis was announced in which EnCana holds a 25 percent non-operated interest.

EnCana has working interest acreage in over 262 exploration blocks comprising approximately 1.5 million gross acres (approximately 663,000 net acres) in the Gulf of Mexico, with options to add approximately 15 additional blocks. Such options were acquired through large regional farm-ins and the Corporation s ongoing land acquisition program.

Alaska

EnCana has working interests in approximately 1.8 million gross acres (approximately 802,000 net acres) of exploration lands in both offshore and onshore Alaska.

Other

EnCana owns and operates various gas gathering and NGLs processing facilities in Colorado. Near Fort Lupton, Colorado, the gathering facilities include field compression and over 1,000 kilometres of pipelines, and the processing plant has a capacity of approximately 90 million cubic feet per day. Near Rifle, Colorado, EnCana s gathering facilities have a capacity of approximately 240 million cubic feet per day and include over 645 kilometres of pipelines. Near Rangely, Colorado, the Corporation s gathering facilities include field compression and over 1,600 kilometres of pipelines. The processing plant has a capacity of approximately 60 million cubic feet per day.

Ecuador

In Ecuador, EnCana is the largest private sector crude oil producer. An indirect, wholly owned subsidiary of EnCana owns one concession in the Oriente Basin, known as the Tarapoa Block. The Corporation has a 100 percent working interest in this concession, which is operated under a participation contract permitting the subsidiary to explore for and produce crude oil at its sole risk and expense during the contract term. The participation contract for the Tarapoa Block has a primary term through to August 1, 2015.

EnCana s 2004 capital investment in core programs for crude oil projects in Ecuador is budgeted to be approximately $180 million, directed primarily to development projects, and includes the drilling of approximately 45 gross crude oil wells (25 net wells).

In the fourth quarter of 2000, EnCana farmed-in to a 40 percent non-operated interest in Block 15 in the Oriente Basin. The concession is operated under a participation contract which has primary terms through to July 2012 for base area production and July 2019 for production resulting from additional exploration.

In January 2003, EnCana acquired majority operating interest in Blocks 14, 17 and Shiripuno, in the Oriente Basin, from Vintage for net cash consideration of approximately $116 million. The acquisition included both developed and undeveloped reserves producing approximately 4,000 barrels of crude oil per day from Blocks 14 and 17. The production contracts for Blocks 14 and 17 expire in July, 2012 and December, 2018, respectively.

At December 31, 2003, EnCana held an average 64 percent interest in the petroleum rights to approximately 1.4 million gross acres (approximately 891,000 net acres, of which approximately 811,000 net acres are undeveloped) in Ecuador. At December 31, 2003, 172 gross crude oil wells (127 net wells) were producing. EnCana s net crude oil production in 2003 was 51,089 barrels per day (36,521 barrels per day in 2002).

With the commissioning of the OCP pipeline completed in November 2003, the Corporation expects 2004 net production from Ecuador to range between 68,000 and 74,000 barrels per day of crude oil.

OCP Pipeline

EnCana is part of a consortium that completed construction of the OCP pipeline in August 2003. The pipeline was fully commissioned in November 2003. OCP is a 500-kilometre pipeline with a capacity of approximately 450,000 barrels per day that runs from the crude oil producing area of Ecuador to the Pacific Coast. Pursuant to the terms of the agreement with the Government of Ecuador, the OCP pipeline will be transferred to the Government of Ecuador, without cost, after a 20-year operating period. EnCana has an indirect 36.3 percent equity interest in OCP, and a 15-year shipping commitment of approximately 108,000 barrels per day.

United Kingdom

EnCana has a working interest in the Scott and Telford crude oil fields located in the U.K. central North Sea, 190 kilometres northeast of Aberdeen, Scotland. EnCana s working interest is 41.0 percent at Scott and 54.3 percent at Telford. In October 2003, EnCana assumed operatorship of the Scott and Telford fields.

Crude oil produced from both fields is processed at the production platform and transported via pipeline through the non-operated Forties pipeline system. The Corporation acquired its initial interests in these fields (13.5 percent in Scott and 20.2 percent in Telford) in January 2000. In October 2003, EnCana increased its ownership by 14 percent in both the Scott and Telford fields through an exchange involving a subsidiary s interest in the Llano crude oil discovery in the Gulf of Mexico. In early 2004, EnCana further increased its ownership through the purchase of additional 13.5 percent and 20.2 percent interests in the Scott and Telford fields, respectively.

EnCana s 2004 capital investment in the U.K. is budgeted to be approximately $360 million, directed primarily to development projects, and includes the drilling of approximately 15 gross crude oil wells (7 net wells).

At December 31, 2003, there were 24 gross crude oil wells (7 net wells) producing. EnCana s net sales of crude oil and NGLs averaged 10,128 barrels per day in 2003 (10,528 barrels per day in 2002). In 2003, average net natural gas sales were approximately 13 million cubic feet per day (approximately 10 million cubic feet per day in 2002).

Development work on the Buzzard discovery in the central North Sea is continuing with initial production anticipated in late 2006. In November 2003, the U.K. Department of Trade and Industry approved the development plan for Buzzard. EnCana is the operator and holds an approximate 43.2 percent interest in the Buzzard field.

At December 31, 2003, EnCana had interests in 63 exploration blocks in the U.K. central North Sea and held a total land position of approximately 1.9 million gross acres (approximately 756,000 net acres, of which approximately 744,000 net acres are undeveloped). Interests range from 8.2 percent to 100 percent. Included in these interests are interests in eight deepwater frontier blocks in the Atlantic Margin west of Great Britain, comprising approximately 241,000 gross acres (approximately 45,000 net acres).

International New Ventures Exploration

Central and West Africa

EnCana has established onshore exploration operations in Chad, based out of the Corporation s office in N Djamena. EnCana has a 50 percent working interest in Permit H comprising approximately 108.5 million gross acres (approximately 54.3 million net acres). EnCana completed the drilling of one exploratory well in February 2004, and activity over the remainder of the year is expected to include seismic surveys and the drilling of an additional two to three exploratory wells.

In 2003, EnCana participated in the drilling of one well in the Gulf of Guinea, offshore Ghana. EnCana has a 40 percent working interest in the Keta Block, comprising approximately 3.7 million gross acres (approximately 1.5 million net acres).

Brazil

EnCana has a 67 percent working interest in Block BM-C-7 comprising approximately 161,000 gross acres (approximately 108,000 net acres) offshore Brazil in the Campos Basin. In 2004, the Corporation plans to drill one exploration well on this block.

Middle East

During 2003, EnCana completed the testing of an exploration well on Block 2 in the State of Qatar. EnCana s share of Block 2 increased to 100 percent during the year. This block encompasses most of the onshore lands in Qatar and covers approximately 2.8 million acres. The Corporation is currently evaluating entry into the second exploration phase on Block 2.

In 2003, EnCana drilled one well on its acreage on Block 47 in the Republic of Yemen. The Corporation has a 53 percent working interest in Block 47 (approximately 1.9 million gross acres and approximately 987,000 net acres). EnCana and its partners relinquished the permit for Block 60 in December 2003.

In 2003, the Corporation initiated exploration activities in the Sultanate of Oman. EnCana has a 100 percent working interest in onshore Blocks 3 and 4, which cover approximately 9.6 million acres. During 2004, EnCana plans to conduct seismic surveys and drill one well.

EnCana has a 50 percent working interest in Block 5 in the Kingdom of Bahrain. Block 5 is comprised of approximately 97,000 gross acres (approximately 48,000 net acres).

Australia

In the fourth quarter of 2003, EnCana sold, subject to regulatory and other approvals, its 25 percent working interest in the John Brookes gas development on the North-West shelf (Blocks WA-214 and WA-205). EnCana has interests remaining in approximately 18.4 million gross acres (approximately 6.5 million net acres) in Australia.

Other

EnCana has also drilled a number of wells in various other countries over the past two years; however, no economic quantities of natural gas or crude oil were found.

MIDSTREAM & MARKETING

Midstream

EnCana s midstream activities are primarily comprised of natural gas storage operations, NGLs processing and power generation operations. In addition, EnCana has minor interests in transportation assets. EnCana s 2004 capital investment in core programs in its midstream operations is budgeted to be approximately $78 million.

Natural Gas Storage

Based upon overall storage capacity, EnCana is the largest independent (non-utility) natural gas storage operator in North America with facilities in Alberta, California and Oklahoma. EnCana also leases natural gas storage capacity from other storage operators located in the U.S. Gulf Coast and mid-continent regions. At December 31, 2003, EnCana had owned and operated storage capacity of approximately 134 billion cubic feet, as well as leased storage capacity of approximately 20 billion cubic feet. The Corporation expects this capacity to increase in 2004 and 2005 upon completion of the expansion of its Wild Goose Gas Storage Facility in northern California, completion of the new Countess Gas Storage Facility in southeast Alberta, and with development of the Starks project in southwest Louisiana.

EnCana provides a portion of its storage capacity under multi-year firm contracts to industry participants on a fee-for-service basis as well as offering short-term firm or interruptible storage services at market based rates. The remaining capacity is used as part of the natural gas storage optimization program (through the purchase and sale of third party gas) and is available to manage EnCana s produced gas sales.

AECO HUB

EnCana operates and markets its Alberta natural gas storage facilities under the commercial name AECO HUB . These facilities, all of which are 100 percent owned by EnCana, include the Suffield Gas Storage Facility, the Hythe Gas Storage Facility and the new Countess Gas Storage Facility. The AECO HUB is Canada s largest natural gas storage and trading hub.

Suffield Gas Storage Facility

Located on the Suffield Block, this facility was the first and is the most significant in the AECO HUB portfolio. It has undergone several expansions since start-up and now has storage capacity of approximately 85 billion cubic feet, a maximum withdrawal capability of approximately 1.8 billion cubic feet per day and a maximum injection capability of approximately 1.6 billion cubic feet per day.

Hythe Gas Storage Facility

In 1999, EnCana expanded its commercial natural gas storage capacity in Alberta through the conversion of a depleted reservoir at Hythe in northwest Alberta. This facility added approximately 10 billion cubic feet of working natural gas capacity, approximately 200 million cubic feet per day of withdrawal capability, and approximately 100 million cubic feet per day of injection capability. The Hythe Gas Storage Facility is connected to both the Alberta pipeline system of TransCanada Corporation and the Alliance Pipeline system. Commencing April 1, 2004, the compression and pipeline facilities related to the Hythe Gas Storage Facility are expected to be utilized by the Upstream division to facilitate incremental production from Cutbank Ridge. Consequently, this facility will not be available for use in providing storage services for a minimum term of one year.

Countess Gas Storage Facility

In October 2002, EnCana announced plans to develop a new natural gas storage facility in southeast Alberta that is expected to store up to 40 billion cubic feet of natural gas. The Countess Gas Storage Facility, designed for peak injections of 950 million cubic feet per day and peak withdrawals of 1.25 billion cubic feet per day, uses two depleted underground reservoirs located about 85 kilometres east of Calgary. The first

10 billion cubic feet of new storage capacity came online in October 2003. As of December 31, 2003, facilities construction was essentially complete, and storage capacity at Countess in 2004 is expected to be approximately 30 billion cubic feet. The full 40 billion cubic feet of storage capacity is expected to be utilized in 2005 after further analysis of initial reservoir performance.

Wild Goose Gas Storage Facility

In April 1999, Wild Goose Storage Inc. (Wild Goose), an indirect wholly owned subsidiary of EnCana, commenced commercial operation of a 14 billion cubic feet storage facility located north of Sacramento, in northern California. The Wild Goose Gas Storage Facility was California s first independent natural gas storage facility and currently has withdrawal capability of approximately 200 million cubic feet per day and injection capability of approximately 80 million cubic feet per day. In July 2002, Wild Goose was granted permission by the California Public Utilities Commission to approximately double the storage size and approximately triple the withdrawal capacity of the facility. Completion of the initial phase expansion is expected in April 2004, bringing the total working gas capacity to approximately 24 billion cubic feet. This expansion is also expected to increase withdrawal capability to approximately 480 million cubic feet per day and expand injection capability to approximately 450 million cubic feet per day.

Salt Plains Gas Storage Facility

In February 2001, Salt Plains Storage Inc., an indirect wholly owned subsidiary of EnCana, acquired substantially all of the assets of a 15 billion cubic feet storage facility located in northern Oklahoma. The Salt Plains Gas Storage Facility has a maximum withdrawal capability of approximately 200 million cubic feet per day and a maximum injection capability of approximately 100 million cubic feet per day.

Starks Project

In October 2003, EnCana Gas Storage Inc., an indirect wholly owned subsidiary of EnCana, announced plans to develop a high-deliverability storage facility in southwest Louisiana. Subject to regulatory approvals, the facility is expected to be in-service during the third quarter of 2005 with approximately 8.65 billion cubic feet of working natural gas capacity, 375 million cubic feet of injection capacity and 400 million cubic feet of withdrawal capacity.

Leased Storage Capacity

EnCana Gas Storage Inc. has entered into contracts to lease storage capacity in the U.S. Gulf Coast and mid-continent regions. Total leased capacity at December 31, 2003 was approximately 20 billion cubic feet, with remaining contract terms ranging from three months to 13 years and an average remaining term of approximately five years.

Natural Gas Liquids

EnCana s NGLs midstream facilities and associated marketing resources are among the largest in Canada. The Corporation holds interests in four NGLs extraction plants that straddle two major natural gas pipelines at Empress, Alberta plus storage and fractionation assets in Saskatchewan, eastern Canada and the U.S.

At Empress, the rights to extract NGLs from natural gas transported through transmission pipelines are acquired from the shippers of the natural gas. In October 2003, the Corporation s Empress NGLs extraction plant completed an expansion that is expected to provide incremental ethane production of up to 17,000 barrels per day. As at December 31, 2003, EnCana s share of the combined processing capacity was approximately two billion cubic feet per day.

Ethane recovered at Empress is sold as a specification product to petrochemical companies for consumption within the Province of Alberta. The remaining liquids components are transported as a mixed stream by pipeline to a plant at Sarnia, Ontario in which EnCana holds an approximate 10.4 percent interest.

The mixed stream is fractionated at Sarnia into marketable products: propane, butane and pentanes plus. These are sold by Kinetic to distributors, refiners and petrochemical manufacturers in Canada and the U.S. under contracts, the terms of which are typically one year or less.

Other significant NGLs midstream assets include: (i) a one-third interest in a pipeline which delivers ethane from extraction plants located in Alberta at Waterton, Empress (four plants), Cochrane and Edmonton to ethylene plants at Joffre and Fort Saskatchewan and storage caverns at Fort Saskatchewan; (ii) a 50 percent interest in a pipeline that delivers NGLs from Empress to storage facilities and the Enbridge pipeline at Kerrobert, Saskatchewan; (iii) interests in a NGLs storage facility and depropanizer at Superior, Wisconsin; and (iv) a 49 percent interest in a propane and butane storage facility at Marysville, Michigan.

Power Generation

EnCana has interests in two 106-megawatt power plants in southern Alberta, which supply electricity to the Power Pool of Alberta. The Cavalier Power Station began selling electricity to the Alberta Power Pool in late August 2001. The plant, located approximately 54 kilometres east of Calgary, is 100 percent owned and operated by EnCana. The Balzac Power Station, in which EnCana holds a 50 percent non-operated interest, is also located near Calgary and was brought into service in December 2001. The Corporation also has a 25 percent non-operated interest in a cogeneration facility in Kingston, Ontario. EnCana s power generation capacity, excluding power generated at the Foster Creek SAGD operation, is approximately 186 megawatts. In 2003, the Corporation generated 598,000 megawatt hours of EnCana owned electricity from the Cavalier, Balzac and Kingston plants (603,000 megawatt hours in 2002).

Transportation

In February 2001, EnCana purchased a 36 percent equity interest in the Trasandino Pipeline system for approximately $64 million. The Trasandino system carries crude oil from Argentina s Neuquen Basin to refineries in Chile. The pipeline is 420 kilometres in length and has a design capacity of approximately 113,000 barrels per day. Shipments on the Trasandino system in 2003 averaged approximately 104,000 barrels per day (approximately 112,000 barrels per day in 2002).

Marketing

Natural Gas Marketing

In 2003, approximately 87 percent of EnCana s produced natural gas sales were directly marketed by EnCana to local distribution companies, industrials and energy marketing companies. The remaining 13 percent of produced natural gas sales were marketed to aggregators who supply natural gas to markets throughout North America. Prices received by EnCana are based primarily upon prevailing index prices for natural gas. Prices are impacted by competing fuels in such markets and by regional supply and demand for natural gas.

To mitigate the market risk associated with forecasted cash flows, EnCana entered into various risk management contracts relating to produced natural gas in 2003. The Corporation 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 programs. To protect against weakening production area prices, EnCana entered into AECO and Rockies basis transactions. Details of these transactions are found in Note 17 to EnCana s audited consolidated financial statements for the year ended December 31, 2003.

In 2003, EnCana sold approximately 47 percent of its produced natural gas at fixed prices, approximately 9 percent at AECO Index based pricing, approximately 39 percent at NYMEX based pricing and approximately 5 percent at other prices. As of December 31, 2003, for 2004 EnCana has arranged for the sale of approximately 45 percent of its natural gas at fixed prices, approximately 9 percent exposed to AECO Index based prices, approximately 42 percent exposed to NYMEX based prices and approximately 4 percent at other prices.

In addition to sales of its proprietary production, EnCana purchases and sells natural gas for the purpose of optimizing the profitability of its midstream assets and the netback price to the Corporation. In 2003, EnCana s sales of purchased natural gas amounted to approximately 903 million cubic feet per day (approximately 962 million cubic feet per day in 2002).

Crude Oil Marketing

EnCana sells and manages the transportation of its western Canadian crude oil to markets in Canada and the U.S. (138,784 barrels per day in 2003 and 116,634 barrels per day in 2002). Crude oil sales are normally executed under spot and monthly evergreen contracts with delivery to major pipeline hubs, such as Edmonton, Hardisty or Cromer, in Alberta, with EnCana arranging the intermediate transportation on the feeder pipeline systems. Sales are also made on a delivered basis using trunk pipeline systems, such as Express, for sales to refinery destinations.

EnCana provides North American marketing services to certain organizations on a fee for service basis. In 2003, EnCana acted as exclusive agent for COS and marketed COS Syncrude volumes of 64,863 barrels per day (24,555 barrels per day in 2002). The COS marketing agreement terminates in the second quarter of 2006. EnCana also provides marketing services to the Alberta Government s Department of Energy (69,264 barrels per day in 2003 and 48,133 barrels per day in 2002). This agency agreement ends in the second quarter of 2007.

In Ecuador, EnCana s crude oil volumes are sold FOB at the marine loading facility at Balao, Esmeraldas Province, Ecuador. A total of 45,561 barrels per day was marketed in 2003 (37,253 barrels per day in 2002). Until September 2003, Ecuador production was transported from the Ecuador Oriente region to Balao via the SOTE Pipeline. EnCana began shipping on the OCP Pipeline in September 2003, and the pipeline was fully commissioned in November 2003. EnCana s production in Ecuador consists of a high viscosity crude oil with characteristics well-suited to refineries on the U.S. West and Gulf Coasts.

In the U.K., EnCana marketed 8,439 barrels per day of crude oil in 2003 (10,543 barrels per day in 2002).

To mitigate the market risk associated with forecasted cash flows, EnCana enters into various risk management contracts relating to crude oil. As of December 31, 2003, for 2004, EnCana had approximately 62,500 barrels per day in costless collars with a price floor averaging $20.00 per barrel and a price cap of $25.69 per barrel. Also for 2004, there are approximately 62,500 barrels per day in fixed price swaps with an average price of $23.13 per barrel. For 2005, EnCana has approximately 10,000 barrels per day in costless three-way put spreads. The three-way put spreads provide a price floor averaging $25.00 per barrel when the WTI price is above $20.00 or the WTI price plus $5.00 if the WTI price is below $20.00. The price cap set by the three-way put spreads is $28.775 per barrel.

NGLs Marketing

In 2003, Kinetic continued to market a portion of EnCana s western Canada NGLs primarily to eastern Canada and the U.S. Kinetic also markets NGLs on behalf of other parties.

In the following section (pages 23-40), unless otherwise indicated, the information for EnCana for periods prior to April 5, 2002 (the date of the Merger) represents information for PanCanadian and does not combine the results of PanCanadian and AEC. Accordingly, the amounts shown exclude the results of AEC prior to April 5, 2002, and the amounts for 2001 and the first quarter of 2002 represent solely the results of PanCanadian.

RESERVES AND OTHER OIL AND GAS INFORMATION

EnCana retained independent qualified reserves evaluators to evaluate and prepare reports on 100 percent of EnCana s crude oil and natural gas reserves as of December 31, 2003. EnCana s Canadian reserves were evaluated by McDaniel & Associates Consultants Ltd., Gilbert Laustsen Jung Associates Ltd. and Ryder Scott Company, EnCana s continental U.S. reserves were evaluated by Netherland, Sewell & Associates, Inc., EnCana s Ecuadorian reserves were evaluated by Ryder Scott Company and EnCana s U.K. reserves were evaluated by DeGolyer and MacNaughton. The previous year, 2002, was the first year for which all of EnCana s reserves were independently evaluated.

EnCana has a reserves committee of independent board members which reviews the qualifications and appointment of the independent qualified reserves evaluators. The committee also reviews the procedures for providing information to the evaluators. All booked reserves are based upon annual evaluations by the independent qualified reserves evaluators. The evaluations are conducted from the fundamental geological and engineering data.

Any references to NGLs in this section include condensate.

Reserve Quantities Information

EnCana s reserves increased in 2003 primarily from exploration and development drilling, and to a lesser extent from acquisitions and upward revisions. Reserve acquisitions were approximately equal to reserve dispositions in 2003. The Corporation s reserves increased in 2002 predominantly from the Merger with AEC, and also partly due to extensions and discoveries. The 2002 increase was partially offset by downward revisions of reserve quantities. In 2001, the increase in reserves due to extensions and discoveries was offset by sales during the year.

The following table sets forth reserves continuity information prepared by EnCana in accordance with U.S. disclosure standards, including FAS 69. The end of year numbers for 2003 represent estimates derived from the reports of the independent qualified reserves evaluators referred to above. The end of year numbers for 2002 represent estimates derived from the reports of the independent petroleum engineering consultants who evaluated EnCana s reserves as of December 31, 2002. The beginning and end of year numbers for 2001 represent internal estimates of PanCanadian at the time.

Net Proved Reserves (EnCana Share After Royalties)[1,2]

Constant Pricing

	Natural Gas (billions of cubic feet)					Crude Oil and Natural Gas Liquids (millions of barrels)					
	Canada	**United States**	**United Kingdom**	**Other**	**Total**	**Canada**	**United States**	**Ecuador**	**United Kingdom**	**Other**	**Total**
2001											
Beginning of year	3,350	208	10		3,568	348.0	16.7		23.7	5.0	393.4
Revisions and improved recovery	59	6			65	5.0	1.6		2.1		8.7
Extensions and discoveries	448	13			461	15.0	2.0				17.0
Purchase of reserves in place	1	25			26						
Sale of reserves in place	(1)				(1)	(48.0)				(5.0)	(53.0)
Production	(353)	(16)	(3)		(372)	(33.4)	(0.7)		(4.2)		(38.3)
End of Year	3,504	236	7		3,747	286.6	19.6		21.6		327.8
Developed	2,908	172	7		3,087	245.3	14.9		21.6		281.8
Undeveloped	596	64			660	41.3	4.7				46.0
Total	3,504	236	7		3,747	286.6	19.6		21.6		327.8
2002											
Beginning of year	3,504	236	7		3,747	286.6	19.6		21.6		327.8
Purchase of AEC reserves in place	2,686	944			3,630	233.7	6.5	168.4			408.6
Revisions and improved recovery	(1,140)	731	7		(402)	(15.5)	4.6	(33.5)	(9.1)		(53.5)
Extensions and discoveries	726	319	10		1,055	96.9	3.3	31.1	89.2		220.5
Purchase of reserves in place	30	530			560	4.9	9.9				14.8
Sale of reserves in place	(129)	(73)			(202)	(18.2)	(0.7)				(18.9)
Production	(604)	(114)	(4)		(722)	(46.5)	(2.3)	(10.2)	(4.1)		(63.1)
End of Year	5,073	2,573	20		7,666	541.9	40.9	155.8	97.6		836.2
Developed	4,139	1,446	9		5,594	299.2	21.9	104.6	8.3		434.0
Undeveloped	934	1,127	11		2,072	242.7	19.0	51.2	89.3		402.2
Total	5,073	2,573	20		7,666	541.9	40.9	155.8	97.6		836.2
2003											
Beginning of year	5,073	2,573	20		7,666	541.9	40.9	155.8	97.6		836.2
Revisions and improved recovery	73	1	3		77	32.3	0.5	0.4	23.5		56.7
Extensions and discoveries	867	706		90	1,663	110.9	7.4	11.9		0.9	131.1
Purchase of reserves in place	9	152	8		169	1.3	0.9	17.3	7.1		26.6
Sale of reserves in place	(60)	(88)		(90)	(238)	(0.2)	(4.7)	(5.1)		(0.9)	(10.9)
Production	(706)	(215)	(5)		(926)	(56.8)	(3.4)	(18.6)	(3.7)		(82.5)
End of Year	5,256	3,129	26		8,411	629.4	41.6	161.7	124.5		957.2
Developed	3,984	1,833	13		5,830	306.1	26.3	115.0	16.7		464.1
Undeveloped	1,272	1,296	13		2,581	323.3	15.3	46.7	107.8		493.1

Total	5,256	3,129	26		8,411	629.4	41.6	161.7	124.5		957.2

Notes:

(1) Definitions:

a. Net reserves are the remaining reserves of EnCana, after deduction of estimated royalties and including royalty interests.

b. Proved reserves are the estimated quantities of crude oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made.

c. Proved Developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

d. Proved Undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(2) EnCana does not file any estimates of total net proved crude oil or natural gas reserves with any U.S. federal authority or agency other than the SEC.

Other Disclosures About Oil and Gas Activities

The tables in this section set forth oil and gas information prepared by EnCana in accordance with U.S. disclosure standards, including FAS 69.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

In calculating the standardized measure of discounted future net cash flows, year end constant prices and cost assumptions were applied to EnCana s annual future production from proved reserves to determine cash inflows. Future production and development costs are based on constant price assumptions and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The discount was computed by application of a 10 percent discount factor to the future net cash flows. The calculation of the standardized measure of discounted future net cash flows is based upon the discounted future net cash flows prepared by EnCana s independent qualified reserves evaluators in relation to the reserves they respectively evaluated, and adjusted by EnCana to account for management s estimates of risk management activities, asset retirement obligations and future income taxes.

EnCana cautions that the discounted future net cash flows relating to proved oil and gas reserves are an indication of neither the fair market value of EnCana s oil and gas properties, nor of the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, asset retirement and production costs and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent may not appropriately reflect future interest rates. The computation also excludes values attributable to EnCana s Syncrude interest (disposed of in 2003) and Midstream & Marketing interest.

Standardized Measure of Discounted Future Net Cash Flows

Relating to Proved Oil and Gas Reserves

	Canada			**United States**			**Ecuador**		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
	($ millions)								
Future cash inflows	35,126	29,890	10,768	17,472	9,398	845	3,533	3,368	
Future production and development costs	14,018	8,686	3,070	2,889	3,360	285	987	908	
Undiscounted pre-tax cash flows	21,108	21,204	7,698	14,583	6,038	560	2,546	2,460	
Future income taxes	5,874	6,353	2,604	4,960	1,504	24	536	585	
Future net cash flows	15,234	14,851	5,094	9,623	4,534	536	2,010	1,875	
Less discount of net cash flows using a 10% rate	5,219	6,018	2,034	4,735	2,383	236	643	617	
Discounted future net cash flows	10,015	8,833	3,060	4,888	2,151	300	1,367	1,258	

	United Kingdom			**Other**			**Total**		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
	($ millions)								
Future cash inflows	3,483	2,565	414				59,614	45,221	12,027
Future production and development costs	1,969	1,233	161				19,863	14,187	3,516

Undiscounted pre-tax cash flows	1,514	1,332	253				39,751	31,034	8,511
Future income taxes	456	483	53	—	—	—	11,826	8,925	2,681
Future net cash flows	1,058	849	200				27,925	22,109	5,830
Less discount of net cash flows using a 10% rate	493	438	60	—	—	—	11,090	9,456	2,330
Discounted future net cash flows	565	411	140	—	—	—	16,835	12,653	3,500

Changes in Standardized Measure of Discounted Future Net Cash Flows

Relating to Proved Oil and Gas Reserves

	Canada			United States			Ecuador		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
	($ millions)								
Balance, beginning of year	8,833	3,060	7,844	2,151	300	145	1,258		
Changes resulting from:									
Sales of oil and gas produced during the period	(3,429)	(2,092)	(1,701)	(889)	(329)	(47)	(258)	(157)	
Discoveries and extensions, net of related costs	1,272	1,293	487	1,381	293	36	126	330	
Purchases of proved AEC reserves in place		6,810			1,044			1,830	
Purchases of proved reserves in place	26	93	4	340	613	30	93		
Sales of proved reserves in place	(95)	(371)	(234)	(108)	(72)		(54)		
Net change in prices and production costs	242	3,358	(7,561)	2,751	194	109	(47)		
Revisions to quantity estimates	416	(1,345)	90	4	667	12	4	(354)	
Accretion of discount	1,636	455	1,197	304	56	21	182		
Future development costs incurred, net of changes	340	101	180	534	54	(70)	89		
Other	470	(67)	21	157	(51)		(27)		
Net change in income taxes	304	(2,462)	2,733	(1,737)	(618)	64	1	(391)	
Balance, end of year	10,015	8,833	3,060	4,888	2,151	300	1,367	1,258	

	United Kingdom			Other			Total		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
	($ millions)								
Balance, beginning of year	411	140	147			49	12,653	3,500	8,185
Changes resulting from:									
Sales of oil and gas produced during the period	(83)	(81)	(89)				(4,659)	(2,659)	(1,837)
Discoveries and extensions, net of related costs		594					2,779	2,510	523
Purchases of proved AEC reserves in place								9,684	
Purchases of proved reserves in place	57						516	706	34
Sales of proved reserves in place						(49)	(257)	(443)	(283)
Net change in prices and production costs	(119)	(1)	12				2,827	3,551	(7,440)
Revisions to quantity estimates	157	(53)	19				581	(1,085)	121
Accretion of discount	91	14	32				2,213	525	1,250
Future development costs incurred, net of changes	108	3	(4)				1,071	158	106
Other	(38)	(8)					562	(126)	21
Net change in income taxes	(19)	(197)	23				(1,451)	(3,668)	2,820
Balance, end of year	565	411	140				16,835	12,653	3,500

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Results of Operations, Capitalized Costs and Costs Incurred

Results of Operations

	Canada			United States			Ecuador		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
	($ millions)								
Oil and gas revenues, net of royalties, transportation and selling costs	4,189	2,630	2,043	1,091	406	73	367	224	
Operating costs, production and mineral taxes	760	538	342	202	77	26	109	67	
Depreciation, depletion and amortization	1,511	871	385	297	206	31	159	79	
Operating income (loss)	1,918	1,221	1,316	592	123	16	99	78	
Income taxes	218	456	423	219	47	6	17	28	
Results of operations	1,700	765	893	373	76	10	82	50	

	United Kingdom			Other			Total		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
	($ millions)								
Oil and gas revenues, net of royalties, transportation and selling costs	102	92	99				5,749	3,352	2,215
Operating costs, production and mineral taxes	19	11	10	20	29	1	1,110	722	379
Depreciation, depletion and amortization	74	39	42	83	35	17	2,124	1,230	475
Operating income (loss)	9	42	47	(103)	(64)	(18)	2,515	1,400	1,361
Income taxes	17	17	17	(4)			467	548	446
Results of operations	(8)	25	30	(99)	(64)	(18)	2,048	852	915

Capitalized Costs

	Canada			United States			Ecuador		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
	($ millions)								
Proved oil and gas properties	18,549	12,504	7,704	3,485	2,769	471	1,372	1,000	
Unproved oil and gas properties	1,981	1,573	203	501	415	116	70	60	
Total capital cost	20,530	14,077	7,907	3,986	3,184	587	1,442	1,060	
Accumulated DD&A	7,498	4,770	3,893	516	262	29	188	73	

Net capitalized costs	13,032	9,307	4,014	3,470	2,922	558	1,254	987

	United Kingdom			Other			Total		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
				($ millions)					
Proved oil and gas properties	675	445	288				24,081	16,718	8,463
Unproved oil and gas properties	77	3	44	317	226	144	2,946	2,277	507
Total capital cost	752	448	332	317	226	144	27,027	18,995	8,970
Accumulated DD&A	230	136	88	206	98	92	8,638	5,339	4,102
Net capitalized costs	522	312	244	111	128	52	18,389	13,656	4,868

Costs Incurred

	Canada			United States			Ecuador		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
	($ millions)								
Acquisitions									
AEC unproved reserves		1,496			444			221	
other unproved reserves	47	12	4	21	202	13	80		
AEC proved reserves		3,540			1,024			686	
other proved reserves	207	78	1	115	457	34	59		
Total acquisitions	254	5,126	5	136	2,127	47	139	907	
Exploration	846	403	304	187	226	129	20	35	
Development	2,131	902	592	651	282	11	111	133	
Total costs incurred	3,231	6,431	901	974	2,635	187	270	1,075	

	United Kingdom			Other			Total		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
	($ millions)								
Acquisitions									
AEC unproved reserves								2,161	
other unproved reserves	16						164	214	17
AEC proved reserves								5,250	
other proved reserves	95					4	476	535	39
Total acquisitions	111					4	640	8,160	56
Exploration	30	16	25	78	118	41	1,161	798	499
Development	96	66	17				2,989	1,383	620
Total costs incurred	237	82	42	78	118	45	4,790	10,341	1,175

Daily Sales Volumes, Royalty Rates and Per-Unit Results

Daily Sales Volumes

The following tables summarize net daily sales volumes for EnCana on a quarterly basis for the periods indicated.

	Daily Sales Volumes 2003 (After Royalties)				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
SALES					
Produced Gas ***(million cubic feet/day)***					
Canada					
Production	1,935	2,008	1,914	1,899	1,922
Inventory withdrawal/(injection)	30				120
Canada Sales	1,965	2,008	1,914	1,899	2,042
United States	588	654	604	558	534
United Kingdom	13	20	7	12	13
Total Produced Gas	2,566	2,682	2,525	2,469	2,589
Oil and Natural Gas Liquids ***(barrels/day)***					
North America					
Light and medium oil	54,459	56,585	54,597	52,733	53,890
Heavy oil	87,867	95,059	94,985	82,001	79,171
Natural gas liquids					
Canada	14,278	13,348	13,758	14,740	15,291
United States	9,291	9,479	9,530	10,194	7,943
Total North America	165,895	174,471	172,870	159,668	156,295
Ecuador					
Production	51,089	72,731	54,582	36,754	39,893
Transferred to OCP Pipeline[1]	(3,213)		(4,919)	(2,039)	(5,941)
Over/(under) lifting	(1,355)	4,621	(9,856)	2,506	(2,679)
Ecuador Sales	46,521	77,352	39,807	37,221	31,273
United Kingdom	10,128	15,067	5,813	9,019	10,610
Total Oil and Natural Gas Liquids	222,544	266,890	218,490	205,908	198,178
Total ***(barrels of oil equivalent/day)***	650,211	713,890	639,323	617,408	629,678
Syncrude	7,629		3,399	7,316	20,070

Notes:

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

	Daily Sales Volumes 2002 (After Royalties)				
	Year	Q4	Q3	Q2	Q1
SALES					
Produced Gas ***(million cubic feet/day)***					
Canada					
Production	1,717	1,943	1,959	1,980	975
Inventory withdrawal/(injection)	(6)	117	(51)	(90)	
Canada Sales	1,711	2,060	1,908	1,890	975
United States	337	516	423	345	58
United Kingdom	10	8	9	8	11
Total Produced Gas	2,058	2,584	2,340	2,243	1,044
Oil and Natural Gas Liquids ***(barrels/day)***					
North America					
Light and medium oil	58,328	55,265	58,321	58,885	60,903
Heavy oil	58,890	77,090	70,795	67,558	19,350
Natural gas liquids					
Canada	13,852	15,987	13,985	14,168	11,212
United States	6,407	10,016	5,901	6,368	3,274
Total North America	137,477	158,358	149,002	146,979	94,739
Ecuador					
Production	27,625	34,856	37,447	37,702	
Over/(under) lifting	2,115	1,044	2,316	5,088	
Ecuador Sales	29,740	35,900	39,763	42,790	
United Kingdom	10,528	7,786	9,538	11,966	12,889
Total Oil and Natural Gas Liquids	177,745	202,044	198,303	201,735	107,628
Total ***(barrels of oil equivalent/day)***	520,745	632,711	588,303	575,568	281,628
Syncrude	23,540	33,918	35,585	24,152	

	Daily Sales Volumes 2001 (After Royalties)				
	Year	Q4	Q3	Q2	Q1
SALES					
Produced Gas ***(million cubic feet/day)***					
Canada					
Production	953	974	951	943	946
Inventory withdrawal/(injection)					
Canada Sales	953	974	951	943	946
United States	43	55	48	36	33
United Kingdom	9	9	10	8	8

Total Produced Gas	1,005	1,038	1,009	987	987
Oil and Natural Gas Liquids ***(barrels/day)***					
North America					
Light and medium oil	60,332	58,591	62,250	59,511	60,981
Heavy oil	19,940	20,168	19,948	17,069	22,602
Natural gas liquids					
Canada	10,142	10,792	9,474	9,944	10,362
United States	2,443	2,224	2,954	2,207	2,383
Total North America	92,857	91,775	94,626	88,731	96,328
United Kingdom	11,362	10,839	12,669	10,914	11,012
Total Oil and Natural Gas Liquids	104,219	102,614	107,295	99,645	107,340
Total ***(barrels of oil equivalent/day)***	271,719	275,614	275,462	264,145	271,840

Average Royalty Rates

The following table sets forth average royalty rates on a quarterly basis for the periods indicated. These rates exclude the impact of financial hedging.

	2003					2002					2001				
	Year	**Q4**	**Q3**	**Q2**	**Q1**	**Year**	**Q4**	**Q3**	**Q2**	**Q1**	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
								(percent)							
Produced Gas															
Canada	12.9	12.2	12.9	14.2	12.4	10.7	13.3	10.4	11.8	2.7	3.0	2.2	2.7	4.3	2.4
United States	20.0	19.5	20.2	20.1	20.5	21.1	21.1	23.1	19.4	19.4	30.6	23.6	22.6	42.9	36.5
Crude Oil															
Canada and United States	10.3	9.7	9.0	10.7	11.8	11.0	10.8	11.7	11.6	9.5	10.8	12.2	10.6	11.4	9.0
Ecuador	25.6	25.4	25.7	24.9	26.9	28.4	28.1	28.5	28.5						
Natural Gas Liquids															
Canada	17.5	14.7	16.6	18.0	20.2	13.8	16.4	13.8	15.6	6.9	4.8	2.4	6.9	6.4	3.7
United States	17.6	17.5	17.0	17.3	18.5	10.8	13.3	12.0	10.5						
Total Upstream	14.5	14.4	14.2	15.1	14.4	13.1	14.8	13.8	13.9	5.4	6.3	6.0	5.8	7.7	5.4

Per-Unit Results

The following tables summarize net per-unit results for EnCana on a quarterly basis for the periods indicated.

	Per-Unit Results 2003				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Produced Gas Canada ($/Mcf)					
Price, net of royalties	4.87	4.41	4.61	4.92	5.53
Production and mineral taxes	0.07	0.10	0.08	0.08	0.02
Transportation and selling	0.38	0.44	0.40	0.35	0.33
Operating expenses	0.48	0.45	0.50	0.47	0.48
Netback excluding hedge	3.94	3.42	3.63	4.02	4.70
Financial hedge	(0.13)	0.25	(0.03)	(0.26)	(0.49)
Netback including hedge	3.81	3.67	3.60	3.76	4.21
Produced Gas United States ($/Mcf)					
Price, net of royalties	4.88	4.71	4.82	4.74	5.32
Production and mineral taxes	0.47	0.42	0.46	0.46	0.57
Transportation and selling	0.40	0.51	0.39	0.36	0.32
Operating expenses	0.28	0.29	0.33	0.31	0.20
Netback excluding hedge	3.73	3.49	3.64	3.61	4.23
Financial hedge	0.02	(0.13)	(0.16)	(0.22)	0.67
Netback including hedge	3.75	3.36	3.48	3.39	4.90
Produced Gas Total North America ($/Mcf)					
Price, net of royalties	4.87	4.49	4.66	4.88	5.49
Production and mineral taxes	0.16	0.18	0.17	0.17	0.14

Transportation and selling	0.39	0.46	0.40	0.35	0.33
Operating expenses	0.43	0.41	0.46	0.43	0.42
Netback excluding hedge	3.89	3.44	3.63	3.93	4.60
Financial hedge	(0.10)	0.16	(0.06)	(0.25)	(0.25)
Netback including hedge	3.79	3.60	3.57	3.68	4.35
Light and Medium Oil North America ($/bbl)					
Price, net of royalties	26.61	25.53	24.31	27.43	29.34
Production and mineral taxes	0.29	0.73	(1.35)	0.71	1.08
Transportation and selling	1.42	1.33	0.71	1.73	1.95
Operating expenses	6.00	6.28	5.93	6.07	5.68
Netback excluding hedge	18.90	17.19	19.02	18.92	20.63
Financial hedge	(4.07)	(3.74)	(3.24)	(2.81)	(6.54)
Netback including hedge	14.83	13.45	15.78	16.11	14.09

	Per-Unit Results 2003				
	Year	Q4	Q3	Q2	Q1
Heavy Oil North America ($/bbl)					
Price, net of royalties	19.61	18.43	17.93	20.07	22.62
Production and mineral taxes	(0.03)	0.09	(0.49)	0.34	(0.02)
Transportation and selling	1.24	1.54	0.58	1.37	1.56
Operating expenses	5.67	4.95	5.93	6.18	5.70
Netback excluding hedge	12.73	11.85	11.91	12.18	15.38
Financial hedge	(3.91)	(3.81)	(3.17)	(2.24)	(6.69)
Netback including hedge	8.82	8.04	8.74	9.94	8.69
Total Oil North America ($/bbl)					
Price, net of royalties	22.29	21.08	20.26	22.95	25.34
Production and mineral taxes	0.09	0.33	(0.80)	0.49	0.43
Transportation and selling	1.31	1.46	0.63	1.51	1.72
Operating expenses	5.80	5.45	5.93	6.13	5.70
Netback excluding hedge	15.09	13.84	14.50	14.82	17.49
Financial hedge	(3.97)	(3.78)	(3.19)	(2.47)	(6.63)
Netback including hedge	11.12	10.06	11.31	12.35	10.86
Natural Gas Liquids Canada ($/bbl)					
Price, net of royalties	24.26	25.13	23.52	21.02	27.31
Transportation and selling	0.17	0.13	0.58		
Netback	24.09	25.00	22.94	21.02	27.31
Natural Gas Liquids United States ($/bbl)					
Price, net of royalties	26.97	26.68	25.50	24.64	32.18
Production and mineral taxes	2.03	2.69	2.64	1.21	1.55
Netback	24.94	23.99	22.86	23.43	30.63
Natural Gas Liquids Total North America ($/bbl)					
Price, net of royalties	25.33	25.77	24.33	22.50	28.98
Production and mineral taxes	0.80	1.12	1.08	0.50	0.53
Transportation and selling	0.10	0.08	0.35		
Netback	24.43	24.57	22.90	22.00	28.45
Total Liquids Canada ($/bbl)					
Price, net of royalties	22.47	21.41	20.54	22.76	25.55
Production and mineral taxes	0.08	0.30	(0.73)	0.44	0.38
Transportation and selling	1.21	1.36	0.62	1.36	1.54
Operating expenses	5.27	5.01	5.43	5.53	5.11
Netback excluding hedge	15.91	14.74	15.22	15.43	18.52
Financial hedge	(3.61)	(3.47)	(2.92)	(2.22)	(5.95)

Netback including hedge	12.30	11.27	12.30	13.21	12.57
Ecuador Oil ($/bbl)					
Price, net of royalties	24.21	23.57	22.13	22.31	30.86
Production and mineral taxes	1.47	1.06	0.45	1.11	4.27
Transportation and selling	2.56	2.81	2.36	2.41	2.35
Operating expenses	4.84	4.62	4.33	5.63	5.09
Netback excluding hedge	15.34	15.08	14.99	13.16	19.15
Financial hedge					
Netback including hedge	15.34	15.08	14.99	13.16	19.15
United Kingdom Oil ($/bbl)					
Price, net of royalties	28.11	27.05	27.92	27.17	30.61
Transportation and selling	1.97	1.70	1.98	1.86	2.45
Operating expenses	5.09	6.23	6.55	4.69	2.92
Netback excluding hedge	21.05	19.12	19.39	20.62	25.24
Financial hedge					
Netback including hedge	21.05	19.12	19.39	20.62	25.24
Total Liquids All Countries ($/bbl)					
Price, net of royalties	23.25	22.51	21.22	22.93	26.89
Production and mineral taxes	0.45	0.59	(0.35)	0.58	1.02
Transportation and selling	1.47	1.74	0.95	1.51	1.64
Operating expenses	4.93	4.75	5.01	5.22	4.77
Netback excluding hedge	16.40	15.43	15.61	15.62	19.46
Financial hedge	(2.54)	(2.15)	(2.18)	(1.61)	(4.45)
Netback including hedge	13.86	13.28	13.43	14.01	15.01

	Per-Unit Results 2002				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Produced Gas Canada ($/Mcf)					
Price, net of royalties(1)	2.86	3.60	2.29	2.93	2.25
Production and mineral taxes	0.08	0.07	0.04	0.10	0.14
Transportation and selling	0.24	0.30	0.21	0.21	0.22
Operating expenses	0.41	0.44	0.42	0.40	0.31
Netback excluding hedge	2.13	2.79	1.62	2.22	1.58
Financial hedge	0.05	(0.06)	0.21	(0.08)	0.21
Netback including hedge	2.18	2.73	1.83	2.14	1.79
Produced Gas United States ($/Mcf)					
Price, net of royalties(1)	2.96	3.48	2.78	2.51	2.36
Production and mineral taxes	0.27	0.34	0.22	0.23	0.29
Transportation and selling	0.47	0.46	0.76	0.23	
Operating expenses	0.28	0.23	0.28	0.31	0.60
Netback excluding hedge	1.94	2.45	1.52	1.74	1.47
Financial hedge	0.29	0.34	0.47	0.05	
Netback including hedge	2.23	2.79	1.99	1.79	1.47
Produced Gas Total North America ($/Mcf)					
Price, net of royalties(1)	2.87	3.58	2.37	2.86	2.26
Production and mineral taxes	0.11	0.12	0.08	0.12	0.15
Transportation and selling	0.28	0.33	0.31	0.22	0.21
Operating expenses	0.39	0.40	0.39	0.39	0.32
Netback excluding hedge	2.09	2.73	1.59	2.13	1.58
Financial hedge	0.09	0.02	0.26	(0.06)	0.20
Netback including hedge	2.18	2.75	1.85	2.07	1.78
Light and Medium Oil North America ($/bbl)					
Price, net of royalties	22.31	24.39	24.09	23.37	17.60
Production and mineral taxes	0.65	0.48	0.51	0.14	1.44
Transportation and selling	0.94	1.22	1.04	0.62	0.87
Operating expenses	4.80	5.15	4.72	5.29	4.08
Netback excluding hedge	15.92	17.54	17.82	17.32	11.21
Financial hedge	(0.83)	(0.91)	(0.64)	(1.16)	(0.62)
Netback including hedge	15.09	16.63	17.18	16.16	10.59
Heavy Oil North America ($/bbl)					
Price, net of royalties	17.88	17.38	19.67	17.76	13.62
Production and mineral taxes	0.22	0.54	0.03	0.04	0.32
Transportation and selling	0.71	0.93	0.81	0.48	0.21
Operating expenses	4.58	4.12	4.96	4.39	5.73

Netback excluding hedge	12.37	11.79	13.87	12.85	7.36
Financial hedge	(0.68)	(0.84)	(0.65)	(0.55)	(0.65)
Netback including hedge	11.69	10.95	13.22	12.30	6.71
Total Oil North America ($/bbl)					
Price, net of royalties	20.08	20.31	21.67	20.37	16.64
Production and mineral taxes	0.43	0.51	0.25	0.08	1.17
Transportation and selling	0.82	1.05	0.92	0.55	0.71
Operating expenses	4.69	4.55	4.85	4.81	4.48
Netback excluding hedge	14.14	14.20	15.65	14.93	10.28
Financial hedge	(0.76)	(0.87)	(0.64)	(0.83)	(0.63)
Netback including hedge	13.38	13.33	15.01	14.10	9.65
Natural Gas Liquids Canada ($/bbl)					
Price, net of royalties	17.55	21.75	17.61	17.41	11.56
Transportation and selling					
Netback	17.55	21.75	17.61	17.41	11.56

	Per-Unit Results 2002				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids United States ($/bbl)					
Price, net of royalties	23.75	25.14	25.64	23.57	16.31
Production and mineral taxes	1.02	0.94	1.32	1.37	
Netback	22.73	24.20	24.32	22.20	16.31
Natural Gas Liquids Total North America ($/bbl)					
Price, net of royalties	19.52	23.06	19.99	19.32	12.64
Production and mineral taxes	0.32	0.36	0.39	0.42	
Transportation and selling					
Netback	19.20	22.70	19.60	18.90	12.64
Total Liquids Canada ($/bbl)					
Price, net of royalties	19.82	20.46	21.27	20.07	16.01
Production and mineral taxes	0.39	0.46	0.22	0.08	1.03
Transportation and selling	0.73	0.94	0.83	0.49	0.63
Operating expenses	4.19	4.06	4.38	4.32	3.93
Netback excluding hedge	14.51	15.00	15.84	15.18	10.42
Financial hedge	(0.68)	(0.77)	(0.58)	(0.75)	(0.55)
Netback including hedge	13.83	14.23	15.26	14.43	9.87
Ecuador Oil ($/bbl)					
Price, net of royalties	22.57	24.02	22.82	21.11	
Production and mineral taxes	1.24	1.57	1.49	0.72	
Transportation and selling	2.00	1.99	2.47	1.56	
Operating expenses	4.86	5.35	4.12	5.13	
Netback excluding hedge	14.47	15.11	14.74	13.70	
Financial hedge	(0.01)			(0.03)	
Netback including hedge	14.46	15.11	14.74	13.67	
United Kingdom Oil ($/bbl)					
Price, net of royalties	24.76	25.73	27.07	25.92	21.18
Transportation and selling	1.69	1.53	1.92	1.62	1.65
Operating expenses	3.28	7.07	3.65	2.01	1.78
Netback excluding hedge	19.79	17.13	21.50	22.29	17.75
Financial hedge	(0.06)				(0.19)
Netback including hedge	19.73	17.13	21.50	22.29	17.56
Total Liquids All Countries ($/bbl)					
Price, net of royalties	20.67	21.51	21.95	20.70	16.60
Production and mineral taxes	0.53	0.66	0.50	0.25	0.87
Transportation and selling	0.97	1.10	1.18	0.76	0.71

Operating expenses	4.09	4.18	4.16	4.21	3.53
Netback excluding hedge	15.08	15.57	16.11	15.48	11.49
Financial hedge	(0.50)	(0.57)	(0.42)	(0.53)	(0.49)
Netback including hedge	14.58	15.00	15.69	14.95	11.00

Notes:

(1) Excludes the effect of $108 million increase to consolidated revenues relating to the mark-to-market value of the AEC fixed price forward natural gas contracts recorded as part of the purchase price allocation.

	Per-Unit Results 2001				
	Year	Q4	Q3	Q2	Q1
Produced Gas Canada ($/Mcf)					
Price, net of royalties	4.06	2.29	2.53	4.56	7.01
Production and mineral taxes	0.14	0.14	0.09	0.10	0.24
Transportation and selling	0.21	0.23	0.21	0.18	0.21
Operating expenses	0.32	0.35	0.33	0.33	0.28
Netback excluding hedge	3.39	1.57	1.90	3.95	6.28
Financial hedge	0.38	0.68	1.39	0.28	(0.87)
Netback including hedge	3.77	2.25	3.29	4.23	5.41
Produced Gas United States ($/Mcf)					
Price, net of royalties	2.46	1.79	2.47	1.95	4.18
Production and mineral taxes	0.49	0.29	0.30	0.60	1.01
Transportation and selling					
Operating expenses	0.68	0.51	0.87	0.71	0.61
Netback excluding hedge	1.29	0.99	1.30	0.64	2.56
Financial hedge					
Netback including hedge	1.29	0.99	1.30	0.64	2.56
Produced Gas Total North America ($/Mcf)					
Price, net of royalties	3.99	2.26	2.53	4.46	6.92
Production and mineral taxes	0.15	0.15	0.10	0.12	0.26
Transportation and selling	0.20	0.22	0.20	0.17	0.20
Operating expenses	0.33	0.36	0.35	0.34	0.29
Netback excluding hedge	3.31	1.53	1.88	3.83	6.17
Financial hedge	0.36	0.64	1.33	0.27	(0.84)
Netback including hedge	3.67	2.17	3.21	4.10	5.33
Light and Medium Oil North America ($/bbl)					
Price, net of royalties	19.31	12.56	22.62	20.54	21.29
Production and mineral taxes	0.78	0.93	0.52	1.31	0.40
Transportation and selling	0.70	0.55	0.75	0.61	0.88
Operating expenses	4.78	4.25	4.71	5.35	4.81
Netback excluding hedge	13.05	6.83	16.64	13.27	15.20
Financial hedge	0.80	5.43	(0.26)	(0.59)	(1.27)
Netback including hedge	13.85	12.26	16.38	12.68	13.93
Heavy Oil North America ($/bbl)					
Price, net of royalties	11.41	7.77	16.62	11.21	10.15
Production and mineral taxes	0.50	0.43	0.39	0.65	0.54
Transportation and selling	0.12	0.11	0.14	(0.02)	0.20
Operating expenses	6.63	6.89	5.68	8.06	6.15

Netback excluding hedge	4.16	0.34	10.41	2.52	3.26
Financial hedge					
Netback including hedge	4.16	0.34	10.41	2.52	3.26
Total Oil North America ($/bbl)					
Price, net of royalties	17.35	11.33	21.16	18.46	18.28
Production and mineral taxes	0.71	0.80	0.49	1.16	0.44
Transportation and selling	0.55	0.44	0.60	0.47	0.70
Operating expenses	5.24	4.93	4.95	5.96	5.17
Netback excluding hedge	10.85	5.16	15.12	10.87	11.97
Financial hedge	0.60	4.04	(0.20)	(0.46)	(0.93)
Netback including hedge	11.45	9.20	14.92	10.41	11.04
Natural Gas Liquids Canada ($/bbl)					
Price, net of royalties	19.70	13.25	18.24	22.30	25.42
Transportation and selling					
Netback	19.70	13.25	18.24	22.30	25.42

	Per-Unit Results 2001				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids United States ($/bbl)					
Price, net of royalties	22.22	16.75	20.90	24.40	27.08
Production and mineral taxes					
Netback	22.22	16.75	20.90	24.40	27.08
Natural Gas Liquids Total North America ($/bbl)					
Price, net of royalties	20.19	13.85	18.87	22.68	25.73
Production and mineral taxes					
Transportation and selling					
Netback	20.19	13.85	18.87	22.68	25.73
Total Liquids Canada ($/bbl)					
Price, net of royalties	17.61	11.56	20.86	18.90	19.06
Production and mineral taxes	0.63	0.70	0.44	1.03	0.39
Transportation and selling	0.49	0.38	0.54	0.41	0.62
Operating expenses	4.65	4.33	4.44	5.27	4.60
Netback excluding hedge	11.84	6.15	15.44	12.19	13.45
Financial hedge	0.53	3.55	(0.18)	(0.41)	(0.83)
Netback including hedge	12.37	9.70	15.26	11.78	12.62
United Kingdom Oil ($/bbl)					
Price, net of royalties	24.62	19.72	23.26	26.78	28.67
Transportation and selling	1.68	1.55	1.76	1.68	1.72
Operating expenses	2.69	4.00	2.04	1.83	3.09
Netback excluding hedge	20.25	14.17	19.46	23.27	23.86
Financial hedge	0.46	4.59	(0.77)	(1.56)	0.05
Netback including hedge	20.71	18.76	18.69	21.71	23.91
Total Liquids All Countries ($/bbl)					
Price, net of royalties	18.44	12.52	21.11	19.85	20.19
Production and mineral taxes	0.55	0.61	0.37	0.89	0.34
Transportation and selling	0.60	0.48	0.66	0.54	0.71
Operating expenses	4.31	4.16	4.02	4.77	4.33
Netback excluding hedge	12.98	7.27	16.06	13.65	14.81
Financial hedge	0.51	3.54	(0.24)	(0.52)	(0.72)
Netback including hedge	13.49	10.81	15.82	13.13	14.09

Drilling Activity

The following tables summarize EnCana s gross participation and net interest in wells drilled for 2001, 2002 and 2003.

Exploration Wells Drilled

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2003:											
Canada	532	511	51	31	35	28	618	570	153	771	570
United States	40	35	7	2	4	2	51	39		51	39
Ecuador			3	2			3	2		3	2
United Kingdom			2	1	5	3	7	4		7	4
Other	1				3	1	4	1		4	1
Total	573	546	63	36	47	34	683	616	153	836	616
2002:											
Canada	423	382	84	72	44	37	551	491	190	741	491
United States	12	12	2	1	3	1	17	14		17	14
Ecuador			7	5			7	5		7	5
United Kingdom			7	3	2	1	9	4		9	4
Other					4	2	4	2		4	2
Total	435	394	100	81	53	41	588	516	190	778	516
2001:											
Canada	403	328	81	59	105	90	589	477	260	849	477
United States	13	11	1		2		16	11		16	11
Ecuador											
United Kingdom			1		2	1	3	1		3	1
Other					4	1	4	1		4	1
Total	416	339	83	59	113	92	612	490	260	872	490

Development Wells Drilled

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2003:											
Canada	3,964	3,901	756	650	24	18	4,744	4,569	1,347	6,091	4,569
United States	426	401			1	1	427	402		427	402
Ecuador			53	39	6	6	59	45		59	45
United Kingdom			3				3			3	
Total	4,390	4,302	812	689	31	25	5,233	5,016	1,347	6,580	5,016

2002:											
Canada	1,397	1,340	433	349	30	23	1,860	1,712	690	2,550	1,712
United States	287	250	3	3	1	1	291	254		291	254
Ecuador			44	37	5	4	49	41		49	41
United Kingdom			2				2			2	
Total	1,684	1,590	482	389	36	28	2,202	2,007	690	2,892	2,007
2001:											
Canada	1,125	1,052	333	198	35	29	1,493	1,279	1,227	2,720	1,279
United States	83	47			3	1	86	48		86	48
Ecuador											
United Kingdom			4	1			4	1		4	1
Total	1,208	1,099	337	199	38	30	1,583	1,328	1,227	2,810	1,328

Notes:

(1) Gross wells are the total number of wells in which EnCana has an interest.

(2) Net wells are the number of wells obtained by aggregating EnCana s working interest in each of its gross wells.

At December 31, 2003, EnCana was in the process of drilling 23 gross wells (21 net wells) in Canada, 20 gross wells (20 net wells) in the United States, 4 gross wells (1.9 net wells) in Ecuador, 1 gross well (0.3 net wells) in the United Kingdom and 2 gross wells (0.9 net wells) in other countries.

Location of Wells

The following table summarizes EnCana s interest in producing wells and wells capable of producing as at December 31, 2003:

Location of Wells

As at December 31, 2003

	Gas		Oil		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	25,200	23,693	6,224	5,104	31,424	28,797
British Columbia	827	703	8	7	835	710
Saskatchewan	548	400	3,571	1,832	4,119	2,232
Total Canada	26,575	24,796	9,803	6,943	36,378	31,739
Colorado	2,133	1,878	7	3	2,140	1,881
Montana	44	39			44	39
Texas	167	163	1	1	168	164
Wyoming	543	363	1	1	544	364
Gulf of Mexico			4	1	4	1
Total United States	2,887	2,443	13	6	2,900	2,449
United Kingdom	1		38	11	39	11
Ecuador			231	189	231	189
Total	29,463	27,239	10,085	7,149	39,548	34,388

Notes:

(1) EnCana has varying royalty interests in 8,715 crude oil wells and 11,661 natural gas wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: 10,773 gross natural gas wells (9,953 net wells) and 321 gross crude oil wells (177 net wells).

Interest in Material Properties

The following table summarizes EnCana s developed, undeveloped and total landholdings as at December 31, 2003:

		Developed		Undeveloped		Total	
		Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
				(thousands of acres)			
Canada							
Alberta	Fee	2,566	2,422	2,746	2,717	5,312	5,139
	Crown	3,710	3,149	6,986	5,978	10,696	9,127
	Freehold	197	63	554	279	751	342

		6,473	5,634	10,286	8,974	16,759	14,608
British Columbia	Fee			7	7	7	7
	Crown	656	549	4,850	4,031	5,506	4,580
		656	549	4,857	4,038	5,513	4,587
Saskatchewan	Fee	12	10	481	467	493	477
	Crown	345	214	1,326	1,128	1,671	1,342
	Freehold	73	37	235	157	308	194
		430	261	2,042	1,752	2,472	2,013
Manitoba	Fee			271	266	271	266
	Crown			30	30	30	30
	Freehold			23	23	23	23
				324	319	324	319
Nova Scotia	Crown			4,404	2,988	4,404	2,988
Newfoundland & Labrador	Crown			4,294	2,781	4,294	2,781
Northwest Territories	Crown			1,019	459	1,019	459
Nunavut	Crown			817	26	817	26
Beaufort	Crown			126	4	126	4
Total Canada		7,559	6,444	28,169	21,341	35,728	27,785

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		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
				(thousands of acres)			
United States							
Colorado	Federal/ State Lands	173	144	439	381	612	525
	Freehold	84	70	215	186	299	256
		4	3	9	8	13	11
	Fee	261	217	663	575	924	792
	Federal/ State	58	23	640	463	698	486
Wyoming	Lands Freehold	4	2	46	33	50	35
		62	25	686	496	748	521
	Federal/ State			1,794	802	1,794	802
Alaska							
	Lands Federal/ State			1,511	663	1,511	663
Gulf of Mexico.							
	Lands Federal Lands	10	7	320	270	330	277
Other	Freehold	18	12	259	126	277	138
		28	19	579	396	607	415
		351	261	5,233	2,932	5,584	3,193
Total United States							
		141	80	1,258	811	1,399	891
Ecuador		44	12	1,822	744	1,866	756
United Kingdom				108,536	54,268	108,536	54,268
Chad				9,606	9,606	9,606	9,606
Oman				18,396	6,512	18,396	6,512
Australia				2,758	2,758	2,758	2,758
Qatar				3,677	1,471	3,677	1,471
Ghana				1,879	987	1,879	987
Yemen				985	862	985	862
Greenland				161	108	161	108
Brazil				97	48	97	48
Bahrain				346	17	346	17
Azerbaijan							
		185	92	149,521	78,192	149,706	78,284
Total International							
		8,095	6,797	182,923	102,465	191,018	109,262
Total							

Notes:

(1) This table excludes approximately 3.6 million gross acres under lease or sublease, reserving to EnCana royalties or other interests.

(2) Fee lands are those in which EnCana owns mineral rights and in which it retains a working interest.

(3) Crown / Federal / State lands are those owned by the federal, provincial, or state government or the First Nations, in which EnCana has purchased a working interest lease.

(4) Freehold lands are owned by individuals (other than a Government or EnCana), in which EnCana holds a working interest lease.

(5) Gross acres are the total area of properties in which EnCana has an interest.

(6) Net acres are the sum of EnCana s fractional interest in gross acres.

Acquisitions, Dispositions and Capital Expenditures

EnCana s growth in recent years has been achieved through both internal growth and acquisitions. EnCana has a large inventory of internal growth opportunities and also continues to examine acquisition opportunities to develop and expand its business. The acquisition opportunities may include significant corporate or asset acquisitions and EnCana may finance any such acquisitions with debt or equity or a combination of both.

The following table summarizes EnCana s net capital investment for 2002 and 2003. *Information for 2002 is presented on the basis of combining the results for PanCanadian and AEC for the period prior to the Merger.*

Net Capital Investment

($ million)

	2003	**2002**
Upstream		
Canada	2,937	1,601
United States	830	616
Ecuador	265	212
United Kingdom	112	82
Other Countries	78	113
	4,222	2,624
Midstream & Marketing	223	51
Corporate	57	46
Core Capital	4,502	2,721
Acquisitions		
Upstream		
Property	510	786
Corporate	207	
Midstream & Marketing	53	
Corporate	50	
Dispositions		
Upstream	(301)	(385)
Corporate	(14)	(60)
Net Capital Investment Continuing Operations	5,007	3,062
Discontinued Operations	(1,585)	172
Total Net Capital Investment	3,422	3,234

As part of a regular dispositions program, EnCana plans to dispose of approximately $365 million of non-core assets in 2004, which includes EnCana s interest in Petrovera sold in February 2004.

Delivery Commitments

As part of ordinary business operations, EnCana has a number of delivery commitments to provide crude oil and natural gas under existing contracts and agreements. These commitments comprise a small portion of EnCana s total revenues and the Corporation has sufficient reserves to meet these commitments. More detailed information relating to such commitments can be found in Note 19 to EnCana s audited consolidated financial statements for the year ended December 31, 2003.

GENERAL

Competitive Conditions

All aspects of the oil and natural gas industry are highly competitive and EnCana actively competes with oil and natural gas and other companies for reserve acquisitions, exploration leases, licenses and concessions, midstream assets and industry personnel.

Environmental Protection

EnCana s worldwide operations are subject to government laws and regulations concerning pollution, protection of the environment and the handling and transport of hazardous materials. These laws and regulations generally require EnCana to remove or remedy the effect of its activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by the use or release of specified substances. The Corporate Responsibility, Environment, Health and Safety Committee of EnCana s Board of Directors approves environmental policy and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/ reclamation strategies are utilized to restore the environment.

EnCana expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. EnCana does not anticipate making material expenditures for compliance with environmental regulations in 2004. In 2003, the Corporation adopted Canadian Institute of Chartered Accountants Handbook Section 3110 Asset Retirement Obligations , whereby the Corporation includes the fair value of future asset retirement obligations for abandonment and reclamation costs in the audited consolidated financial statements.

Based on EnCana s current estimate, the total anticipated undiscounted future cost of abandonment and reclamation costs to be incurred over the life of the reserves is estimated at $3.2 billion.

Employees

At December 31, 2003, EnCana employed 3,854 full time equivalent (FTE) employees as set forth in the following table:

	Number of FTE Employees As at December 31, 2003
Upstream	2,808
Midstream & Marketing	280
Corporate	766
Total	3,854

Foreign Operations

As at December 31, 2003, approximately 90 percent of EnCana s reserves and production were located in North America, which limits EnCana s exposure to risks and uncertainties in countries considered politically and economically unstable. EnCana s operations and related assets outside North America may be adversely affected by changes in governmental policy, social instability or other political or economic developments which are not within the control of EnCana, including the expropriation of property, the cancellation or modification of contract rights and restrictions on repatriation of cash. The Corporation has undertaken to mitigate these risks where practical and considered warranted.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following sets forth selected financial information for EnCana for the periods indicated. The information for EnCana includes the results of AEC from the closing date of the Merger. As such, the amounts reported for EnCana for the year ended December 31, 2002 reflect 12 months of PanCanadian or EnCana results, combined with the nine months of post-Merger AEC results. The amounts for EnCana for 2001 represent solely the results of PanCanadian.

	Year Ended December 31		
	2003	2002	2001
	($million, except per share amounts)		
Revenues, net of royalties	10,216	6,276	3,244
Cash flow from continuing operations(3,5)	4,420	2,267	1,463
Cash flow(5)	4,459	2,419	1,494
Net earnings from continuing operations(1,2,3)	2,167	735	832
Net earnings(1,2)	2,360	812	854
Total assets	24,110	19,912	6,823
Long-term debt	6,088	5,051	1,467
Cash dividends(4)	139	108	818
Per Share Data(1,2)			
Cash flow from continuing operations(5)			
Per share basic	9.32	5.43	5.72
Per share diluted	9.21	5.36	5.65
Cash flow(5)			
Per share basic	9.41	5.79	5.85
Per share diluted	9.30	5.72	5.77
Net earnings from continuing operations			
Per share basic	4.57	1.76	3.26
Per share diluted	4.52	1.74	3.21
Net earnings			
Per share basic	4.98	1.94	3.34
Per share diluted	4.92	1.92	3.30

Notes:

(1) In accordance with Canadian GAAP, the Corporation is required to translate long-term debt issued in Canada and denominated in U.S. dollars into Canadian dollars at the period-end exchange rate. Resulting foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings or, in the case of long-term debt held by self-sustaining operations, in the currency translation adjustment account included in Shareholders Equity in the Consolidated Balance Sheet. As a result, 2003 net earnings includes an after-tax unrealized foreign exchange gain of $433 million (2002 $17 million gain; 2001 $28 million loss).

(2) Canadian GAAP requires the Corporation to recognize impacts of tax rate changes that are substantively enacted. Gains or losses from these changes are recorded in the Consolidated Statement of Earnings and included as an adjustment to Future Income Taxes in the Consolidated Balance Sheet. Tax rate reductions increased 2003 net earnings by $359 million (2002 $20 million; 2001 $53 million).

(3) Following the Merger, the Corporation determined to discontinue the Houston-based merchant energy operation of a subsidiary of its predecessor company, PanCanadian, which was included in the Midstream & Marketing segment. Accordingly, these operations were accounted for as discontinued operations. On July 9, 2002, the Corporation announced that it planned to sell its 70 percent equity investment in Cold Lake and its 100 percent interest in Express. Both crude oil pipeline systems were acquired in the business combination with AEC on April 5, 2002. These sales were completed in January 2003 for $1.0 billion (C$1.6 billion), including the assumption of debt, with a resulting after-tax gain on sale of $169 million. Accordingly, these operations were accounted for as discontinued operations. On February 28, 2003, the Corporation completed the sale of its 10 percent working interest in Syncrude to COS for net cash consideration of $690 million (C$1,026 million), subject to post-closing adjustments. On July 10, 2003 the Corporation completed the sale of its remaining 3.75 percent interest in Syncrude and a gross overriding royalty for net cash consideration of $309 million (C$427 million), subject to post-closing

adjustments. This transaction completed the Corporation s disposition of its interests in Syncrude and, as a result, these operations have been accounted for as discontinued operations.

(4) Represents cash dividends paid to common shareholders at a rate of C$0.40 per share annually. As part of the CPL reorganization, the Corporation paid a Special Dividend of $754 million (C$1,180 million or C$4.60 per common share) on September 14, 2001. The amounts shown as dividends on the Consolidated Statements of Retained Earnings and Cash Flows include both the Special Dividend and the quarterly dividend. EnCana s Board of Directors has declared a dividend of $0.10 per share payable on March 31, 2004 to common shareholders of record on March 15, 2004. EnCana s dividend policy is examined annually by the Board of Directors.

(5) Cash Flow from Continuing Operations, Cash Flow, Cash Flow from Continuing Operations per share-basic, Cash Flow from Continuing Operations per share-diluted, Cash Flow per share-basic, Cash Flow per share-diluted are not measures that have any standardized meaning prescribed by Canadian GAAP and are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this annual information form in order to provide shareholders and potential investors with additional information regarding the Corporation s liquidity and its ability to generate funds to finance its operations. Management utilizes Cash Flow and Cash Flow from Continuing Operations as key measures to assess the ability of the Corporation to finance operating activities and capital expenditures.

MANAGEMENT S DISCUSSION AND ANALYSIS

Management s Discussion and Analysis for the year ended December 31, 2003, accompanying the 2003 audited consolidated financial statements, is incorporated by reference.

MARKET FOR SECURITIES

All of the outstanding common shares of EnCana are listed and posted for trading on the Toronto Stock Exchange and the New York Stock Exchange. The Corporation s Coupon Reset Subordinated Term Securities, Series A (Term Securities) and 8.50 percent Preferred Securities are listed and posted for trading on the Toronto Stock Exchange and the Corporation s 9.50 percent Preferred Securities are listed and posted for trading on the New York Stock Exchange.

In February 2004, EnCana announced its intention to redeem all of the Term Securities on March 23, 2004.

DIRECTORS AND OFFICERS

The following information is provided for each director and executive officer of EnCana as at the date of this annual information form:

Directors

Name and Municipality of Residence	Director Since[13]	Principal Occupation
MICHAEL N. CHERNOFF[2,6] West Vancouver, British Columbia	1999	Corporate Director
RALPH S. CUNNINGHAM[2,3] Montgomery, Texas	2003	Corporate Director
PATRICK D. DANIEL[1,5] Calgary, Alberta	2001	President & Chief Executive Officer Enbridge Inc. *(Energy, transportation and services)*
IAN W. DELANEY[3,4] Toronto, Ontario	1999	Chairman of the Board Sherritt International Corporation *(Nickel/ cobalt mining, oil and natural gas production, electricity generation and coal mining)*
WILLIAM R. FATT[1,8] Toronto, Ontario	1995	Chief Executive Officer Fairmont Hotels & Resorts Inc. *(Hotels)*
MICHAEL A. GRANDIN[3,5,6,9] Calgary, Alberta	1998	Chairman & Chief Executive Officer Fording Canadian Coal Trust *(Metallurgical coal)*
BARRY W. HARRISON[1,4,10] Calgary, Alberta	1996	Corporate Director and independent businessman
RICHARD F. HASKAYNE, O.C., F.C.A.[3,4] Calgary, Alberta	1992	Chairman of the Board TransCanada Corporation *(Pipelines and energy services)*
DALE A. LUCAS[1,5] Calgary, Alberta	1997	Corporate Director
KEN F. MCCREADY[2,5,11] Calgary, Alberta	1992	President K.F. McCready & Associates Ltd. *(Sustainable energy development consulting company)*
GWYN MORGAN Calgary, Alberta	1993	President & Chief Executive Officer EnCana Corporation
VALERIE A.A. NIELSEN[2,6] Calgary, Alberta	1990	Corporate Director
DAVID P. O BRIEN[4,7,12] Calgary, Alberta	1990	Chairman EnCana Corporation

Name and Municipality of Residence	Director Since[13]	Principal Occupation
JANE L. PEVERETT[1] West Vancouver, British Columbia	2003	Chief Financial Officer British Columbia Transmission Corporation *(Electricity transmission)*
DENNIS A. SHARP[2,4] Calgary, Alberta	1998	Chairman & Chief Executive Officer UTS Energy Corporation *(Oil and natural gas company)*
JAMES M. STANFORD[1,3,6] Calgary, Alberta	2001	President Stanford Resource Management Inc. *(Investment management)*

Notes:

(1) Audit Committee.

(2) Corporate Responsibility, Environment, Health and Safety Committee.

(3) Human Resources and Compensation Committee.

(4) Nominating and Corporate Governance Committee.

(5) Pension Committee.

(6) Reserves Committee.

(7) Ex-officio non-voting member of all other committees. As an ex-officio non-voting member, Mr. O Brien attends as his schedule permits and may vote when necessary to achieve a quorum.

(8) Mr. Fatt was a director of Unitel Communications Inc. in 1995 when it made a filing pursuant to the *Companies Creditors Arrangement Act* (Canada).

(9) Mr. Grandin was a director of Pegasus Gold Inc. in 1998 when that company filed voluntarily to reorganize under Chapter 11 of the Bankruptcy Code (United States). A liquidation plan for that company received court confirmation later that year.

(10) Mr. Harrison was a director of Gauntlet Energy Corporation in June 2003 when it filed for and was granted an order pursuant to the *Companies Creditors Arrangement Act* (Canada). A plan of arrangement for that company received court confirmation later that year.

(11) Mr. McCready was a director of Colonia Corporation when the company was placed into receivership in October 2000. The company came out of receivership in October 2001.

(12) Mr. O Brien resigned as a director of Air Canada on November 26, 2003. On April 1, 2003, Air Canada obtained an order from the Ontario Superior Court of Justice providing creditor protection under the *Companies Creditors Arrangement Act* (Canada). Air Canada also made a concurrent petition under Section 304 of the U.S. Bankruptcy Code.

(13) Denotes the year each individual became a director of AEC or PanCanadian, if prior to the Merger, or EnCana, if after the Merger.

EnCana does not have an Executive Committee of its Board of Directors.

At the date of this annual information form, there are 16 directors of the Corporation. At the next Annual Meeting of Shareholders, shareholders will be asked to elect as directors the 16 nominees listed in the above table to serve until the close of the next annual meeting of shareholders, or until their respective successors are duly elected or appointed. Subject to mandatory retirement age restrictions which have been established by the Board of Directors, all of the directors shall be eligible for re-election.

Executive Officers

Name and Municipality of Residence	Office
GWYN MORGAN Calgary, Alberta	President & Chief Executive Officer
RANDALL K. ERESMAN Calgary, Alberta	Executive Vice-President & Chief Operating Officer
ROGER J. BIEMANS Denver, Colorado	Executive Vice-President
BRIAN C. FERGUSON Calgary, Alberta	Executive Vice-President, Corporate Development
GERALD J. MACEY Calgary, Alberta	Executive Vice-President
R. WILLIAM OLIVER Calgary, Alberta	Executive Vice-President
GERARD J. PROTTI Calgary, Alberta	Executive Vice-President, Corporate Relations
DRUDE RIMELL Calgary, Alberta	Executive Vice-President, Corporate Services
JOHN D. WATSON Calgary, Alberta	Executive Vice-President & Chief Financial Officer

During the last five years, all of the directors and executive officers have served in various capacities with EnCana or its predecessor companies or have held the principal occupation indicated opposite their names except for the following:

Mr. Chernoff was President of Pacalta Resources Ltd. from 1988 to 1996 and Chairman of the Board of that company from 1988 to May 1999.

Mr. Daniel was President and Chief Operating Officer of Interprovincial Pipe Line Corporation from May 1994 to January 2001.

Mr. Fatt was Chairman and Chief Executive Officer of FHR Holdings Inc. (formerly Canadian Pacific Hotels & Resorts Inc.) from January 1998 to October 2001.

Mr. Grandin was President of PanCanadian Energy Corporation from October 2001 to April 2002. He was Executive Vice-President and Chief Financial Officer of Canadian Pacific Limited from December 1997 to October 2001.

Mr. O Brien was Chairman and Chief Executive Officer of PanCanadian Energy Corporation from October 2001 to April 2002 and Chairman, President and Chief Executive Officer of Canadian Pacific Limited from May 1996 to October 2001.

Ms. Peverett was President of Union Gas Limited from April 2002 to May 2003, was President and Chief Executive Officer from April 2001 to April 2002, was Senior Vice President Sales & Marketing from June 2000 to April 2001, and was Chief Financial Officer from March 1999 to June 2000. She was Vice President Finance of Westcoast Energy Inc. from June 1998 to March 1999.

Mr. Stanford was President and Chief Executive Officer of Petro-Canada from January 1993 to January 2000.

All of the directors and executive officers of EnCana listed above beneficially owned, as of February 25, 2004, directly or indirectly, or exercised control or direction over an aggregate of 1,187,935 common shares representing 0.26 percent of the issued and outstanding voting shares of EnCana, and directors and executive officers held options to acquire an aggregate of 2,677,116 additional common shares.

Investors should be aware that some of the directors and officers of the Corporation are directors and officers of other private and public companies. Some of these private and public companies may, from time to time, be involved in business transactions or banking relationships which may create situations in which conflicts might arise. Any such conflicts shall be resolved in accordance with the procedures and requirements of the relevant provisions of the CBCA, including the duty of such directors and officers to act honestly and in good faith with a view to the best interests of the Corporation.

SUPPLEMENTAL OIL AND GAS INFORMATION

The following information is provided in addition to the information required under U.S. disclosure standards.

Reserve Quantities Information

The following table sets forth estimates of gross proved reserves derived in the same manner as the net proved reserves continuity information on page 24 above. Gross proved reserves refer to the sum of (i) working interest reserves before deduction of royalty burdens payable and (ii) royalty interest reserves (lessor royalty and overriding royalty volumes derived from other working interest owners). The definitions of proved reserves, developed and undeveloped, are the same as those presented on page 24 above.

Gross Proved Reserves (Before Royalties)[(1)]

Constant Pricing

	Natural Gas (billions of cubic feet)				Crude Oil and Natural Gas Liquids (millions of barrels)				
	Canada	United States	United Kingdom	Total	Canada	United States	Ecuador	United Kingdom	Total
2001 End of Year									
Developed	3,009	226	7	3,242	268.9	20.4		21.6	310.9
Undeveloped	586	69		655	47.4	3.7			51.1
Total	3,595	295	7	3,897	316.3	24.1		21.6	362.0
2002 End of Year									
Developed	4,715	1,808	9	6,532	336.0	27.3	142.7	8.3	514.3
Undeveloped	1,068	1,362	11	2,441	287.0	22.6	69.8	89.3	468.7
Total	5,783	3,170	20	8,973	623.0	49.9	212.5	97.6	983.0
2003 End of Year									
Developed	4,576	2,283	13	6,872	350.0	32.5	156.1	16.7	555.3
Undeveloped	1,412	1,582	13	3,007	392.2	18.9	62.3	107.8	581.2
Total	5,988	3,865	26	9,879	742.2	51.4	218.4	124.5	1,136.5

Notes:

(1)

Includes EnCana s royalty interest volumes. At December 31, 2003, these volumes amounted to approximately 183 billion cubic feet of natural gas and 14.8 million barrels of liquids in Canada. At December 31, 2002, these volumes were approximately 225 billion cubic feet of natural gas and 18.7 million barrels of liquids in Canada. At December 31, 2001, these volumes were approximately 336 billion cubic feet of natural gas and 21.3 million barrels of liquids in Canada.

Daily Sales Volume and Per-Unit Results

The following tables summarize gross and net daily sales volumes and per-unit results for EnCana on a quarterly basis for the periods indicated. *The information for 2002 is presented on the basis of combining the results for PanCanadian and AEC for the period prior to the Merger.*

	Daily Sales Volumes 2003 (Before Royalties)(1)				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
SALES					
Produced Gas ***(million cubic feet/day)***					
Canada					
Production	2,222	2,287	2,197	2,213	2,190
Inventory withdrawal/(injection)	35				141
Canada Sales	2,257	2,287	2,197	2,213	2,331
United States	735	813	757	698	672
United Kingdom	13	20	7	12	13
Total Produced Gas	3,005	3,120	2,961	2,923	3,016
Oil and Natural Gas Liquids ***(barrels/day)***					
North America					
Light and medium oil	60,316	62,284	59,708	59,012	60,246
Heavy oil	98,304	105,703	104,702	91,939	90,636
Natural gas liquids					
Canada	17,307	15,656	16,488	17,970	19,162
United States	11,269	11,486	11,487	12,329	9,751
Total North America	187,196	195,129	192,385	181,250	179,795
Ecuador					
Production	68,865	97,446	73,760	49,006	54,726
Transferred to OCP Pipeline(2)	(4,437)		(6,805)	(2,816)	(8,191)
Over/(under) lifting	(1,905)	6,192	(13,412)	3,385	(3,771)
Ecuador Sales	62,523	103,638	53,543	49,575	42,764
United Kingdom	10,128	15,067	5,813	9,019	10,610
Total Oil and Natural Gas Liquids	259,847	313,834	251,741	239,844	233,169
Total ***(barrels of oil equivalent/day)***	760,680	833,834	745,241	727,011	735,836
Syncrude	7,697		3,401	7,383	20,272

Notes:

(1) Includes EnCana s royalty interest volumes.

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

	Daily Sales Volumes 2002 (Before Royalties)(1)				
	Year(2)	Q4	Q3	Q2	Q1(2)
SALES					
Produced Gas ***(million cubic feet/day)***					
Canada					
Production	2,220	2,226	2,209	2,262	2,188
Inventory withdrawal/(injection)	28	149	(80)	(118)	160
Canada Sales	2,248	2,375	2,129	2,144	2,348
United States	500	654	550	428	365
United Kingdom	10	8	9	8	11
Total Produced Gas	2,758	3,037	2,688	2,580	2,724
Oil and Natural Gas Liquids ***(barrels/day)***					
North America					
Light and medium oil	66,333	62,369	65,345	66,807	70,914
Heavy oil	78,029	86,019	80,797	76,233	68,846
Natural gas liquids					
Canada	17,399	19,121	16,225	16,796	17,448
United States	7,961	11,558	6,702	7,115	6,427
Total North America	169,722	179,067	169,069	166,951	163,635
Ecuador					
Production	50,980	48,486	52,344	52,744	50,351
Over/(under) lifting	101	1,448	3,235	7,120	(11,577)
Ecuador Sales	51,081	49,934	55,579	59,864	38,774
United Kingdom	10,528	7,786	9,538	11,966	12,889
Total Oil and Natural Gas Liquids	231,331	236,787	234,186	238,781	215,298
Total ***(barrels of oil equivalent/day)***	690,998	742,954	682,186	668,781	669,298
Syncrude	31,556	34,261	36,039	24,295	31,548

	Daily Sales Volumes 2002 (After Royalties)(1)				
	Year(2)	Q4	Q3	Q2	Q1(2)
SALES					
Produced Gas ***(million cubic feet/day)***					
Canada					
Production	1,953	1,943	1,959	1,980	1,930
Inventory withdrawal/(injection)	22	117	(51)	(90)	113
Canada Sales	1,975	2,060	1,908	1,890	2,043
United States	395	516	423	345	295
United Kingdom	10	8	9	8	11

Total Produced Gas	**2,380**	**2,584**	**2,340**	**2,243**	**2,349**
Oil and Natural Gas Liquids ***(barrels/day)***					
North America					
Light and medium oil	59,222	55,265	58,321	58,885	64,531
Heavy oil	69,465	77,090	70,795	67,558	62,237
Natural gas liquids					
Canada	14,778	15,987	13,985	14,168	14,968
United States	7,019	10,016	5,901	6,368	5,757
Total North America	150,484	158,358	149,002	146,979	147,493
Ecuador					
Production	36,521	34,856	37,447	37,702	36,082
Over/(under) lifting	70	1,044	2,316	5,088	(8,295)
Ecuador Sales	36,591	35,900	39,763	42,790	27,787
United Kingdom	10,528	7,786	9,538	11,966	12,889
Total Oil and Natural Gas Liquids	197,603	202,044	198,303	201,735	188,169
Total ***(barrels of oil equivalent/day)***	594,270	632,711	588,303	575,568	579,669
Syncrude	31,267	33,918	35,585	24,152	31,337

Notes:

(1) Includes EnCana s royalty interest volumes.

(2) Includes AEC volumes for the first quarter of 2002.

The following per-unit results are presented in Canadian dollars. The results are not measures that have any standardized meaning prescribed by Canadian GAAP and are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been provided as additional information.

	Per-Unit Results (C$)							
	2003					2002		
	Year	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Produced Gas Canada (C$/Mcf)								
Price, net of transportation and selling	6.34	5.25	5.80	6.43	7.85	5.17	3.24	4.23
Royalties[1]	0.92	0.78	0.85	1.05	1.00	0.77	0.39	0.65
Operating expenses	0.57	0.51	0.58	0.54	0.63	0.59	0.58	0.54
Netback excluding hedge	4.85	3.96	4.37	4.84	6.22	3.81	2.27	3.04
Financial hedge	(0.18)	0.29	(0.04)	(0.31)	(0.65)	(0.08)	0.29	(0.12)
Netback including hedge	4.67	4.25	4.33	4.53	5.57	3.73	2.56	2.92
Produced Gas United States (C$/Mcf)								
Price, net of transportation and selling	6.28	5.54	6.11	6.13	7.55	4.74	3.16	3.56
Royalties[1]	1.79	1.52	1.73	1.74	2.23	1.42	0.99	0.98
Operating expenses	0.31	0.30	0.36	0.33	0.25	0.28	0.34	0.38
Netback excluding hedge	4.18	3.72	4.02	4.06	5.07	3.04	1.83	2.20
Financial hedge	0.04	(0.13)	(0.17)	(0.24)	0.80	0.42	0.57	0.06
Netback including hedge	4.22	3.59	3.85	3.82	5.87	3.46	2.40	2.26
Produced Gas Total North America (C$/Mcf)								
Price, net of transportation and selling	6.32	5.33	5.88	6.36	7.78	5.08	3.21	4.11
Royalties[1]	1.13	0.98	1.08	1.22	1.28	0.91	0.51	0.70
Operating expenses	0.50	0.45	0.53	0.49	0.54	0.52	0.53	0.52
Netback excluding hedge	4.69	3.90	4.27	4.65	5.96	3.65	2.17	2.89
Financial hedge	(0.13)	0.18	(0.07)	(0.30)	(0.33)	0.03	0.35	(0.09)
Netback including hedge	4.56	4.08	4.20	4.35	5.63	3.68	2.52	2.80
Light and Medium Oil North America (C$/bbl)								
Price, net of transportation and selling	35.33	31.84	32.59	35.78	41.36	36.36	36.01	35.35
Royalties[1,2]	4.42	3.78	3.59	4.56	5.82	4.81	4.56	4.36
Operating expenses	7.63	7.29	8.02	7.54	7.68	7.16	6.58	7.25
Netback excluding hedge	23.28	20.77	20.98	23.68	27.86	24.39	24.87	23.74
Financial hedge	(5.21)	(4.47)	(4.08)	(3.52)	(8.83)	(1.26)	(0.89)	(1.59)
Netback including hedge	18.07	16.30	16.90	20.16	19.03	23.13	23.98	22.15
Heavy Oil North America (C$/bbl)								
Price, net of transportation and selling	25.74	22.21	23.96	25.99	31.80	25.81	29.44	26.85
Royalties[1,2]	2.92	2.32	2.45	3.10	3.99	3.43	3.67	3.09

Operating expenses	7.05	5.94	7.38	7.52	7.52	5.64	6.71	5.87
Netback excluding hedge	15.77	13.95	14.13	15.37	20.29	16.74	19.06	17.89
Financial hedge	(4.95)	(4.52)	(3.95)	(2.80)	(8.83)	(1.18)	(0.89)	(0.76)
Netback including hedge	10.82	9.43	10.18	12.57	11.46	15.56	18.17	17.13
Total Oil North America (C$/bbl)								
Price, net of transportation and selling	29.39	25.78	27.09	29.80	35.61	30.26	32.38	30.82
Royalties[1,2]	3.49	2.86	2.87	3.67	4.72	4.01	4.07	3.68
Operating expenses	7.27	6.44	7.61	7.53	7.59	6.28	6.66	6.51
Netback excluding hedge	18.63	16.48	16.61	18.60	23.30	19.97	21.65	20.63
Financial hedge	(5.05)	(4.50)	(4.00)	(3.08)	(8.83)	(1.22)	(0.89)	(1.15)
Netback including hedge	13.58	11.98	12.61	15.52	14.47	18.75	20.76	19.48
Natural Gas Liquids Canada (C$/bbl)								
Price, net of transportation and selling	33.97	32.90	31.65	29.40	41.25	34.15	27.51	27.07
Royalties	6.01	4.85	5.24	5.28	8.33	5.60	3.80	4.24
Netback	27.96	28.05	26.41	24.12	32.92	28.55	23.71	22.83

	Per-Unit Results (C$)							
	2003					2002		
	Year	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Natural Gas Liquids United States (C$/bbl)								
Price, net of transportation and selling	37.83	35.11	35.18	34.45	48.59	39.47	40.07	36.65
Royalties(1)	8.98	9.05	9.02	7.37	10.92	6.54	6.60	5.75
Netback	28.85	26.06	26.16	27.08	37.67	32.93	33.47	30.90
Natural Gas Liquids Total North America (C$/bbl)								
Price, net of transportation and selling	35.49	33.83	33.10	31.45	43.73	36.15	31.18	29.92
Royalties(1)	7.18	6.63	6.79	6.13	9.21	5.95	4.62	4.69
Netback	28.31	27.20	26.31	25.32	34.52	30.20	26.56	25.23
Total Liquids Canada (C$/bbl)								
Price, net of transportation and selling	29.84	26.38	27.51	29.77	36.25	30.69	31.89	30.42
Royalties(1)	3.74	3.03	3.08	3.84	5.13	4.19	4.04	3.74
Operating expenses	6.56	5.89	6.92	6.73	6.73	5.56	5.99	5.83
Netback excluding hedge	19.54	17.46	17.51	19.20	24.39	20.94	21.86	20.85
Financial hedge	(4.55)	(4.11)	(3.64)	(2.75)	(7.83)	(1.08)	(0.80)	(1.02)
Netback including hedge	14.99	13.35	13.87	16.45	16.56	19.86	21.06	19.83
Ecuador Oil (C$/bbl)								
Price, net of transportation and selling	31.13	28.16	28.40	29.50	43.90	35.38	33.59	31.67
Royalties(1)	10.36	8.82	8.59	9.78	17.12	12.29	12.51	10.76
Operating expenses	4.97	4.53	4.45	5.91	5.63	6.04	4.60	5.70
Netback excluding hedge	15.80	14.81	15.36	13.81	21.15	17.05	16.48	15.21
Financial hedge								(0.04)
Netback including hedge	15.80	14.81	15.36	13.81	21.15	17.05	16.48	15.17
United Kingdom Oil (C$/bbl)								
Price, net of transportation and selling	36.50	33.36	35.79	35.39	42.53	37.99	39.30	37.78
Operating expenses	6.99	8.20	9.03	6.56	4.41	11.10	5.71	3.12
Netback	29.51	25.16	26.76	28.83	38.12	26.89	33.59	34.66

Notes:

(1) Includes production and mineral taxes.

(2) Excludes impact of amendments, made in Q3 2003, related to prior years which reduced royalties by C$21 million.

ADDITIONAL INFORMATION

Additional information, including directors and officers remuneration, principal holders of EnCana s securities, and options to purchase securities, is contained in the Information Circular for EnCana s most recent annual meeting of shareholders that involved the election of directors. Additional financial information is contained in EnCana s audited consolidated financial statements for the year ended December 31, 2003.

When the securities of EnCana are in the course of a distribution pursuant to a short form prospectus or a preliminary short form prospectus has been filed in respect of a distribution of its securities, EnCana will, upon request to the Corporate Secretary as listed below, provide to any person the following information:

(i) one copy of the Corporation s annual information form, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the annual information form,

(ii) one copy of the audited consolidated financial statements of EnCana for its most recently completed financial year for which financial statements have been filed together with the accompanying report of the auditor and one copy of the most recent interim financial statements of EnCana that have been filed, if any, for any period after the end of its most recently completed financial year,

(iii) one copy of the information circular of EnCana in respect of its most recent annual meeting of shareholders that involved the election of directors, and

(iv) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above.

At any other time, EnCana will, upon request to the Corporate Secretary as listed below, provide to any person one copy of any of the documents referred to in (i), (ii) and (iii) above, provided EnCana may require the payment of a reasonable charge if the request is made by a person or Corporation who is not a security holder of EnCana.

For additional copies of this annual information form or any of the materials listed in the preceding paragraphs, please contact:

Kerry D. Dyte
General Counsel
and Corporate Secretary
EnCana Corporation
1800, 855 2nd Street S.W.
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5

Corporate Development Department:
Phone: 403-645-2000
Fax: 403-645-4617

APPENDIX A

Report on Reserves Data by Independent Qualified Reserves Evaluators

To the Board of Directors of EnCana Corporation (the Corporation):

1. We have evaluated the Corporation s reserves data as at December 31, 2003. The reserves data consist of the following:

    (i) estimated proved oil and gas reserve quantities as at December 31, 2003 using constant prices and costs; and

    (ii) the related estimates of discounted future net cash flows under the standardized measure calculation for proved oil and gas reserve quantities.

2. The reserves data are the responsibility of the Corporation s management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

    We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society) with the necessary modifications to reflect definitions and standards under the U.S. Financial Accounting Standards Board policies (the FASB Standards) and the legal requirements of the U.S. Securities and Exchange Commission (SEC Requirements).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with the principles and definitions outlined above.

4. The following table sets forth both the estimated proved reserve quantities (after royalties) and related estimates of future net cash flows (before deduction of income taxes) assuming constant prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2003:

		Estimated Proved Reserve Quantities After Royalty		Related Estimates of Future Net Cash Flow
Evaluator and Preparation Date of Report	**Reserves Location**	**Gas**	**Liquids**	**BTax, 10% discount rate**
		(Bcf)	**(MMbbl)**	**($USMM)**
McDaniel & Associates Consultants Ltd. January 10, 2004	Canada	3,217	451.4	8,719
Gilbert Laustsen Jung Associates Ltd. January 23, 2004	Canada	2,019	136.1	4,808
Ryder Scott Company January 5, 2004	Canada	20	42.0	261
Netherland, Sewell & Associates, Inc. January 6, 2004	United States	3,130	41.6	7,304
Ryder Scott Company January 5, 2004	Ecuador		161.7	1,894
DeGolyer and MacNaughton January 2, 2004	UK - North Sea	26	124.4	814
Totals		8,411	957.2	23,800

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5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook as modified by the FASB Standards and SEC requirements.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Reserves are estimates only, and not exact quantities. In addition, as the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

(signed) McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

(signed) Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta, Canada

(signed) Netherland, Sewell & Associates, Inc.
Dallas, Texas, U.S.A.

(signed) DeGolyer and MacNaughton
Dallas, Texas, U.S.A.

(signed) Ryder Scott Company
Houston, Texas, U.S.A./Calgary, Alberta, Canada

February 9, 2004

APPENDIX B

Report of Management and Directors on Reserves Data and Other Information

Management and directors of EnCana Corporation (the Corporation) are responsible for the preparation and disclosure of information with respect to the Corporation s oil and gas activities in accordance with securities regulatory requirements. In the case of the Corporation, the regulatory requirements are covered under NI 51-101 as amended by an MRRS Decision Document dated December 16, 2003, and require disclosure of information contemplated by, and consistent with, US Disclosure Requirements and US Disclosure Practices (as defined in the Decision Document). Required information includes reserves data, which consist of the following:

(i) proved oil and gas reserve quantities estimated as at December 31, 2003 using constant prices and costs; and

(ii) the related estimates of discounted future net cash flows under the standardized measure calculation for proved oil and gas reserve quantities.

Independent qualified reserves evaluators have evaluated the Corporation s reserves data. A report from the independent qualified reserves evaluators dated February 9, 2004 (the IQRE Report), highlighting the standards they followed and their results, accompanies this Report.

The Reserves Committee of the board of directors (the Board of Directors) of the Corporation, which Committee is comprised exclusively of non-management and unrelated directors, has:

(a) reviewed the Corporation s procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions placed by management affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data as outlined in the IQRE Report with management and each of the independent qualified reserves evaluators.

The Board of Directors has reviewed the standardized measure calculation with respect to the Corporation s proved oil and gas reserve quantities. The Board of Directors has reviewed the Corporation s procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has approved:

(a) the content and filing with securities regulatory authorities of the proved oil and gas reserve quantities, related standardized measure calculation and other oil and gas activity information, contained in the annual information form of the Corporation accompanying this Report;

(b) the filing of the IQRE Report; and

(c) the content and filing of this Report.

Reserves data are estimates only, and are not exact quantities. In addition, as the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) Gwyn Morgan

President & Chief Executive Officer

(signed) Brian C. Ferguson

Executive Vice-President, Corporate Development

(signed) David P. O Brien

Director and Chairman of the Board

(signed) James M. Stanford

Director and Chairman of the Reserves Committee

February 25, 2004

ENCANA CORPORATION

2003

Management s Discussion

and Analysis

NOTE REGARDING FORWARD - LOOKING STATEMENTS

ADVISORY In the interest of providing EnCana Corporation (EnCana or the Company) shareholders and potential investors with information regarding the Company and its subsidiaries, certain statements throughout this Management s Discussion and Analysis (MD&A) constitute forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements are typically identified by words such as anticipate , believe , expect , plan , intend , forecast , target , project or similar words suggest outcomes or statements regarding an outlook. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: production estimates for crude oil, natural gas and NGLs for 2004 and beyond; the Company s oilsands strategy; projected increases in oil shipment volumes through the OCP pipeline; the timing for completion of the various phases of the Countess and Wild Goose gas storage projects and storage capacities, injection and withdrawal rates expected upon completion; the production and growth potential, including the Company s plans therefore, with respect to EnCana s various assets and initiatives, including assets and initiatives in North America, Ecuador, the U.K. central North Sea, the Gulf of Mexico and potential new ventures exploration growth platforms; the potential for acquisitions, the disposition of non-core assets and the expansion of storage and other Midstream assets; the Company s projected capital investment levels for 2004 and the source of funding therefore; projections with respect to the sufficiency of the Company s credit facilities and forecasted capital resources to support planned capital investment programs and projected financial requirements; the effect of the Company s risk management program, including the impact of derivative financial instruments; the Company s plans for the execution of share purchases under its Normal Course Issuer Bid; the Company s defence of lawsuits; the impact of the Kyoto Accord and similar initiatives in the U.S.A. on operating costs; proved oil and gas reserves and reserve life index projections; the Company s projected ability to extend its debt program on an ongoing basis; the impact of safety and environmental risk management programs; projected volatility of crude oil prices in 2004 and the impact which weather and economic activity levels may have on commodity prices and storage demand in 2004 and beyond; projected net earnings and cash flow sensitivity to changes in commodity prices for 2004; projected tax rates and projected cash taxes payable for 2004 and the assumptions on which they are based; the impact on 2004 natural gas production of regulatory rulings and the impact of pipeline rate increases on AECO basis prices in 2004 and beyond.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company s actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of oil and gas prices; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company s and its subsidiaries marketing operations, including credit risks; imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved or probable reserves; the Company s and its subsidiaries ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company s ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company s and its subsidiaries ability to secure adequate product transportation; changes in environmental and other regulations; political and economic conditions in the countries in which the Company and its subsidiaries operate, including Ecuador; the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company and its subsidiaries operate and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions brought against the Company and its subsidiaries; the risk that the anticipated synergies to be realized by the merger of Alberta Energy Company Ltd. (AEC) and the Company will not be realized; costs relating to the merger of AEC and the Company 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.

Statements relating to reserves , or resources or resource potential are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A, and EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

NOTE REGARDING RESERVES DATA AND OTHER OIL AND GAS INFORMATION

ADVISORY The reserves and other oil and gas information contained in this MD&A has been prepared in accordance with U.S. disclosure standards, in reliance on an exemption from the Canadian disclosure standards granted to EnCana by Canadian securities regulatory authorities. Such information may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 (NI 51-101). The reserves quantities disclosed in this MD&A represent net proved reserves calculated on a constant price basis using the standards contained in U.S. Regulation S-X.

The primary differences between the U.S. requirements and the NI 51-101 requirements are that (i) the U.S. standards require disclosure only of proved reserves, whereas NI 51-101 requires disclosure of proved and probable reserves, and (ii) the U.S. standards require that the reserves and related future net revenue be estimated under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made, whereas NI 51-101 requires disclosure of proved reserves and the related future net revenue estimated using constant prices and costs as at the last day of the financial year, and of proved and probable reserves and related future net revenue using forecast prices and costs. The definitions of proved reserves also differ, but according to the Canadian Oil and Gas Evaluation Handbook (the reference source for the definition of proved reserves under NI 51-101) differences in the estimated proved reserve quantities based on constant prices should not be material. EnCana concurs with this assessment.

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

Natural gas volumes are sold based on heat content or in millions of British Thermal Units (MMBtu) but physically measured in thousands of cubic feet. The average heat content per cubic foot of EnCana s natural gas is approximately 1,040 Btu or a conversion ratio of 1 mcf = 1.040 MMBtu.

MANAGEMENT S DISCUSSION AND ANALYSIS

This Management s Discussion and Analysis (MD&A) for EnCana Corporation (EnCana or the Company) should be read in conjunction with the audited annual Consolidated Financial Statements (Consolidated Financial Statements) and accompanying notes. The Consolidated Financial Statements and comparative information have been prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP) in the currency of the United States (except where indicated as being in another currency). A reconciliation to United States GAAP is included in Note 20 to the Consolidated Financial Statements. This MD&A is dated February 6, 2004.

OVERVIEW

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

The audited Consolidated Financial Statements, including the 2001 and 2002 comparative figures, have been presented in United States dollars (U.S. dollars). The Company has adopted the U.S. dollar as its reporting currency since most of its revenues are closely tied to the U.S. dollar and to facilitate direct comparisons to other North American upstream exploration and development companies. In this MD&A, all references to $ are to the U.S. dollar. References to C$ are to the Canadian dollar.

In this MD&A and in the supplementary information to the audited Consolidated Financial Statements, reserves quantities, production and sales volumes are presented on an after royalties basis consistent with U.S. protocol reporting.

Changing the reporting currency affects the presentation in the Company s Consolidated Financial Statements, but not the underlying accounting records. The functional currency of the Company, and its subsidiaries, remains Canadian dollars for Canadian legal entities and U.S. dollars and pounds sterling for non-Canadian legal entities. The financial results of Canadian and United Kingdom (U.K.) legal entities have been translated into U.S. dollars as described in Notes 1 and 2 of the Consolidated Financial Statements.

Impacts on results due to the change in the U.S./Canadian dollar exchange rate in prior periods have been significant when analyzing specific components of the Canadian business contained in the Consolidated Financial Statements. The stronger Canadian dollar resulted in gains on U.S. dollar denominated long-term debt borrowed in Canada, but adversely affected the reported U.S. dollar costs of operating, capital expenditures and depreciation, depletion and amortization (DD&A) denominated in Canadian dollars. Since commodity prices received are based on U.S. dollars, or on Canadian dollar prices which are closely tied to the U.S. dollar, revenues for the Company were relatively unaffected by the exchange rate change.

BUSINESS SEGMENTS

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

BUSINESS ENVIRONMENT

Commodity Price and Foreign Exchange Benchmarks

(average for the year unless otherwise noted)	2003	2003 vs 2002	2002	2002 vs 2001	2001
AECO Price *(C$ per thousand cubic feet)*	**$ 6.70**	**65%**	$ 4.07	35%	$ 6.30
NYMEX Price *($ per million British thermal units)*	**5.39**	**67%**	3.22	25%	4.27
AECO/NYMEX Basis Differential *($ per million British thermal units)*	**0.65**	**2%**	0.66	128%	0.29
WTI *($ per barrel)*	**30.99**	**19%**	26.15	1%	25.95
WTI/Bow River Differential *($ per barrel)*	**8.01**	**35%**	5.93	40%	9.87
WTI/OCP NAPO Differential (Ecuador) *($ per barrel)* (1)	**8.06**				
WTI/Oriente Differential (Ecuador) *($ per barrel)*	**5.59**	**34%**	4.16	41%	7.02
U.S./Canadian Dollar Year End Exchange Rate	**0.774**	**22%**	0.633	1%	0.628
U.S./Canadian Dollar Average Exchange Rate	**0.716**	**12%**	0.637	1%	0.646

(1) This reference price was not available previously and represents the average differential for the period of September (OCP Pipeline shipment commencement) to December 2003.

M3

Natural gas prices rebounded in 2003 from weaker prices experienced in 2002. Continuing concerns about overall North American storage inventory levels, cooler than normal temperatures experienced in the fourth quarter and a lack of confidence concerning prospects for North American supply growth resulted in an increase in the average New York Mercantile Exchange (NYMEX) price of 67 percent in 2003 when compared to 2002. The average NYMEX gas price in the fourth quarter of 2003 was $4.58 per MMBtu, an increase of 15 percent over the fourth quarter price in 2002 of $3.98 per MMBtu. Lower gas prices in 2002 were the result of high levels of natural gas in storage from decreased demand. The AECO/NYMEX basis differential in the fourth quarter of 2003 averaged $0.37 per MMBtu below NYMEX. This represented an improvement of $0.26 per MMBtu over the average in the same period in 2002 of $0.63 per MMBtu. The improvement in the basis differential can be attributed to a stronger Canadian dollar and higher prices for the portion of sales volumes transported from Alberta to Eastern Canada.

In 2003, EnCana sold approximately 47 percent of its produced natural gas at fixed prices, approximately 9 percent at AECO Index based pricing, approximately 39 percent at NYMEX based pricing and approximately 5 percent at other prices. As of December 31, 2003, the Company had arranged for the sale of its projected 2004 natural gas production of approximately 45 percent at fixed prices, approximately 9 percent at AECO Index based prices, approximately 42 percent at NYMEX based prices and approximately 4 percent at other prices.

World crude oil prices increased significantly in 2003 over 2002 and 2001 as supply disruptions in Venezuela and Nigeria preceded the invasion of Iraq. The slow return of Iraqi oil production and OPEC s successful production management combined with strong Asian demand kept crude oil inventories low with resulting upward pressure on prices. The benchmark West Texas Intermediate (WTI) crude oil price of $31.16 per barrel in the fourth quarter of 2003 was $2.93 higher than the $28.23 per barrel in the fourth quarter of 2002.

Canadian heavy oil differentials, as evidenced by the WTI/Bow River differential, widened in absolute terms in 2003 compared to 2002. The widening is primarily due to the higher price for WTI. As a percentage of WTI, Bow River s average sales price for 2003 was 74 percent of WTI as compared to 77 percent in 2002. In 2001, Canadian heavy oil differentials were very wide due to refinery problems and narrowed in 2002 as those problems were rectified.

Ecuador s Oriente differential also widened in 2003 compared to 2002 as a result of the increase in WTI prices. In September 2003, the OCP Pipeline became operational resulting in the creation of a new Ecuadorian crude called NAPO blend. NAPO blend is a heavier crude than Oriente and therefore has a wider differential to WTI.

The 2003 year end U.S./Canadian dollar exchange rate increased by 22 percent when compared to 2002 and was $0.774 per $1 Canadian at December 31, 2003 compared to $0.633 and $0.628 at the end of 2002 and 2001 respectively. The change from 2002 was primarily the result of the economic slowdown in the U.S., continuing differences between Canadian and U.S. interest rates and the U.S. current account deficit.

MANAGEMENT STRATEGY

Upstream capital investment programs are principally focused on growing reserves and production in North American resource plays where the Company believes it has a competitive advantage through exploitation of existing resource holdings in strategic gas developments at Greater Sierra and Cutbank Ridge in British Columbia, Southern Alberta, Jonah and Mamm Creek in the U.S. Rockies as well as oil development at Foster Creek, Pelican Lake and Suffield. In addition to Ecuador, the development of discoveries in the U.K. central North Sea and the Gulf of Mexico are expected to add further to oil growth. Additional upside potential exists in the East Coast of Canada and international exploration activities. Midstream opportunities are focused on expansion and development of the Company s North American gas storage business.

The success of these strategies is subject to numerous risk factors such as (including but not limited to) fluctuations in commodity prices, foreign exchange rates and interest rates, in addition to credit, operational and safety and environmental risks. A number of these risks have been partially mitigated through the risk management program detailed in Note 17 of the Consolidated Financial Statements and discussed in the Risk Management section of this MD&A.

2003 VERSUS 2002 COMPARATIVES

The 2002 comparative figures included in the Consolidated Financial Statements for the year ended December 31, 2003 exclude the results of Alberta Energy Company Ltd. (AEC) prior to the April 5, 2002 merger (Merger) with AEC.

CONSOLIDATED FINANCIAL RESULTS

Consolidated Financial Summary

($ millions, except per share amounts)	2003	2003vs 2002	2002	2002vs 2001	2001
Revenues, Net of Royalties	**$10,216**	**63%**	$ 6,276	93%	$3,244
Net Earnings from Continuing Operations	**2,167**	**195%**	735	12%	832
per share basic	**4.57**	**160%**	1.76	46%	3.26
per share diluted	**4.52**	**160%**	1.74	46%	3.21
Net Earnings	**2,360**	**191%**	812	5%	854
per share basic	**4.98**	**157%**	1.94	42%	3.34
per share diluted	**4.92**	**156%**	1.92	42%	3.30
Cash Flow from Continuing Operations	**4,420**	**95%**	2,267	55%	1,463
per share basic	**9.32**	**72%**	5.43	5%	5.72
per share diluted	**9.21**	**72%**	5.36	5%	5.65
Cash Flow	**4,459**	**84%**	2,419	62%	1,494
per share basic	**9.41**	**63%**	5.79	1%	5.85
per share diluted	**9.30**	**63%**	5.72	1%	5.77
Total Assets	**24,110**	**21%**	19,912	192%	6,823
Long-Term Debt	**6,088**	**21%**	5,051	244%	1,467
Cash Dividends (1)	**139**	**29%**	108	87%	818

(1) Represents cash dividends paid to common shareholders at the rate of C$0.40 per share annually. 2001 also includes a special dividend paid to common shareholders of C$4.60 per share as part of the reorganization of Canadian Pacific Limited, the former principal shareholder of the Company s predecessor, PanCanadian Petroleum Ltd.

Cash Flow from Continuing Operations, Cash Flow, Cash Flow from Continuing Operations per share-basic, Cash Flow from Continuing Operations per share-diluted, Cash Flow per share-basic and Cash Flow per share-diluted are not measures that have any standardized meaning prescribed by Canadian GAAP and are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this MD&A in order to provide shareholders and potential investors with additional information regarding the Company s liquidity and its ability to generate funds to finance its operations. Management utilizes Cash Flow and Cash Flow from Continuing Operations as key measures to assess the ability of the Company to finance operating activities and capital expenditures.

EnCana s cash flow from continuing operations and net earnings from continuing operations increased 95 percent and 195 percent respectively compared to 2002 as a result of growth in sales volumes, higher commodity prices and the inclusion of a full year of post Merger operations, partially offset by increased expenses.

Net earnings for the year also included an unrealized after-tax gain on the U.S. dollar denominated debt issued in Canada of $433 million, or $0.90 per diluted share resulting from the increase in the value of the Canadian dollar versus the U.S. dollar, and a $359 million, or $0.75 per diluted share recovery of future income taxes resulting from reductions in the Canadian federal and Alberta corporate income tax rates. Impacts on results due to the change in the U.S./Canadian dollar exchange rate have been significant when analyzing specific components contained in the

Consolidated Financial Statements. For every 100 dollars denominated in Canadian currency spent on capital projects, operating expenses and administrative expenses, the Company incurred additional costs, as reported in U.S. dollars, of approximately $7.90 based on the increase in the average U.S./Canadian dollar exchange rate in 2003 of $0.716 over 2002 of $0.637. Revenues for the Company were relatively unaffected by the increased exchange rate since commodity prices received are based in U.S. dollars or in Canadian dollar prices which are closely tied to the U.S. dollar.

2002 VERSUS 2001

Cash flow from continuing operations and net earnings from continuing operations in 2002 increased 55 percent and decreased 12 percent respectively compared to 2001. The cash flow increase was due to the inclusion of nine months of post Merger results in 2002, reduced operating costs associated with crude oil production, partially offset by reduced natural gas prices. The net earnings drop was the result of weaker natural gas prices, increased depreciation, depletion and amortization rates resulting from the Merger, partially offset by increased sales volumes resulting from the Merger and the Company s expansion of its North American operations.

Earnings from Continuing Operations Excluding Unrealized Foreign Exchange on Translation of Canadian Issued U.S. Dollar Debt (After Tax) and Tax Rate Reductions

The following table has been prepared in order to provide shareholders and potential investors with information clearly presenting the effect of the translation of the outstanding U.S. dollar debt issued in Canada and the effect of the reduction in the Canadian and Alberta tax rates on the Company s results. The majority of these unrealized gains/losses on U.S. dollar debt issued in Canada relate to debt with maturity dates in excess of 5 years. In accordance with Canadian GAAP, the Company is required to translate U.S. dollar denominated long-term debt issued in Canada into Canadian dollars at the period end exchange rate. Resulting foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings. Canadian GAAP also requires the Company to recognize impacts of tax rate changes that are substantively enacted. Gains or losses from these changes are also recorded in the Consolidated Statement of Earnings and included as an adjustment to Future Income Taxes in the Consolidated Balance Sheet.

($ millions)	**2003**	**2002**	**2001**
Net Earnings from Continuing Operations, as reported	**$2,167**	$735	$832
Deduct: Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt (after-tax) (1)	**433**	17	(28)
Deduct: Future tax recovery due to tax rate reductions (2)	**359**	20	53
Earnings from Continuing Operations, excluding unrealized foreign exchange on translation of Canadian issued U.S. dollar debt (after-tax) and tax rate reductions	**$1,375**	$698	$807

($ per Common Share Diluted			
Net Earnings from Continuing Operations, as reported	**$4.52**	$1.74	$ 3.21
Deduct: Unrealized foreign exchange gain (loss) on translation of Canadian issued U.S. dollar debt (after-tax) (1)	**0.90**	0.04	(0.11)
Deduct: Future tax recovery due to tax rate reductions (2)	**0.75**	0.05	0.20
Earnings from Continuing Operations, excluding unrealized foreign exchange on translation of Canadian issued U.S. dollar debt (after-tax) and tax rate reductions	**$2.87**	$1.65	$ 3.12

(1) Unrealized gain (loss) has no impact on cash flow.

(2) Future tax adjustments have no impact on cash flow.

Earnings from Continuing Operations, excluding unrealized foreign exchange on translation of Canadian issued U.S. dollar debt (after tax) and tax rate reductions is not a measure that has any standardized meaning prescribed by Canadian GAAP and is considered a non-GAAP measure. Therefore, this measure may not be comparable to similar measures presented by other issuers. This measure has been described and presented in this MD&A in order to provide shareholders and potential investors with additional information regarding the Company s finances and results of operations. Management believes items such as foreign exchange gains and losses or tax rate reductions distort results and reduce comparability of the Company s underlying financial performance between periods.

Quarterly results were as follows:

2003 and 2002 Quarterly Summary

	2003				**2002**			
($ millions, except per share amounts)	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1***
Revenues, Net of Royalties	**$2,850**	**$2,291**	**$2,332**	**$2,743**	$2,116	$1,780	$1,693	$ 687
Net Earnings from Continuing Operations	**426**	**286**	**805**	**650**	248	79	318	90
per share basic	**0.92**	**0.60**	**1.67**	**1.35**	0.52	0.17	0.69	0.35
per share diluted	**0.91**	**0.60**	**1.66**	**1.34**	0.51	0.16	0.68	0.35
Net Earnings	**426**	**290**	**807**	**837**	282	136	303	91
per share basic	**0.92**	**0.61**	**1.68**	**1.74**	0.59	0.29	0.66	0.36
per share diluted	**0.91**	**0.61**	**1.67**	**1.73**	0.58	0.28	0.65	0.35
Cash Flow from Continuing Operations	**1,217**	**973**	**1,039**	**1,191**	874	583	569	241
per share basic	**2.63**	**2.06**	**2.16**	**2.48**	1.83	1.22	1.23	0.94
per share diluted	**2.61**	**2.04**	**2.14**	**2.46**	1.81	1.21	1.22	0.93
Cash Flow	**1,254**	**977**	**1,007**	**1,221**	935	651	591	242
per share basic	**2.71**	**2.06**	**2.10**	**2.54**	1.96	1.37	1.28	0.95
per share diluted	**2.69**	**2.04**	**2.08**	**2.52**	1.94	1.35	1.26	0.94

* Excludes the pre-merger results of AEC.

Quarterly results in 2003, as compared to the same periods in 2002, reflect the impacts of increasing commodity prices, increased production volumes, inclusion of a full year of post Merger results and are partially offset by increased expenses. The 2003 after tax unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt of $433 million was reported as $140 million in the first quarter, $168 million in the second quarter, $12 million in the third quarter and $113 million in the fourth quarter. The 2003 future tax recovery due to tax rate reductions of $359 million was recorded in the second quarter.

ACQUISITIONS AND DIVESTITURES

On October 1, 2003, an EnCana U.K. subsidiary became the operator of the Scott and Telford fields in the U.K. central North Sea marking the close of the purchase and sale agreements to exchange the 22.5 percent non-operated interest in the Llano oil discovery in the Gulf of Mexico for a 14 percent interest in both the Scott and Telford oil fields. In early 2004, the EnCana U.K. subsidiary completed the purchase of additional 13.5 percent and 20.2 percent interests in the Scott and Telford fields, respectively, for net cash consideration of approximately $126 million. As a result of these acquisitions and the initial ownership interest held, the EnCana U.K. subsidiary now holds a 41 percent interest in the Scott field and a 54.3 percent interest in the Telford field.

On July 18, 2003, an EnCana U.S. subsidiary acquired the common shares of Savannah Energy Inc. (Savannah) for net cash consideration of approximately $91 million. Included in this acquisition were interests in developed and undeveloped reserves and landholdings in Texas, U.S.A. which are currently producing approximately 21 million cubic feet of natural gas per day.

On January 31, 2003, the Company expanded its production and landholdings in Ecuador through the purchase of interests held by Vintage Petroleum Inc. for net cash consideration of approximately $116 million. This acquisition included interests in developed and undeveloped reserves producing approximately 4,000 barrels of oil per day in three blocks adjacent to Block 15, where an EnCana subsidiary has an existing non-operated working interest.

During 2003, the Company acquired and disposed of other properties that had a less significant impact on operations. On a net basis, the total amount of additional acquisitions over dispositions was $183 million. Property acquisitions have been included as part of total capital expenditures as discussed in the Liquidity and Capital Resources section of this MD&A.

DISCONTINUED OPERATIONS

Syncrude

During 2003, subsidiaries of the Company completed the sale of their working interest together with EnCana s gross overriding royalty in the Syncrude Joint Venture for net cash consideration of approximately $1.0 billion (C$1.45 billion). There was no gain or loss recorded on this sale. Net earnings from Syncrude operations were $24 million in 2003. With the sale of the Syncrude interest completed, the Company intends to focus its oilsands strategy on developing its high quality bitumen resources, recovered through producing wells using Steam Assisted Gravity Drainage (SAGD) technology on 100 percent owned and operated lands at Foster Creek and Christina Lake.

Midstream Pipelines

Subsidiaries of the Company closed the sale of their 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 $1.0 billion (C$1.6 billion), including the assumption of related long-term debt by the purchaser. An after-tax gain on sale of $169 million was recorded in relation to these transactions.

These sales were part of EnCana s strategic realignment to focus on developing its large portfolio of higher return growth assets. The proceeds were used for general corporate purposes, including debt reduction, prior to being re-deployed as discussed in the Liquidity and Capital Resources section of this MD&A.

The Syncrude and Midstream-Pipelines operations described above have been accounted for as discontinued operations as disclosed in Note 5 to the Consolidated Financial Statements.

RESULTS OF OPERATIONS

UPSTREAM OPERATIONS*

Financial Results *($ millions)*

	2003				2002				2001			
Year ended December 31	Produced Gas & NGLs (1)	Crude Oil	Other	Total	Produced Gas & NGLs (1)	Crude Oil	Other	Total	Produced Gas & NGLs (1)	Crude Oil	Other	Total
Revenues, Net of Royalties	**$4,690**	**$1,457**	**$180**	**$6,327**	$2,440	$1,158	$ 76	$3,674	$1,670	$621	$24	$2,315
Expenses												
Production and Mineral Taxes	**160**	**29**		**189**	85	34		119	55	22		77
Transportation and Selling	**370**	**120**		**490**	216	61		277	78	22		100
Operating	**402**	**401**	**170**	**973**	290	265	71	626	123	163	8	294
Depreciation, Depletion and Amortization	**1,368**	**669**	**96**	**2,133**	827	355	51	1,233	292	166	20	478
Upstream Income	**$2,390**	**$ 238**	**$ (86)**	**$2,542**	$1,022	$ 443	$(46)	$1,419	$1,122	$248	$ (4)	$1,366

* Upstream results exclude Syncrude operations which have been accounted for as discontinued operations as described in Note 5 to the Consolidated Financial Statements.

(1) NGL results includes Condensate.

Sales Volumes

(After Royalties)	2003	2003 vs 2002	2002	2002 vs 2001	2001
Produced Gas *(million cubic feet per day)*	**2,566**	**25%**	2,058	105%	1,005
Crude Oil *(barrels per day)*	**198,078**	**26%**	156,691	72%	91,093
NGLs *(barrels per day)*	**24,466**	**16%**	21,054	60%	13,126
Continuing Operations *(barrels of oil equivalent per*	**650,211**	**25%**	520,745	92%	271,719

day)[1]					
Syncrude *(barrels per day)*	**7,629**	**68%**	23,540		
Total *(barrels of oil equivalent per day)* [1]	**657,840**	**21%**	544,285	100%	271,719

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

Revenue Variance [1]

	2003 compared to 2002			2002 compared to 2001		
($ millions)	**Price**	**Volume**	**Total**	**Price**	**Volume**	**Total**
Produced Gas and NGLs	**$1,336**	**$ 914**	**$2,250**	$(459)	$1,229	$ 770
Crude Oil	**(5)**	**304**	**299**	52	485	537
Other			**104**			52
Total Revenue, Net of Royalties	**$1,331**	**$1,218**	**$2,653**	$(407)	$1,714	$1,359

(1) Includes continuing operations only.

CONSOLIDATED UPSTREAM RESULTS

The Company s 2003 Upstream revenues, net of royalties, increased $2,653 million, or 72 percent, over 2002 due to the increase in commodity prices, growth in sales volumes and the inclusion of a full year of post Merger results. The revenue variance table shows the 2003 increase over 2002 to be approximately 50 percent volume and 50 percent price related. The 25 percent growth in barrels of oil equivalent sales volumes from continuing operations, compared to 2002, reflected increased production in the U.S. Rockies, the addition of a full year of post Merger volumes, the removal of transportation capacity restrictions in Ecuador as a result of the completion of the OCP Pipeline and the expansion of production from the Company s SAGD projects.

Production and mineral tax increases in 2003 are the result of higher prices in the U.S. and Ecuador and a full year of post Merger results.

The increased expenditures for transportation and selling in 2003 are attributable to growth in North American volumes, increases in Ecuador volumes as a result of the commencement of shipments on the OCP Pipeline, a full year of post Merger results and the effect of the change in the U.S./Canadian dollar exchange rate on Canadian transportation and selling expenses.

Upstream operating costs, excluding costs related to Other activities, increased 45 percent compared to 2002, and 94 percent when comparing 2002 to 2001. The increase in 2003 over 2002 is due to additional production volumes, a full year of post Merger results, as well as higher unit operating expenses. Operating expenses from continuing operations, excluding Other activities, were $3.38 per barrel of oil equivalent for 2003 up from $2.92 per barrel of oil equivalent in 2002 and $2.88 per barrel of oil equivalent in 2001. The increase is mainly related to the change in the average U.S./Canadian dollar exchange rate and its impact on Canadian dollar denominated operating expenses, as well as increased costs for maintenance, workovers, higher fuel and power expense due to higher natural gas prices and an increased proportionate share of costs from SAGD operations. The increase in 2002 over 2001 resulted primarily from the inclusion of nine months operations from the Merger.

DD&A expense increased 73 percent, or $900 million, compared to 2002 and 158 percent, or $755 million, comparing 2002 to 2001. On a barrel of oil equivalent basis, excluding Other, DD&A rates were $8.58 per barrel for 2003 compared to $6.22 per barrel and $4.62 per barrel in 2002 and 2001 respectively. The increased DD&A rate in 2003 reflects increased future development costs related to the proved reserves added for SAGD projects and the U.S. Rockies, and the effect of the increase in the U.S./Canadian dollar exchange rate on the Canadian DD&A expense. The 2003 future development costs are approximately $1.81 per barrel of oil equivalent of the DD&A rate calculation compared to $0.53 per barrel of oil equivalent in 2002. The higher costs in 2002 compared to 2001 primarily reflected the additional charges associated with the addition of the post Merger assets, which were recorded at their fair value as part of the allocation of the purchase price.

Other activities added $180 million in revenues and $170 million in operating expenses in 2003 and include activities that do not result directly in the production of oil and gas. These activities include revenue from third party gas processing, gas gathering and electrical generation associated with cogeneration of steam. The higher DD&A expense, reflected in Other activities, includes an expense of approximately $103 million for impairments on Upstream international exploration prospects deemed not to be commercially viable, offset by a gain realized on divestiture of an exploration property.

Produced Gas and NGLs [(1)]

Financial Results Canada Year ended December 31 ($ millions)	**2003**	**2003 vs 2002**	**2002**	**2002 vs 2001**	**2001**
Revenues, Net of Royalties	**$ 3,523**	**79%**	$ 1,971	23%	$ 1,598
Expenses					
Production and Mineral Taxes	**52**	**4%**	50	4%	48
Transportation and Selling	**274**	**81%**	151	110%	72
Operating	**342**	**34%**	255	128%	112
Depreciation, Depletion and Amortization	**1,075**	**72%**	625	139%	261
Segment Income	**$ 1,780**	**100%**	$ 890	19%	$ 1,105

Gas Volume *(million cubic feet per day)*	**1,965**	**15%**	1,711	80%	953
NGL Volume *(barrels per day)*	**14,278**	**3%**	13,852	37%	10,142

(1) NGL results include Condensate.

Financial Results - United States

Year ended December 31 ($ millions)	**2003**	**2003 vs 2002**	**2002**	**2002 vs 2001**	**2001**
Revenues, Net of Royalties	**$1,143**	**152%**	$ 454	669%	$ 59
Expenses					
Production and Mineral Taxes	**108**	**209%**	35	400%	7
Transportation and Selling	**86**	**46%**	59		
Operating	**60**	**71%**	35	218%	11
Depreciation, Depletion and Amortization	**293**	**45%**	202	552%	31
Segment Income	**$ 596**	**385%**	$ 123	1130%	$ 10
Gas Volume *(million cubic feet per day)*	**588**	**74%**	337	684%	43
NGL Volume *(barrels per day)*	**9,291**	**45%**	6,407	162%	2,443

(1) NGL results include Condensate.

Financial Results United Kingdom

Year ended December 31 ($ millions)	2003	2003 vs 2002	2002	2002 vs 2001	2001
Revenues, Net of Royalties	**$ 24**	**60%**	$ 15	15%	$ 13
Expenses					
Production and Mineral Taxes					
Transportation and Selling	**10**	**67%**	6		6
Operating					
Depreciation, Depletion and Amortization					
Segment Income	**$ 14**	**56%**	$ 9	29%	$ 7
Gas Volume *(million cubic feet per day)*	**13**	**30%**	10	11%	9
NGL Volume *(barrels per day)*	**897**	**13%**	795	47%	541

(1) NGL results include Condensate.

In 2003, revenues, net of royalties from sales of produced gas and NGLs contributed 74 percent of the Company s total Upstream revenue and in total were $2,250 million higher than in 2002. The increase in 2003 revenues net of royalties from produced gas and NGLs over 2002 was due to increased commodity prices, drilling successes in both Canada and the U.S., significant property acquisitions in the U.S. Rockies in 2002 and a full year of post Merger results. Natural gas revenues in 2003 were reduced by a loss of $91 million due to financial currency and commodity hedging activities, compared to a gain of $65 million in 2002 and a gain of $134 million in 2001.

Gas sales from the U.S. have risen 74 percent, or 251 million cubic feet per day, when comparing 2003 to 2002 due to drilling successes and property acquisitions combined with a full year of post Merger results. Canadian gas sales volumes have increased 254 million cubic feet per day primarily due to inclusion of a full year of post Merger operations. 2003 Canadian production gains achieved through resource development were offset by higher than anticipated declines at Ladyfern, divestments in non-core producing areas and weather delays for well tie-ins. Volume increases in 2002 compared to 2001 is due to the inclusion of nine months of post Merger results in 2002.

Per Unit Results Produced Gas

	Produced Gas Canada			Produced Gas U.S.		
($ per thousand cubic feet)	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
Price, net of royalties	**$ 4.87**	$2.86	$4.06	**$4.88**	$2.96	$2.46
Expenses						
Production and mineral taxes	**0.07**	0.08	0.14	**0.47**	0.27	0.49
Transportation and selling	**0.38**	0.24	0.21	**0.40**	0.47	
Operating	**0.48**	0.41	0.32	**0.28**	0.28	0.68

Netback excluding hedging	**$ 3.94**	$2.13	$3.39	**$3.73**	$1.94	$1.29
Financial hedge	**(0.13)**	0.05	0.38	**0.02**	0.29	
Netback including hedging	**$ 3.81**	$2.18	$3.77	**$3.75**	$2.23	$1.29

Per Unit Results NGLs[1]

	NGLs Canada			NGLs U.S.		
($ per barrel)	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
Price, net of royalties	**$24.26**	$17.55	$19.70	**$26.97**	$23.75	$22.22
Expenses						
Production and mineral taxes				**2.03**	1.02	
Transportation and selling	**0.17**					
Netback	**$24.09**	$17.55	$19.70	**$24.94**	$22.73	$22.22

(1) NGL results include Condensate.

Average realized prices for natural gas in the U.S. and Canada increased approximately 65 percent and 70 percent respectively in 2003 compared to 2002. Concerns about overall North American storage inventory levels and a lack of confidence concerning prospects for North American supply growth were the primary reasons for the overall increase. Lower realized gas prices in Canada experienced in 2002 compared to 2001 were caused by high levels of natural gas in storage during 2002 resulting from decreased demand. Average realized prices for NGLs in the U.S. and Canada increased approximately 14 percent and 38 percent respectively in 2003 compared to 2002. NGL realized price increases generally resulted from changes in the price of WTI discussed previously in this MD&A.

Per unit production and mineral tax expense for produced gas in the U.S. Rockies was higher in 2003 than 2002 by $0.20 per thousand cubic feet due to higher natural gas prices. Per unit produced gas production and mineral taxes were $0.22 per thousand cubic feet lower in 2002 than in 2001, reflecting the addition of properties attracting lower production and mineral tax rates as a result of the Merger.

For Canadian produced gas operations, per unit transportation and selling costs were higher in 2003 by $0.14 per thousand cubic feet primarily due to an increased proportion of sales transported to more distant markets and the change in the U.S./Canadian dollar exchange rate. Per unit transportation and selling expense in the U.S. decreased $0.07 per thousand cubic feet when compared to 2002 due to shorter average transportation distances to markets.

Per unit operating expenses for Canadian produced gas were higher in 2003 by $0.07 per thousand cubic feet as a result of increased maintenance, workovers, the effect of the change in the U.S./Canadian dollar exchange rate and production from higher operating cost areas. Operating expenses in the U.S. per unit remained flat for 2003 over 2002. Canadian per unit operating expenses were higher in 2002 compared to 2001 reflecting the addition of higher cost operations from the Merger combined with higher processing fees, gathering, maintenance and electricity costs. U.S. per unit operating expenses decreased in 2002 compared to 2001 reflecting the addition of significant lower cost operations and higher production volumes from the Merger.

Crude Oil

Financial Results North America

Year ended December 31 ($ millions)	**2003**	**2003 vs 2002**	**2002**	**2002 vs 2001**	**2001**
Revenues, Net of Royalties	**$ 951**	**15%**	$ 825	58%	$ 523
Expenses					
Production and Mineral Taxes	**4**	**80%**	20	9%	22
Transportation and Selling	**69**	**97%**	35	119%	16
Operating	**300**	**49%**	201	31%	153
Depreciation, Depletion and Amortization	**436**	**84%**	237	91%	124
Segment Income	**$ 142**	**57%**	$ 332	60%	$ 208
Volumes *(barrels per day)*	**142,326**	**21%**	117,218	46%	80,272

Financial Results - Ecuador

Year ended December 31 ($ millions)	**2003**	**2003 vs 2002**	**2002**	**2002 vs 2001**	**2001**

Revenues, Net of Royalties	**$ 412**	**68%**	$ 245		$
Expenses					
Production and Mineral Taxes	**25**	**79%**	14		
Transportation and Selling	**45**	**114%**	21		
Operating	**83**	**57%**	53		
Depreciation, Depletion and Amortization	**159**	**101%**	79		
Segment Income	**$ 100**	**28%**	$ 78		$
Volumes *(barrels per day)*	**46,521**	**56%**	29,740		

Financial Results - United Kingdom

Year ended December 31 ($ millions)	**2003**	**2003 vs 2002**	**2002**	**2002 vs 2001**	**2001**
Revenues, Net of Royalties	**$ 94**	**7%**	$ 88	10%	$ 98
Expenses					
Production and Mineral Taxes					
Transportation and Selling	**6**	**20%**	5	17%	6
Operating	**18**	**64%**	11	10%	10
Depreciation, Depletion and Amortization	**74**	**90%**	39	7%	42
Segment Income	**$ (4)**	**112%**	$ 33	18%	$ 40
Volumes *(barrels per day)*	**9,231**	**5%**	9,733	10%	10,821

In 2003, total revenues, net of royalties for crude oil, increased $299 million, or 26 percent, over 2002. The improvement is attributable to increased production volumes, a full year of post Merger volumes and higher average realized commodity prices offset by increased losses related to financial hedging. Crude oil revenues were reduced by a loss of approximately $206 million resulting from financial commodity and currency hedging. This compares with a loss of $33 million in 2002 and a gain of $20 million in 2001.

North American crude oil sales volumes averaged 142,326 barrels per day compared to 117,218 barrels per day in 2002. The improvement in North American sales volumes reflects the inclusion of a full year of post Merger volumes, increased production at Foster Creek including completion of the Phase 1 expansion and a full year of commercial production at Christina Lake combined with continued development at Suffield and Pelican Lake. Sales volumes in 2002 were higher than 2001 volumes of 80,272 primarily due to the inclusion of nine months of post Merger results.

Ecuador crude oil sales volumes increased by 56 percent in 2003 to 46,521 barrels per day compared to volumes of 29,740 barrels per day in 2002 primarily due to the inclusion of a full year of post Merger volumes and the removal of transportation capacity constraints as a result of the commencement of shipments on the OCP Pipeline in September, partially offset by the requirement to provide line fill for OCP of approximately 3,213 barrels per day. Sales volumes during the fourth quarter of 2003 averaged 77,352 barrels per day compared with 35,900 barrels per day in the same period in 2002. The Company has a shipping commitment of approximately 108,000 barrels per day on the OCP Pipeline and currently does not have transportation capacity constraints on its production. The Company s shipping commitment was based on estimated gross production volumes which included the royalty portion taken in-kind by the Ecuadorian government. The Ecuadorian government subsequently decided to transport its royalty volumes on the SOTE pipeline. As a result of this decision the Company incurs additional transportation costs of approximately $0.80 to $1.10 per barrel on the current level of volumes transported through the OCP Pipeline.

Acquisition of additional interests in the Scott and Telford fields was the major contributor to higher crude oil volumes of 13,665 barrels per day from the U.K. central North Sea in the fourth quarter of 2003 compared to 7,151 barrels per day in the same period in 2002. Crude oil volumes for 2003 averaged 9,231 barrels per day compared to 9,733 barrels per day and 10,821 barrels per day in 2002 and 2001 respectively. The overall decrease in 2003 average volumes resulted from natural declines and unscheduled downtime partially offset by the additional ownership interests.

Per Unit Results Crude Oil

	North America			Ecuador			United Kingdom		
($ per barrel)	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
Price, net of royalties	**$22.29**	$20.08	$17.35	**$24.21**	$22.57	$	**$28.11**	$24.76	$24.62
Expenses									
Production and mineral taxes	**0.09**	0.43	0.71	**1.47**	1.24				
Transportation and selling	**1.31**	0.82	0.55	**2.56**	2.00		**1.97**	1.69	1.68
Operating	**5.80**	4.69	5.24	**4.84**	4.86		**5.09**	3.28	2.69
Netback excluding hedging	**$15.09**	$14.14	$10.85	**$15.34**	$14.47	$	**$21.05**	$19.79	$20.25
Financial hedge	**(3.97)**	(0.76)	0.60		(0.01)			(0.06)	0.46
Netback including hedging	**$11.12**	$13.38	$11.45	**$15.34**	$14.46	$	**$21.05**	$19.73	$20.71

Average realized crude oil prices in 2003 increased approximately 10 percent over 2002 and approximately 14 percent in 2002 when compared to 2001. Continuing concerns over tensions in the Middle East combined with strong Asian demand and OPEC s management of its production quotas were the primary reasons for the overall increase in 2003 offset by increased crude oil price differentials. The change in 2002 over 2001 reflects the average price weightings of additional volumes from the Merger.

North American per unit production and mineral taxes were $0.09 per barrel compared to $0.43 per barrel in 2002. North American 2003 per unit production and mineral taxes include the impact of mineral tax amendments, related to prior years and recorded in the third quarter of 2003, which reduced mineral taxes by approximately $16 million or $0.30 per barrel. Production and mineral taxes in Ecuador increased $0.23 per barrel, or 19 percent, in 2003 over 2002. This is due to the increased production from the Tarapoa block and higher realized prices from the Tarapoa volumes. The Company is required to pay the Ecuadorian government a percentage of revenue from this block based on realized prices over a base price.

Per unit transportation and selling costs in North America were higher by $0.49 per barrel, or 60 percent, over 2002. The increase resulted primarily from increased heavy crude oil volumes which attract a 20 percent premium transportation charge over light oil combined with annual tariff increases. Compared to 2002, higher per unit transportation and selling costs in Ecuador reflect the higher unit costs on the OCP Pipeline in 2003 compared to the SOTE pipeline system resulting from the ship or pay obligations on the system requiring the Company to pay for a prescribed amount of capacity at a fixed rate. Per unit transportation and selling costs in the U.K. increased 17 percent in 2003 compared to 2002, primarily as a result of the strengthening of the British pound relative to the U.S. dollar.

The increase in North American unit operating expenses for crude oil of $1.11 per barrel over 2002 is attributable to the increase in the U.S./Canadian dollar exchange rate, higher maintenance costs, increased production of heavy oil volumes from SAGD projects at Foster Creek and Christina Lake, combined with higher fuel and electricity costs resulting from the rise in natural gas prices. The U.K. 2003 per unit operating expenses increased 55 percent over 2002 due to unscheduled maintenance costs, acquisition related costs as well as the strengthening of the British pound relative to the U.S. dollar.

Midstream & Marketing Operations Financial Results (1)

	Midstream			Marketing			Total		
($ millions)	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
Revenues	**$1,084**	$440	$154	**$2,803**	$2,154	$777	**$3,887**	$2,594	$931
Expenses									
Transportation and selling				**55**	87	11	**55**	87	11
Operating	**261**	174	142	**63**	13	12	**324**	187	154
Purchased product	**762**	169		**2,693**	2,031	739	**3,455**	2,200	739
Depreciation, depletion and amortization	**40**	24	9	**8**	12	1	**48**	36	10
	$ 21	$ 73	$ 3	**$ (16)**	$ 11	$ 14	**$ 5**	$ 84	$ 17

(1) Excludes financial results related to discontinued operations as described in Note 5 to the Consolidated Financial Statements.

Revenues from continuing Midstream & Marketing operations increased by $1,293 million in 2003 from 2002 due primarily to higher commodity prices and the inclusion of a full year of post Merger results. Despite higher revenues in 2003, financial results were negatively impacted by short-term market factors. Narrower summer/ winter price spreads resulted in lower revenues from third-party gas storage contracts and reduced margins from optimization activities. In addition, natural gas processing margins decreased due to relatively higher feedstock prices and reduced seasonal demand for propane. The change in operations between 2002 and 2001 was mostly the result of the addition of AEC midstream assets which included gas storage facilities and natural gas processing to the existing midstream segment.

Midstream operating expenses increased in 2003 due to the inclusion of a full year of post Merger results and the effect of the change in the U.S./Canadian dollar on the Canadian operations as well as he higher cost of natural gas and increased throughput volumes for NGL processing. The higher costs reflected in 2002 over 2001 was due to the inclusion of nine months of post Merger activity.

Marketing Financial Results on a Product Basis (1)

($ millions)	Gas			Crude Oil and NGLs			Total		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
Revenues	**$1,442**	$931	$385	**$1,361**	$1,223	$392	**$2,803**	$2,154	$777
Expenses									
Transportation and selling	**10**	37		**45**	50	11	**55**	87	11
Operating	**49**	5	7	**14**	8	5	**63**	13	12
Purchased product	**1,396**	862	366	**1,297**	1,169	373	**2,693**	2,031	739
Depreciation, depletion and amortization	**3**	6	1	**5**	6		**8**	12	1
	$ (16)	$ 21	$ 11	**$**	$ (10)	$ 3	**$ (16)**	$ 11	$ 14

(1) Excludes financial results related to discontinued operations as described in Note 5 to the Consolidated Financial Statements.

EnCana s Marketing operations include marketing activities to optimize the value from the Company s proprietary production, the purchase of third party product primarily for the optimization of midstream assets and optimization of transportation commitments not fully utilized for the Company s own production. The increase in 2003 revenues reflects higher commodity prices experienced in the energy industry for the year. The increased revenue is comparatively offset by the change in product purchased. The change in Marketing s operating expense in 2003 is primarily due to the $20 million settlement related to the discontinued Merchant Energy operations, discussed in the Contractual Obligations and Contingencies section of this MD&A, and the inclusion of a full year of post Merger results.

Corporate
Corporate Items

($ millions)	2003	2003 vs 2002	2002	2002 vs 2001	2001
Administration	**$ 173**	**45%**	$119	120%	$ 54
Interest, net	**287**	**1%**	290	753%	34
Foreign exchange (gain) loss	**(601)**	**4193%**	(14)	217%	12
Income tax expense	**445**	**22%**	366	13%	419

The increase in administrative expense in 2003 reflected the inclusion of the full year of post Merger operations, the effect of the change in the U.S./Canadian dollar exchange rate, higher governance costs and increased salary and consultant expenses. On a per unit basis, excluding discontinued operations volumes, administrative costs were $0.73 per barrel of oil equivalent for 2003 compared with $0.63 per barrel of oil equivalent for 2002 and $0.54 per barrel of oil equivalent for 2001.

Net interest expense remained relatively unchanged in 2003 compared to 2002. The higher net interest expense in 2002 over 2001 resulted primarily from the additional expense associated with the comparatively higher average debt level outstanding as a result of the Merger and redemption of capital securities.

The majority of the foreign exchange gain of $601 million resulted from the change in the U.S./Canadian dollar period end exchange rate applied to U.S. dollar denominated debt issued in Canada. Under Canadian GAAP, the Company is required to translate long-term debt borrowed in Canada and denominated in U.S. dollars into Canadian dollars at the period-end exchange rate. Resulting foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings.

The effective tax rate for 2003 was 17 percent compared to 33 percent for 2002 and 33 percent for 2001. The decrease in the effective tax rate included the impact of a $359 million reduction in future income taxes resulting from the reductions in the Canadian federal and Alberta corporate income tax rates which were enacted in 2003 and related changes to the Canadian federal resource allowance deduction. The Canadian federal tax rate, which was reduced in other industries in 2000, is to be reduced by seven percentage points over the period 2003-2007 from 28 percent to 21 percent. In addition, the Canadian federal resource allowance deduction is to be phased out and replaced with a deduction for crown royalties paid over the same period. The Alberta tax rate was reduced by one half of one percentage point from 13 percent to 12.5 percent. The decrease also reflects the tax treatment of realized and unrealized Canadian capital gains of $581 million derived from a weakening of the U.S. dollar in relation to the Canadian dollar and the utilization of previously unrecognized capital losses. Income tax expense also reflects the translation of Canadian taxes denominated in Canadian dollars utilizing the increased average U.S./Canadian dollar exchange rate.

Current income tax expense was a recovery of $56 million for 2003, a recovery of $38 million for 2002, and an expense of $324 million for 2001. Current income tax expense was abnormally low in 2003 and 2002 in large part as a result of the merger with AEC, the subsequent business reorganization of the Company s business units at the end of 2002 and early 2003 and the amalgamation with AEC on January 1, 2003. The recovery relates principally to a shift of approximately $90 million of previously anticipated current income tax expense in 2003 to 2004.

The operations of the Company are complex and related tax interpretations, regulations and legislation in the various jurisdictions that the Company and its subsidiaries operate in are continually changing. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

LIQUIDITY AND CAPITAL RESOURCES

Company expectations are that existing credit facilities and present and forecast capital resources will be sufficient to support its capital investment programs and future growth prospects in addition to enabling the Company to meet all other current and expected financial requirements. Fluctuations in commodity prices, product demand, foreign exchange rates, interest rates and various other risks may impact capital resources but have been partially mitigated through the risk management program detailed in Note 17 of the Consolidated Financial Statements and discussed in the Risk Management section of this MD&A.

EnCana s cash flow from continuing operations was $4,420 million in 2003 up $2,153 million, or 95 percent, compared with $2,267 million in 2002 and $1,463 million in 2001. The increase in cash flow from continuing operations was primarily the result of higher revenues from increases in commodity prices, inclusion of a full year of post Merger results and growth in sales volumes, partially offset by higher operating expenses.

EnCana s net debt, adjusted for working capital, was $5,931 million as at December 31, 2003 compared with $3,933 million at December 31, 2002 and $1,446 million at December 31, 2001. Working capital was $157 million at December 31, 2003, compared to $1,118 million at December 31, 2002. The 2002 working capital balance included $1,055 million related to the net assets and liabilities of Discontinued Operations. Cash flow together with proceeds from the dispositions of the Syncrude interest, Cold Lake and Express Pipeline Systems interests and other asset dispositions were used for the purchase of shares under the Company s Normal Course Issuer Bid, capital expenditures and acquisitions. The cash shortfall as a result of these activities and working capital changes increased net debt in 2003 by $1,998 million.

On October 2, 2003, the Company issued $500 million notes due in 10 years at 4.75 percent. The proceeds from this issue were used primarily to repay existing bank and commercial paper indebtedness.

Net debt to capitalization was 34 percent, up from 31 percent at December 31, 2002. Net debt to Earnings Before Interest, Taxes, Depreciation, Depletion and Amortization (EBITDA) was 1.3 times the trailing 12-month cash flow at the end of the year. EBITDA is a measure that has no standardized meaning prescribed by Canadian GAAP and is considered a non-GAAP measure. Therefore, the measure may not be comparable to similar measures presented by other issuers. This measure is described and presented in this MD&A, in order to provide shareholders and potential investors with additional information regarding the Company s liquidity and ability to generate funds to finance its operations. Management calculates net debt to EBITDA for credit analysts who use the measure to gauge a Company s ability to generate sufficient funds to cover its net debt.

As at December 31, 2003, the Company had available unused committed bank credit facilities in the amount of $1,575 million.

On December 31, 2003, the Company had $418 million of preferred securities recorded as long-term debt on its Consolidated Balance Sheet. Due to the adoption of the new Canadian accounting standard for liabilities and equity as discussed in the Accounting Policy Changes section of this MD&A these preferred securities were reclassified from equity to liabilities retroactively and, accordingly, all prior periods have been restated to reflect this change.

In October 2003, EnCana received approval from the Toronto Stock Exchange to purchase, for cancellation, common shares under a Normal Course Issuer Bid. Under the bid, EnCana is entitled to purchase for cancellation up to 23.2 million of its common shares over a 12-month period ending October 21, 2004. In 2003, combined purchases under the current bid and a previous bid were 23.8 million shares at an average price of C$49.65 per share. These purchases more than offset the approximately 5.5 million shares issued in 2003 as a result of the exercise of share purchase options. In 2004, EnCana has purchased for cancellation 2.5 million of its shares at an average price of C$54.52 per share under its current Normal Course Issuer Bid, approximately equal to share option exercises.

In February 2004, the Company announced its intention to redeem, on March 23, 2004, all of its Coupon Reset Subordinated Term Securities, Series A (Term Securities) which have an aggregate principal amount of approximately C$126 million. The redemption price of the Term Securities is the principal amount plus accrued and unpaid interest to the redemption date. As at December 31, 2003, the Term Securities have been included as part of the Current Portion of Long-Term Debt in the Consolidated Financial Statements.

Goodwill

At December 31, 2003, the Company had $1,911 million in goodwill (2002 $1,563 million) recorded on its Consolidated Balance Sheet as a result of the merger with AEC. As disclosed in Note 4 to the Consolidated Financial Statements, there were no transactions creating additional goodwill during 2003. The increase in goodwill results from the change in the year end rates to convert Canadian dollars to U.S. dollars.

CAPITAL EXPENDITURES

Capital Investment

($ millions)	2003[1]	2003 vs 2002	2002	2002 vs 2001	2001
Upstream					
Canada	**$3,198**	**130%**	$1,388	51%	$ 919
United States	**968**	**18%**	1,176	746%	139
Ecuador	**265**	**58%**	168		
United Kingdom	**223**	**172%**	82	78%	46
Other Countries	**78**	**33%**	117	179%	42
Total Upstream	**$4,732**	**61%**	$2,931	156%	$1,146
Midstream & Marketing	**276**	**487%**	47	51%	96
Corporate	**107**	**149%**	43	153%	17
Total	**$5,115**	**69%**	$3,021	140%	$1,259

(1) Includes acquisitions of $613 million but excludes dispositions on continuing operations of approximately $315 million.

The Company s consolidated capital expenditures increased 69 percent, or $2,094 million, compared to 2002 and 140 percent, or $1,762 million, when comparing 2002 over 2001. The majority of expenditures in both 2003 and 2002 were directed towards natural gas exploration and development in North America. The Company s capital investment was funded by cash flow in excess of amounts paid for purchases under the Normal Course Issuer Bid, proceeds received on the dispositions of the Syncrude interest and interests in the Cold Lake and Express Pipeline Systems as well as debt. Total cash proceeds received for dispositions, including the Syncrude interest and the Cold Lake and Express Pipeline Systems, amounted to $1,900 million compared to $423 million in 2002 and $134 million in 2001. Dispositions on continuing operations include the amount received for the 22.5 percent interest in the Llano oil discovery in the Gulf of Mexico which was exchanged for an additional 14 percent ownership in both the Scott and Telford fields of the U.K. central North Sea.

Upstream Capital Expenditures

Upstream capital expenditures in 2003 were higher by 61 percent, or $1,801 million, over 2002 and 156 percent, or $1,785 million, higher in 2002 over 2001. Increases in capital spending reflect the full twelve months of post Merger results in 2003 and nine months of post Merger results in 2002, increased operating activity, as well as the impact of the increase in the U.S./Canadian dollar exchange rate in 2003. The majority of 2003 expenditures related to North American properties, with spending in Canada directed primarily towards exploration and development of southern Alberta shallow gas projects as well as natural gas properties at Greater Sierra and Cutbank Ridge in northeast British Columbia. The higher Canadian capital expenditures over 2002 was the result of increased property acquisitions, inclusion of a full year of post Merger expenditures, the Cutbank Ridge land purchase and associated drilling, expansion of the Greater Sierra drilling program, acceleration of the 2004 capital program into 2003, and the effect of the change in the U.S./Canadian dollar exchange rate on Canadian denominated expenditures. Capital expenditures in the United States focused primarily on natural gas exploration and development at Jonah and Mamm Creek. Capital spending in the United States included $138 million in property acquisitions in 2003 compared to $656 million in 2002. Excluding property acquisitions, capital spending in the United States increased 60 percent to $830 million from $520 million as a result of increased drilling activity. Capital spending on international interests, excluding acquisitions, focused on production expansion in Ecuador and the U.K central North Sea as well as evaluating various other prospects in Africa, Australia, Brazil, Greenland and the Middle East. Also included is the purchase of an additional 14 percent ownership in both the Scott and Telford fields in the U.K. central North Sea in exchange for the 22.5 percent interest in the Llano oil discovery in the Gulf of Mexico and other minor property acquisitions. In addition to the Upstream capital expenditures in the table above are corporate acquisitions where the Company acquired additional interests in Ecuador for $116 million and acquired interests in developed and undeveloped reserves, landholdings and natural gas production in North Texas for $91 million.

U.K. Buzzard Development In 2003, the Company received approval of the plan to develop the Buzzard oilfield located 53 kilometres off the coast of Scotland in the United Kingdom including approval of the environmental impact assessments. The Company s U.K. subsidiary is the operator of the project and holds a 43.2 percent interest. The field is expected to start production in late 2006 and reach a plateau by mid 2007 of 75,000 barrels per day of crude oil net to EnCana. As of December 31, 2003, the Company had invested approximately $90 million in the project and estimates future development costs to be an additional $770 million. The next phase of development in 2004 includes fabrication of the offshore platform and the start of pipeline installation.

Canadian East Coast In 2003, the Company, along with its partners, completed the drilling of five exploratory wells in the Canadian East Coast region. EnCana was the operator of three of these wells. Two of these exploration wells drilled near the Deep Panuke discovery (100 percent owned Margaree and 24.5 percent owned MarCoh) have increased the Company s confidence in the commercial potential of this discovery. During 2003, the Company withdrew the original development application for Deep Panuke filed in March 2002 with the National Energy Board and the Canada-Nova Scotia Offshore Petroleum Board. Further examination of the potential economic viability of the Deep Panuke project will be undertaken prior to the preparation of a revised development plan. As of December 31, 2003, the Company had invested approximately $340 (C$500) million on its Canadian East Coast assets including Deep Panuke. Until assessments of the economics are complete, the timing of any potential start of production and amount of additional costs which may be incurred are not determinable.

Western Canada Cutbank Ridge During 2003, the Company completed the acquisition of approximately 500,000 net acres of prospective natural gas development lands in Cutbank Ridge, which is located in the foothills of British Columbia and Alberta. The Company purchased either 100 percent or a majority interest in 39 parcels of land totalling roughly 350,000 net acres for approximately $270 (C$369) million. The Company had previously acquired about 150,000 net acres through purchases and land swaps with other companies and Crown land sales. In 2003, the Company drilled 19 wells which produced 14 million cubic feet per day in December. As of December 31, 2003, the Company had invested approximately $360 (C$500) million on Cutbank Ridge and estimates 2004 spending to be approximately $125 (C$160) million. In 2004, the Company plans to drill 40 net natural gas wells at Cutbank Ridge.

Western Canadian Basin Coalbed Methane In 2003, the Company expanded coalbed methane development on its 700,000 acres of 100 percent owned fee title lands in southern Alberta. During 2003, the Company drilled approximately 270 wells, increasing current production from the commercial demonstration project to 10 million cubic feet per day. As of December 31, 2003, the Company had invested approximately $60 (C$80) million on coalbed methane development in southern Alberta and estimates 2004 spending to be approximately $100 (C$130) million. Over the next 5 years, the Company expects to increase natural gas production from coal seams to more than 200 million cubic feet per day.

Gulf of Mexico The Company s operating partner completed drilling four appraisal wells in 2003 at the Tahiti oilfield which is located 304 kilometres southwest of New Orleans. As of December 31, 2003, the Company had invested approximately $301 million in the Gulf of Mexico including Tahiti. The Company holds a 25 percent interest in the Tahiti project. The next phase of development in 2004 includes the front end engineering and design of the project. Until completion of this phase and assessments of the economics are complete, the timing of any potential start of production and amount of additional costs which may be incurred are difficult to determine.

RESERVES

Proved Reserves by Country

Constant Prices After Royalties

	Natural Gas			**Crude Oil and NGLs[2]**			**Total [1]**				
As at December 31	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2003 vs 2002**	**2002**	**2002 vs 2001**	**2001**
	(billions of cubic feet)			**(millions of barrels)**			**(millions of barrels of oil equivalent)**				
Canada	**5,256**	5,073	3,504	**629**	542	287	**1,505**	**8%**	1,388	59%	871
United States	**3,129**	2,573	236	**42**	41	20	**564**	**20%**	470	696%	59
Ecuador				**162**	156		**162**	**4%**	156		
United Kingdom	**26**	20	7	**124**	97	21	**128**	**28%**	100	356%	22
Total	**8,411**	7,666	3,747	**957**	836	328	**2,359**	**12%**	2,114	122%	952

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

(2) Includes condensate.

EnCana s policy is to retain independent qualified reserves evaluators to prepare reports on 100 percent of its oil and gas reserves. The reserves for both 2003 and 2002 were independently evaluated. The reserves for 2001 were internally evaluated. The Company has a Reserves Committee comprised entirely of independent directors which oversees the selection, qualifications and reporting procedures of the independent engineering consultants.

Proved Reserves Reconciliation by Country

Constant Prices After Royalties

	Natural Gas					Crude Oil and Natural Gas Liquids (2)						
As at December 31, 2003	**Canada**	**USA**	**UK**	**Other**	**Total**	**Canada**	**USA**	**Ecuador**	**UK**	**Other**	**Total**	**Total**
	(billions of cubic feet)					(millions of barrels)						(MMBOE) (1)
Start of year	5,073	2,573	20		7,666	542	41	156	97		836	2,114
Revisions and improved recovery	73	1	3		77	32	1		24		57	70
Extensions and discoveries	867	706		90	1,663	111	7	12		1	131	408
Acquisitions	9	152	8		169	1	1	17	7		26	55
Divestitures	(60)	(88)		(90)	(238)		(5)	(5)		(1)	(11)	(51)
Production	(706)	(215)	(5)		(926)	(57)	(3)	(18)	(4)		(82)	(237)
End of year	5,256	3,129	26		8,411	629	42	162	124		957	2,359

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

(2) Includes condensate.

During 2003, the Company added approximately 482 million barrels of oil equivalent, or 203 percent of its production, to its proved reserves through drilling successes, acquisitions of selected properties and revisions net of property dispositions. EnCana s proved reserves as at December 31, 2003, on a constant price basis, after royalties, totalled 2,359 million barrels of oil equivalent representing a reserve life index of approximately 10 years based on 2003 production volumes.

Midstream & Marketing Capital Expenditures

Expenditures in 2003 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. Approximately $91 million was spent in 2003 on the Countess facility and $65 million on expansion of the Wild Goose facility. Capital spending also included approximately $53 million related to equipment operating lease buyouts.

The Company has completed gas injections into the first 10 billion cubic feet of new storage capacity at Countess. The second and third phases of the Countess storage facility are expected to take total capacity to about 40 billion cubic feet by the second quarter of 2005. As of November 2003, the expansion of the Wild Goose storage facility had increased withdrawal capability from 200 million cubic feet per day to 320 million cubic feet per day. By April 2004, withdrawal capacity is expected to be further increased to 480 million cubic feet per day while injection capacity is expected to rise from 80 million to 450 million cubic feet per day and total working gas inventory capacity will increase from 14 billion cubic feet to 24 billion cubic feet.

In early July, a subsidiary of the Company increased its equity interest in the OCP Pipeline in Ecuador from 31.4 percent to 36.3 percent. The OCP Pipeline completed performance testing in October 2003. As at December 31, 2003, OCP was shipping approximately 220,000 barrels per day and is expected to increase shipping volumes as field productivity increases in coming years. The shippers have ship or pay commitments of 350,000 barrels per day. The Company currently is transporting all of its Ecuadorian production through the OCP Pipeline. Prior to completion, the OCP asset was considered part of the Company s Midstream & Marketing division. Since the completion, the Company s equity interest in the OCP Pipeline has been transferred to the Upstream business segment and is included as part of the Ecuadorian region results.

Corporate Capital Expenditures

Corporate capital expenditures related primarily to spending on business information systems, the buyout of operating leases, leasehold improvements and furniture and office equipment. Expenditures in 2002 and 2001 related primarily to spending on business information systems.

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares. As at December 31, 2003, there were 460.6 million outstanding common shares compared to 478.9 million and 254.9 million at the end of 2002 and 2001 respectively. There were no Preferred Shares outstanding during these periods. Employees and directors have been granted options to purchase Common Shares under various plans. These plans and their terms and outstanding balances are disclosed in detail in Note 15 to the Consolidated Financial Statements.

The Compensation Committee of the Board of Directors, in 2003, approved a long-term incentive strategy for employees throughout EnCana which includes a significantly reduced level of stock option grants to be supplemented by grants of Performance Share Units (PSUs). Beginning in 2004, it is the Company s intention that most stock options granted will have an associated Tandem Share Appreciation Right (TSAR) and employees may elect to exercise either the stock option or the associated TSAR. PSUs and TSARs will result in cash payments by the Company and

Common Shares will not be issued. These cash payments will be accounted for as expenses of the Company and equity dilution will not occur.

As previously detailed in the liquidity and capital section of this MD&A, the Company obtained regulatory approval under Canadian securities laws to purchase Common Shares under two consecutive Normal Course Issuer Bids which commenced in October 2002 and may continue until October 21, 2004. Under the terms of the bids, the Company repurchased for cancellation 23.8 million Common Shares during 2003, and as of December 31, 2003, was entitled to purchase for cancellation an additional 19.6 million Common Shares.

OFF BALANCE SHEET ARRANGEMENTS

LEASES

During 2003, the Company exercised buyout options and closed out a number of operating leases that were in place at the prior year end. These operating leases were on a variety of moveable field equipment, natural gas storage equipment and aircraft, which required periodic lease payments and were recorded as operating or administrative costs. The leases of the equipment and aircraft were financed by variable interest entities that were sponsored by various financial institutions. During 2003, the Company paid $262 million to close out these lease obligations by purchasing the related equipment which was included in the 2003 total capital spending figures discussed earlier in the MD&A.

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

VARIABLE INTEREST ENTITIES

In December 2003, the Financial Accounting Standards Board (FASB) in the United States issued Interpretation Number 46R Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51 . The standard mandates that variable interest entities be consolidated by their primary beneficiary. The standard is effective the first reporting period ending after March 15, 2004 for all entities with the exception of special purpose entities as defined in prior accounting guidance. The standard is effective for the first period ending after December 15, 2003 for previously defined special purpose entities. In Canada, the Accounting Standards Board (AcSB) has suspended the effective dates for Accounting Guideline AcG15, Consolidation of Variable Interest Entities in order to amend the guideline to harmonize with the corresponding U.S. guidance. The AcSB plans to issue an exposure draft in the immediate future with an effective period beginning on or after November 1, 2004.

At December 31, 2003, the Company did not have any variable interests in variable interest entities where the Company was the primary beneficiary.

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. The following table summarizes the Company s contractual obligations at December 31, 2003:

Contractual Obligations (1)

	Expected Payment Date				
($ millions)	**2004**	**2005 to 2006**	**2007 to 2008**	**2009+**	**Total**
Long-Term Debt	$ 287	$ 221	$ 713	$3,257	$ 4,478
Asset Retirement Obligations	13	10		3,200	3,223
Operating Leases (2)	44	85	74	211	414
Pipeline Transportation	449	717	627	2,116	3,909
Capital Commitments	259	43		38	340

Purchase of Goods and Services	297	225	14		536
Product Purchases	142	79	49	157	427
Total Contractual Obligations	$1,491	$1,380	$1,477	$8,979	$13,327

(1) In addition, the Company has made commitments related to its risk management program. See Note 17 in the Consolidated Financial Statements. The Company also has an obligation to fund its Pension Plan as disclosed in Note 16 of the Consolidated Financial Statements.

(2) Related to office space and computer lease obligations.

In addition to the long-term debt payments outlined above, at December 31, 2003, the Company had $1,814 million outstanding related to Banker s Acceptances, Commercial Paper and LIBOR loans that are supported by revolving credit facilities and term loan borrowings. The Company intends and expects that it will have the ability to extend the term of this debt on an ongoing basis. Further details regarding the Company s long-term debt are described in Note 13 to the Consolidated Financial Statements.

Additional disclosure regarding the contractual obligations outlined above is included in Note 19 to the Consolidated Financial Statements.

As at December 31, 2003, EnCana had entered into long-term, fixed price, physical contracts with a current delivery of approximately 69 million cubic feet per day with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 200 billion cubic feet at a weighted average price of $3.48 per thousand cubic feet. At December 31, 2003, these transactions had an unrealized loss of $108 million.

LEGAL PROCEEDINGS RELATED TO DISCONTINUED MERCHANT ENERGY OPERATIONS

In July 2003, the Company s indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. (WD), concluded a settlement with the U.S. Commodity Futures Trading Commission (CFTC) of a previously disclosed CFTC investigation. The investigation related to alleged inaccurate reporting of natural gas trading information during 2000 and 2001 by former employees of WD s now discontinued Houston-based merchant energy trading operation to energy industry publications that compiled and reported index prices. All Houston-based merchant energy trading operations were discontinued following the Merger in 2002. Under the terms of the settlement, WD agreed to pay a civil monetary penalty in the amount of $20 million without admitting or denying the findings in the CFTC s order.

The Company and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California and, along with other energy companies, are defendants in several other lawsuits in California (many of which are class actions) and three class action lawsuits filed in the United States District Court in New York. Several of the California class action lawsuits were transferred by the Judicial Panel on Multidistrict Litigation on a consolidated basis to the Nevada District Court and the New York lawsuits were consolidated in New York District Court by the plaintiff s application. The California lawsuits relate to sales of natural gas in California from 1999 to the present and contain allegations that the defendants engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws to artificially raise the price of natural gas through various means including the illegal sharing of price information through online trading, price indices and wash trading. The New York lawsuits claim that the defendants alleged manipulation of natural gas price indices resulted in higher prices of natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. The Gallo complaint claims damages in excess of $30 million, before potential trebling under California laws. As is customary, the class actions do not specify the amount of damages claimed.

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

ACCOUNTING POLICIES AND ESTIMATES

CRITICAL ACCOUNTING POLICIES

Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. The following discussion outlines the accounting policies and practices that are critical to determining EnCana s financial results.

Full Cost Accounting

EnCana follows the Canadian Institute of Chartered Accountants guideline on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs associated with the acquisition of, exploration for, and the development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of depreciation, depletion and amortization. A downward revision in a reserve estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates (see asset impairment discussion below), the excess must be written off as an expense charged against earnings. In the event of a property disposition, proceeds are normally deducted from the full cost pool without recognition of a gain or loss unless there is a change in the DD&A rate of 20 percent or greater.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired and was the result of the Merger with AEC, is assessed by the Company for impairment at least annually. Goodwill was allocated to the business segments at the time of the Merger based on their respective book values compared to fair values. If it is determined that the fair value of the assets and liabilities of the business segment is less than the book value of the business segment at the time of assessment, an impairment amount is determined by deducting the fair value from the book value and applying it against the book balance of goodwill. The offset is charged to the Consolidated Statement of Earnings as additional DD&A.

Oil and Gas Reserves

EnCana s proved oil and gas reserves are 100 percent evaluated and reported on by independent petroleum engineering consultants. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery based on cash flow forecasts.

Asset Impairments

Under full cost accounting, a ceiling test is performed to ensure that unamortized capitalized costs in each cost centre do not exceed their fair value. An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than carrying amount, the impairment loss is limited to an amount by which the carrying amount exceeds the sum of:

i) the fair value of reserves; and

ii) the costs of unproved properties that have been subject to a separate impairment test.

Foreign Currency Translation

The accounts of self-sustaining operations are translated using the current rate method, whereby assets and liabilities are translated at year-end exchange rates, while revenues and expenses are translated using average annual rates. Translation gains and losses relating to the self-sustaining operations are included as a separate component of shareholders equity.

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statement of Earnings.

Derivative Financial Instruments

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

The Company enters into financial transactions to reduce its exposure to price fluctuations with respect to a portion of its oil and gas production to help achieve returns on new projects, targeted returns on new investments and steady funding of growth projects or to mitigate market price risk associated with cash flows expected to be generated from budgeted capital programs. These transactions generally are swaps, collars or options and are generally entered into with major financial institutions or commodities trading institutions. Realized gains and losses from these derivative financial instruments are recognized in oil and gas revenues as the related production occurs.

The Company may also utilize derivative financial instruments such as interest rate swap agreements to manage the fixed and floating interest rate mix of the Company s total debt portfolio and related overall cost of borrowing. The interest rate swap agreements involve the periodic exchange of payments, without the exchange of the normal principal amount upon which the payments are based, and are recorded as an adjustment of interest expense on the hedged debt instrument.

The Company may enter into hedges of its foreign currency exposures on foreign currency denominated long-term debt by entering into offsetting forward exchange contracts. Foreign exchange translation gains and losses on these instruments are accrued under other current, or non-current, assets or liabilities on the balance sheet and recognized in foreign exchange in the period to which they relate, offsetting the respective translation losses and gains recognized on the underlying foreign currency long-term debt. Premiums or discounts on these forward instruments are amortized as an adjustment of interest expense over the term of the contract.

The Company also purchases foreign exchange forward contracts to hedge anticipated sales to customers in the United States. Foreign exchange translation gains and losses on these instruments are recognized as an adjustment of the revenues when the sale is recorded.

Hedging Relationships

The Canadian Institute of Chartered Accountants (CICA) modified Accounting Guideline 13 (AcG 13) Hedging Relationships , effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. In addition, the CICA simultaneously amended EIC 128, Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments to require that all derivative instruments that do not qualify as a hedge under AcG 13, or are not designated as a hedge, be recorded in the balance sheet as either an asset or liability with changes in fair value recognized in earnings. In 2004, the Company has elected not to designate any of its current price risk management activities as accounting hedges under AcG13 and accordingly, will account for all derivatives using the mark-to-market accounting method. The impact on the Company s financial statements at January 1, 2004 is an increase in assets of $145 million, an increase in liabilities of $380 million and a deferred loss of $235 million which will be recognized as the contracts expire.

Pensions

The Company accrues for its obligations under its employee benefit plans and the related costs, net of plan assets.

The cost of pensions and other retirement benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management s best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The obligation is discounted using a market interest rate at the beginning of the year on high quality corporate debt instruments.

Pension expense includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10% of the greater of the benefit obligation and the fair value of plan assets. The amortization period covers the expected average remaining services lives of employees covered by the plans.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plan.

Pension costs are a component of compensation costs.

CHANGES IN ACCOUNTING PRINCIPLES AND PRACTICES

As at December 31, 2003, the Company has adopted the following changes in accounting principles and practices:

Change in the Company s Reporting Currency

The Company has adopted the U.S. dollar as its reporting currency as a result of its revenues being closely tied to the value of the U.S. dollar and to facilitate direct comparisons to most other North American upstream exploration and development companies. The change results in all self-sustaining financial results being translated from Canadian dollars to U.S. dollars using the current rate method, as described earlier under Accounting Guidelines in this MD&A, with exchange gains and losses reported as a separate component of shareholders equity. Monetary assets and liabilities denominated in currencies, other than the applicable functional currency (as described in the Overview section of this MD&A), are translated at the year-end exchange rate with gains and losses recorded in the Consolidated Statement of Earnings.

Stock Based Compensation

The Company early adopted the fair value recognition for stock based compensation as required by the CICA accounting standard Handbook section 3870, Stock-Based Compensation and Other Stock-Based Payments . This standard requires an option pricing model be used to determine the fair value of each option granted and the amount recognized over the vesting period of the option. Previously, the Company used the intrinsic value method to account for such compensation which resulted in no expense being recognized in the Company s financial results. As a result of early adopting, the Company can implement the new standard prospectively. The impact on the Company s 2003 net earnings has been disclosed in Note 2 of the Consolidated Financial Statements.

Asset Retirement Obligations

At December 31, 2003, the Company retroactively early adopted the Canadian accounting standard for accounting for asset retirement obligations as outlined in the CICA Handbook section 3110. The standard requires that the fair value of an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. The depreciation of the capitalized asset retirement cost will be determined on a basis consistent with depreciation, depletion and amortization. With the passage of time, accretion will increase the carrying amount of the asset retirement obligation. Previously the Company used the unit of production method to match estimated future retirement costs with the revenues generated from the producing assets. The impact of this change has been disclosed in Note 2 of the Consolidated Financial Statements.

Preferred Securities

The Company retroactively adopted the new Canadian accounting standard for liabilities and equity as outlined in the CICA Handbook section 3860, whereby the preferred securities issued by the Company are now recorded as a liability. All prior periods have been restated.

Full Cost Accounting

The Company early adopted Accounting Guideline AcG-16, Oil and Gas Accounting-Full Cost . The new guideline has modified how the ceiling test is performed, which requires cost centres be tested for recoverability using undiscounted future cash flows which are determined by using forward indexed prices applied to proved reserves. When the carrying amount of a cost centre is not recoverable, the cost centre would be written down to its fair value. Fair value is estimated using accepted present value techniques which incorporate risks and other uncertainties as well as the future value of reserves when determining expected cash flows. Additional disclosures are also required as provided in Note 11 of the Consolidated Financial Statements. There is no impact on the Company s reported financial results as a result of applying the new Accounting Guideline other than additional required disclosure.

RISK MANAGEMENT

EnCana s results are impacted by external market risks associated with fluctuations in commodity prices, foreign exchange rates and interest rates in addition to credit, operational and safety and environmental risks. The Company partially mitigates its exposure to market risks through the use of various financial instruments and physical contracts. The use of derivative instruments is governed under formal policies approved by senior management, and is subject to limits established by the Board of Directors.

The following table summarizes the unrecognized gains/(losses) on the Company s risk management activities discussed below.

	Contract Maturity			
As at December 31, 2003 ($ millions)	**2004**	**2005**	**2006 and beyond**	**Total**
Natural Gas	$ (29)	$38	$48	$ 57
Crude Oil	(275)	(4)		(279)

Gas Storage	(25)			(25)
Power	4			4
Foreign Currency	7			7
Interest Rates	22	14	8	44
Total	$(296)	$48	$56	$(192)

COMMODITY PRICES

As a means of mitigating exposure to commodity price volatility, the Company has entered into various financial instrument agreements and physical contracts as disclosed in Note 17 of the Consolidated Financial Statements.

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

The Company has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated from budgeted capital programs and in other cases to the mitigation of market price risks for specific assets and obligations.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by the Company are swaps, collars or options which are entered into with major financial institutions, integrated energy companies or commodities trading institutions. Gains or losses from these derivative financial instruments are recognized in oil and gas revenues in the period in which the related production occurs. Effective January 1, 2004, the Company adopted AcG 13 of the CICA and will use the mark-to-market accounting method as described earlier in this MD&A under Hedging Relationships.

NATURAL GAS

Produced Gas

The Company entered into swaps which fix the AECO and NYMEX prices and collars which fix the range of AECO and NYMEX prices. To help protect against widening natural gas price differentials in various production areas, the Company has entered into swaps to fix the AECO and Rockies price differential from the NYMEX price. 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. As of December 31, 2003, the total unrecognized gain related to all significant natural gas risk management contracts was $40 million.

Purchased Gas

The Company has also entered into contracts to purchase and sell natural gas as part of its daily ongoing operations of the Company s proprietary production management. These contracts had an unrecognized gain of $17 million at December 31, 2003.

CRUDE OIL

Produced Crude Oil

The Company has partially mitigated its exposure to the WTI NYMEX price for a portion of its oil production with fixed price swaps, costless collars and 3 way put spreads. As of December 31, 2003, the total unrecognized loss related to all significant crude oil risk management contracts was $279 million.

Purchased Crude Oil

As part of the crude oil marketing activities, the Company partially mitigated its exposure to the risk around crude oil inventory and third party margins through the use of futures and options. As at December 31, 2003, there was no gain or loss related to these contracts.

GAS STORAGE OPTIMIZATION

As part of its gas storage optimization program, the Company has entered into financial instruments and physical contracts at various locations and terms over the next 9 months to manage the price volatility of the corresponding physical transactions and inventories. The financial instruments used include futures, fixed for floating swaps and basis swaps. As of December 31, 2003, the unrecognized loss related to these contracts was $25 million.

POWER PURCHASE ARRANGEMENTS

The Company has an electricity contract that expires in 2005. This contract was entered into as part of a cost management strategy. At December 31, 2003, this contract had an unrecognized gain of $4 million.

FOREIGN CURRENCY

As a means of mitigating the exposure to fluctuations in the U.S. to Canadian exchange rate, the Company has entered into foreign exchange contracts in the amount of $88 million at an average exchange rate of US$0.715 for the period to June 2004. The unrecognized loss with respect to these contracts was $7 million at December 31, 2003. The Company has also entered into foreign exchange contracts in conjunction with crude oil marketing transactions. Gains or losses on these contracts are recognized when the difference between the average month spot rate and the rate on the date of settlement is determined.

INTEREST RATES

The Company has entered into various interest rate and cross currency interest rate swap transactions as a means of mitigating its exposure to the interest rates on debt instruments. The unrealized gain with respect to these transactions was $44 million at December 31, 2003.

CREDIT RISK

A substantial portion of the Company s accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. The Board of Directors has approved a credit policy governing the Company s credit portfolio and procedures are in place to ensure adherence to this policy. With respect to counterparties to financial instruments, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

OPERATIONAL, SAFETY AND ENVIRONMENTAL RISK

Operational risks are partially mitigated through a comprehensive insurance program designed to protect the Company from significant losses arising from the risk exposures.

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

KYOTO PROTOCOL

The Kyoto Accord (Accord) becomes effective once ratification from at least 55 Parties to the Convention representing 55 percent of Annex 1 Party emissions (developed countries) is obtained. Currently there is uncertainty surrounding whether or not the Accord will enter into force. The USA is notable in that it has rejected the protocol. Regardless, several states in the USA have begun initiatives to better manage greenhouse gas emissions. The initiatives in the USA are not expected have a material impact on EnCana s operations in the foreseeable future.

In December 2002, the Canadian Federal Government ratified the Accord committing Canada to reducing greenhouse gas emissions to 6 percent below 1990 levels over the period 2008 2012. It is premature to predict what impact the resulting potential regulations could have on the sector but it is possible that the Company would face minor increases in operating costs in order to comply with a greenhouse gas emissions reduction target. The federal government has also committed to several important principles that will continue to protect the competitiveness of the oil and gas industry beyond 2012, including a limit to the costs levied against excess emissions, a ten-year target lock-in period for new projects and additional flexibility mechanisms for achieving compliance.

ALBERTA ENERGY AND UTILITIES BOARD (AEUB) RULING

The Company s 2003 production volumes, primarily from the Primrose Block in north eastern Alberta, were affected by an AEUB decision, in September, to shut-in natural gas production that put at risk the recovery of bitumen resources in the area. The decision resulted in EnCana s annualized natural gas production in the region to decline by approximately three million cubic feet per day. The future impact of this decision is not known at this time but is not expected to be material.

OUTLOOK

Outlook Volumes

	2004	**2004 vs 2003 (2)**	**2003**
Produced Gas *(million cubic feet per day)*	2,700 to 2,850	8%	2,566

Crude Oil and NGL s *(barrels per day)*	240,000 to 260,000	12%	222,544
Total *(barrels of oil equivalent per day)* (1)	690,000 to 735,000	10%	650,211

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

(2) Percentage growth based on mid-point of guidance and excludes discontinued operations.

2004 Capital Investment

($ millions)	
Upstream	$ 3,700 to $4,000
Midstream & Marketing and Corporate	$ 145
Core Capital	$ $3,845 to $4,145
Divestitures	$ (365)
Net Capital	$ 3,480 to $3,780

M25

EnCana plans to continue to focus on growing natural gas production and storage capacity in North America and crude oil production in Canada, Ecuador and the U.K. central North Sea to deliver near term growth, with the Gulf of Mexico oil and Canadian East Coast gas growth platforms adding to longer term growth. The Company also plans to continue its efforts to expand its medium and long-term growth prospects through focussed international new ventures exploration.

Strong storage injection requirements 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. The outlook for 2004 and beyond will be principally impacted by weather, timing of new production and economic activity.

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

The Company expects its 2004 core capital investment program, of between $3,845 million and $4,145 million, to be funded from cash flow, proceeds from the divestitures of non-core assets and long-term debt.

EnCana s results are affected by external market factors, such as fluctuations in the prices of crude oil and natural gas, as well as movements in foreign currency exchange rates. The following tables provide projected estimates for 2004 of the sensitivity of the Company s 2004 net earnings and cash flow to changes in commodity prices and the U.S./Canadian dollar exchange rate.

Sensitivity of 2004 Net Earnings and Cash Flow (Including Hedges) (1)

($ millions)	Net Earnings	Cash Flow
$0.25 per million British thermal units increase in the NYMEX gas price	75	75
$1.00 per barrel increase in the WTI oil price	10	10
$0.01 decrease in the U.S./Canadian dollar exchange rate	(20)	(5)

(1) Hedge position as at January 31, 2004.

Sensitivity of 2004 Net Earnings and Cash Flow (Excluding Hedges)

($ millions)	Net Earnings	Cash Flow
$0.25 per million British thermal units increase in the NYMEX gas price	145	145
$1.00 per barrel increase in the WTI oil price	40	40
$0.01 decrease in the U.S./Canadian dollar exchange rate	(15)	1

These estimates are based on management s assumptions utilized for 2004 planning purposes, as discussed in this section. Assumptions include certain levels and profiles of capital expenditures, operating costs, projected sales volumes, tax rates, interest rates, foreign currency exchange rates, inflation rates and other assumptions that impact operations. These assumptions can vary significantly from actual events and may result in material variances from the expected results.

In determining the current income tax expense deducted in arriving at these estimates, management has assumed a combined marginal tax rate of approximately 36 percent. This tax rate is itself affected in varying degrees by the assumptions referred to in the preceding paragraph. In addition, it has been assumed that marginal income in Canada will be taxed at marginal income tax rates, and that marginal income in the U.S.A. will be subject to Alternative Minimum Tax. Marginal rates in other jurisdictions are not expected to be material.

In November 2003, EnCana provided guidance for 2004 cash taxes in the range of $585 million to $730 million. Subsequently, in determining current income tax expense for 2003, approximately $90 million of current income tax was shifted to 2004 and, accordingly, the previous guidance has been increased by the same amount (i.e., revised guidance $675 million to $820 million). This guidance is also based on assumptions utilized for 2004 planning purposes, as discussed in this section, including natural gas prices based on NYMEX of approximately $4.90 per MMbtu, crude oil prices based on WTI of approximately $26.50 per barrel and a U.S. dollar to Canadian dollar exchange rate of $0.73.

February 6, 2004

ENCANA CORPORATION

Consolidated Financial

Statements

For the Year Ended December 31, 2003

EnCana Corporation

MANAGEMENT REPORT

The accompanying Consolidated Financial Statements of EnCana Corporation are the responsibility of Management. The financial statements have been prepared by Management in United States dollars in accordance with Canadian generally accepted accounting principles and include certain estimates that reflect Management s best judgements. Financial information contained throughout the annual report is consistent with these financial statements.

The Company has developed and maintains an extensive system of internal controls that provides reasonable assurance that all transactions are accurately recorded, that the financial statements realistically report the Company s operating and financial results and that the Company s assets are safeguarded. The Company s Internal Audit department reviews and evaluates the adequacy of and compliance with the Company s internal controls. The policy of the Company is to maintain the highest standard of ethics in all its activities and it has a written business conduct and ethics practice.

The Company s Board of Directors has approved the information contained in the financial statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee, which has a written mandate that complies with the current requirements of the United States Sarbanes-Oxley Act of 2002 and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange and the Toronto Stock Exchange. The Audit Committee meets at least on a quarterly basis.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, was appointed by a vote of shareholders at the Company s last annual meeting to audit the Consolidated Financial Statements and provide an independent opinion.

Gwyn Morgan
President &
Chief Executive Officer

John D. Watson
Executive Vice-President &
Chief Financial Officer

February 6, 2004

EnCana Corporation

AUDITORS REPORT

TO THE SHAREHOLDERS OF ENCANA CORPORATION

We have audited the Consolidated Balance Sheets of EnCana Corporation as at December 31, 2003 and December 31, 2002 and the Consolidated Statements of Earnings, Retained Earnings and Cash Flows for each of the years in the three-year period ended December 31, 2003. These financial statements are the responsibility of the Company s Management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by Management, as well as evaluating the overall financial statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and December 31, 2002 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2003 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
Canada

February 6, 2004

COMMENTS BY AUDITOR FOR U.S. READERS ON CANADA-U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company s financial statements, such as the changes described in Note 2 to the Consolidated Financial Statements. Our report to the shareholders dated February 6, 2004 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors report when the change is properly accounted for and adequately disclosed in the financial statements.

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
Canada

February 6, 2004

EnCana Corporation

CONSOLIDATED STATEMENT OF EARNINGS

For the years ended
December 31

($ millions, except per share amounts)		**2003**	**2002**	**2001**
			(restated Note 2)	**(restated Note 2)**
REVENUES, NET OF ROYALTIES	*(Note 4)*	**$10,216**	$6,276	$3,244
EXPENSES	*(Note 4)*			
Production and mineral taxes		**189**	119	77
Transportation and selling		**545**	364	111
Operating		**1,297**	813	448
Purchased product		**3,455**	2,200	739
Depreciation, depletion and amortization		**2,222**	1,304	510
Administrative		**173**	119	54
Interest, net	*(Note 7)*	**287**	290	34
Accretion of asset retirement obligation	*(Note 14)*	**19**	13	8
Foreign exchange (gain) loss	*(Note 8)*	**(601)**	(14)	12
Stock-based compensation	*(Note 2)*	**18**		
Gain on corporate disposition	*(Note 6)*		(33)	
		7,604	5,175	1,993
NET EARNINGS BEFORE INCOME TAX		**2,612**	1,101	1,251
Income tax expense	*(Note 9)*	**445**	366	419
NET EARNINGS FROM CONTINUING OPERATIONS		**2,167**	735	832
NET EARNINGS FROM DISCONTINUED OPERATIONS	*(Note 5)*	**193**	77	22
NET EARNINGS		**$ 2,360**	$ 812	$ 854
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	*(Note 18)*			
Basic		**$ 4.57**	$ 1.76	$ 3.26
Diluted		**$ 4.52**	$ 1.74	$ 3.21

NET EARNINGS PER COMMON SHARE	*(Note 18)*			
Basic		**$ 4.98**	$ 1.94	$ 3.34
Diluted		**$ 4.92**	$ 1.92	$ 3.30

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

For the years ended December 31

($ millions)		**2003**	**2002**	**2001**
			(restated Note 2)	**(restated Note 2)**
RETAINED EARNINGS, BEGINNING OF YEAR				
As previously reported		**$3,457**	$2,787	$2,806
Retroactive adjustment for changes in accounting policies	*(Note 2)*	**66**	32	10
As restated		**3,523**	2,819	2,816
Net Earnings		**2,360**	812	854
Dividends on Common Shares	*(Note 18)*	**(139)**	(108)	(818)
Charges for Normal Course Issuer Bid	*(Note 15)*	**(468)**		
Other	*(Note 18)*			(33)
RETAINED EARNINGS, END OF YEAR		**$5,276**	$3,523	$2,819

See accompanying notes to Consolidated Financial Statements.

EnCana Corporation

CONSOLIDATED BALANCE SHEET

As at December 31

($ millions)		**2003**	**2002**
			(restated Note 2)
ASSETS			
Current Assets			
Cash and cash equivalents		**$ 148**	$ 116
Accounts receivable and accrued revenues		**1,367**	1,258
Inventories	*(Note 10)*	**573**	281
Assets of discontinued operations	*(Note 5)*		2,155
		2,088	3,810
Property, Plant and Equipment, net	*(Notes 4, 11)*	**19,545**	14,247
Investments and Other Assets	*(Note 12)*	**566**	292
Goodwill		**1,911**	1,563
	(Note 4)	**$24,110**	$19,912
LIABILITIES SHAREHOLDERS EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 1,579**	$ 1,445
Income tax payable		**65**	13
Current portion of long-term debt	*(Note 13)*	**287**	134
Liabilities of discontinued operations	*(Note 5)*		1,100
		1,931	2,692
Long-Term Debt	*(Note 13)*	**6,088**	5,051
Other Liabilities		**21**	54
Asset Retirement Obligation	*(Note 14)*	**430**	309
Future Income Taxes	*(Note 9)*	**4,362**	3,088
		12,832	11,194
Shareholders Equity			
Share capital	*(Note 15)*	**5,305**	5,511

Share options, net	**55**	84
Paid in surplus	**18**	51
Retained earnings	**5,276**	3,523
Foreign currency translation adjustment	**624**	(451)
	11,278	8,718
	$24,110	$19,912

Commitments and Contingencies *(Note 19)*

See accompanying notes to Consolidated Financial Statements.

Approved by the Board

David P. O Brien
Director

Barry W. Harrison
Director

EnCana Corporation

CONSOLIDATED STATEMENT OF CASH FLOWS

For the years ended December 31

($ millions)		**2003**	**2002**	**2001**
			(restated Note 2)	**(restated Note 2)**
OPERATING ACTIVITIES				
Net earnings from continuing operations		**$ 2,167**	$ 735	$ 832
Depreciation, depletion and amortization		**2,222**	1,304	510
Future income taxes	*(Note 9)*	**501**	404	95
Unrealized foreign exchange (gain) loss	*(Note 8)*	**(545)**	(23)	35
Accretion of asset retirement obligation	*(Note 14)*	**19**	13	8
Other		**56**	(166)	(17)
Cash flow from continuing operations		**4,420**	2,267	1,463
Cash flow from discontinued operations		**39**	152	31
Cash flow		**4,459**	2,419	1,494
Net change in other assets and liabilities		**(84)**	(17)	(40)
Net change in non-cash working capital from continuing operations	*(Note 18)*	**(81)**	(853)	350
Net change in non-cash working capital from discontinued operations		**17**	64	(29)
		4,311	1,613	1,775
INVESTING ACTIVITIES				
Capital expenditures	*(Note 4)*	**(5,115)**	(3,021)	(1,259)
Proceeds on disposal of property, plant and equipment		**301**	363	31
Corporate (acquisitions) and dispositions	*(Note 6)*	**(193)**	60	56
Business combination with Alberta Energy Company Ltd.	*(Note 3)*		(80)	
Equity investments		**(161)**		
Net change in investments and other		**(63)**	43	19
		(83)	186	55

Net change in non-cash working capital from continuing operations	*(Note 18)*			
Discontinued operations		**1,585**	(146)	6
		(3,729)	(2,595)	(1,092)
FINANCING ACTIVITIES				
Issuance of short-term debt				281
Repayment of short-term debt				(439)
Issuance of long-term debt		**1,609**	1,506	990
Repayment of long-term debt		**(963)**	(1,206)	(256)
Issuance of common shares	*(Note 15)*	**114**	88	31
Purchase of common shares	*(Note 15)*	**(868)**		(4)
Dividends on common shares	*(Note 18)*	**(139)**	(108)	(818)
Other		**(13)**	(53)	
Net change in non-cash working capital from continuing operations	*(Note 18)*	**2**	(7)	1
Discontinued operations		**(282)**	271	
		(540)	491	(214)
DEDUCT: FOREIGN EXCHANGE LOSS (GAIN) ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		**10**	(2)	(5)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		**32**	(489)	474
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR		**116**	605	131
CASH AND CASH EQUIVALENTS, END OF YEAR		**$ 148**	$ 116	$ 605
Supplemental Cash Flow Information	*(Note 18)*			

See accompanying notes to Consolidated Financial Statements.

ENCANA FINANCIAL PERFORMANCE

Prepared using Canadian generally accepted accounting principles.
All amounts in US$ millions, unless otherwise indicated.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
For the year ended December 31, 2003

NOTE 1

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries (EnCana or the Company), and are presented in accordance with Canadian generally accepted accounting principles. In these Consolidated Financial Statements, unless otherwise indicated, all dollar amounts are expressed in United States (U.S.) dollars. All references to US$ or to $ are to United States dollars and references to C$ are to Canadian dollars.

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.

A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries, and are presented in accordance with Canadian generally accepted accounting principles. Information prepared in accordance with generally accepted accounting principles in the United States is included in Note 20.

Investments in jointly controlled companies, jointly controlled partnerships (collectively called affiliates) and unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Company s proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Investments in companies and partnerships in which the Company does not have direct or joint control over the strategic operating, investing and financing decisions, but does have significant influence on them, are accounted for using the equity method.

B) Foreign Currency Translation

The accounts of self-sustaining operations are translated using the current rate method, whereby assets and liabilities are translated at year-end exchange rates, while revenues and expenses are translated using average annual rates. Translation gains and losses relating to the self-sustaining operations are included as a separate component of shareholders equity.

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statement of Earnings.

C) Measurement Uncertainty

The timely preparation of the financial statements in conformity with Canadian generally accepted accounting principles requires that Management make estimates and assumptions and use judgement regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, asset retirement costs and obligations and amounts used for ceiling test and impairment calculations are based on estimates of oil and natural gas reserves and future costs required to develop those reserves. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

The values of pension assets and obligations and the amount of pension costs charged to net earnings depend on certain actuarial and economic assumptions which by their nature are subject to measurement uncertainty.

D) Revenue Recognition

Revenues associated with the sales of the Company s natural gas, natural gas liquids (NGLs) and crude oil owned by the Company are recognized when title passes from the Company to its customer. Crude oil and natural gas produced and sold by the Company below or above its working interest share in the related resource properties results in production underliftings or overliftings. Underliftings are recorded as inventory and overliftings are recorded as deferred revenue.

Marketing revenues and purchased product are recorded on a gross basis as the Company takes title to product and has the risks and rewards of ownership. Revenues associated with the services provided where the Company acts as agent are recorded as the services are provided. Revenues associated with the sale of natural gas storage services are recognized when the services are provided. Sales of electric power are recognized when the title is transferred to the customer.

E) Employee Benefit Plans

The Company accrues for its obligations under its employee benefit plans and the related costs, net of plan assets.

The cost of pensions and other retirement benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management s best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The obligation is discounted using a market interest rate at the beginning of the year on high quality corporate debt instruments.

Pension expense includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10% of the greater of the benefit obligation and the fair value of plan assets. The amortization period covers the expected average remaining services lives of employees covered by the plan.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plans.

F) Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, the Company records future income taxes for the effect of any difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in earnings in the period that the change occurs.

G) Earnings Per Share Amounts

Basic net earnings per common share is computed by dividing the net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per common share amounts are calculated giving effect to the potential dilution that would occur if stock options were exercised or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price.

H) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less when purchased.

I) Inventories

Product inventories are valued at the lower of average cost and net realizable value on a first-in, first-out basis. Materials and supplies are valued at cost.

J) Property, Plant and Equipment

Upstream

The Company accounts for crude oil and natural gas properties in accordance with the Canadian Institute of Chartered Accountants guideline on full cost accounting in the oil and gas industry. Under this method, all costs associated with the acquisition of, exploration for and the development of, natural gas and crude oil reserves, including asset retirement costs, are capitalized on a country-by-country cost centre basis.

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. For purposes of this calculation, oil is converted to gas on an energy equivalent basis. Capitalized costs subject to depletion include estimated future costs to be incurred in developing proved reserves. Proceeds from the disposal of properties are normally deducted from the full cost pool without recognition of gain or loss unless that deduction would result in a change to the rate of depreciation, depletion and amortization of 20% or greater in which case a gain or loss is recorded. Costs of major development projects and costs of acquiring and evaluating significant unproved properties are excluded, on a cost centre basis, from costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties, or impairment has occurred.

An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of:

i. the fair value of proved and probable reserves; and

ii. the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

Midstream

Midstream facilities, including natural gas storage facilities, natural gas liquids extraction plant facilities and power generation facilities, are carried at cost and depreciated on a straight line basis over the estimated service lives of the assets, which range from 20 to 25 years. Capital assets related to pipelines are carried at cost and depreciated or amortized using the straight-line method over their economic lives, which range from 20 to 35 years.

K) Capitalization of Costs

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred.

Interest is capitalized during the construction phase of large capital projects.

L) Amortization of Other Assets

Amortization of deferred items included in Investments and Other Assets is provided for, where applicable, on a straight-line basis over the estimated useful lives of the assets.

M) Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed by the Company for impairment at least annually. Goodwill and all other assets and liabilities have been allocated to business levels, within the Company s segments, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit s assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit s goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

N) Asset Retirement Obligations

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when identified and a reasonable estimate of fair value can be made. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, offshore production platforms and natural gas processing plants. These obligations also include items for which the Company has made promissory estoppel. The asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Asset retirement costs for natural gas and crude oil assets are amortized using the unit-of-production method.

Amortization of asset retirement costs are included in depreciation, depletion and amortization on the Consolidated Statement of Earnings. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings.

Actual expenditures incurred are charged against the accumulated obligation.

O) Stock-based Compensation

The Company records compensation expense in the Consolidated Financial Statements for stock options granted to employees and directors using the fair value method. Fair values are determined using the Black-Scholes option pricing model. Compensation costs are recognized over the vesting period (see Note 2).

Obligations for cash payments under the Company s share appreciation rights, deferred share units and performance share units are accrued as compensation expense over the vesting period. Fluctuations in the price of the Company s common shares will change the accrued compensation expense and are recognized when they occur.

P) Derivative Financial Instruments

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

The Company has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated from budgeted capital programs, and in other cases to the mitigation of market price risks for specific assets and obligations. When applicable, the Company also identifies all relationships between hedging instruments and hedged items, as well as its risk management objective and the strategy for undertaking hedge transaction. This would include linking the particular derivative to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. Where specific hedges are executed, the Company assesses, both at the inception of the hedge and on an ongoing basis, whether the derivative used in the particular hedging transaction is effective in offsetting changes in fair values or cash flows of the hedged item.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by the Company are swaps, collars or options which are entered into with major financial institutions, integrated energy companies or commodities trading institutions. Gains and losses from these derivative financial instruments are recognized in oil and gas revenues as the related production occurs.

The Company may also utilize derivative financial instruments such as interest rate swap agreements to manage the fixed and floating interest rate mix of the Company s total debt portfolio and related overall cost of borrowing. The interest rate swap agreements involve the periodic exchange of payments, without the exchange of the normal principal amount upon which the payments are based, and are recorded as an adjustment of interest expense on the hedged debt instrument.

The Company may also enter into hedges of its foreign currency exposures on foreign currency denominated long-term debt by entering into offsetting forward exchange contracts. Foreign exchange translation gains and losses on these instruments are accrued under other current, or non-current, assets or liabilities on the balance sheet and recognized in foreign exchange in the period to which they relate, offsetting the respective translation losses and gains recognized on the underlying foreign currency long-term debt. Premiums or discounts on these forward instruments are amortized as an adjustment of interest expense over the term of the contract.

The Company may also purchase foreign exchange forward contracts to hedge anticipated sales to customers in the United States and the related accounts receivable. Foreign exchange translation gains and losses on these instruments are recognized as an adjustment of the revenues when the sale is recorded.

Q) Reclassification

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

R) Recently Issued Accounting Pronouncements

During 2003, the following amended standard was issued:

Hedging Relationships

The Canadian Institute of Chartered Accountants (CICA) modified Accounting Guideline 13 (AcG 13) Hedging Relationships , effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. In addition, the CICA simultaneously amended EIC 128, Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments to require that all derivative instruments that do not qualify as a hedge under AcG 13, or are not designated as a hedge, be recorded in the balance sheet as either an asset or liability with changes in fair value recognized in earnings. For 2004, the Company has elected not to designate any of its current price risk management activities as accounting hedges under AcG 13 and, accordingly, will account for all derivatives using the mark-to-market accounting method. The impact on the Company s financial statements at January 1, 2004, is an increase in assets of $145 million, an increase in liabilities of $380 million and a deferred loss of $235 million which will be recognized as the contracts expire ($162 million, net of tax).

NOTE 2

CHANGES IN ACCOUNTING POLICIES AND PRACTICES

A) Reporting Currency

The Company has adopted the United States dollar as its reporting currency since most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American upstream exploration and development companies. The Company uses the current rate method for foreign currency translations. All prior periods have been restated to reflect the United States dollar as the reporting currency.

B) Preferred Securities

The Company has retroactively adopted the amendments made to CICA Handbook section 3860, Financial Instruments Disclosure and Presentation . As a result, the preferred securities issued by the Company are now recorded as a liability and included in long-term debt. The effect on the Company s Consolidated Statement of Earnings was to increase net earnings by $6 million (2002 $2 million decrease; 2001 $3 million decrease). The effect to the Company s Consolidated Balance Sheet is to increase current portion of long-term debt by $97 million, increase long-term debt by $321 million and decrease shareholders equity by $418 million (2002 $369 million increase to long-term debt; $289 million decrease to preferred securities of subsidiary; $80 million decrease to shareholders equity).

C) Asset Retirement Obligations

The Company has retroactively early adopted the Canadian accounting standard outlined in CICA Handbook section 3110, Asset Retirement Obligations . This new section requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms and natural gas processing plants. The obligations included within the scope of this section are those for which a company faces a legal obligation for settlement or has made promissory estoppel. The initial measurement of the asset retirement obligation is at fair value, defined as the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale.

The asset retirement cost, equal to the fair value of the retirement obligation, is capitalized as part of the cost of the related long-lived asset and allocated to expense on a basis consistent with depreciation, depletion and amortization.

The Company previously estimated costs of dismantlement, removal, site reclamation and other similar activities and recorded them into earnings on a unit-of production basis over the remaining life of the proved reserves and accumulated a liability on the Consolidated Balance Sheet. Upon adoption, all prior periods have been restated for the change in accounting policy. The change results in an increase in net earnings of $36 million for the year ended December 31, 2003 (2002 $34 million; 2001 $22 million). The effect of this change on the December 31, 2003 Consolidated Balance Sheet is an increase in property, plant and equipment of $142 million (2002 $94 million), no change in the assets of discontinued operations (2002 $11 million decrease), an increase in liabilities of $22 million (2002 $16 million), an increase to retained earnings of $102 million (2002 $66 million) and an increase in foreign currency translation adjustment of $18 million (2002 $1 million).

D) Stock-based Compensation

The Company has early adopted the Canadian accounting standard as outlined in CICA Handbook section 3870, Stock-based Compensation and Other Stock-based Payments . As allowed by the section, this policy has been adopted prospectively, meaning all prior years have not been restated.

The adoption of the new accounting standard for stock-based compensation resulted in the Company recognizing an expense of $18 million in 2003.

E) Full Cost Accounting

The Company has early adopted the new CICA Accounting Guideline AcG 16, Oil and Gas Accounting Full Cost . The new guideline modifies how the ceiling test is performed, and requires cost centres be tested for recoverability using undiscounted future cash flows from proved reserves which are determined by using forward indexed prices. When the carrying amount of a cost centre is not recoverable, the cost centre would be written down to its fair value. Fair value is estimated using accepted present value techniques which incorporate risks and other uncertainties when determining expected cash flows (see Note 1). Additional disclosures are also required as provided in Note 11. There is no impact on the Company s reported financial results as a result of applying the new Accounting Guideline AcG 16.

F) Employee Future Benefits

The Company has early adopted the amendments made to disclosure requirements in the CICA Handbook section 3461, Employee Future Benefits (see Note 16). There is no impact on the Company s reported financial results as a result of applying these increased disclosure requirements.

G) Summary of Changes in Accounting Policies and Practices

The following table summarizes the effect of the changes in accounting policies:

		2003			**2002**		
As at and for the years ended December 31		**As Reported**	**Change**	**As Restated**	**As Reported**	**Change**	**As Restated**
Consolidated Balance Sheet							
Assets							
Assets of discontinued operations	*(C)*	**$**	**$**	**$**	$ 2,166	$ (11)	$ 2,155
Property, plant and equipment, net	*(C)*	**19,403**	**142**	**19,545**	14,153	94	14,247
Liabilities							
Liabilities of discontinued operations	*(C)*	**$**	**$**	**$**	$ 1,113	$ (13)	$ 1,100
Current portion of long-term debt	*(B)*	**190**	**97**	**287**	134		134
Long-term debt	*(B)*	**5,767**	**321**	**6,088**	4,682	369	5,051
Preferred securities of subsidiary	*(B)*				289	(289)	
Other liabilities & asset retirement obligation	*(C)*	**473**	**(22)**	**451**	357	6	363
Future income taxes	*(C)*	**4,318**	**44**	**4,362**	3,065	23	3,088
Shareholders Equity							
Preferred securities	*(B)*	**$ 418**	**$ (418)**	**$**	$ 80	$ (80)	$
Paid in surplus	*(D)*		**18**	**18**	51		51
Retained earnings	*(C)*	**5,192**	**84**	**5,276**	3,457	66	3,523
Foreign currency translation adjustment	*(C)*	**606**	**18**	**624**	(452)	1	(451)
Consolidated Statement of Earnings							
Net Earnings	*(B),(C),(D)*	**$ 2,336**	**$ 24**	**$ 2,360**	$ 780	$ 32	$ 812
Net Earnings per							
Common Share Diluted	*(B),(C),(D)*	**$ 4.88**	**$ 0.04**	**$ 4.92**	$ 1.84	$ 0.08	$ 1.92

NOTE 3

BUSINESS COMBINATION WITH ALBERTA ENERGY COMPANY LTD.

On January 27, 2002, PanCanadian Energy Corporation (PanCanadian) and Alberta Energy Company Ltd. (AEC) announced plans to combine the companies. The transaction was accomplished through a plan of arrangement (the Arrangement) under the Business Corporations Act (Alberta). The Arrangement included a common share exchange, pursuant to which holders of common shares of AEC received 1.472 common shares of PanCanadian for each common share of AEC that they held. The transaction closed April 5, 2002, and PanCanadian changed its name to EnCana Corporation.

This business combination has been accounted for using the purchase method with the results of operations of AEC included in the Consolidated Financial Statements from the date of acquisition.

The calculation of the purchase price and the allocation to assets and liabilities acquired as of April 5, 2002 is shown below:

Calculation of Purchase Price:		
Common Shares issued to AEC shareholders *(millions)*	218.5	
Price of Common Shares *(C$ per common share)*	38.43	
Value of Common Shares issued		$ 5,281
Fair value of AEC share options exchanged for share options of EnCana Corporation (Share options)		105
Transaction Costs		94
Total purchase price		5,480
Plus: Fair value of liabilities assumed		
Current liabilities		1,120
Long-term debt (including preferred securities)		3,714
Other non-current liabilities		180
Future income taxes		1,665
Total Purchase Price and Liabilities Assumed		$12,159
Fair Value of Assets Acquired:		
Current assets		$ 946
Property, plant and equipment, net		8,897
Other non-current assets		381
Goodwill		1,935
Total Fair Value of Assets Acquired		$12,159

Goodwill Allocation:	
Upstream	$ 1,504
Midstream & Marketing	49
	1,553
Discontinued Operations	382
Total Goodwill Allocation	$ 1,935

NOTE 4

SEGMENTED INFORMATION

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

Upstream includes the Company s exploration for, and development and production of, natural gas, natural gas liquids and crude oil and other related activities. The majority of the Company s Upstream operations are located in Canada, the United States, the United Kingdom and Ecuador. International new venture exploration is mainly focused on opportunities in Africa, South America and the Middle East.

Midstream & Marketing includes natural gas storage operations, natural gas liquids processing and power generation operations, as well as marketing activities. These marketing activities include the sale and delivery of produced product, and the purchasing of third party product primarily for the optimization of midstream assets, as well as the optimization of transportation arrangements not fully utilized for the Company s own production.
Midstream & Marketing purchases all of the Company s North American Upstream production. Transactions between business segments are based on market values and eliminated on consolidation. The tables in this note present financial information on an after eliminations basis.

In 2003, the Company redefined its business segments to those described above. All prior periods have been restated to conform to the current presentation.

Operations that have been discontinued are disclosed in Note 5.

Results of Operations (for the years ended December 31)

	Upstream			**Midstream & Marketing**		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**
Revenues, Net of Royalties	**$6,327**	$3,674	$2,315	**$3,887**	$2,594	$931
Expenses						
Production and mineral taxes	**189**	119	77			
Transportation and selling	**490**	277	100	**55**	87	11
Operating	**973**	626	294	**324**	187	154
Purchased product				**3,455**	2,200	739
Depreciation, depletion and amortization	**2,133**	1,233	478	**48**	36	10
Segment Income	**$2,542**	$1,419	$1,366	**$ 5**	$ 84	$ 17

	Corporate			**Consolidated**		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**

Revenues, Net of Royalties	**$ 2**	$ 8	$ (2)	**$10,216**	$6,276	$3,244
Expenses						
Production and mineral taxes				**189**	119	77
Transportation and selling				**545**	364	111
Operating				**1,297**	813	448
Purchased product				**3,455**	2,200	739
Depreciation, depletion and amortization	**41**	35	22	**2,222**	1,304	510
Segment Income	**$(39)**	$(27)	$(24)	**2,508**	1,476	1,359
Administrative				**173**	119	54
Interest, net				**287**	290	34
Accretion of asset retirement obligation				**19**	13	8
Foreign exchange (gain) loss				**(601)**	(14)	12
Stock-based compensation				**18**		
Gain on corporate disposition					(33)	
				(104)	375	108
Net Earnings Before Income Tax				**2,612**	1,101	1,251
Income tax expense				**445**	366	419
Net Earnings from Continuing Operations				**$ 2,167**	$ 735	$ 832

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Geographic and Product Information (for the years ended December 31)

UPSTREAM

	North America								
	Produced Gas and NGLs								
	Canada			United States			Crude Oil		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
Revenues, Net of Royalties	**$3,523**	$1,971	$1,598	**$1,143**	$454	$59	**$951**	$825	$523
Expenses									
Production and mineral taxes	**52**	50	48	**108**	35	7	**4**	20	22
Transportation and selling	**274**	151	72	**86**	59		**69**	35	16
Operating	**342**	255	112	**60**	35	11	**300**	201	153
Depreciation, depletion and amortization	**1,075**	625	261	**293**	202	31	**436**	237	124
Segment Income	**$1,780**	$ 890	$1,105	**$ 596**	$123	$10	**$142**	$332	$208

	Ecuador			U.K. North Sea			Other			Total Upstream		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
Revenues, Net of Royalties	**$412**	$245	$	**$118**	$103	$111	**$180**	$ 76	$24	**$6,327**	$3,674	$2,315
Expenses												
Production and mineral taxes	**25**	14								**189**	119	77
Transportation and selling	**45**	21		**16**	11	12				**490**	277	100
Operating	**83**	53		**18**	11	10	**170**	71	8	**973**	626	294
Depreciation, depletion and amortization	**159**	79		**74**	39	42	**96**	51	20	**2,133**	1,233	478
Segment Income	**$100**	$ 78	$	**$ 10**	$ 42	$ 47	**$ (86)**	$(46)	$ (4)	**$2,542**	$1,419	$1,366

MIDSTREAM & MARKETING

	Midstream			Marketing			Total Midstream Marketing		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
Revenues	**$1,084**	$440	$154	**$2,803**	$2,154	$777	**$3,887**	$2,594	$931
Expenses									
Transportation and selling				**55**	87	11	**55**	87	11
Operating	**261**	174	142	**63**	13	12	**324**	187	154
Purchased product	**762**	169		**2,693**	2,031	739	**3,455**	2,200	739
Depreciation, depletion and amortization	**40**	24	9	**8**	12	1	**48**	36	10
Segment Income	**$ 21**	$ 73	$ 3	**$ (16)**	$ 11	$ 14	**$ 5**	$ 84	$ 17

Capital Expenditures

For the years ended December 31	2003	2002	2001
Upstream			
Canada	**$3,198**	$1,388	$ 919
United States	**968**	1,176	139
Ecuador	**265**	168	
United Kingdom	**223**	82	46
Other Countries	**78**	117	42
	4,732	2,931	1,146
Midstream & Marketing	**276**	47	96
Corporate	**107**	43	17
Total	**$5,115**	$3,021	$1,259

Additions to Goodwill
There were no additions to goodwill during the year (see Note 3).

Property, Plant and Equipment and Total Assets

	Property, Plant and Equipment		Total Assets	
As at December 31	2003	2002	2003	2002
Upstream	**$18,532**	$13,656	**$21,742**	$16,042
Midstream & Marketing	**784**	470	**1,879**	1,403
Corporate	**229**	121	**489**	312
Assets of Discontinued Operations				2,155
Total	**$19,545**	$14,247	**$24,110**	$19,912

Export Sales

Sales of natural gas, crude oil and natural gas liquids produced or purchased in Canada made outside of Canada were $1,484 million (2002 $1,333 million; 2001 $785 million).

Major Customers

In connection with the marketing and sale of the Company s own and purchased natural gas and crude oil, for the year ended December 31, 2003, the Company had two customers which individually accounted for 10 percent of its consolidated revenues, net of royalties (2002 none). One customer, a major international integrated energy company with a high quality investment grade credit rating, purchased approximately $1,362 million. The second customer, a Canadian natural gas clearing exchange with substantial credit controls, purchased approximately $1,056 million.

The majority of the Company s crude oil produced in Ecuador is sold to a single marketing company. Payments are secured by letters of credit from a major financial institution which has a high quality investment grade credit rating.

The majority of the Company s revenues in the United Kingdom is earned from a single customer who has a high quality investment grade credit rating.

NOTE 5

DISCONTINUED OPERATIONS

2003

On February 28, 2003, the Company completed the sale of its 10 percent working interest in the Syncrude Joint Venture (Syncrude) to Canadian Oil Sands Limited for net cash consideration of C$1,026 million ($690 million). On July 10, 2003 the Company completed the sale of the remaining 3.75 percent interest in Syncrude and a gross overriding royalty for net cash consideration of C$427 million ($309 million). This transaction completed the Company s disposition of its interest in Syncrude and, as a result, these operations have been accounted for as discontinued operations. There was no gain or loss on this sale.

2002

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.

On November 19, 2002, the Company announced that it had entered into agreements to sell its discontinued pipelines operations for approximately C$1.6 billion ($1 billion) including the assumption of long-term debt by the purchaser. On January 2, 2003 and January 9, 2003, these sales were completed resulting in a gain on sale of C$263 million ($ 169 million).

For comparative purposes, the following tables present the effect of only the Merchant Energy discontinued operations on the Consolidated Financial Statements for the year ended December 31, 2001. The tables do not include any financial information related to Midstream Pipelines or Upstream Syncrude for 2001 as EnCana did not own these operations.

Consolidated Statement of Earnings
2003

UPSTREAM SYNCRUDE

For the years ended December 31	**2003**	**2002**
Revenues, Net of Royalties	**$87**	$232
Expenses		
Transportation and selling	**2**	3
Operating	**46**	105
Depreciation, depletion and amortization	**7**	16
Interest, net		1
	55	125
Net Earnings Before Income Tax	**32**	107
Income tax expense	**8**	28
Net Earnings from Discontinued Operations	**$24**	$ 79

2002
MIDSTREAM & MARKETING

	Merchant Energy			Midstream Pipelines			Total		
For the years ended December 31	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
Revenues	**$**	$922	$2,646*	**$**	$135	$	**$**	$1,057	$2,646
Expenses									
Operating					50			50	
Purchased product		931	2,578*					931	2,578
Depreciation, depletion and amortization			4		18			18	4
Administrative		22	27					22	27
Interest, net					19			19	
Foreign exchange (gain)					(3)			(3)	
(Gain) loss on discontinuance		19		**(220)**			**(220)**	19	
		972	2,609	**(220)**	84		**(220)**	1,056	2,609
Net Earnings (Loss) Before Income Tax		(50)	37	**220**	51		**220**	1	37
Income tax expense (recovery)		(17)	15	**51**	20		**51**	3	15
Net Earnings (Loss) from Discontinued Operations	**$**	$ (33)	$ 22	**$ 169**	$ 31	$	**$ 169**	$ (2)	$ 22

* Upon review of additional information related to 2001 sales and purchases of natural gas by the U.S. marketing subsidiary, the Company has determined certain revenue and expenses should have been reflected in the financial statements on a net basis rather than included on a gross basis as revenues and expenses purchased product. The amendment had no effect on net earnings or cash flow but revenues and expenses purchased product have been reduced by $727 million.

Consolidated Total

For the years ended December 31	2003	2002	2001
Revenues, Net of Royalties	**$ 87**	$1,289	$2,646
Expenses			
Transportation and selling	**2**	3	
Operating	**46**	155	
Purchased product		931	2,578
Depreciation, depletion and amortization	**7**	34	4
Administrative		22	27
Interest, net		20	
Foreign exchange (gain)		(3)	
(Gain) loss on discontinuance	**(220)**	19	
	(165)	1,181	2,609
Net Earnings Before Income Tax	**252**	108	37
Income tax expense	**59**	31	15
Net Earnings from Discontinued Operations	**$ 193**	$ 77	$ 22

Consolidated Balance Sheet

As all discontinued operations have either been disposed of or wind up has been completed, there are no remaining assets or liabilities at December 31, 2003. The balance sheet below shows the assets and liabilities of these operations as at December 31, 2002.

As at December 31, 2002	Syncrude	Merchant Energy	Midstream Pipelines	Total
Assets				
Cash and cash equivalents	$ 18	$	$ 43	$ 61
Accounts receivable and accrued revenues	41		20	61
Inventories	9		1	10
	68		64	132
Property, plant and equipment, net	884		517	1,401
Investments and other assets			237	237
Goodwill	264		121	385

	1,216		939	2,155
Liabilities				
Accounts payable and accrued liabilities	68	3	25	96
Income tax payable	(4)		11	7
Short-term debt	277			277
Current portion of long-term debt			15	15
	341	3	51	395
Long-term debt			365	365
Future income taxes	236		104	340
	577	3	520	1,100
Net Assets of Discontinued Operations	$ 639	$ (3)	$ 419	$ 1,055

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NOTE 6

CORPORATE (ACQUISITIONS) AND DISPOSITIONS

For the years ended December 31	2003	2002	2001
Acquisitions			
Vintage	**$(116)**	$	$
Savannah	**(91)**		
Other			(47)
	(207)		(47)
Dispositions			
EnCana Suffield Gas Pipeline Inc.		60	
Other	**14**		103
	14	60	103
	$(193)	$60	$ 56

On January 31, 2003, the Company acquired the Ecuadorian interests of Vintage Petroleum Inc. (Vintage) for net cash consideration of $116 million. On July 18, 2003, the Company acquired the common shares of Savannah Energy Inc. (Savannah) for net cash consideration of $91 million. Savannah s operations are in Texas, U.S.A.

These purchases were accounted for using the purchase method with the results reflected in the consolidated results of EnCana from the dates of acquisition. These acquisitions were accounted for as follows:

	Vintage	Savannah
Working Capital	$ 1	$ 1
Property, Plant and Equipment	126	110
Future Income Taxes	(11)	(20)
	$116	$ 91

In 2002, the Company sold its investment in EnCana Suffield Gas Pipeline Inc. for total proceeds of $60 million, with a gain on sale of $33 million.

NOTE 7

INTEREST, NET

For the years ended December 31	2003	2002	2001
Interest Expense Long-Term Debt	**$281**	$252	$ 55
Early Retirement of Long-Term Debt		34	
Interest Expense Other	**20**	10	
Interest Income	**(14)**	(6)	(21)
	$287	$290	$ 34

The Company has entered into a series of one or more interest rate swaps, foreign exchange swaps and option transactions on certain of its long-term notes and debentures detailed below (see also Note 13). The net effect of these transactions reduced interest costs in 2003 by $23 million (2002 $20 million; 2001 $11 million).

	Principal Amount	Indenture Interest	Net Swap to	Effective Rate
8.40% due December 15, 2004 C$100 million	US$73 million	C$ Fixed	US$ Floating*	3 month LIBOR less 41 basis points
8.75% due November 9, 2005 C$200 million	US$73 million	C$ Fixed	US$ Fixed*	4.99%
	US$73 million	C$ Fixed	US$ Floating*	3 month LIBOR less 4 basis points
7.50% due August 25, 2006 C$100 million	US$73 million	C$ Fixed	US$ Fixed*	4.14%
5.80% due June 2, 2008 C$225 million	US$71 million	C$ Fixed	US$ Fixed*	4.80%
	C$125 million	C$ Fixed	C$ Floating	3 month Bankers Acceptance less 5 basis points
7.00% due March 23, 2034 C$126 million	C$126 million	C$ Fixed	C$ Floating	3 month Bankers Acceptance plus 104 basis points

* These instruments have been subject to multiple swap transactions.

NOTE 8

FOREIGN EXCHANGE (GAIN) LOSS

For the years ended December 31	2003	2002	2001
Unrealized Foreign Exchange (Gain) Loss on Translation of U.S. Dollar Debt Issued in Canada	**$(545)**	$(23)	$ 35
Other Foreign Exchange (Gains) Losses	**(56)**	9	(23)
	$(601)	$(14)	$ 12

NOTE 9

INCOME TAXES

For the years ended December 31	2003	2002	2001
Provision for Income Taxes			
Current			
Canada	**$(136)**	$ (26)	$320
United States	**39**	(31)	1
Ecuador	**39**	17	
Other	**2**	2	3
	(56)	(38)	324
Future	**860**	424	148
Future tax rate reductions	**(359)**	(20)	(53)
	$ 445	$366	$419

The net future income tax liability is comprised of:

As at December 31	2003	2002
Future Tax Liabilities		
Capital assets in excess of tax values	**$3,515**	$2,821
Timing of Partnership items	**1,162**	513

Future Tax Assets		
Net operating losses carried forward	**(174)**	(203)
Other	**(141)**	(43)
Net Future Income Tax Liability	**$4,362**	$3,088

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

For the years ended December 31	**2003**	**2002**	**2001**
Net Earnings Before Income Tax	**$2,612**	$1,101	$1,251
Canadian Statutory Rate	**40.95%**	42.3%	42.8%
Expected Income Taxes	**1,070**	467	536
Effect on Taxes Resulting from:			
Non-deductible Canadian crown payments	**231**	147	74
Canadian resource allowance	**(258)**	(200)	(167)
Large corporations tax	**27**	23	9
Statutory rate differences	**(50)**	(36)	(12)
Effect of tax rate changes	**(359)**	(20)	(53)
Non-taxable capital gains	**(119)**	(9)	
Previously unrecognized capital losses	**(119)**		
Other	**22**	(6)	32
	$ 445	$ 366	$ 419
Effective Tax Rate	**17.0%**	33.2%	33.5%

The approximate amounts of tax pools available are as follows:

As at December 31	2003	2002
Canada	**$ 6,904**	$4,444
United States	**2,112**	2,175
Ecuador	**1,015**	831
United Kingdom	**230**	123
	$10,261	$7,573

The current income tax provision includes amounts payable or recoverable in respect of Canadian partnership earnings included in the Consolidated Financial Statements for partnerships that have a later year end than the Company.

NOTE 10

INVENTORIES

As at December 31	2003	2002
Product		
Upstream	**$ 11**	$ 34
Midstream & Marketing	**546**	239
Parts and Supplies	**16**	8
	$573	$281

NOTE 11

PROPERTY, PLANT AND EQUIPMENT, NET

	2003			2002		
As at December 31	Cost	Accumulated DD&A*	Net	Cost	Accumulated DD&A*	Net
Upstream						
Canada	$20,607	$(7,500)	$13,107	$14,077	$(4,770)	$ 9,307
United States	4,062	(523)	3,539	3,184	(262)	2,922

Ecuador	1,442	(188)	1,254	1,060	(73)	987
United Kingdom	752	(231)	521	448	(135)	313
Other Countries	316	(205)	111	225	(98)	127
Total Upstream	27,179	(8,647)	18,532	18,994	(5,338)	13,656
Midstream & Marketing	915	(131)	784	541	(71)	470
Corporate	320	(91)	229	191	(70)	121
	$28,414	$(8,869)	$19,545	$19,726	$(5,479)	$14,247

* Depreciation, depletion and amortization

Included in Midstream is $97 million (2002 $47 million) related to cushion gas, required to operate the gas storage facilities, which is not subject to depletion.

Included in the property, plant and equipment cost are asset retirement costs of $245 million (2002 $175 million). Administrative costs have not been capitalized as part of the capital expenditures.

Upstream costs in respect of significant unproved properties and major development projects excluded from depletable costs were:

For the years ended December 31	2003	2002	2001
Canada	**$1,035**	$ 562	$257
United States	**604**	282	116
Ecuador	**89**		
United Kingdom	**175**	112	
Other Countries	**111**	127	88
	$2,014	$1,083	$461

The costs excluded from depletable costs in Other Countries represent costs related to unproved properties incurred in cost centres that are considered to be in the pre-production stage. Currently, there are no proved reserves in these cost centres. All costs, net of any associated revenues, in these cost centres have been capitalized. Ultimate recoverability of these costs will be dependent upon the finding of proved oil and natural gas reserves. At December 31, 2003, the Company completed its impairment review of pre-production cost centres and determined that $85 million of costs should be charged to the Consolidated Statement of Earnings (2002 $ nil).

The prices used in the ceiling test evaluation of the Company s natural gas, crude oil and natural gas liquids reserves at December 31, 2003 were:

	2004	**2005**	**2006**	**2007**	**2008**	**% decrease to 2015**
Natural Gas *($/mcf)*						
Canada	$ 4.05	$ 3.87	$ 3.28	$ 3.37	$ 3.69	0.4%
United States	4.40	4.18	3.41	3.51	3.95	0.4%
United Kingdom	1.76	1.57	1.44	1.44	1.44	
Crude Oil *($/barrel)*						
Canada	$17.41	$16.03	$14.42	$13.86	$13.67	1.6%
Ecuador	18.26	16.18	14.28	14.35	14.36	
United Kingdom	26.82	24.88	21.01	20.44	20.41	0.1%
Natural Gas Liquids *($/barrel)*						
Canada	$23.25	$21.40	$19.10	$19.09	$19.20	0.4%
United States	23.62	21.84	19.91	19.53	19.36	0.2%
United Kingdom	20.05	18.57	16.83	16.71	16.67	0.2%

NOTE 12

INVESTMENTS AND OTHER ASSETS

As at December 31	**2003**	**2002**
Equity Investments	**$217**	$ 62
Value Added Tax Recoverable	**112**	56
Marketing Contracts	**22**	27
Deferred Financing Costs	**31**	28
Deferred Pension Costs	**53**	15
Other	**131**	104
	$566	$292

Equity Investments

Included in Equity Investments is the following:

i. Included in Midstream & Marketing is a 36% indirect equity investment in Oleoducto Transandino (OTA), which owns a crude oil pipeline that ships crude oil from the producing areas of Argentina to refineries in Chile.

ii. Included in Upstream Ecuador is a 36% indirect equity investment in Oleoducto de Crudos Pesados (OCP) Ltd. (OCP), which is the owner of a crude oil pipeline in Ecuador that ships crude oil from the producing areas of Ecuador to a new export marine terminal.

The Company is a shipper on the OCP Pipeline and pays commercial rates for tariffs.

NOTE 13

LONG TERM DEBT

As at December 31	Note	2003	2002
Canadian Dollar Denominated Debt			
Revolving credit and term loan borrowings	*B*	**$1,425**	$ 879
Unsecured notes and debentures	*C*	**1,335**	1,155
Preferred securities	*D*	**252**	206
		3,012	2,240
U.S. Dollar Denominated Debt			
Revolving credit and term loan borrowings	*E*	**417**	441
U.S. unsecured notes and debentures	*F*	**2,713**	2,284
Preferred securities	*D*	**150**	150
		3,280	2,875
Increase in Value of Debt Acquired	*G*	**83**	70
Current Portion of Long-Term Debt	*H*	**(287)**	(134)
		$6,088	$5,051

A) Overview

Revolving credit and term loan borrowings

At December 31, 2003, the Company had in place a revolving credit and term loan facility for $4 billion Canadian dollars or its equivalent amount in U.S. dollars (US$3 billion). The facility consists of two tranches of C$2 billion (US$1.5 billion) each. One tranche is fully revolving for a 364-day period with provision for annual extensions at the option of the lenders and upon notice from the Company. If not extended, this tranche converts to a non-revolving reducing loan for a term of one year. The second tranche is fully revolving for a period of three years from the date of the agreement, December 2002. This tranche is extendible annually for an additional one year period at the option of the lenders and upon notice from the Company. The facility is unsecured and bears interest at either the lenders rates for Canadian prime commercial loans, U.S. base rate loans, Bankers Acceptances rates, or at LIBOR plus applicable margins.

At December 31, 2003, a subsidiary of the Company had in place a credit facility totalling $300 million (C$388 million). The facility is guaranteed by EnCana Corporation and fully revolving for three years from the date of the Agreement, December 2003. The facility is extendable annually for an additional one year period at the option of the lenders and upon notice from the subsidiary. This facility bears interest at either the lenders U.S. base rate or at LIBOR plus applicable margins.

One of the Company s partnerships has a credit agreement, consisting of a term loan facility, senior secured notes and a levelization account, relating to the construction of a cogeneration plant. The term loan bears interest at the prevailing prime lending rate plus 0.25%. The notes bear interest at the prevailing prime lending rate plus 1.25%. The partnership also has an option under the credit agreement to use an average Bankers Acceptance rate plus a margin that will vary during the term. The levelization account accumulates interest at the yield rate of the most recent Government of Canada bond issue with a 20-year maturity as of January 20th each year. The term loan and senior notes are secured by the project facilities.

Revolving credit and term loan borrowings include Bankers Acceptances and Commercial Paper of $1,749 million (2002 $871 million) maturing at various dates with a weighted average interest rate of 2.55% and LIBOR loans of $65 million (C$84 million) with a weighted average interest rate of 1.69%. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

Standby fees paid in 2003 relating to revolving credit and term loan agreements were approximately $3 million (2002 $3 million).

Unsecured notes and debentures

Unsecured notes and debentures include medium term notes and senior notes that are issued from time to time under trust indentures. The Company s current medium term note program was renewed in 2003 with C$1 billion ($774 million) unutilized at December 31, 2003. The notes may be denominated in Canadian dollars or in foreign currencies.

The Company has in place a shelf prospectus for U.S. Unsecured Notes in the amount of US$2.0 billion under the Multijurisdictional Disclosure System. The shelf prospectus provides that debt securities in U.S. dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and expiry dates are determined by reference to market conditions at the date of issue. At December 31, 2003, US$1.5 billion remains unutilized.

B) Canadian revolving credit and term loan borrowings

	C$ Principal Amount	2003	2002
Bankers Acceptances	**$ 773**	**$ 598**	$276
Commercial Paper	**1,033**	**799**	580
Cogeneration Facility, matures March 31, 2016	**36**	**28**	23
	$ 1,842	**$1,425**	$879

C) Canadian unsecured notes and debentures

	C$ Principal Amount	2003	2002
8.15% due July 31, 2003	**$**	**$**	$ 63
6.60% due on June 30, 2004	**50**	**39**	32
7.00% due December 1, 2004	**100**	**77**	63
5.95% due October 1, 2007	**200**	**155**	127
5.30% due December 3, 2007	**300**	**232**	189
5.95% due June 2, 2008	**100**	**77**	63
5.80% due June 2, 2008	**125**	**97**	79
5.80% due June 19, 2008	**100**	**77**	63
6.10% due June 1, 2009	**150**	**116**	95
7.15% due December 17, 2009	**150**	**116**	95
8.50% due March 15, 2011	**50**	**39**	32
7.10% due October 11, 2011	**200**	**155**	127
7.30% due September 2, 2014	**150**	**116**	95
5.50% / 6.20% due June 23, 2028	**50**	**39**	32
	$1,725	**$1,335**	$1,155

D) Preferred securities

	C$ Principal Amount	2003	2002

Canadian Dollar			
7.00% due on March 23, 2034	**$ 126**	**$ 97**	$ 80
8.50% due September 30, 2048	**200**	**155**	126
	$ 326	**252**	206
U.S. Dollar			
9.50% due September 30, 2048		**150**	150
		$402	$356

The preferred securities are unsecured junior subordinated debentures. Subject to certain conditions, the Company has the right to defer payments of interest on the securities for up to 20 consecutive quarterly periods. The Company may satisfy its obligation to pay deferred interest or the principal amount by delivering sufficient equity securities to the Trustee.

On March 23, 1999, the Company issued C$126 million of Coupon Reset Subordinated Term Securities Series A due March 23, 2034. Interest is payable semi-annually at a rate of 7% per annum for the first five years and is reset at the Five Year Government of Canada Yield plus 2% on each fifth anniversary of the date of issuance. The securities are redeemable by the Company, in whole or in part, at any time on or after March 23, 2004, at par plus accrued and unpaid interest. With respect to these securities, the Company entered a series of option transactions that result in an effective floating interest rate equal to three-month Bankers Acceptance rate plus 104 basis points on C$126 million. On February 4, 2004, the Company announced its intention to repurchase these securities on March 23, 2004.

The 8.50% and the 9.50% preferred securities were acquired in the business combination with AEC. Interest on these securities is paid quarterly. These securities are redeemable by the Company, in whole or in part, at any time on or after August 9, 2004 and September 30, 2004 respectively at par plus accrued and unpaid interest.

E) U.S. revolving credit and term loan borrowings

	2003	2002
Commercial Paper	**$352**	$ 16
LIBOR Loan	**65**	425
	$417	$441

F) U.S. unsecured notes and debentures

	C$ Amount	2003	2002
Floating Rate			
5.50% due on March 17, 2003		**$**	$ 71
8.40% due December 15, 2004	**94***	**73**	73
8.75% due November 9, 2005	**94***	**73**	73
Fixed Rate			
8.75% due November 9, 2005	**94***	**73**	73
7.50% due August 25, 2006	**94***	**73**	73
5.80% due June 2, 2008	**92***	**71**	71
7.65% due September 15, 2010		**200**	200
6.30% due November 1, 2011		**500**	500
4.75% due October 15, 2013		**500**	
8.125% due September 15, 2030		**300**	300
7.20% due November 1, 2031		**350**	350
7.375% due November 1, 2031		**500**	500
		$2,713	$2,284

* The Company has entered into a series of cross-currency and interest rate swap transactions that effectively convert these Canadian dollar denominated notes to U.S. dollars. The effective U.S. dollar principal is shown in the table.

G) Increase in value of debt acquired

Certain of the notes and debentures of the Company were acquired in the business combination described in Note 3 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 28 years.

H) Current portion of long-term debt

	2003	2002
5.50% Medium Term Note due March 17, 2003	**$**	$ 71
8.15% Debenture due July 31, 2003		63
7.00% Coupon Reset Subordinated Term Securities due March 23, 2034	**97**	
6.60% Medium Term Note due June 30, 2004	**39**	
7.00% Medium Term Note due December 1, 2004	**77**	
8.40% Medium Term Note due December 15, 2004	**73**	
Cogeneration Facility	**1**	
	$287	$134

I) Mandatory debt payments

	C$ Principal Amount	US$ Principal Amount	Total US$ Equivalent
2004	$ 278	$ 73	**$ 287**
2005	2	146	**147**
2006	2	73	**74**
2007	503		**389**
2008	328	71	**324**
Thereafter	2,780	2,917	**5,071**
Total	$3,893	$3,280	$**6,292**

The amount due in 2004 excludes Bankers Acceptances and Commercial Paper, which are fully supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

NOTE 14

ASSET RETIREMENT OBLIGATION

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas properties.

As at December 31	2003	2002
Asset Retirement Obligation, Beginning of Year	**$309**	$163
Liabilities Incurred	**64**	146
Liabilities Settled	**(23)**	(13)
Accretion Expense	**19**	13
Other	**61**	
Asset Retirement Obligation, End of Year	**$430**	$309

The total undiscounted amount of estimated cash flows required to settle the obligation is $3,223 million (2002 $2,516 million), which has been discounted using a credit-adjusted risk free rate of 5.9 percent. Most of these obligations are not expected to be paid for several years, or decades, in the future and will be funded from general company resources at the time of removal.

NOTE 15

SHARE CAPITAL

Authorized

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares.

Issued and Outstanding

	2003		2002	
As at December 31	Number (millions)	Amount	Number (millions)	Amount
Common Shares Outstanding, Beginning of Year	**478.9**	**$5,511**	254.9	$ 142
Shares Issued to AEC Shareholders *(Note 3)*			218.5	5,281
Shares Issued under Option Plans	**5.5**	**114**	5.5	88
Shares Repurchased	**(23.8)**	**(320)**		

Common Shares Outstanding, End of Year	**460.6**	**$5,305**	478.9	$5,511

Normal Course Issuer Bid

Effective October 16, 2002, the Company received approval from the Toronto Stock Exchange for a Normal Course Issuer Bid. Under the bid, the Company could purchase for cancellation up to 23,843,565 of its Common Shares, representing five percent of the 476,871,300 Common Shares outstanding as at October 4, 2002. On October 20, 2003, the Company received regulatory approval for a new Normal Course Issuer Bid commencing October 22, 2003. Under this bid, the Company may purchase for cancellation up to 23,212,341 of its Common Shares, representing five percent of the 464,246,813 Common Shares outstanding as of October 14, 2003. The current Normal Course Issuer Bid expires on October 21, 2004.

In 2003, the Company purchased, for cancellation, 23,839,400 Common Shares for total consideration of $868 million. Of the $868 million paid, $320 million was charged to share capital, $80 million was charged to paid in surplus and $468 million was charged to retained earnings.

Stock Options

The Company has stock-based compensation plans that allow employees to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were 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 successor and/or related company replacement plans expire 10 years from the date the options were granted.

In conjunction with the business combination transaction described in Note 3, options to purchase AEC common shares were replaced with options to purchase Common Shares of EnCana (AEC replacement plan) in a manner consistent with the provisions of the AEC stock option plan. Options granted under the AEC plan prior to April 21, 1999 expire after seven years and options granted after April 20, 1999 expire after five years. The business combination resulted in these replacement options, along with all options outstanding under the EnCana plan, becoming exercisable after the close of business on April 5, 2002.

EnCana Plan

Pursuant to the terms of a stock option plan, options may be granted to certain key employees to purchase Common Shares of the Company. Options granted prior to February 27, 1997, are exercisable at half the number of options granted after two years and are fully exercisable after three years. The options expire 10 years after the date granted. Options granted on or after February 27, 1997, and prior to November 4, 1999, are exercisable after three years and expire five years after the date granted. Options granted on or after November 4, 1999, are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, are fully exercisable after three years and expire five years after the date granted. For stock options granted after February 27, 1997, and prior to November 4, 1999, the employees can surrender their options in exchange for, at the election of the Company, cash or a payment in common stock for the difference between the market price and exercise price. It is the Company s intent that all options issued in 2004 will have an associated Tandem Share Appreciation Right (TSAR) attached to them.

Canadian Pacific Limited Replacement Plan

As part of the Canadian Pacific Limited (CPL) reorganization, as described in Note 18, CPL stock options were replaced with stock options granted by the Company in a manner that was consistent with the provisions of the CPL stock option plan. Under CPL s stock option plan, options were granted to certain key employees to purchase common shares of CPL at a price not less than the market value of the shares at the grant date. The options expire 10 years after the grant date and are all exercisable.

Directors Plan

Effective April 5, 2002, the Company amended the director stock option plan. Under the terms of the plan, new non-employee directors were given an initial grant of 15,000 options to purchase Common Shares of the Company. Thereafter, there was an annual grant of 7,500 options to each non-employee director. Options, which expire five years after the grant date, are 100 percent exercisable on the earlier of the next annual general meeting following the grant date and the first anniversary of the grant date. On October 23, 2003, issuances of stock options under this plan were discontinued.

The following tables summarize the information about options to purchase Common Shares:

	2003		**2002**	
As at December 31	**Stock Options (millions)**	**Weighted Average Exercise Price (C$)**	**Stock Options (millions)**	**Weighted Average Exercise Price (C$)**
Outstanding, Beginning of Year	**29.6**	**39.74**	10.5	32.31
Granted under EnCana Plan	**6.3**	**47.98**	12.1	48.13
Granted under AEC Replacement Plan			13.1	32.01
Granted under Directors Plan	**0.1**	**47.87**	0.1	48.04
Exercised	**(5.5)**	**29.11**	(5.5)	25.20
Forfeited	**(1.7)**	**41.18**	(0.7)	43.81

Outstanding, End of Year	**28.8**	**43.13**	29.6	39.74
Exercisable, End of Year	**15.6**	**38.92**	17.7	34.10

	Outstanding Options			Exercisable Options	
As at December 31 **Range of Exercise Price (C$)**	**Number of Options Outstanding (millions)**	**Weighted Average Remaining Contractual Life (years)**	**Weighted Average Exercise Price (C$)**	**Number of Options Outstanding (millions)**	**Weighted Average Exercise Price (C$)**
13.50 to 19.99	1.5	0.9	18.86	1.5	18.86
20.00 to 24.99	1.3	1.5	22.38	1.3	22.38
25.00 to 29.99	2.2	1.5	26.49	2.2	26.49
30.00 to 43.99	1.3	2.2	38.89	1.2	38.52
44.00 to 53.00	22.5	3.7	47.93	9.4	47.63
	28.8	2.8	43.13	15.6	38.92

At December 31, 2003, there were 7.9 million Common Shares reserved for issuance under stock option plans (2002 12.8 million).

As described in Note 2, the Company recorded stock-based compensation expense in the Consolidated Statement of Earnings for stock options granted to employees and directors in 2003 using the fair-value method. Compensation expense has not been recorded in the Consolidated Statement of Earnings related to stock options granted prior to 2003. If the Company had applied the fair-value method to options granted prior to 2003, pro forma Net Earnings and Net Earnings per Common Share in 2003 would have been $2,326 million; $4.91 per common share basic; $4.85 per common share diluted (2002 $761 million; $1.82 per common share basic; $1.80 per common share diluted).

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:

For the years ended December 31	**2003**	**2002**
Weighted Average Fair Value of Options Granted *(C$)*	**$12.21**	$13.31
Risk-free Interest Rate	**3.87%**	4.29%
Expected Lives *(years)*	**3.00**	3.00
Expected Volatility	**0.33**	0.35
Annual Dividend per Share *(C$/common share)*	**$ 0.40**	$ 0.40

NOTE 16

COMPENSATION PLANS

A) Pensions

The most recent actuarial evaluation completed for the Company is dated December 31, 2003.

The Company sponsors both defined benefit and defined contribution plans providing pension and other retirement and post-employment benefits to substantially all of its employees.

For the years ended December 31	**2003**	**2002**	**2001**
Total expense for defined contribution plans	**$12**	$ 9	$ 6

Information about defined benefit post-retirement benefit plans, in aggregate, is as follows:

As at December 31	**2003**	**2002**
Accrued Benefit Obligation, Beginning of Year	**$167**	$ 85
Plan acquisition		55
Current service cost	**6**	3
Interest cost	**12**	8

Benefits paid	**(11)**	(5)
Actuarial loss	**13**	10
Contributions	**1**	
Special termination benefits		2
Changes as a result of curtailment		1
Plan amendments	**1**	8
Foreign exchange	**39**	
Accrued Benefit Obligation, End of Year	**$228**	$167

As at December 31	**2003**	**2002**
Fair Value of Plan Assets, Beginning of Year	**$117**	$ 84
Plan acquisition		53
Transfers to defined contribution plan		(6)
Actual return on plan assets	**14**	(10)
Employer contributions	**51**	1
Employees contributions	**1**	
Benefits paid	**(11)**	(5)
Foreign exchange	**31**	
Fair Value of Plan Assets, End of Year	**$203**	$117

As at December 31	**2003**	**2002**
Funded Status Plan Assets less than Benefit Obligation	**$(25)**	$(50)
Amounts Not Recognized		
Unamortized Net Actuarial Loss	**66**	51
Unamortized Past Service Cost	**13**	10
Net Transitional Asset	**(9)**	(9)
Accrued Benefit Asset	**$ 45**	$ 2

As at December 31	**2003**	**2002**
Prepaid Benefit Cost	**$53**	$ 15
Accrued Benefit Cost	**(8)**	(13)
Net Amount Recognized	**$45**	$ 2

Included in the above accrued benefit obligation and fair value of plan assets at year-end for EnCana Corporation are unfunded benefit obligations of $14 million related to the Company s other post retirement benefit plan. At the end of 2002, the Company had unfunded obligations of $34 million related to three of the Company s defined benefit pension plans and the other post retirement benefit plans.

The weighted average assumptions used to determine benefit obligations are as follows:

As at December 31	**2003**	**2002**
Discount Rate	**6.0%**	6.5%
Rate of Compensation Increase	**4.75%**	3.5%

The weighted average assumptions used to determine periodic expense are as follows:

For the years ended December 31	**2003**	**2002**
Discount Rate	**6.5%**	6.5%
Expected Long-term Rate of Return on Plan Assets		
Registered pension plans	**6.75%**	7.0%
Supplemental pension plans	**3.375%**	3.5%
Rate of Compensation Increase	**4.75%**	3.5%

The periodic expense for benefits is as follows:

For the years ended December 31	2003	2002	2001
Current Service Cost	**$ 6**	$ 3	$ 2
Interest Cost	**12**	8	5
Expected Return on Plan Assets	**(9)**	(8)	(6)
Amortization of Net Actuarial Loss	**4**	1	
Amortization of Transitional Obligation	**(2)**	(2)	(2)
Amortization of Past Service Cost	**1**	1	1
Curtailment Loss		1	
Special Termination Benefits		2	
Expense for Defined Contribution Plan	**12**	9	6
Net Benefit Plan Expense	**$24**	$15	$ 6

The average remaining service period of the active employees covered by the defined benefit pension plan is eight years. The average remaining service period of the active employees covered by the other retirement benefits plan is 13 years.

After the business combination transaction as described in Note 3, a number of employees were involuntarily terminated. Terminated members of the defined benefit pension plan, who were age 50 or above, could elect enhanced benefits under the registered pension plan. For pension accounting purposes, this resulted in special termination benefits being provided and a curtailment event that impacted some of the pension arrangements sponsored by the Company.

Assumed health care cost trend rates are as follows:

As at December 31	**2003**
Health care cost trend rate for next year	**10%**
Rate that the trend rate gradually trends to	**5%**
Year that the trend rate reaches the rate which it is expected to remain at	**2014**

Assumed health care cost trend rates have an effect on the amounts reported for the other benefit plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase	**One Percentage Point Decrease**
Effect on Total of Service and Interest Cost	$	$
Effect on Post Retirement Benefit Obligation	$ 2	$ (1)

The Company s pension plan asset allocations are as follows:

	Target Allocation %		**% of Plan Assets at December 31**		
Asset Category	**Normal**	**Range**	**2003**	**2002**	**Expected Long-term Rate of Return**
Domestic Equity	35	25-45	35	32	
Foreign Equity	30	20-40	29	31	
Bonds	30	20-40	27	27	
Real Estate and Other	5	0-20	9	10	

Total	100	100	100	6.75%

The expected rate of return on plan assets is based on historical and projected rates of return for each asset class in the plan investment portfolio. The objective of the asset allocation policy is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices.

The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investments, credit rating categories and foreign currency exposure. The Company expects to contribute $6 million to the plans in 2004. Contributions by the participants to the pension and other benefits plans were $1 million for the year ended December 31, 2003 (2002 nil). Estimated future payments for pension and other benefits are as follows:

2004	$ 12
2005	12
2006	13
2007	13
2008	14
2009 2013	84
Total	$148

B) Share Appreciation Rights

The Company has in place a program whereby certain employees are granted Share Appreciation Rights (SAR s) which entitle the employee to receive a cash payment equal to the excess of the market price of the Company s Common Shares at the time of exercise over the exercise price of the right. SAR s granted expire after five years.

The following tables summarize the information about the SAR s:

	2003		2002	
As at December 31	**Weighted Average Outstanding SAR's**	**Exercise Price ($)**	**Weighted Average Outstanding SAR's**	**Exercise Price ($)**
Canadian Dollar Denominated *(C$)*				
Outstanding, beginning of year	**2,284,901**	**35.56**		
Granted			600,000	38.35
Acquired April 5, in AEC acquisition			2,637,421	30.70
Exercised	**(1,101,987)**	**35.17**	(648,902)	27.67
Forfeited	**(7,844)**	**46.28**	(303,618)	39.08
Outstanding, end of year	**1,175,070**	**35.87**	2,284,901	35.56
Exercisable, end of year	**1,175,070**	**35.87**	2,284,901	35.56
U.S. Dollar Denominated *(US$)*				
Outstanding, beginning of year	**1,346,437**	**28.52**		
Acquired April 5, in AEC acquisition			1,711,095	28.32
Exercised	**(589,340)**	**27.91**	(223,703)	26.33
Forfeited	**(3,680)**	**30.73**	(140,955)	29.88
Outstanding, end of year	**753,417**	**28.98**	1,346,437	28.52
Exercisable, end of year	**753,417**	**28.98**	1,346,437	28.52

	SAR's Outstanding	
	Weighted Average	**Weighted**

As at December 31, 2003 Range of Exercise Price ($)	Number of SAR's	Remaining Contractual Life (years)	Average Exercise Price ($)
Canadian Dollar Denominated *(C$)*			
20.00 to 29.99	600,656	1.05	26.69
30.00 to 39.99	74,720	2.82	38.22
40.00 to 49.99	486,303	2.20	46.39
50.00 to 60.00	13,391	2.32	51.37
	1,175,070	1.65	35.87
U.S. Dollar Denominated *(US$)*			
20.00 to 29.99	336,408	1.75	27.10
30.00 to 40.00	417,009	1.83	30.49
	753,417	1.80	28.98

During the year, the Company recorded compensation costs of $12 million related to the outstanding SAR s (2002 - $4 million).

C) Deferred Share Units

The Company has in place a program whereby Directors and certain key employees are issued Deferred Share Units (DSU s), which are equivalent in value to a Common Share of the Company. DSU s granted to Directors vest immediately. DSU s granted to Senior Executives in 2003 vest over a three year period.

The following table summarizes the information about the DSU s:

As at December 31	2003 Outstanding DSU s	2003 Average Share Price (C$)	2002 Outstanding DSU s	2002 Average Share Price (C$)
Outstanding, Beginning of Year	**309,167**	**48.69**		
Acquired April 5, in AEC acquisition			29,631	47.29
Granted, Directors	**37,149**	**48.56**	22,500	49.75
Granted, Senior Executives	**1,976**	**49.91**	260,000	49.75
Exercised	**(29,042)**	**48.04**	(2,964)	48.00
Outstanding, End of Year	**319,250**	**48.68**	309,167	48.69
Exercisable, End of Year	**80,645**	**48.68**	49,167	48.20

During the year, the Company recorded compensation costs of $4 million related to the outstanding DSU s (2002 $4 million).

D) Performance Share Units

During 2003, the Company put in place a program whereby certain employees may be granted Performance Share Units (PSU s) which entitle the employee to receive a cash payment, upon vesting, equal to the value of one Common Share of the Company. Each PSU vests at the end of a three year period. Their ultimate value will depend upon EnCana s performance measured over the three year period. Performance will be measured by total stock price change plus dividends relative to a fixed North American oil and gas comparison group. If EnCana s performance is below the median of the comparison group, the units awarded will be forfeited. If EnCana s performance is at or above the median of the comparison group, the value of the PSU s shall be determined by EnCana s relative ranking, with payments ranging from one to two times the market price of an equivalent number of EnCana Common Shares.

The following table summarizes the information about the PSU s:

Average

As at December 31, 2003	**Outstanding PSU s**	**Share Price (C$)**
Outstanding, Beginning of Year		
Granted	**128,893**	**46.52**
Exercised		
Forfeited	**(2,610)**	**46.52**
Outstanding, End of Year	**126,283**	**46.52**
Exercisable, End of Year		

During the year, the Company recorded compensation costs of $1 million related to the outstanding PSU s (2002 $nil).

NOTE 17

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

As at December 31	**Note**	**2003**	**2002**
Commodity Price Risk	*A*		
Crude oil		**$(279)**	$ (77)
Natural gas		**57**	191
Gas storage optimization		**(25)**	(27)
Natural gas liquids			(2)
Power		**4**	(2)
Foreign Currency Risk	*B*	**7**	(57)
Interest Rate Risk	*C*	**44**	39
		$(192)	$ 65

A) Commodity Price Risk

Crude Oil

As at December 31, 2003, the Company s oil risk management activities had an unrecognized loss of $279 million. The contracts were as follows:

	Notional Volumes (bbls/d)	**Term**	**Average Price (US$/bbl)**	**Unrecognized Gain/(Loss)**
Fixed WTI NYMEX Price	62,500	2004	23.13	$ (162)
Collars on WTI NYMEX	62,500	2004	20.00-25.69	(115)
3-way Put Spread	10,000	2005	20.00/25.00/28.77	(3)
				(280)
Crude Oil Marketing Financial Positions (1)				(2)
Crude Oil Marketing Physical Positions (1)				3
				$ (279)

(1) The crude oil marketing activities are part of the daily ongoing operations of the Company s proprietary production management.

Natural Gas

At December 31, 2003, the gas risk management activities had an unrecognized gain of $57 million. The contracts were as follows:

	Notional Volumes (MMcf/d)	Physical/ Financial	Term	Price		Unrecognized Gain/(Loss)
Fixed Price Contracts						
Sales Contracts						
Fixed AECO price	453	Financial	2004	6.20	C$/mcf	$ 5
NYMEX Fixed price	732	Financial	2004	5.13	US$/mcf	(86)
Chicago Fixed price	40	Financial	2004	5.41	US$/mcf	(1)
AECO Collars	71	Financial	2004	5.34-7.52	C$/mcf	2
NYMEX Collars	50	Physical	2004	2.46-4.90	US$/mcf	(16)
NYMEX Collars	50	Physical	2005	2.46-4.90	US$/mcf	(13)
NYMEX Collars	46	Physical	2006-2007	2.46-4.90	US$/mcf	(20)
Basis Contracts						
Sales Contracts						
Fixed NYMEX to AECO basis	343	Financial	2004	(0.54)	US$/mcf	22
Fixed NYMEX to Rockies basis	255	Financial	2004	(0.48)	US$/mcf	18
Fixed NYMEX to Rockies basis	413	Physical	2004	(0.50)	US$/mcf	26
Fixed NYMEX to San Juan basis	60	Financial	2004	(0.63)	US$/mcf	1
Fixed NYMEX to San Juan basis	50	Physical	2004	(0.64)	US$/mcf	1
Fixed NYMEX to CIG basis	38	Financial	2004	(0.10)	US$/mcf	
Fixed NYMEX to AECO basis	877	Financial	2005	(0.66)	US$/mcf	6
Fixed NYMEX to Rockies basis	283	Financial	2005	(0.49)	US$/mcf	16
Fixed NYMEX to Rockies basis	393	Physical	2005	(0.47)	US$/mcf	26
Fixed NYMEX to San Juan basis	75	Financial	2005	(0.63)	US$/mcf	(1)
Fixed NYMEX to San Juan basis	50	Physical	2005	(0.64)	US$/mcf	(1)
Fixed NYMEX to CIG basis	50	Financial	2005	(0.10)	US$/mcf	1
Fixed NYMEX to AECO basis	402	Financial	2006-2008	(0.65)	US$/mcf	24
Fixed NYMEX to Rockies basis	175	Financial	2006-2008	(0.57)	US$/mcf	13
Fixed NYMEX to Rockies basis	207	Physical	2006-2007	(0.49)	US$/mcf	22
Fixed NYMEX to San Juan basis	62	Financial	2006	(0.62)	US$/mcf	(1)
Fixed NYMEX to San Juan basis	42	Physical	2006	(0.64)	US$/mcf	(1)
Fixed NYMEX to CIG basis	31	Financial	2006-2007	(0.10)	US$/mcf	
Purchase Contracts						
Fixed NYMEX to AECO basis	47	Financial	2004	(0.80)	US$/mcf	(3)

Gas Marketing Financial Positions [1]	(2)
Gas Marketing Physical Positions [1]	19
	$ 57

(1) The gas marketing activities are part of the daily ongoing operations of the Company s proprietary production management.

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 nine months to manage the price volatility of the corresponding physical transactions and inventories.

As at December 31, 2003, the unrecognized loss on gas storage optimization risk management activities was $25 million, which was as follows:

	Notional Volumes (bcf)	Price (US$/mcf)	Unrecognized Gain/(Loss)
Financial Instruments			
Purchases	286.7	5.63	$ 109
Sales	312.4	5.69	(132)
			(23)
Physical Contracts			(2)
			$ (25)

At December 31, 2003, the unrecognized loss on physical contracts of $2 million was more than offset by unrealized gains on physical inventory in storage.

Power

As part of the business combination with AEC, the Company acquired two electricity contracts, one expiring in 2003 and the other in 2005. These contracts were originally entered into as part of an electricity cost management strategy. At December 31, 2003, the unrecognized gain on the remaining contract was $4 million.

B) Foreign Currency Risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the Company s operating and financial results. The Company has significant operations outside of Canada, which are subject to these foreign exchange risks.

The following forward foreign currency exchange contracts were in place to hedge future commodity revenue streams as at December 31, 2003:

	Amount Hedged (US$)	Average Exchange Rate (C$/US$)	Unrecognized Gain
2004	$88	0.715	$ 7

C) Interest Rate Risk

The Company has entered into various derivative contracts to manage the Company s interest rate exposure on debt instruments. The impact of these transactions is described in Note 7.

The unrecognized gains on the outstanding financial instruments as at December 31, 2003 were:

	Unrecognized Gain
5.80% Medium Term Notes	$ 12
7.50% Medium Term Notes	9
8.40% Medium Term Notes	6
8.75% Debenture	17
	$ 44

At December 31, 2003, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $22 million (2002 $16 million).

D) Fair Value of Financial Assets and Liabilities

The fair values of financial instruments that are included in the Consolidated Balance Sheet, other than long-term borrowings, approximate their carrying amount due to the short-term maturity of those instruments.

The estimated fair values of long-term borrowings have been determined based on market information where available, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Company at year end.

	2003		2002	
As at December 31	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Financial Assets				
Cash and cash equivalents	**$ 148**	**$ 148**	$ 116	$ 116
Accounts receivable	**1,367**	**1,367**	1,258	1,258
Financial Liabilities				
Accounts payable, income taxes payable	**$1,644**	**$1,644**	$1,458	$1,458
Long-term debt	**6,375**	**6,767**	5,185	5,461

E) Credit Risk

A substantial portion of the Company s accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. The Board has approved a credit policy governing the Company s credit portfolio and procedures are in place to ensure adherence to this policy. With respect to counterparties to financial instruments, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

The majority of the proceeds from the sale of the Company s crude oil production in Ecuador are received from one marketing company. Accounts receivable on these sales are supported by letters of credit issued by a major international financial institution. All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

NOTE 18

SUPPLEMENTARY INFORMATION

A) Per Share Amounts

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

For the years ended December 31	**2003**	**2002**	**2001**
Weighted Average Common Shares Outstanding Basic	**474.1**	417.8	255.6
Effect of Stock Options and Other Dilutive Securities	**5.6**	4.8	3.2
Weighted Average Common Shares Outstanding Diluted	**479.7**	422.6	258.8

B) Net Change in Non-Cash Working Capital from Continuing Operations

For the years ended December 31	2003	2002	2001
Operating Activities			
Accounts receivable and accrued revenues	**$ 232**	$(253)	$ (8)
Inventories	**(241)**	(56)	19
Accounts payable and accrued liabilities	**(118)**	(10)	32
Income taxes payable	**46**	(534)	307
	$ (81)	$(853)	$350
Investing Activities			
Accounts payable and accrued liabilities	**$ (83)**	$ 186	$ 55
Financing Activities			
Accounts payable and accrued liabilities	**$ 2**	$ (7)	$ 1

C) Supplementary Cash Flow Information

For the years ended December 31	2003	2002	2001
Interest Paid	**$ 288**	$265	$47
Income Taxes (Received) Paid	**$(195)**	$646	$22

D) Corporate Reorganization of Canadian Pacific Limited

On February 13, 2001, CPL announced a reorganization whereby its 85% interest in PanCanadian Petroleum Limited (predecessor to PanCanadian Energy Corporation) would be distributed to CPL common shareholders by a Plan of Arrangement. Following shareholder and court approvals, the Plan of Arrangement was implemented on October 1, 2001, and PanCanadian Petroleum Limited became a wholly owned subsidiary of the new public company, PanCanadian Energy Corporation. Effective January 1, 2002, these companies were amalgamated and continued under the name of PanCanadian Energy Corporation.

As part of the CPL reorganization, the Company paid a Special Dividend of C$1,180 million ($754 million), or C$4.60 per Common Share ($2.94 per Common Share), on September 14, 2001. The amounts shown as dividends on the Consolidated Statements of Retained Earnings and Cash Flows include both the Special Dividend and the regular quarterly dividend.

E) Related Party Transactions

In 2001, the Company paid C$50 million ($33 million) relating to a previously contracted purchase price adjustment in respect of C$200 million of capital losses acquired in 1997 from a subsidiary of CPL (the majority shareholder of the Company prior to the corporate reorganization as described previously). The purchase price adjustment, which was contingent on certain economic events, has been recorded as a charge to retained earnings.

Prior to the previously described corporate reorganization of CPL, the Company purchased materials and utilized services from other companies with which it was affiliated. All such transactions were conducted on an arm s length basis and were not material in relation to the Company s overall activities.

NOTE 19

COMMITMENTS AND CONTINGENCIES

Commitments

As at December 31, 2003	**2004**	**2005**	**2006**	**2007**	**2008**	**Thereafter**	**Total**
Pipeline Transportation	$ 449	$383	$334	$314	$313	$2,116	**$3,909**
Purchases of Goods and Services	297	149	76	12	2		**536**
Product Purchases	142	47	32	25	24	157	**427**
Operating Leases	44	43	42	40	34	211	**414**
Capital Commitments	259	27	16			38	**340**
Total	$1,191	$649	$500	$391	$373	$2,522	**$5,626**
Product Sales	$ 502	$113	$ 69	$ 62	$ 65	$ 359	**$1,170**

In addition to the above, the Company has made commitments related to its risk management program (see Note 17).

Contingencies

Legal Proceedings

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

Discontinued Merchant Energy Operations

In July 2003, the Company s indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. (WD), concluded a settlement with the U.S. Commodity Futures Trading Commission (CFTC) of a previously disclosed CFTC investigation. The investigation related to alleged inaccurate reporting of natural gas trading information during 2000 and 2001 by former employees of WD s now discontinued Houston-based merchant energy trading operation to energy industry publications that compiled and reported index prices. All Houston-based merchant energy trading operations were discontinued following the business combination transaction in 2002. Under the terms of the settlement, WD agreed to pay a civil monetary penalty in the amount of $20 million without admitting or denying the findings in the CFTC s order.

The Company and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California and, along with other energy companies, are defendants in several other lawsuits in California (many of which are class actions) and three class action lawsuits filed in the United States District Court in New York. Several of the California class action lawsuits were transferred by the Judicial Panel on Multidistrict Litigation on a consolidated basis to the Nevada District Court and the New York lawsuits were consolidated in New York District Court by the plaintiff s application. The California lawsuits relate to sales of natural gas in California from 1999 to the present and contain allegations that the defendants engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws to artificially raise the price of natural gas through various means including the illegal sharing of price information through online trading, price indices and wash trading. The New York lawsuits claim that the defendants alleged manipulation of natural gas price indices resulted in higher prices of natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. The Gallo complaint claims damages in excess of $30 million, before potential trebling under California laws. As is customary, the class actions do not specify the amount of damages claimed.

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

Other

The Company is responsible for the retirement of long-lived assets related to its oil and gas properties and Midstream facilities at the end of their useful lives. The Company has recognized a liability of $430 million based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

The operations of the Company are complex, and related tax interpretations, regulations and legislation in the various jurisdictions that the Company operates in are continually changing. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

NOTE 20

UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP) which, in most respects, conform to accounting principles generally accepted in the United States (U.S. GAAP). The significant differences between Canadian and U.S. GAAP are described in this note.

Reconciliation of Net Earnings Under Canadian GAAP to U.S. GAAP

For the years ended December 31	**Note**	**2003**	**2002**	**2001**
Net Earnings Canadian GAAP		**$2,360**	$ 812	$ 854
Less:				
Net Earnings from Discontinued Operations Canadian GAAP		**193**	77	22
Net Earnings from Continuing Operations Canadian GAAP		**2,167**	735	832
Increase (Decrease) under U.S. GAAP:				
Revenues, net of royalties	*B*	**(205)**	(174)	99
Depreciation, depletion and amortization	*A,G*	**14**	(41)	(37)
Accretion of asset retirement obligation	*G*		13	8
Additional depletion	*A*			(94)

Interest expense, net	*B*	**70**	126	(11)
Stock-based compensation	*C*	**(1)**	(3)	(10)
Income taxes	*E,G*	**45**	21	6
Net Earnings from Continuing Operations U.S. GAAP		**2,090**	677	793
Net Earnings from Discontinued Operations U.S. GAAP		**193**	77	22
Net Earnings before change in accounting policy U.S. GAAP		**2,283**	754	815
Cumulative effect of change in accounting policy, net of income tax	*G*	**66**		
Net Earnings U.S. GAAP		**$2,349**	$ 754	$ 815
Net Earnings per Common Share before change in accounting policy U.S. GAAP				
Basic		**$ 4.82**	$ 1.81	$ 3.19
Diluted		**$ 4.76**	$ 1.78	$ 3.15
Net Earnings per Common Share including cumulative effect of change in accounting policy U.S. GAAP				
Basic		**$ 4.95**	$ 1.81	$ 3.19
Diluted		**$ 4.90**	$ 1.78	$ 3.15

Consolidated Statement of Earnings U.S. GAAP

For the years ended December 31	Note	2003	2002	2001
Revenues, Net of Royalties	*B*	**$10,011**	$6,102	$3,343
Expenses				
Production and mineral taxes		**189**	119	77
Transportation and selling		**545**	364	111
Operating		**1,297**	813	448
Purchased product		**3,455**	2,200	739
Depreciation, depletion and amortization	*A,G*	**2,208**	1,345	641
Administrative	*C*	**174**	122	64
Interest, net	*B*	**217**	164	45
Accretion of asset retirement obligation	*G*	**19**		
Foreign exchange (gain) loss		**(601)**	(14)	12
Stock-based compensation		**18**		
Gain on corporate disposition			(33)	
Net Earnings Before Income Tax		**2,490**	1,022	1,206
Income tax expense	*E*	**400**	345	413
Net Earnings from Continuing Operations U.S. GAAP		**2,090**	677	793
Net Earnings from Discontinued Operations U.S. GAAP		**193**	77	22
Net Earnings before change in accounting policy U.S. GAAP		**$ 2,283**	$ 754	$ 815
Cumulative effect of change in accounting policy, net of tax	*G*	**66**		
Net Earnings U.S. GAAP		**$ 2,349**	$ 754	$ 815
Net Earnings from Continuing Operations per Common Share - U.S. GAAP				
Basic		**$ 4.41**	$ 1.62	$ 3.10
Diluted		**$ 4.36**	$ 1.60	$ 3.06
Net Earnings per Common Share before change in accounting policy U.S. GAAP				
Basic		**$ 4.82**	$ 1.81	$ 3.19
Diluted		**$ 4.76**	$ 1.78	$ 3.15
Net Earnings per Common Share including cumulative effect of change in accounting policy U.S. GAAP				
Basic		**$ 4.95**	$ 1.81	$ 3.19
Diluted		**$ 4.90**	$ 1.78	$ 3.15

Statement of Other Comprehensive Income

For the years ended December 31	**Note**	**2003**	**2002**	**2001**
Net Earnings U.S. GAAP		**$2,349**	$754	$ 815
Adoption of FAS 133, net of tax	*B,F*			(53)
Change in Fair Value of Financial Instruments	*B,F*	**4**	(7)	49
Foreign Currency Translation Adjustment	*D*	**1,046**	136	(210)
Other		**6**	(6)	
Other Comprehensive Income		**$3,405**	$877	$ 601

Condensed Consolidated Balance Sheet

As at December 31	Note	2003 As Reported	2003 U.S. GAAP	2002 As Reported	2002 U.S. GAAP
Assets					
Current Assets		**$ 2,088**	**$ 2,088**	$ 3,810	$ 3,821
Financial Assets	*B*		**145**		127
Property, Plant and Equipment, net	*A,G*	**19,545**	**19,419**	14,247	14,038
Investments and Other Assets	*B*	**566**	**569**	292	299
Goodwill		**1,911**	**1,911**	1,563	1,563
		$24,110	**$24,132**	$19,912	$19,848
Liabilities and Shareholders Equity					
Current Liabilities		**$ 1,931**	**$ 1,931**	$ 2,692	$ 2,705
Financial Liabilities	*B*		**380**		208
Long-Term Debt		**6,088**	**6,088**	5,051	5,051
Other Liabilities	*B*	**21**	**8**	54	53
Asset Retirement Obligation	*G*	**430**	**430**	309	303
Future Income Taxes	*E,G*	**4,362**	**4,223**	3,088	2,991
		12,832	**13,060**	11,194	11,311
Share Capital	*C*	**5,305**	**5,318**	5,511	5,524
Share Options, net		**55**	**55**	84	84
Paid in Surplus		**18**	**18**	51	51
Retained Earnings		**5,276**	**5,076**	3,523	3,325
Foreign Currency Translation Adjustment	*D*	**624**		(451)	
Accumulated Other Comprehensive Income			**605**		(447)
		11,278	**11,072**	8,718	8,537
		$24,110	**$24,132**	$19,912	$19,848

Condensed Consolidated Statement of Cash Flows U.S. GAAP

For the years ended December 31	**2003**	**2002**	**2001**
Cash From Operating Activities			
Net earnings from continuing operations	**$ 2,090**	$ 677	$ 793
Depreciation, depletion and amortization	**2,208**	1,345	641
Future income taxes	**456**	383	89
Accretion of asset retirement obligation	**19**		
Foreign exchange (gain) loss	**(545)**	(23)	35
Unrealized loss (gain) on risk management contracts	**135**	48	(88)
Other	**57**	(163)	(7)
Cash flow from continuing operations	**4,420**	2,267	1,463
Cash flow from discontinued operations	**39**	152	31
Cash Flow	**4,459**	2,419	1,494
Net change in other assets and liabilities	**(84)**	(17)	(40)
Net change in non-cash working capital from continuing operations	**(81)**	(853)	350
Net change in non-cash working capital from discontinued operations	**17**	64	(29)
	$ 4,311	$ 1,613	$ 1,775
Cash Used in Investing Activities	**$ (3,729)**	$ (2,595)	$ (1,092)
Cash (Used in) From Financing Activities	**$ (540)**	$ 491	$ (214)

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Notes:

A) Full Cost Accounting

The full cost method of accounting for crude oil and natural gas operations under Canadian and U.S. GAAP differ in the following respect. Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum of the present value, discounted at 10%, of the estimated unescalated future net operating revenue from proved reserves plus unimpaired unproved property costs less future development costs, related production costs and applicable taxes. Under Canadian GAAP, a similar ceiling test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize escalated pricing to determine whether impairment exists. However, the impaired amount is measured using the fair value of reserves.

In computing its consolidated net earnings for U.S. GAAP purposes, the Company recorded additional depletion in 2001 and certain years prior to 2001 as a result of the application of the ceiling test. These charges were not required under the Canadian GAAP ceiling tests. As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes.

B) Derivative Instruments and Hedging

For U.S. GAAP, the Company adopted Statement of Financial Accounting Standards (FAS) 133 effective January 1, 2001. FAS 133 requires that all derivatives be recorded on the balance sheet as either assets or liabilities at their fair value. Changes in the derivative s fair value are recognized in current period earnings unless specific hedge accounting criteria are met. Management has currently not designated any of the financial instruments as hedges for U.S. GAAP purposes under FAS 133.

Realized and unrealized gain/(loss) on derivatives related to:

For the years ended December 31	2003	2002	2001
Commodity Prices (Revenues, net of royalties)	**$(205)**	$(174)	$ 99
Interest and Currency Swaps (Interest, net)	**70**	126	(11)
Total Unrealized (Loss) Gain	**$(135)**	$ (48)	$ 88

The adoption of FAS 133 at January 1, 2001 resulted in recognition of derivative assets with a fair value of $572 million, derivative liabilities with a fair value of $628 million, a $78 million ($53 million, net of tax) charge to other comprehensive income and a $22 million ($15 million, net of tax) increase to net earnings under U.S. GAAP.

As at December 31, 2003, it is estimated that over the following 12 months, $4 million ($2 million, net of tax) will be reclassified into net earnings from other comprehensive income.

C) Stock-based Compensation CPL Reorganization

Under Canadian GAAP, compensation costs have been recognized in the financial statements for stock options granted to employees and Directors in 2003. For the effect of stock-based compensation on the Canadian GAAP financials, which would be the same adjustment under U.S. GAAP, see Note 15.

Under FASB Interpretation No. 44 Accounting for Certain Transactions involving Stock Compensation , compensation expense must be recorded if the intrinsic value of the stock options is not exactly the same immediately before and after an equity restructuring. As part of the Corporate reorganization, as described in Note 18, an equity restructuring occurred which resulted in CPL stock options being replaced with stock options granted by PanCanadian as described in Note 15. This resulted in the replacement options having a different intrinsic value after the restructuring than prior to the restructuring. Canadian GAAP does not require revaluation of these options.

D) Foreign Currency Translation Adjustments

U.S. GAAP requires gains or losses arising from the translation of self-sustaining operations to be included in other comprehensive income. Canadian GAAP requires these amounts to be recorded in Shareholders Equity.

E) Future Income Taxes

Under U.S. GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted tax rates.

The future income tax adjustments included in the Reconciliation of Net Earnings under Canadian GAAP to U.S. GAAP and the Condensed Consolidated Balance Sheet include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

The following table provides a reconciliation of the statutory rate to the actual tax rate:

For the years ended December 31	2003	2002	2001
Using Canadian GAAP			
Net earnings before income tax	**$2,612**	$1,101	$1,251
Canadian Statutory Rate	**40.95%**	42.3%	42.8%
Expected Income Tax	**$1,070**	$ 467	$ 536
Effect on Taxes Resulting from:			
Non-deductible Canadian crown payments	**231**	147	74
Canadian resource allowance	**(258)**	(200)	(167)
Large corporations tax	**27**	23	9
Statutory rate differences	**(50)**	(36)	(12)
Effect of tax rate changes	**(359)**	(20)	(53)
Non-taxable capital gains	**(119)**	(9)	
Previously unrecognized capital losses	**(119)**		
Other	**22**	(6)	32
	445	366	419
U.S. GAAP Adjustments to Net Earnings Before Income Tax	**(122)**	(79)	(45)
Expected Income Tax	**(50)**	(33)	(19)
Depletion			2
Other	**5**	12	11
	(45)	(21)	(6)
Income Tax U.S. GAAP	**$ 400**	$ 345	$ 413
Effective Tax Rate	**16.1%**	33.8%	34.2%

The net deferred income tax liability is comprised of:

As at December 31	2003	2002
Future Tax Liabilities Property, plant and equipment in excess of tax values	**$3,416**	$2,714
Timing of partnership items	**1,162**	513

Future Tax Assets		
Net operating losses carried forward	**(174)**	(203)
Other	**(181)**	(33)
Net Future Income Tax Liability	**$4,223**	$2,991

F) Other Comprehensive Income

U.S. GAAP requires the disclosure, as other comprehensive income, of changes in equity during the period from transaction and other events from non-owner sources. Canadian GAAP does not require similar disclosure. Other comprehensive income arose from the transition adjustment resulting from the January 1, 2001 adoption of FAS 133. At December 31, 2003, accumulated other comprehensive income related to these items was a loss of $9 million, net of tax.

G) Asset Retirement Obligation

The Company early adopted the Canadian accounting standard for asset retirement obligations, as outlined in the CICA handbook section 3110. This standard is equivalent to U.S. FAS 143, Accounting for Asset Retirement Obligations, which was effective for fiscal periods beginning on or after January 1, 2003. Early adopting the Canadian standard eliminated a U.S. GAAP reconciling item in respect to accounting for the obligation, however a difference is created in how the transition amounts are disclosed.

U.S. GAAP requires the cumulative impact of a change in an accounting policy be presented in the current year Consolidated Statement of Earnings and prior periods not be restated. The following table illustrates the pro forma impact on the Company s financial results under U.S. GAAP if the prior periods had been restated:

As at and for the years ended December 31	As Reported	Change	As Restated
2002 Consolidated Balance Sheet			
Assets			
Current assets	$ 3,821	$ (11)	$ 3,810
Property, plant and equipment, net	14,038	94	14,132
Liabilities			
Current liabilities	$ 2,705	$ (13)	$ 2,692
Other liabilities & asset retirement obligation	356	6	362
Future income taxes	2,991	23	3,014
Shareholders Equity			
Retained earnings	$ 3,325	$ 66	$ 3,391
Foreign currency translation adjustment	(447)	1	(446)
2002 Consolidated Statement of Earnings			
Net Earnings	$ 754	$ 34	$ 788
Net Earnings per Common Share Diluted	$ 1.78	$ 0.08	$ 1.86
2001 Consolidated Statement of Earnings			
Net Earnings	$ 815	$ 22	$ 837
Net Earnings per Common Share Diluted	$ 3.15	$ 0.08	$ 3.23

H) Recent Accounting Pronouncements

During 2003, the following new standard was issued:

Variable Interest Entities

In December 2003, the Financial Accounting Standards Board (FASB) in the United States issued Interpretation Number 46R Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51 . The standard mandates that variable interest entities be consolidated by their primary beneficiary. The standard is effective the first reporting period ending after March 15, 2004 for all entities with the exception of special purpose entities as defined in prior accounting guidance. The standard is effective for the first period ending after December 15, 2003 for previously defined special purpose entities. In Canada, the Accounting Standards Board (AcSB) has suspended the effective dates for Accounting Guideline AcG15, Consolidation of Variable Interest Entities in order to amend the guideline to harmonize with the corresponding U.S. guidance. The AcSB plans to issue an exposure draft in the immediate future with an effective period beginning on or after November 1, 2004.

At December 31, 2003, the Company did not have any variable interest in variable-interest entities.

ADDITIONAL DISCLOSURE

Certifications and Disclosure Regarding Controls and Procedures.

(a) Certifications. See Exhibits 99.1 and 99.2 to this Annual Report on Form 40-F.

(b) Disclosure Controls and Procedures. As of the end of the registrant s fiscal year ended December 31, 2003, an evaluation of the effectiveness of the registrant s disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)) was carried out by the registrant s principal executive officer and principal financial officer. Based upon that evaluation, the registrant s principal executive officer and principal financial officer have concluded that as of the end of that fiscal year, the registrant s disclosure controls and procedures are effective to ensure that information required to be disclosed by the registrant in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms.

It should be noted that while the registrant s principal executive officer and principal financial officer believe that the registrant s disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the registrant s disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

(c) Changes in Internal Control Over Financial Reporting. During the fiscal year ended December 31, 2003, there were no changes in the registrant s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the registrant s internal control over financial reporting.

Notices Pursuant to Regulation BTR.

None.

Audit Committee Financial Expert.

The registrant s board of directors has determined that Jane L. Peverett, a member of the registrant s audit committee, qualifies as an audit committee financial expert (as such term is defined in Form 40-F).

Code of Ethics.

The registrant has adopted a code of ethics (as that term is defined in Form 40-F), entitled the Business Conduct and Ethics Practice (the Code of Ethics), that applies to its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions (together, the Financial Supervisors).

The Code of Ethics is available for viewing on the registrant s website at www.encana.com.

Since the adoption of the Code of Ethics, there have not been any amendments to the Code of Ethics or waivers, including implicit waivers, from any provision of the Code of Ethics.

Principal Accountant Fees and Services.

The following table provides information about the fees billed to the registrant for professional services rendered by PricewaterhouseCoopers LLP during fiscal 2003 and 2002:

(US$ thousands)	**2003**	**2002**
Audit Fees	$ 1,977	$ 1,556
Audit-Related Fees	127	158
Tax Fees	1,408	1,491
All Other Fees	26	592
Total	$ 3,538	$ 3,797

Audit Fees. Audit fees consist of fees for the audit of the registrant s annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

Audit-Related Fees. Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of the registrant s financial statements and are not reported as Audit Fees. During fiscal 2003 and 2002, the services provided in this category included due diligence reviews in connection with acquisitions, research of accounting and audit-related issues, review of reserves disclosure and the completion of audits required by contracts to which the registrant is a party.

Tax Fees. Tax fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal 2003 and 2002, the services provided in this category included assistance and advice in relation to the preparation of corporate income tax returns, expatriate tax services and, in 2002 only, shareholder tax assistance.

All Other Fees. During fiscal 2003, the services provided in this category included the review of the registrant s Corporate Responsibility Report and the payment of maintenance fees associated with a working paper documentation package used by the registrant s internal audit group. During fiscal 2002, the services provided in this category included information technology consulting services that were provided prior to the enactment of the Sarbanes-Oxley Act of 2002 and the adoption of rules thereunder.

Pre-Approval Policies and Procedures.

(a) The registrant has adopted the following policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by PricewaterhouseCoopers LLP:

The audit committee of the board of directors has established a budget for the provision of a specified list of audit and permitted non-audit services that the audit committee believes to be typical, recurring or otherwise likely to be provided by PricewaterhouseCoopers LLP. The budget generally covers the period between the adoption of the budget and the next meeting of the audit committee, but at the option of the audit committee it may cover a longer or shorter period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that (i) the audit committee knows precisely what services it is being asked to pre-approve and (ii) it is not necessary for any member of management to make a judgment as to whether a proposed service fits within the pre-approved services.

Subject to the next paragraph, the audit committee has delegated authority to the Chairman of the audit committee (or if the Chairman is unavailable, any other member of the Committee) to pre-approve the provision of permitted services by PricewaterhouseCoopers LLP and not otherwise pre-approved by the audit committee, including the fees and terms of the proposed services (Delegated Authority). Any required determination about the Chairman s unavailability is required to be made by the good faith judgment of the applicable other member(s) of the audit committee after considering all facts and circumstances deemed by such member(s) to be relevant. All pre-approvals granted pursuant to Delegated Authority must be presented by the member(s) who granted the pre-approvals to the full audit committee at its next meeting.

The fees payable in connection with any particular service to be provided by PricewaterhouseCoopers LLP that has been pre-approved pursuant to Delegated Authority (i) may not exceed Cdn.$200,000, in the case of pre-approvals granted by the Chairman of the audit committee, and (ii) may not exceed Cdn.$50,000, in the case of pre-approvals granted by any other member of the audit committee.

All proposed services or the fees payable in connection with such services that have not already been pre-approved must be pre-approved by either the audit committee or pursuant to Delegated Authority. Prohibited services may not be pre-approved by the audit committee or pursuant to Delegated Authority.

(b) Of the fees reported in this Annual Report on Form 40-F under the heading Principal Accountant Fees and Services , US$35,300 of the fees billed by PricewaterhouseCoopers LLP in respect of tax services were approved by the audit committee of the board of directors of the registrant pursuant to the *de minimus* exception provided by Section (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

Off-Balance Sheet Arrangements.

The required disclosure is included in the section of this Annual Report on Form 40-F entitled Principal Documents , under the heading Off Balance Sheet Arrangements in the registrant s Management s Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2003.

Tabular Disclosure of Contractual Obligations.

The required disclosure is included in the section of this Annual Report on Form 40-F entitled Principal Documents , under the heading Contractual Obligations and Contingencies in the registrant s Management s Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2003.

Identification of the Audit Committee.

The registrant has a separately-designated standing audit committee established in accordance with section 3(a)(58)(A) of the Exchange Act. The members of the audit committee are: Patrick D. Daniel, William R. Fatt, Barry W. Harrison, Dale A. Lucas, Jane L. Peverett, James M. Stanford and David P. O Brien (ex officio).

Disclosure Pursuant to the Requirements of the New York Stock Exchange.

Presiding Director at Meetings of Non-Management Directors

The registrant schedules regular executive sessions in which the registrant s non-management directors (as that term is defined in the rules of the New York Stock Exchange) meet without management participation. Mr. David P. O Brien serves as the presiding director (the Presiding Director) at such sessions. Each of the registrant s non-management directors is unrelated as such term is used in the rules of the Toronto Stock Exchange.

Communication with Non-Management Directors

Shareholders may send communications to the registrant s non-management directors by writing to the Presiding Director, c/o Kerry D. Dyte, General Counsel and Corporate Secretary, EnCana Corporation, 1800, 855 2nd Street S.W., Calgary, Alberta, Canada, T2P 2S5. Communications will be referred to the Presiding Director for appropriate action. The status of all outstanding concerns addressed to the Presiding Director will be reported to the board of directors as appropriate.

Corporate Governance Guidelines

According to Section 303A.09 of the NYSE Listed Company Manual, a listed company must adopt and disclose a set of corporate governance guidelines with respect to specified topics. Such guidelines are required to be posted on the listed company s website. The registrant operates under corporate governance principles that are consistent with the requirements of Section 303A.09 of the NYSE Listed Company Manual, and which are described under the heading Statement of Corporate Governance Practices in the registrant s Information Circular in connection with its 2004 Annual Meeting. However, the registrant has not codified its corporate governance principles into formal guidelines in order to post them on its website.

Board Committee Mandates

The Mandates of the registrant s audit committee, human resources and compensation committee, and nominating and corporate governance committee are each available for viewing on the registrant s website at www.encana.com, and are available in print to any shareholder who requests them. Requests for copies of these documents should be made by contacting: Kerry D. Dyte, General Counsel and Corporate Secretary, EnCana Corporation, 1800, 855 2nd Street S.W., P.O. Box 2850, Calgary, Alberta, Canada T2P 2S5. Alternatively, requests for these documents may be made by contacting the registrant s Corporate Development Department at (403) 645-2000 (Fax: (403) 645-4617).

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking.

The registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Securities and Exchange Commission (the Commission) staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

B. Consent to Service of Process.

The Company has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

Any change to the name or address of the agent for service of process of the registrant shall be communicated promptly to the Securities and Exchange Commission by an amendment to the Form F-X referencing the file number of the relevant registration statement.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 5, 2004.

EnCana Corporation

By: /s/ Thomas G. Hinton
Name: Thomas G. Hinton
Title: Treasurer

By: /s/ Gerald T. Ince
Name: Gerald T. Ince
Title: Assistant Treasurer

EXHIBIT INDEX

Exhibit	Description
99.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934
99.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934
99.3	Section 1350 Certification of Chief Executive Officer
99.4	Section 1350 Certification of Chief Financial Officer
99.5	Consent of PricewaterhouseCoopers LLP
99.6	Consent of McDaniel & Associates Consultants Ltd.
99.7	Consent of Netherland, Sewell & Associates, Inc.
99.8	Consent of Ryder Scott Company
99.9	Consent of DeGolyer and MacNaughton
99.10	Consent of Gilbert Laustsen Jung Associates Ltd.