ENCANA CORP
Form 40-F
February 23, 2007

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

FORM 40-F

(Check One)

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

or

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

For the fiscal year ended **December 31, 2006**

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

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:

[X] Annual Information Form [X] 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: **783,737,893 common shares**

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 ___ No_X_

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_X_ No___

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. 333-124218, 333-85598 and 333-13956) and Form F-9 (File Nos. 333-133648, 333-133648-01 and 333-137182)

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, 2006;

(b) Management s Discussion and Analysis for the fiscal year ended December 31, 2006; and

(c) Consolidated Financial Statements for the fiscal year ended December 31, 2006 *(Note 20 to the Consolidated Financial Statements relates to United States Accounting Principles and Reporting (U.S. GAAP)).*

ANNUAL INFORMATION FORM

February 23, 2007

ENCANA CORPORATION

ANNUAL INFORMATION FORM

This is the annual information form of EnCana Corporation ("EnCana" or the "Corporation") for the year ended December 31, 2006. 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.

Unless otherwise specified, all dollar amounts are expressed in United States ("U.S.") dollars and all references to "dollars" or to "$" are to U.S. dollars and all references to "C$" are to Canadian dollars. All production and reserves information is presented on an after royalties basis consistent with U.S. protocol reporting.

Unless otherwise indicated, all financial information included 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.

TABLE OF CONTENTS

NOTE REGARDING FORWARD-LOOKING STATEMENTS

This annual information form contains certain forward-looking statements or information (collectively referred to in this note as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as "projected", "anticipate", "believe", "expect", "plan", "intend" or 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: oilsands strategy and the benefits of this strategy, Suffield development plans, potential shut-ins and the possible receipt of royalty credits, the effect of Alberta Energy & Utilities Board commingling guidelines, capital investment levels and the allocation thereof, drilling plans and the timing and location thereof, production capacity and levels and the timing of achieving such capacity and levels, the timing of completion of the Foster Creek and Christina Lake expansions, the anticipated capacities of and the timing of capacity expansions for the Wood River and Borger refineries, anticipated capacity for and timing of expansion of the Steeprock natural gas plant, the development of the Jonah area, the potential for natural gas resource play development on the Foix permit lands, reserves estimates, the level of expenditures for compliance with environmental regulations, site restoration costs including abandonment and reclamation costs, pending litigation, exploration plans, acquisition and divestiture plans, including farmout plans and net cash flows.

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 and assumptions regarding oil and natural gas prices, assumptions based upon EnCana's current guidance, 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 market optimization 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, the ability of EnCana and ConocoPhillips to successfully manage and operate the integrated North American heavy oil business and the ability of the parties to obtain necessary regulatory approvals, refining and marketing margins, potential disruption or unexpected technical difficulties in developing new products and manufacturing processes, potential failure of new products to achieve acceptance in the market, unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities, unexpected difficulties in manufacturing, transporting or refining synthetic crude oil, risks associated with technology, 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 construction of gas storage facilities, wells and pipelines, 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 or the interpretation of such 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, 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, except as required by law, 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

National Instrument 51-101 ("NI 51-101") of the Canadian Securities Administrators imposes 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 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 effective date of the estimation, 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 reserves quantities based on constant prices should not be material. EnCana concurs with this assessment.

EnCana has disclosed proved reserves quantities using the standards contained in SEC 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" ("SFAS 69").

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

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

CORPORATE STRUCTURE

Name and Incorporation

EnCana Corporation is incorporated under the *Canada Business Corporations Act* ("CBCA"). Its executive and registered office is located at 1800, 855 - 2nd Street S.W., Calgary, Alberta, Canada T2P 2S5.

EnCana was formed through the business combination (the "Merger"), on April 5, 2002, of Alberta Energy Company Ltd. ("AEC") and PanCanadian Energy Corporation ("PanCanadian").

On April 27, 2005, EnCana amended its articles to effect a two-for-one share split.

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 as at December 31, 2006. Each of these subsidiaries and partnerships had total assets that exceeded 10 percent of the total consolidated assets of EnCana or revenues that exceeded 10 percent of the total consolidated revenues of EnCana as at and for the year ended December 31, 2006:

Subsidiaries & Partnerships	Percentage Owned(1)	Jurisdiction of Incorporation, Continuance or Formation
EnCana Oil & Gas Partnership	100	Alberta
EnCana USA Holdings	100	Delaware
3080763 Nova Scotia Company	100	Nova Scotia
Alenco Inc.	100	Delaware
EnCana Oil & Gas (USA) Inc.	100	Delaware
EnCana Marketing (USA) Inc.	100	Delaware
EnCana Heritage Lands	100	Alberta
1140102 Alberta Ltd.	100	Alberta
EnCana Resource Developments Ltd.(2)	100	Alberta

Notes:

(1) Includes indirect ownership.

(2) Effective January 1, 2007, EnCana Resource Developments Ltd. amalgamated with its wholly owned subsidiary, EnCana Oil & Gas Co. Ltd., with the resulting name of EnCana Oil & Gas Co. Ltd.

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, 2006.

GENERAL DEVELOPMENT OF THE BUSINESS

EnCana is one of North America's leading natural gas producers, is among the largest holders of natural gas and oil resource lands onshore North America and is a technical and cost leader in the in-situ recovery of oilsands bitumen. EnCana's other operations include the transportation and marketing of crude oil, natural gas and natural gas liquids, as well as the refining of crude oil and the marketing of refined petroleum products. EnCana pursues profitable growth from its portfolio of long-life resource plays situated in Canada and the United States. The Corporation is also engaged in select exploration activities internationally.

Following the Merger in 2002, the majority of EnCana's Upstream operations were located in Canada, the U.S., Ecuador and the U.K. central North Sea. From the time of the Merger through early 2004, EnCana focused on the development and expansion of its highest growth, highest return assets in these key areas. Beginning in 2004, EnCana sharpened its strategic focus to concentrate on its inventory of North American resource play assets. As part of its ongoing strategic focus, the Corporation has completed a number of acquisitions while continuing with the divestiture of its non-core assets. A portion of the divestiture proceeds were used to fund EnCana's normal course issuer bid program. In 2006, EnCana purchased approximately 85.6 million shares under the program for a total cost of approximately $4.2 billion.

In January of 2007, EnCana, with ConocoPhillips, completed the creation of an integrated heavy oil business. This venture provides greater certainty of execution for EnCana's oilsands projects and gives EnCana immediate participation in the North American refining industry.

Effective January 1, 2007, EnCana has been reorganized into six operating divisions:

- Canadian Plains Division, which includes the majority of EnCana's legacy oil and gas assets
- Canadian Foothills Division, which includes the majority of EnCana's Canadian natural gas resource plays
- USA Division, which includes the majority of the Corporation's upstream U.S. assets, including its key resource plays
- Integrated Oilsands Division, which includes all of the assets within the newly created integrated heavy oil business (including the U.S. refinery assets), as well as the Corporation's other oilsands interests and the natural gas assets on the Cold Lake Air Weapons Range
- Offshore & International Division, which includes the Corporation's offshore East Coast Canadian assets as well as assets in Brazil, the Middle East, Greenland and France
- Midstream & Marketing Division, which continues to provide coordination of the Corporation's natural gas and crude oil market optimization activities, and includes the Cavalier and Balzac power assets

In 2006, for financial reporting purposes, EnCana has defined its operations into the following segments: (i) Upstream; (ii) Market Optimization; and (iii) Corporate. All divisions are reported under Upstream with the exception of the Midstream & Marketing Division, which is reported under Market Optimization. In 2007, the Integrated Oilsands Division will be reported under a new Integrated Oilsands segment.

The following describes the significant events of the last three years. In this section, all divestiture proceeds are provided on a before tax basis unless otherwise noted.

2006 Projects:

- In November 2005, EnCana announced plans to examine a number of proposals from other companies who were interested in participating in the development of EnCana's oilsands assets. In October 2006, EnCana announced it had entered into an agreement with ConocoPhillips to create an integrated heavy oil business consisting of upstream and downstream assets.

The creation of the integrated heavy oil business was completed on January 3, 2007. The business is comprised of two 50/50 operating entities, one Canadian upstream enterprise managed by EnCana and one U.S. downstream enterprise managed by ConocoPhillips, with both EnCana and ConocoPhillips contributing equally valued assets and equity. For further information refer to the "Narrative Description of the Business" in this annual information form.

2006 Acquisitions:

In June 2006, EnCana increased its working interest in the Deep Bossier play in East Texas from 30 percent to 50 percent and purchased an additional 7,600 net acres in Robertson County for approximately $250 million. The transaction resulted in additional production of approximately 4.3 million cubic feet per day of natural gas.

2006 Divestitures:

In February 2006, EnCana completed the sale of all of its oil and pipeline interests in Ecuador for approximately $1.4 billion. The Ecuador assets included interests in five Oriente Basin blocks (Tarapoa Block, Block 14, Block 17, Shiripuno Block and EnCana's economic interest in relation to Block 15) and a 36.3 percent interest in the Oleoducto de Crudos Pesados ("OCP") pipeline.

Subsequent to the divestiture, in May 2006, the Government of Ecuador seized the Block 15 assets. As part of the sales agreement with the purchaser, EnCana had agreed to indemnify the purchaser for certain defined losses. In August 2006, EnCana paid an indemnity claim of approximately $265 million, relating to the Block 15 assets, calculated in accordance with the terms of the agreement. EnCana expects no further liability.

In February 2006, a subsidiary of EnCana sold Entrega Gas Pipeline LLC for approximately $244 million. As part of the sale, EnCana committed approximately 500 million cubic feet per day to the Rockies Express Project.

In May 2006, a subsidiary of EnCana completed the first of two phases in the sale of its non-strategic natural gas storage assets for proceeds of approximately $1.3 billion. Phase one storage assets included facilities in Alberta, Oklahoma and Louisiana.

In August 2006, a subsidiary of EnCana completed the sale of its 50 percent interest in the Chinook heavy oil discovery in Block BM-C-7 offshore Brazil for proceeds of approximately $367 million. EnCana continues to hold a non-operated working interest in 10 deep water exploration blocks offshore Brazil.

In November 2006, a subsidiary of EnCana completed the second phase in the sale of its non-strategic natural gas storage assets for approximately $215 million. Phase two of the asset sale included the Wild Goose storage facility in California.

In December 2006, a subsidiary of EnCana completed the divestiture of the remainder of its NGL assets, the majority of which were sold in 2005, by selling its final 10 percent share of the Empress straddle plant joint venture facility for approximately $13 million.

In addition to the transactions completed in 2006, EnCana has a number of divestitures that were completed after December 31, 2006 or are still in progress:

In September 2006, EnCana announced its intention to divest its assets in northern Canada. The assets include all of its Mackenzie Delta / Beaufort Sea licenses and discoveries as well as all of its Arctic Islands licenses. In December 2006, EnCana completed the sale of a portion of its northern Canada assets.

In January 2007, a subsidiary of EnCana completed the sale of all of its interests in its Chad exploration assets for approximately $203 million. The Chad assets included a 50 percent working interest in approximately 54 million gross acres in seven sedimentary basins.

2005 Projects:

In September and October 2005, a wholly owned partnership of EnCana signed agreements with Methanex Corporation ("Methanex") and Provident Energy Ltd. ("Provident") under which Methanex provides terminalling services to EnCana at Methanex's terminal facilities at Kitimat, British Columbia, and Provident provides terminalling services to EnCana at Provident's terminal facilities at Redwater, Alberta.

5

EnCana now imports up to 25,000 barrels per day of offshore diluent to help transport its growing oilsands production in northeast Alberta to markets in the U.S.

In December 2005, Entrega Gas Pipeline LLC, an affiliate of EnCana Oil & Gas (USA) Inc., completed material portions of the construction of the first segment of its U.S. Federal Energy Regulatory Commission regulated pipeline project, from Meeker Hub, Colorado to Wamsutter, Wyoming. This segment of the pipeline came into service in February 2006.

2005 Acquisitions:

In September 2005, a subsidiary of EnCana completed the purchase of approximately 325,000 net acres of exploration land in the Maverick Basin in southwest Texas for approximately $148 million.

In December 2005, a subsidiary of EnCana completed the purchase of approximately 24,000 total net acres (2,000 net developed acres) of development land in the Fort Worth Basin for approximately $178 million. The purchase included properties producing approximately 16 million cubic feet per day of natural gas.

2005 Divestitures:

In May 2005, subsidiaries of EnCana completed the sale of the Corporation's Gulf of Mexico assets for approximately $2.1 billion. The Gulf of Mexico assets included the Corporation's interests in the Tahiti, Tonga, Sturgis, Sawtooth, Jack and St. Malo discoveries. EnCana had an average 40 percent interest in 239 exploration blocks covering approximately 1.4 million gross acres in the Gulf of Mexico.

In June 2005, EnCana completed the sale of western Canadian conventional oil and natural gas assets producing approximately 6,400 barrels of oil equivalent per day for approximately $321 million.

In December 2005, EnCana and certain affiliates completed the sale of substantially all of their natural gas liquids processing business for approximately $625 million. The divested assets included interests in four NGLs extraction plants at Empress, Alberta, storage and fractionation assets in Saskatchewan, eastern Canada and the U.S. and EnCana's 100 percent interest in Kinetic Resources, an NGL marketer. EnCana had previously acquired the 25 percent minority interest in the Kinetic partnership earlier in the year.

2004 Projects:

In March 2004, a 10 billion cubic feet expansion was completed at the Wild Goose natural gas storage facility in northern California. The expansion increased the total working gas capacity to approximately 24 billion cubic feet.

2004 Acquisitions:

In the first quarter of 2004, a subsidiary of EnCana completed the purchase, through two separate transactions, of additional interests in the U.K. central North Sea, for net cash consideration of approximately $131 million.

In May 2004, a subsidiary of EnCana completed the acquisition of Tom Brown, Inc. ("Tom Brown") for total consideration of approximately $2.7 billion, including debt of approximately $406 million. Tom Brown was a resource play focused, natural gas exploration and production company headquartered in Denver, Colorado. At the time of the acquisition, Tom Brown had assets in the Piceance, Green River, Wind River, Paradox, East Texas, Permian and Western Canada Sedimentary basins.

In December 2004, a subsidiary of EnCana purchased natural gas assets in the Fort Worth Basin of north Texas for approximately $251 million.

2004 Divestitures:

In February 2004, EnCana sold its 53.3 percent interest in Petrovera Resources ("Petrovera"), an Alberta partnership that produced heavy oil in western Canada, for net cash consideration of approximately $287 million. In order to facilitate the transaction, the Corporation purchased the 46.7 percent interest of its partner for approximately $253 million and then sold the 100 percent interest in Petrovera for a total of approximately $540 million.

In July 2004, a subsidiary of EnCana sold assets in New Mexico for approximately $228 million.

In August 2004, EnCana sold conventional natural gas properties in northeast Alberta for approximately $225 million.

In September 2004, the Corporation sold conventional oil and gas assets for approximately $388 million. This transaction included properties in east central and southern Alberta producing predominantly medium and heavy oil.

In December 2004, a subsidiary of EnCana completed the sale of all of its U.K. central North Sea assets for approximately $2.1 billion. These interests included a 43.2 percent interest in the Buzzard oil field, a 41.0 and 54.3 percent interest, respectively, in the Scott and Telford oil fields, other satellite discoveries, plus interests in exploration licenses covering more than 740,000 net acres in the central North Sea.

In December 2004, EnCana sold its 25 percent non-operated partnership interest in the Kingston CoGen Limited Partnership ("Kingston CoGen") for net cash consideration of approximately $25 million. Kingston CoGen owns a 110 megawatt cogeneration plant in Kingston, Ontario.

In December 2004, EnCana sold its interest in the Alberta Ethane Gathering System joint venture for approximately $108 million.

NARRATIVE DESCRIPTION OF THE BUSINESS

The following map outlines EnCana's onshore North America landholdings and key resource plays as of December 31, 2006. The map also identifies the Borger and Wood River refineries that were contributed to the integrated heavy oil business by ConocoPhillips in January 2007.

The vast majority of EnCana's operations are located in Canada and the U.S., while the Offshore & International Division is mainly focusing on opportunities off the East Coast of Canada, in Brazil, the Middle East, Greenland and France.

At December 31, 2006, EnCana had net proved reserves of approximately 12.4 trillion cubic feet of natural gas and 1.1 billion barrels of crude oil, bitumen and NGLs, as estimated by independent qualified reserves evaluators. Proved developed reserves comprise approximately 62 percent of total natural gas reserves, approximately 75 percent of crude oil and NGLs reserves excluding bitumen and approximately 13 percent of bitumen reserves. See "Reserves and Other Oil and Gas Information" in this annual information form.

Within western Canada, EnCana has an industry-leading land position of approximately 23.8 million gross acres (approximately 21.0 million net acres, of which approximately 12.1 million net acres are undeveloped). The mineral rights on approximately 38 percent of the total net acreage is 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. In 2006, EnCana had core capital expenditures in Canada of approximately $4,015 million ($3,984 million in western Canada) and drilled approximately 3,009 net wells (3,007 in western Canada).

In the U.S., EnCana's landholdings are approximately 6.4 million acres (approximately 5.5 million net acres, of which approximately 5.0 million net acres are undeveloped), with the majority in Colorado, Wyoming, Washington and Texas. In 2006, EnCana had core capital expenditures of approximately $2,061 million and drilled approximately 639 net wells within the U.S.

As noted previously, EnCana's operations are divided into six divisions. The following narrative describes each division in greater detail.

Canadian Plains Division

The Canadian Plains Division encompasses the majority of EnCana's legacy natural gas production activities in southern Alberta and Saskatchewan as well as the Corporation's crude oil (excluding in-situ oilsands) development and production activities in Alberta and Saskatchewan. Two key resource plays are located in the Canadian Plains Division: (i) Shallow Gas; and (ii) Pelican Lake. The Shallow Gas key resource play is contained within the Suffield, Langevin and Brooks North areas.

In 2006, the Canadian Plains Division had core capital expenditures of approximately $768 million and drilled approximately 1,635 net wells. EnCana's 2007 core capital investment in the Canadian Plains Division is projected to be approximately $870 million, which includes the drilling of approximately 2,100 net wells.

The following table summarizes landholdings for the Canadian Plains Division as at December 31, 2006.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Suffield	918	904	69	68	987	972	98%
Brooks North	556	554	12	12	568	566	100%
Langevin	1,198	1,080	1,231	1,143	2,429	2,223	92%
Drumheller	360	349	20	18	380	367	97%
Pelican Lake	139	139	277	262	416	401	96%
Weyburn	91	80	587	580	678	660	97%
Other	926	879	833	765	1,759	1,644	93%
Canadian Plains Total	4,188	3,985	3,029	2,848	7,217	6,833	95%

The following table sets forth daily average production figures for the periods indicated.

Production (annual average)	Natural Gas (MMcf/d) 2006	Natural Gas (MMcf/d) 2005	Crude Oil and NGLs (bbls/d) 2006	Crude Oil and NGLs (bbls/d) 2005	Total Production (MMcfe/d) 2006	Total Production (MMcfe/d) 2005
Suffield	241	243	17,350	20,756	345	368
Brooks North	272	283	726	1,155	276	290
Langevin	238	255	10,400	12,405	300	329
Drumheller	104	107	2,251	2,654	118	123
Pelican Lake	2	4	23,563	25,752	143	159
Weyburn			15,136	13,562	91	81
Other	49	47	7,566	8,382	94	97
Canadian Plains Total	906	939	76,992	84,666	1,367	1,447

Note:

(1) The Shallow Gas key resource play, located mainly in the Suffield, Brooks North and Langevin areas, had 2006 average production of approximately 600 million cubic feet per day (625 million cubic feet per day in 2005).

The following table summarizes EnCana's interests in producing wells as at December 31, 2006. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2006.

Producing Wells (number of wells)	Producing Gas Wells Gross	Producing Gas Wells Net	Producing Oil Wells Gross	Producing Oil Wells Net	Total Producing Wells Gross	Total Producing Wells Net
Suffield	8,790	8,759	732	730	9,522	9,489
Brooks North	5,949	5,859	46	46	5,995	5,905
Langevin	6,042	5,642	233	227	6,275	5,869
Drumheller	1,154	1,119	97	95	1,251	1,214
Pelican Lake	29	29	452	452	481	481
Weyburn			999	456	999	456
Other	1,127	1,108	673	635	1,800	1,743
Canadian Plains Total	23,091	22,516	3,232	2,641	26,323	25,157

Note:

(1) At December 31, 2006, the Shallow Gas key resource play had 20,192 gross producing gas wells (19,682 net gas wells).

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

Suffield

EnCana holds interests in the Upper Cretaceous shallow natural gas horizons and deeper formations in the Suffield area in southeast Alberta. Suffield is one of the core areas of the Shallow Gas key resource play. EnCana also produces conventional heavy oil in the area. The Suffield area is largely made up of the Suffield Block, where operations are carried out by EnCana in cooperation with the Canadian military according to guidelines established under agreements with the Government of Canada. EnCana plans to continue development of its shallow gas and heavy oil resources at Suffield. In 2007, as part of its ongoing application to continue shallow gas infill drilling in the National Wildlife Area, EnCana will be preparing an Environmental Impact Statement and participating in an Alberta Energy & Utilities Board ("EUB") joint panel hearing as part of the Canadian Environmental Assessment Act. In 2006, EnCana drilled approximately 460 net wells in the area and production averaged approximately 241 million cubic feet per day of natural gas.

Brooks North

EnCana produces natural gas, crude oil and NGLs from the Cretaceous horizons in the Brooks area of southern Alberta, located east of Calgary. This area is another core area of the Shallow Gas key resource play and is largely comprised of EnCana fee title lands. In 2006, EnCana drilled approximately 473 net wells in the area and production averaged approximately 272 million cubic feet per day of natural gas. Completion operations in 2007 are expected to benefit significantly from the recent EUB self-declared commingling process, which became effective December 15, 2006. It is anticipated that the new process will allow EnCana to complete additional zones in a well bore at minimal incremental cost.

Langevin

The Langevin area produces predominantly shallow gas from the Upper Cretaceous formations in southeast Alberta and southwestern Saskatchewan. Certain parts of this area are included in EnCana's Shallow Gas key resource play. Development of this area focuses on infill drilling and optimization of existing wells, and is largely comprised of EnCana fee title lands. In 2006, EnCana drilled approximately 426 net wells in the area and production averaged approximately 238 million cubic feet per day of natural gas.

Drumheller

EnCana produces natural gas, crude oil and NGLs from the Cretaceous horizons in the Drumheller area of southern Alberta. The area is mainly a conventional Mannville gas play, and is largely comprised of EnCana fee title lands. In 2006, EnCana drilled approximately 167 net wells in the area and production averaged approximately 104 million cubic feet per day of natural gas.

Pelican Lake

Pelican Lake is one of EnCana's key resource plays producing crude oil in northeast Alberta. In 2006, EnCana continued to expand its waterflood program to approximately 80 percent of the field at Pelican Lake, while expanding the polymer pilot from 11 injection wells to 37 injection wells. In order to process the increased fluid volumes associated with the waterflood and polymer projects, EnCana has expanded the facility infrastructure, with additional facility projects to be completed in 2007. EnCana reached payout at Pelican Lake in 2006, changing the royalty from one percent of gross revenues to 25 percent of net revenues. The success of the waterflood program at Pelican Lake increased 2006 crude oil production by approximately five percent compared to 2005; however, because EnCana reached payout, after-royalties production decreased.

EnCana also holds a 38 percent non-operated 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.

Weyburn

EnCana has a 62 percent working interest (50 percent economic interest) in the unitized portion of the Weyburn crude oil field in southeast Saskatchewan. EnCana is the operator and expects to improve ultimate recovery in the enhanced oil recovery area of the field with a carbon dioxide ("CO_2") miscible flood project. In 2006, EnCana focused on continuing its infill drilling program with 56 new wells in the unit. As of December 31, 2006, there were 44 patterns on CO_2 injection out of a planned total of 75 patterns.

Canadian Foothills Division

The Canadian Foothills Division includes EnCana's key natural gas growth assets in British Columbia and Alberta. Four key resource plays are located in the Canadian Foothills Division: (i) Greater Sierra; (ii) Cutbank Ridge; (iii) Bighorn; and (iv) Coalbed Methane Integrated ("CBM Integrated"). The CBM Integrated key resource play (Horseshoe Canyon coalbed methane and commingled shallow gas), is completely contained within the Clearwater business unit.

In 2006, the Canadian Foothills Division had core capital expenditures of approximately $2,467 million and drilled approximately 1,274 net wells. EnCana's 2007 core capital investment in the Canadian Foothills Division is projected to be approximately $2,150 million, which includes the drilling of approximately 1,370 net wells.

The following table summarizes landholdings for the Canadian Foothills Division as at December 31, 2006.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Greater Sierra	645	568	2,470	2,111	3,115	2,679	86%
Cutbank Ridge	227	194	851	762	1,078	956	89%
Bighorn	261	147	774	478	1,035	625	60%
Clearwater	3,434	3,050	3,509	3,293	6,943	6,343	91%
Sexsmith/Hythe/Saddle Hills	362	225	259	195	621	420	68%
Other	300	202	1,386	1,061	1,686	1,263	75%
Canadian Foothills Total	5,229	4,386	9,249	7,900	14,478	12,286	85%

The following table sets forth daily average production figures for the periods indicated.

Production (annual average)	Natural Gas (MMcf/d)		Crude Oil and NGLs (bbls/d)		Total Production (MMcfe/d)	
	2006	2005	2006	2005	2006	2005
Greater Sierra	213	219	837	793	218	224
Cutbank Ridge	170	92	82		170	92
Bighorn	91	55	1,480	867	100	60
Clearwater	483	447	11,555	12,330	552	521
Sexsmith/Hythe/Saddle Hills	93	99	2,046	1,989	105	111
Other	116	137	3,370	3,717	136	159
Canadian Foothills Total	1,166	1,049	19,370	19,696	1,281	1,167

Note:

(1) The CBM Integrated key resource play, located within the Clearwater business unit, had 2006 average production of approximately 194 million cubic feet per day (112 million cubic feet per day in 2005).

The following table summarizes EnCana's interests in producing wells as at December 31, 2006. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2006.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Greater Sierra	829	772	3	3	832	775
Cutbank Ridge	370	330			370	330
Bighorn	205	128	1		206	128
Clearwater	7,103	6,314	204	111	7,307	6,425

Sexsmith/Hythe/Saddle Hills	329	261	67	50	396	311
Other	577	427	186	101	763	528
Canadian Foothills Total	9,413	8,232	461	265	9,874	8,497

Note:

(1) At December 31, 2006, the CBM Integrated key resource play had 3,137 gross producing gas wells (2,890 net gas wells).

12

The following describes EnCana's major producing areas or activities in the Canadian Foothills Division.

Greater Sierra

The Greater Sierra area of northeast British Columbia is one of EnCana's key natural gas resource plays. Average natural gas production in the area was approximately 213 million cubic feet per day in 2006. Production has remained relatively constant over the past two years as EnCana has reduced capital expenditures, and is currently targeting a drilling program that will continue to maintain current production levels. EnCana is selectively farming out a small portion of its Greater Sierra land position to third parties.

As at December 31, 2006, EnCana held an average 99 percent interest in 13 production facilities in the area that were capable of processing approximately 486 million cubic feet per day of natural gas. EnCana also holds a 100 percent interest in the Ekwan pipeline which has a capacity of approximately 400 million cubic feet per day and transports natural gas from northeast British Columbia to Alberta.

Cutbank Ridge

Cutbank Ridge is a key natural gas resource play located in the Canadian Rocky Mountain foothills, southwest of Dawson Creek, British Columbia. Key producing horizons in Cutbank Ridge include the Cadomin, Doig and Montney zones. The majority of the Corporation's lands in this area were purchased in 2003. In 2006, EnCana drilled approximately 116 net natural gas wells at Cutbank Ridge and production averaged approximately 170 million cubic feet per day of natural gas.

In 2006, a significant extension to the Cutbank Ridge resource play was added with the addition of the Montney zone. EnCana has had a small number of wells producing from the Montney formation as far back as 1999, and the application of new technologies has started to achieve positive results within the formation. At year end 2006, approximately 18 percent of the wells in Cutbank Ridge were producing out of the Montney formation, with 58 wells (25 drilled in 2006) producing approximately 43 million cubic feet of natural gas per day.

In order to facilitate increased production from Cutbank Ridge, EnCana completed phase one of the Steeprock natural gas processing plant in the fourth quarter of 2006. The plant, located approximately 60 kilometres south of Dawson Creek, British Columbia, is expected to have a licensed capacity of 198 million cubic feet of natural gas per day once both phases are complete. Phase one of the plant has a capacity of approximately 70 million cubic feet per day with a current throughput of approximately 60 million cubic feet per day. EnCana anticipates that phase two will be completed in the first half of 2008.

Bighorn

The Bighorn area in west central Alberta is another of EnCana's key natural gas resource plays, focusing on exploitation of multi-zone stacked Cretaceous sands in the Deep Basin. EnCana has an average working interest of approximately 60 percent in approximately 1,035,000 gross acres (625,000 net acres) of land in the Bighorn area. The primary producing properties in Bighorn are Wild River, Resthaven, Kakwa, and Berland. In 2006, EnCana drilled approximately 52 net wells in the area and production averaged approximately 91 million cubic feet per day of sweet natural gas.

EnCana has a working interest in a number of gas plants within Bighorn. The Wild River plant, in which EnCana holds a 70 percent working interest, was expanded to a capacity of approximately 30 million cubic feet per day in January 2006. In April 2006, the Resthaven plant, in which EnCana has a 65 percent working interest, was brought on stream, with a capacity of approximately 100 million cubic feet of natural gas per day. The Kakwa gas plant, with a capacity of approximately 30 million cubic feet per day, was commissioned in September 2006, and operated at close to capacity through the fourth quarter of 2006. EnCana owns 50 percent of this plant and has firm processing capacity for the remaining 50 percent. The Berland River plant was recently expanded, and EnCana now has a 24 percent working interest and approximately 40 million cubic feet per day net capacity.

The new commingling guidelines announced by the EUB in December 2006, have a positive impact on operations in the business unit. The majority of Bighorn's land base falls within the EUB's Deep Basin

Development Entity No. 2. The primary benefits for the business unit are significant cost reductions on new well completions and the potential to access additional zones with the same number of fractures.

Clearwater

The Clearwater business unit extends from the U.S. border to just north of Edmonton, and was created by merging the former Chinook and Parkland business units. The primary focus of Clearwater is the CBM Integrated key natural gas resource play; however, Clearwater is also charged with the development of the Mannville coalbed methane fairway, and deeper Cretaceous reservoirs. EnCana holds a combination of both fee lands, where it owns the mineral rights, and crown lands within Clearwater. In 2006, EnCana drilled 729 net CBM Integrated wells, and production averaged approximately 194 million cubic feet per day of natural gas from the CBM Integrated resource play.

Sexsmith/Hythe/Saddle Hills

EnCana produces natural gas, crude oil and NGLs in the Sexsmith/Hythe/Saddle Hills area in northwest Alberta. EnCana also operates and has a 62 percent interest in the 210 million cubic feet per day Sexsmith sour natural gas and liquids processing plant and an 85 percent interest in the 50 million cubic feet per day Saddle Hills sweet natural gas plant. EnCana also 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 275-kilometre natural gas gathering system in the area.

USA Division

EnCana's operations in the USA Division are focused on exploiting long-life unconventional natural gas formations in the Jonah field in southwest Wyoming, the Piceance Basin in northwest Colorado and the East Texas, Fort Worth and Maverick Basins in Texas. The Corporation also has landholdings in the Columbia River Basin in Washington State. The majority of the production in the USA Division is from the following four key resource plays: (i) Jonah; (ii) Piceance; (iii) East Texas; and (iv) Fort Worth. The USA Division also has interests in natural gas gathering and processing assets, primarily in Colorado, Wyoming, Texas and Utah.

In 2006, the USA Division had core capital expenditures of approximately $2,061 million and drilled approximately 639 net wells. EnCana's 2007 core capital investment in the USA Division is projected to be approximately $1,890 million, which includes the drilling of approximately 660 net wells.

The following table summarizes landholdings for the USA Division as at December 31, 2006.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Jonah	12	10	147	141	159	151	95%
Piceance	246	233	815	763	1,061	996	94%
East Texas	98	59	669	614	767	673	88%
Fort Worth	37	35	168	161	205	196	96%
Maverick Basin	4	4	479	339	483	343	71%
Columbia River Basin			823	811	823	811	99%
Other	276	177	2,588	2,164	2,864	2,341	82%
USA Total	673	518	5,689	4,993	6,362	5,511	87%

The following table sets forth daily average production figures for the periods indicated.

Production (annual average)	Natural Gas (MMcf/d)		Crude Oil and NGLs (bbls/d)		Total Production (MMcfe/d)	
	2006	2005	2006	2005	2006	2005
Jonah	464	435	4,257	3,939	489	459
Piceance	326	307	2,416	2,965	341	325
East Texas	99	90	277	304	100	92
Fort Worth	101	70	607	345	105	72
Other	192	193	5,401	6,337	225	230
USA Total	1,182	1,095	12,958	13,890	1,260	1,178

The following table summarizes EnCana's interests in producing wells as at December 31, 2006. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2006.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Jonah	669	609			669	609
Piceance	2,229	2,003			2,229	2,003
East Texas	827	412	12	6	839	418
Fort Worth	639	560	13	12	652	572
Other	3,014	1,414	17	5	3,031	1,419
USA Total	7,378	4,998	42	23	7,420	5,021

The following describes EnCana's major producing areas or activities in the USA Division.

Jonah

EnCana produces natural gas and associated NGLs from the Jonah field, located in the Green River Basin in southwest Wyoming. The Jonah key resource play produces from the Lance formation, which contains vertically stacked sands that exist at depths between 8,500 and 11,500 feet. The wells are stimulated with multi-stage advanced hydraulic fracturing techniques.

In March 2006, EnCana obtained a favorable Environmental Impact Statement regulatory approval from the U.S. Bureau of Land Management. The approval provides EnCana access to 600 remaining 10-acre spacing locations and additional locations at tighter spacing, as required, to achieve optimal recovery. In 2006, EnCana drilled approximately 163 net wells in the Jonah area, up from 104 net wells in 2005. Daily production of natural gas averaged approximately 464 million cubic feet in 2006 compared to approximately 435 million cubic feet in 2005.

Piceance

The Piceance Basin in northwest Colorado is one of EnCana's key natural gas resource plays. The basin is characterized by thick natural gas accumulations primarily in the Williams Fork formation. The May 2004 acquisition of Tom Brown included properties and natural gas production in the basin. In 2006, EnCana drilled approximately 220 net wells in the basin, compared to 266 in 2005. Despite drilling fewer wells in 2006, production of natural gas has grown to an average of approximately 326 million cubic feet per day from approximately 307 million cubic feet per day in 2005.

In 2006, EnCana finalized four agreements to jointly develop portions of the Piceance Basin. Over the next three years, it is expected that EnCana will drill approximately 267 wells with outside funds and EnCana's partners will fund the drilling of approximately 182 wells, allowing the third parties to earn approximately 20,000 net acres.

15

East Texas

EnCana produces natural gas and associated NGLs in the East Texas Basin. The East Texas properties were acquired as part of the Tom Brown acquisition in 2004, and the basin is one of EnCana's key resource plays. In July 2006, EnCana increased its working interest in the Deep Bossier play in East Texas from 30 percent to 50 percent through a property acquisition. This tight gas, multi-zone play targets the Bossier and Cotton Valley zones. During 2006, EnCana drilled approximately 59 net wells in the basin and production averaged approximately 99 million cubic feet per day of natural gas.

Fort Worth

EnCana produces natural gas and associated NGLs in the Fort Worth Basin in north Texas. The Fort Worth Basin is one of EnCana's key resource plays. Since entering the area in 2003, the Corporation has assembled a significant land position in the Barnett Shale play in this basin. EnCana is applying horizontal drilling and multi-stage reservoir stimulation to improve performance in this play. In the fourth quarter of 2005, a subsidiary of EnCana completed the purchase of additional development land and producing properties in the basin. EnCana drilled approximately 97 net wells in the basin in 2006 and production averaged approximately 101 million cubic feet per day of natural gas.

Maverick Basin

EnCana controls approximately 479,000 undeveloped gross acres (339,000 net acres) in the Maverick Basin of southwest Texas. This acreage, purchased in September 2005 for approximately $148 million, contains significant exploratory potential in the Pearsall Shale, plus multi-zone potential in the uphole section. In 2007, the Corporation expects to drill up to six wells, both vertical and horizontal, to assess this potential shale play.

Columbia River Basin

EnCana holds approximately 823,000 undeveloped gross acres (811,000 net acres) in the Columbia River Basin in Washington State. This sedimentary basin is covered with 5,000 to 15,000 feet of volcanic basalt and as a result it is relatively under-explored. In 2006, EnCana drilled two wells to a depth of approximately 14,000 feet. Log and completions data obtained from these wells is currently under review. A third well is being drilled on the play, and is expected to reach total depth in the second quarter of 2007. EnCana's operations in the Columbia River Basin are largely funded by an outside partner who will eventually earn an interest in this play.

Gathering & Processing Facilities

EnCana owns and operates various gas gathering and processing facilities. Near Rifle, Colorado, EnCana owns a refrigeration plant with a capacity of approximately 440 million cubic feet per day and over 675 kilometres of pipelines. The Corporation's gathering and processing facilities near Rangely, Colorado, include over 1,620 kilometres of pipelines and a processing facility with a capacity of approximately 60 million cubic feet per day. In Texas, EnCana's gathering facilities include field compression and over 360 kilometres of pipelines. Near Ft. Lupton, Colorado, the gathering and processing facilities include field compression, over 1,000 kilometres of pipelines and a processing facility with a capacity of approximately 90 million cubic feet per day. Near Moab, Utah, EnCana owns a cryogenic natural gas processing plant with a capacity of approximately 60 million cubic feet per day. In west central Wyoming, EnCana has field compression, over 500 kilometres of pipelines and a refrigeration facility with a capacity of approximately 70 million cubic feet per day.

Integrated Oilsands Division

The Integrated Oilsands Division includes all of the assets within the newly created integrated heavy oil business with ConocoPhillips described below, as well as the Corporation's other oilsands interests and the natural gas assets on the Cold Lake Air Weapons Range. The Division has assets in both Canada and the United States, and contains two key crude oil resource plays: (i) Foster Creek; and (ii) Christina Lake. As at December 31, 2006, the Corporation held oilsands rights of approximately 860,000 gross acres (754,000 net acres) within the Athabasca and Cold Lake oilsands areas, as well as the exclusive rights to lease an additional 505,000 net acres on the Cold Lake Air Weapons Range.

In 2006, the Integrated Oilsands Division had core capital expenditures of approximately $745 million and drilled approximately 98 net wells (eight oil wells and 90 gas wells). EnCana's 2007 core capital investment in the Integrated Oilsands Division is projected to be approximately $850 million which includes approximately $770 million related to the drilling of approximately 32 net wells and refinery expansion projects associated with the newly created integrated heavy oil business.

The information relating to landholdings, production and producing wells in the following tables is as of December 31, 2006, prior to the contribution of Foster Creek and Christina Lake into the integrated heavy oil business with ConocoPhillips.

The following table summarizes landholdings for the Integrated Oilsands Division as at December 31, 2006.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Cold Lake Air Weapons Range	373	351	449	445	822	796	97%
Foster Creek	8	8	51	51	59	59	100%
Christina Lake	1	1	43	43	44	44	100%
Borealis			338	338	338	338	100%
Other	163	105	671	508	834	613	74%
Integrated Oilsands Total	545	465	1,552	1,385	2,097	1,850	88%

The following table sets forth daily average production figures for the periods indicated.

Production (annual average)	Natural Gas (MMcf/d)		Crude Oil and NGLs (bbls/d)		Total Production (MMcfe/d)	
	2006	2005	2006	2005	2006	2005
Cold Lake Air Weapons Range	106	129			106	129
Foster Creek			36,910	29,019	221	174
Christina Lake			5,858	5,360	35	32
Other	7	8	5,185	4,176	38	33
Integrated Oilsands Total	113	137	47,953	38,555	400	368

The following table summarizes EnCana's interests in producing wells as at December 31, 2006. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2006.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Cold Lake Air Weapons Range	642	618			642	618
Foster Creek			62	62	62	62
Christina Lake	4	4	8	8	12	12
Other	77	58	79	66	156	124
Integrated Oilsands Total	723	680	149	136	872	816

The following describes EnCana's major producing areas or activities in the Integrated Oilsands Division.

Cold Lake Air Weapons Range

EnCana produces natural gas from the Cold Lake Air Weapons Range located in northeast Alberta. EnCana holds surface access and natural gas rights for exploration, development and transportation from areas within the Cold Lake Air Weapons Range which were granted by the Government of Canada. The majority of EnCana's natural gas production in the area is processed through wholly owned and operated compression facilities. In 2006, natural gas production was impacted by the September 2003 EUB decision to shut-in natural gas production that may put at risk the recovery of bitumen resources in the area. The decision resulted in a decrease in annualized natural gas production of approximately 22 million cubic feet per day in 2006, and 22 million cubic feet per day in 2005. No additional wells were shut-in during 2005 or 2006. The Alberta Government's Department of Energy ("ADOE") is providing financial assistance in the form of a royalty credit, which is equal to approximately 50 percent of the cash flow lost as a result of the shut-in wells.

There is a potential that approximately 13 million cubic feet per day of natural gas production will be shut-in commencing in April 2007, due to additional risk of recovery of the bitumen resources in the area. A hearing on this matter is expected to commence in February 2007.

Foster Creek

As of December 31, 2006, EnCana had a 100 percent working interest in Foster Creek, one of the Corporation's key crude oil resource plays. EnCana holds surface access rights from the Governments of Canada and Alberta and oilsands rights for exploration, development and transportation from areas within the Cold Lake Air Weapons Range which were granted by the Government of Alberta. Additionally, EnCana has the exclusive rights to lease several hundred thousand acres of oilsands rights in other areas on the Cold Lake Air Weapons Range. EnCana is currently operating a thermal oil recovery project in the Foster Creek area using steam-assisted gravity drainage ("SAGD") technology.

In the fourth quarter of 2006, EnCana completed the second stage of an expansion that added an additional 20,000 barrels per day of capacity, increasing production capacity at Foster Creek to approximately 60,000 barrels per day. Current expansions already underway are expected to increase production capacity to approximately 120,000 barrels per day by the end of 2009.

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 alternate methods of artificial lift where EnCana is operating new pump designs that are expected to enable the Corporation to optimize SAGD performance by operating at lower pressures, thereby realizing lower steam-oil ratios and decreasing facility capital costs. At December 31, 2006, EnCana had 45 wells on electrical submersible pumps at Foster Creek, and the Corporation expects to continue to utilize this technology on new SAGD wells.

EnCana is also focused on reducing its reliance on steam in bitumen production. EnCana has piloted two technologies using solvents as part of the extraction process. The Vapex process, which uses solvent in place of steam, was piloted at Foster Creek from 2002 to 2005. Results from the Vapex pilot are being utilized during investigations into new production strategies for bitumen recovery. The Solvent Aided Process ("SAP") is discussed in the Christina Lake section below.

EnCana continues to operate its 80 megawatt, natural gas-fired cogeneration facility in conjunction with its SAGD operation at Foster Creek. The steam generated by the facility is being used within the SAGD operation and the excess power generated is being sold into the Alberta Power Pool grid.

Christina Lake

Christina Lake is one of EnCana's newest key resource plays. As of December 31, 2006, EnCana had a 100 percent owned thermal crude oil recovery pilot project at Christina Lake that also uses SAGD technology. In 2006, the Corporation approved an expansion that is expected to increase production capacity to approximately 18,000 barrels per day by the second half of 2008. In 2006, EnCana completed the installation of a remote water disposal system for the plant.

In 2004, EnCana commenced a pilot SAP program at Christina Lake. This process mixes a small amount of solvent with steam to enhance recovery. EnCana continues to produce and monitor current SAP pilot wells and recently began work with another SAP well test in the main reservoir.

Borealis

EnCana has a 100 percent working interest in approximately 338,000 acres in the Borealis area, which is located approximately 90 kilometres north of Fort McMurray. Borealis is not included in the venture with

ConocoPhillips. Since 2000, the Corporation has drilled approximately 190 delineation wells in the area as of December 31, 2006. In 2007, EnCana plans to continue its stratigraphic well program by drilling approximately 50 wells to further delineate these lands. Environmental work is ongoing to support future applications for development.

Integrated Heavy Oil Business

On January 3, 2007, EnCana completed the creation of an integrated heavy oil business with ConocoPhillips. The integrated heavy oil business includes Canadian upstream assets contributed by EnCana and U.S. downstream assets contributed by ConocoPhillips.

The upstream portion of the integrated heavy oil business is conducted through FCCL Oil Sands Partnership (the "Upstream Partnership") which owns the Foster Creek and Christina Lake oilsands projects contributed by EnCana. EnCana and ConocoPhillips each own 50 percent of the Upstream Partnership. EnCana is the operating and managing partner of the Upstream Partnership. The downstream portion of the integrated heavy oil business is conducted through WRB Refining LLC ("WRB") which owns the Wood River and Borger refineries contributed by ConocoPhillips. EnCana and ConocoPhillips each own 50 percent of WRB; however, ConocoPhillips will hold a disproportionate economic interest in the Borger refinery for two years: 85 percent in 2007 and 65 percent in 2008. ConocoPhillips is the operator and manager of WRB. The Upstream Partnership has a Management Committee, while WRB has a Board of Directors; both are comprised of three EnCana and three ConocoPhillips representatives, with each company holding equal voting rights.

The goal of the Upstream Partnership is to increase current production of approximately 50,000 barrels per day to approximately 400,000 barrels per day of bitumen by 2015, with the intention to transport and sell the bitumen at major Alberta trading hubs.

The Borger refinery, located in Borger, Texas, has a current capacity of approximately 146,000 barrels per day of crude oil and approximately 50,000 barrels per day of NGLs. It processes mainly light-sour and medium-sour crude oil and NGLs that it receives from North American pipeline systems to produce gasoline, diesel and jet fuel, and natural gas liquids and solvents. The refined products are transported via pipelines to markets in Texas, New Mexico, Colorado and the mid-continent.

The Wood River refinery, located in Roxana, Illinois, has a current throughput of approximately 306,000 barrels per day, including approximately 30,000 barrels per day of bitumen capacity. It processes a mix of light-low-sulfur and heavy-high-sulfur crude oil that it receives from North American crude oil pipelines to produce gasoline, diesel and jet fuel, petrochemical feedstock and asphalt. The gasoline and diesel are transported via pipelines to markets in the Midwest. The remaining products are transported via pipeline, truck, barge and railcar to markets in the Midwest.

The goal of WRB is to expand heavy oil processing capacity at the Wood River and Borger facilities from approximately 60,000 barrels per day to approximately 550,000 barrels per day (30,000 to 275,000 barrels per day of bitumen handling capacity) by 2015. WRB plans to purchase and transport all feedstocks for the refineries and sell the refined products.

Offshore & International Division

EnCana invests a small portion of its capital in exploration opportunities beyond its core geographic areas, primarily off the East Coast of Canada, in Brazil, the Middle East, Greenland and France. In 2006, EnCana's Offshore & International Division had core capital expenditures of approximately $106 million and drilled approximately four net wells. EnCana's 2007 core capital investment in the Offshore & International Division is projected to be approximately $88 million, which includes the drilling of approximately five net wells.

East Coast of Canada

At December 31, 2006, EnCana held an interest in approximately 2.7 million gross acres (1.7 million net acres) offshore the East Coast of Canada, which includes Nova Scotia and Newfoundland & Labrador. EnCana operates 10 of its 16 licenses in these areas and has an average working interest of approximately 61 percent.

EnCana is the operator of the Deep Panuke field, located offshore Nova Scotia, and has an approximate 85 percent working interest at December 31, 2006. EnCana continues to examine the potential economic viability of the Deep Panuke project. In June 2006, EnCana and the Province of Nova Scotia reached an Offshore Strategic Energy Agreement that established the framework for the potential development of Deep Panuke. Subsequently, in November 2006, EnCana filed the Development Plan Application with the Canada-Nova Scotia Offshore Petroleum Board. The filing included an Environmental Assessment Report and an application to the National Energy Board for approval of the construction and operation of an offshore pipeline.

Brazil

EnCana has non-operated interests in 10 deep and ultra-deep water exploration blocks offshore Brazil, nine of which are operated by Petrobras, the Brazilian national oil company. EnCana's landholdings on these offshore blocks total approximately 1.7 million gross acres (0.5 million net acres) with an average working interest of 31 percent. EnCana and its partners drilled one gross exploration well in 2006 in the Campos Basin.

The Corporation is also working with Petrobras on the development of heavy oil technology that may be used to develop Brazil's significant heavy oil reserves.

Middle East

EnCana has a 50 percent working interest in Block 2, which encompasses most of the onshore lands in the State of Qatar and covers approximately 2.2 million gross acres (1.1 million net acres). In 2005, EnCana reached an agreement to farmout 50 percent of its working interest in the block. The farmout was approved by Qatar Petroleum in February 2006. Two gross wells are planned for the block in 2007.

EnCana also has a 50 percent working interest in onshore Blocks 3 and 4 in the Sultanate of Oman. The blocks cover approximately 8.6 million gross acres (4.3 million net acres). Three gross wells are planned in 2007.

Greenland

EnCana has an 87 percent working interest in two exploration blocks offshore Greenland, comprising approximately 1.7 million gross acres (1.5 million net acres). In 2007, EnCana plans to farmout a portion of its interests on both blocks.

France

In February 2006, EnCana was granted a 100 percent interest in the Foix exploration permit, which encompasses approximately 859,000 gross acres in the onshore Aquitaine Basin in southwest France. The Corporation has plans for a multi-well exploration drilling program in 2007 to identify the potential for a natural gas resource play development.

Midstream & Marketing Division

EnCana's divisional marketing groups are focused on enhancing the netback price of the Corporation's proprietary production. Correspondingly, the Midstream & Marketing Division coordinates the market optimization activities that include third party purchases and sales of product to provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. In addition, EnCana's power assets are managed to optimize the Corporation's electricity costs, particularly in the Province of Alberta.

Natural Gas Marketing

In 2006, approximately 89 percent of EnCana's produced natural gas sales were directly marketed by EnCana to local distribution companies, industrials, other producers and energy marketing companies. The remaining 11 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.

EnCana mitigates the market risk associated with forecasted cash flows, by entering into various risk management contracts relating to produced natural gas. For 2007, after taking into account its risk management contracts, EnCana's gas sales price portfolio exposure consists of approximately 42 percent at an average fixed NYMEX price of approximately $8.49 per million cubic feet, approximately seven percent with an insured NYMEX strike price of approximately $6.00 per million cubic feet and approximately 51 percent unhedged. Details of these transactions are found in Note 16 to EnCana's audited consolidated financial statements for the year ended December 31, 2006.

Crude Oil Marketing

EnCana, through its operating divisions, sells and manages the transportation of its western Canadian crude oil to markets in Canada and the U.S. (134,869 barrels per day in 2006 and 131,638 barrels per day in 2005). Crude oil sales are normally executed under spot and monthly evergreen contracts with delivery to major pipeline hubs, such as Edmonton and Hardisty, 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 the Enbridge system, for sales to U.S. refinery destinations.

EnCana provides North American marketing services to certain organizations on a fee for service basis. In 2006, EnCana acted as exclusive agent for Canadian Oil Sands Limited ("COS") and marketed COS' Syncrude volumes of 47,583 barrels per day (81,019 barrels per day in 2005). The COS marketing agreement terminated in the second quarter of 2006. EnCana also provides marketing services to the ADOE (45,542 barrels per day in 2006 and 48,425 barrels per day in 2005). This agency agreement ends in the second quarter of 2007.

To help mitigate the market risk associated with forecasted cash flows, EnCana enters into various risk management contracts relating to crude oil. Details of these transactions are found in Note 16 to EnCana's audited consolidated financial statements for the year ended December 31, 2006.

Power

EnCana is a large consumer of electricity in Alberta and uses a portfolio of physical assets, short to medium term purchases and sales and spot market purchases to manage the cost of electricity for its operating divisions in Alberta's deregulated market. The physical assets include two, 106 megawatt gas-fired power plants in southern Alberta. The Cavalier Power Station, 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. EnCana's electricity requirements in Alberta are approximately 185 megawatts and its generation capacity is approximately 159 megawatts, excluding both the electricity requirements and generation capacity of the Integrated Oilsands Division.

RESERVES AND OTHER OIL AND GAS INFORMATION

EnCana has retained independent qualified reserves evaluators to evaluate and prepare reports on 100 percent of EnCana's natural gas, crude oil and NGLs reserves annually since its inception. In 2006, EnCana's Canadian reserves were evaluated by McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd., and its U.S. reserves were evaluated by Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton.

EnCana has a Reserves Committee of independent board members which reviews the qualifications and appointment of the independent qualified reserves evaluators. The Reserves 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.

Reserves Quantities Information

EnCana's natural gas reserves increased approximately five percent in 2006 as a result of successful exploration and development drilling, which resulted in extensions and discoveries of 1,620 billion cubic feet. Included in the revisions and improved recovery category for changes in natural gas reserves were positive revisions in Canada and downward revisions in the U.S., resulting in total positive revisions of 213 billion cubic feet, or approximately two percent of proved natural gas reserves at the beginning of 2006. CBM Integrated accounted for the majority of the positive revisions in Canada. Downward revisions of 88 billion cubic feet in the U.S. were largely a consequence of proved undeveloped reserves being removed given planned moderation in activity levels over the next five years.

In 2005 and 2004, natural gas reserves increased from exploration and development drilling and acquisitions.

EnCana's crude oil and NGLs reserves were essentially unchanged at year-end 2006 in comparison to year-end 2005. Significant increases in proved reserves primarily at Christina Lake and Foster Creek were offset by the completion of the sale of EnCana's interests in Ecuador and negative revisions in Canada. The downward revision in Canada was a consequence of net reserves being reduced in light of higher calculated average royalty rates at Foster Creek stemming from an almost two fold increase in field prices relative to the prior year-end.

In 2005, crude oil and NGLs reserves increased significantly, largely as a result of the reinstatement, due to prices at year-end 2005, of 363 million barrels that appeared as a downward revision in 2004 due to anomalously lower bitumen prices at year-end 2004. The Corporation's crude oil and NGLs reserves decreased in 2004 primarily as a result of the divestiture of non-core properties and the negative revision in Canadian bitumen reserves.

In keeping with U.S. standards requiring 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 that the estimate is made), reference year-end 2006 prices were as follows: crude oil (WTI) $60.85/bbl, (Edmonton Light) C$67.58/bbl, both essentially unchanged from year-end 2005; Foster Creek field price C$35.10/bbl, an increase of 91 percent from year-end 2005; natural gas (Henry Hub) $5.64/MMbtu, a decrease of 45 percent from year-end 2005; and natural gas (AECO) C$6.07/MMbtu, a decrease of 37 percent from year-end 2005.

The following table sets forth reserves continuity information prepared by EnCana in accordance with U.S. disclosure standards, including SFAS 69. The end of year numbers represent estimates derived from the reports of the independent qualified reserves evaluators referred to above.

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**	**Total**	**Canada**	**United States**	**Ecuador**	**United Kingdom**	**Total**
2004									
Beginning of year	5,256	3,129	26	8,411	629.4	41.6	161.7	124.5	957.2
Revisions and improved recovery	67	(252)		(185)	31.1	0.2	(11.5)		19.8
Extensions and discoveries	1,422	1,009		2,431	93.6	47.6	21.2		162.4
Purchase of reserves in place	65	1,150	10	1,225	29.4	11.7		10.1	51.2
Sale of reserves in place	(215)	(82)	(25)	(322)	(97.3)	(5.4)		(128.4)	(231.1)
Production	(771)	(318)	(11)	(1,100)	(56.6)	(4.7)	(28.1)	(6.2)	(95.6)
End of year before bitumen revisions	5,824	4,636		10,460	629.6	91.0	143.3		863.9
Revisions due to bitumen price					(362.7)[3]				(362.7)
End of year	5,824	4,636		10,460	266.9	91.0	143.3		501.2
Developed	4,406	2,496		6,902	210.2	31.5	122.5		364.2
Undeveloped	1,418	2,140		3,558	56.7	59.5	20.8		137.0
Total	5,824	4,636		10,460	266.9	91.0	143.3		501.2
2005									
Beginning of year	5,824	4,636		10,460	266.9	91.0	143.3		501.2
Revisions due to bitumen price					362.7[4]				362.7
Beginning of year before bitumen revisions	5,824	4,636		10,460	629.6	91.0	143.3		863.9
Revisions and improved recovery	202	(260)		(58)	222.1	(3.2)	8.1		227.0
Extensions and discoveries	1,289	1,252		2,541	148.1	8.9	10.2		167.2
Purchase of reserves in place	7	76		83		0.4			0.4
Sale of reserves in place	(30)	(37)		(67)	(15.1)	(39.0)			(54.1)
Production	(775)	(400)		(1,175)	(52.2)	(5.0)	(26.6)		(83.8)
End of year	6,517	5,267		11,784	932.5	53.1	135.0[5]		1,120.6
Developed	4,513	2,718		7,231	318.7	32.2	104.0		454.9
Undeveloped	2,004	2,549		4,553	613.8	20.9	31.0		665.7
Total	6,517	5,267		11,784	932.5	53.1	135.0		1,120.6
2006									
Beginning of year	6,517	5,267		11,784	932.5	53.1	135.0		1,120.6
Revisions and improved recovery	301	(88)		213	(39.0)	(1.1)			(40.1)

	Natural Gas (billions of cubic feet)			Crude Oil and Natural Gas Liquids (millions of barrels)			
Extensions and discoveries	1,014	606	1,620	238.7	6.4		245.1
Purchase of reserves in place		68	68		0.3		0.3
Sale of reserves in place	(6)	(32)	(38)	(0.1)		(130.6)	(130.7)
Production	(798)	(431)	(1,229)	(52.7)	(4.7)	(4.4)	(61.8)
End of year	7,028	5,390	12,418	1,079.4(6)	54.0		1,133.4
Developed	4,718	2,964	7,682	316.9	33.5		350.4
Undeveloped	2,310	2,426	4,736	762.5	20.5		783.0
Total	7,028	5,390	12,418	1,079.4(6)	54.0		1,133.4

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.

(3) Removal of the Corporation's Foster Creek proved bitumen reserves as a result of low bitumen prices on December 31, 2004.

(4) Reinstatement, as a result of year-end 2005 prices, of the Corporation's Foster Creek proved bitumen reserves that were deducted as a revision due to bitumen price at year-end 2004.

(5) The Corporation divested its Ecuadorian operations in 2006.

(6) Proved crude oil and NGLs reserves at December 31, 2006 include approximately 800 million barrels of bitumen, of which 796 million barrels was attributable to the Corporation's interests in Foster Creek and Christina Lake on that date. Effective January 2, 2007, these interests were contributed to the Upstream Partnership in which the Corporation has a 50 percent interest. Accordingly, effective as at that date, the Corporation's reserves associated with those properties were reduced by 398 million barrels.

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 SFAS 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 price 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 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 Market Optimization interests.

Standardized Measure of Discounted Future Net Cash Flows
Relating to Proved Oil and Gas Reserves

	Canada			United States			Ecuador		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
				($ millions)					
Future cash inflows	72,262	71,786	37,791	27,165	40,504	27,063		5,350	3,317
Less future:									
Production costs	20,471	16,765	7,760	4,123	3,262	2,462		2,093	1,136
Development costs	9,355	6,164	3,157	4,715	4,174	3,213		429	198
Asset retirement obligation payments	2,397	2,269	1,749	396	264	193		24	22
Income taxes	8,816	13,170	6,279	5,349	11,041	7,021		662	342
Future net cash flows	31,223	33,418	18,846	12,582	21,763	14,174		2,142	1,619
Less 10% annual discount for estimated timing of cash flows	14,627	13,281	6,668	6,128	10,291	6,686		574	417
Discounted future net cash flows	16,596	20,137	12,178	6,454	11,472	7,488		1,568	1,202

	United Kingdom			Total		
	2006	2005	2004	2006	2005	2004
			($ millions)			
Future cash inflows				99,427	117,640	68,171
Less future:						
Production costs				24,594	22,120	11,358

Development costs	14,070	10,767	6,568
Asset retirement obligation payments	2,793	2,557	1,964
Income taxes	14,165	24,873	13,642
Future net cash flows	43,805	57,323	34,639
Less 10% annual discount for estimated timing of cash flows	20,755	24,146	13,771
Discounted future net cash flows	23,050	33,177	20,868

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	Canada			United States			Ecuador		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
	($ millions)								
Balance, beginning of year	20,137	12,178	10,015	11,472	7,488	4,888	1,568	1,202	1,367
Changes resulting from:									
Sales of oil and gas produced during the period	(5,970)	(5,720)	(3,965)	(2,373)	(2,436)	(1,474)	(142)	(604)	(264)
Discoveries and extensions, net of related costs	2,584	4,278	3,562	877	3,582	2,436		159	236
Purchases of proved reserves in place		26	531	69	237	2,786			
Sales of proved reserves in place	(19)	(279)	(1,579)	(85)	(486)	(271)	(1,359)		
Net change in prices and production costs	(5,797)	11,624	2,264	(7,636)	4,716	143		967	(294)
Revisions to quantity estimates	155	1,071	546	265	(700)	(542)		88	(125)
Accretion of discount	2,809	1,629	1,349	1,714	1,103	725		147	176
Previously estimated development costs incurred net of change in future development costs	(805)	(888)	57	(350)	162	22	(46)	(148)	15
Other	(174)	63	32	(381)	(64)	(49)		8	(29)
Net change in income taxes	3,676	(3,845)	(634)	2,882	(2,130)	(1,176)	(21)	(251)	120
Balance, end of year	16,596	20,137	12,178	6,454	11,472	7,488		1,568	1,202

	United Kingdom			Total		
	2006	2005	2004	2006	2005	2004
	($ millions)					
Balance, beginning of year			565	33,177	20,868	16,835
Changes resulting from:						
Sales of oil and gas produced during the period			(78)	(8,485)	(8,760)	(5,781)
Discoveries and extensions, net of related costs				3,461	8,019	6,234
Purchases of proved reserves in place			77	69	263	3,394
Sales of proved reserves in place			(899)	(1,463)	(765)	(2,749)
Net change in prices and production costs				(13,433)	17,307	2,113
Revisions to quantity estimates				420	459	(121)
Accretion of discount			82	4,523	2,879	2,332
Previously estimated development costs incurred net of change in future development costs				(1,201)	(874)	94
Other				(555)	7	(46)
Net change in income taxes			253	6,537	(6,226)	(1,437)
Balance, end of year				23,050	33,177	20,868

Results of Operations, Capitalized Costs and Costs Incurred

Results of Operations

	Canada			United States			Ecuador(1)		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**	**2006**	**2005**	**2004**
					($ millions)				
Oil and gas revenues, net of royalties, transportation and selling costs	7,190	6,701	4,787	3,096	3,052	1,861	190	873	451
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	1,220	981	822	723	616	387	48	269	187
Depreciation, depletion and amortization	2,146	1,961	1,752	869	712	487	84	234	263
Operating income (loss)	3,824	3,759	2,213	1,504	1,724	987	58	370	1
Income taxes	1,235	1,274	841	556	638	375	21	134	5
Results of operations	2,589	2,485	1,372	948	1,086	612	37	236	(4)

	United Kingdom			Other			Total		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**	**2006**	**2005**	**2004**
					($ millions)				
Oil and gas revenues, net of royalties, transportation and selling costs			117	2			10,478	10,626	7,216
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations			39	11	6	4	2,002	1,872	1,439
Depreciation, depletion and amortization			118	10	8	25	3,109	2,915	2,645
Operating income (loss)			(40)	(19)	(14)	(29)	5,367	5,839	3,132
Income taxes			(15)				1,812	2,046	1,206
Results of operations			(25)	(19)	(14)	(29)	3,555	3,793	1,926

Note:

(1) The sale of EnCana's Ecuador operations was completed in February 2006, and a loss on sale of $279 million, including indemnities, was recorded. Depreciation, depletion and amortization in 2006 and 2005 represents provisions which have been recorded against the net book value to recognize management's best estimate of the difference between the selling price and the underlying accounting value of the related investments at February 28, 2006 and December 31, 2005.

Capitalized Costs

	Canada			United States			Ecuador		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**	**2006**	**2005**	**2004**
					($ millions)				
Proved oil and gas properties	31,546	27,074	22,455	9,796	7,753	7,552		1,926	1,784
Unproved oil and gas properties	1,700	1,998	1,855	1,221	870	728		18	45

	Canada			United States			Ecuador		
Total capital cost	33,246	29,072	24,310	11,017	8,623	8,280		1,944	1,829
Accumulated DD&A	14,261	12,131	9,770	2,595	1,750	1,046		778	534
Net capitalized costs	18,985	16,941	14,540	8,422	6,873	7,234		1,166	1,295

	United Kingdom			Other			Total		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
				($ millions)					
Proved oil and gas properties							41,342	36,753	31,791
Unproved oil and gas properties				361	470	425	3,282	3,356	3,053
Total capital cost				361	470	425	44,624	40,109	34,844
Accumulated DD&A				98	222	247	16,954	14,881	11,597
Net capitalized costs				263	248	178	27,670	25,228	23,247

Costs Incurred

	Canada			United States			Ecuador		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
					($ millions)				
Acquisitions									
Unproved reserves			42	278	271	954			
Proved reserves	47	30	204	6	141	2,051			
Total acquisitions	47	30	246	284	412	3,005			
Exploration costs	403	817	555	236	264	164	1	15	28
Development costs	3,611	3,333	2,669	1,826	1,724	1,103	46	164	213
Total costs incurred	4,061	4,180	3,470	2,346	2,400	4,272	47	179	241

	United Kingdom			Other			Total		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
					($ millions)				
Acquisitions									
Unproved reserves							278	271	996
Proved reserves			130				53	171	2,385
Total acquisitions			130				331	442	3,381
Exploration costs			22	75	70	79	715	1,166	848
Development costs			364				5,483	5,221	4,349
Total costs incurred			516	75	70	79	6,529	6,829	8,578

Sales Volumes, Royalty Rates and Per-Unit Results

Sales Volumes

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

	Sales Volumes 2006				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
SALES VOLUMES					
Continuing Operations:					
Produced Gas ***(MMcf/d)***					
Canada					
Production	2,185	2,205	2,162	2,192	2,182
Inventory withdrawal/(injection)					
Canada Sales	2,185	2,205	2,162	2,192	2,182
United States	1,182	1,201	1,197	1,169	1,161
Total Produced Gas	3,367	3,406	3,359	3,361	3,343
Oil and Natural Gas Liquids ***(bbls/d)***					
North America					
Light and Medium Oil	44,360	41,872	45,980	43,727	45,889
Heavy Oil Foster Creek/Christina Lake	42,768	46,678	43,073	39,215	42,050
Heavy Oil Other	43,369	39,498	37,605	46,128	50,431
Natural Gas Liquids[(1)]					
Canada	11,713	11,856	11,387	11,607	12,006
United States	12,494	12,250	12,520	12,793	12,415
Total Oil and Natural Gas Liquids	154,704	152,154	150,565	153,470	162,791
Total Continuing Operations ***(MMcfe/d)***	4,295	4,319	4,262	4,282	4,320
Discontinued Operations:					
Ecuador					
Production	11,996				48,650
(Under)/over lifting	370				1,500
Ecuador Sales *(bbls/d)*	12,366				50,150
Total Discontinued Operations ***(MMcfe/d)***	74				301
Total ***(MMcfe/d)***	4,369	4,319	4,262	4,282	4,621

Note:

(1) Natural gas liquids include condensate volumes.

	Sales Volumes 2005				
	Year	Q4	Q3	Q2	Q1
SALES VOLUMES					
Continuing Operations:					
Produced Gas *(MMcf/d)*					
Canada					
Production	2,125	2,172	2,123	2,151	2,052
Inventory withdrawal/(injection)	7				27
Canada Sales	2,132	2,172	2,123	2,151	2,079
United States	1,095	1,154	1,099	1,061	1,067
Total Produced Gas	3,227	3,326	3,222	3,212	3,146
Oil and Natural Gas Liquids *(bbls/d)*					
North America					
Light and Medium Oil	47,328	45,792	43,313	50,020	50,280
Heavy Oil Foster Creek/Christina Lake	34,379	39,839	32,580	31,025	34,027
Heavy Oil Other	48,711	48,547	48,509	51,249	46,519
Natural Gas Liquids[1]					
Canada	11,907	12,287	11,924	11,719	11,692
United States	13,675	12,824	14,131	13,095	14,666
Total Oil and Natural Gas Liquids	156,000	159,289	150,457	157,108	157,184
Total Continuing Operations *(MMcfe/d)*	4,163	4,282	4,125	4,155	4,089
Discontinued Operations:					
Ecuador					
Production	72,916	70,480	71,896	73,662	75,695
(Under)/over lifting	(1,851)	(537)	(3,186)	(486)	(3,208)
Ecuador Sales *(bbls/d)*	71,065	69,943	68,710	73,176	72,487
Total Discontinued Operations *(MMcfe/d)*	426	419	412	439	435
Total *(MMcfe/d)*	4,589	4,701	4,537	4,594	4,524

Note:

(1) Natural gas liquids include condensate volumes.

	Sales Volumes 2004				
	Year	Q4	Q3	Q2	Q1
SALES VOLUMES					
Continuing Operations:					
Produced Gas ***(MMcf/d)***					
Canada					
Production	2,105	2,106	2,138	2,177	2,000
Inventory withdrawal/(injection)	(6)	(26)			
Canada Sales[1]	2,099	2,080	2,138	2,177	2,000
United States	869	1,007	958	824	684
Total Produced Gas	2,968	3,087	3,096	3,001	2,684
Oil and Natural Gas Liquids ***(bbls/d)***					
North America					
Light and Medium Oil	56,215	52,725	52,824	64,448	54,940
Heavy Oil Foster Creek/Christina Lake	33,105	33,035	34,384	33,624	31,353
Heavy Oil Other	51,059	46,301	55,298	46,275	56,376
Natural Gas Liquids[2]					
Canada	13,452	13,452	12,804	13,588	13,971
United States	12,586	13,957	14,363	12,752	9,237
Total Oil and Natural Gas Liquids[3]	166,417	159,470	169,673	170,687	165,877
Total Continuing Operations ***(MMcfe/d)***	3,966	4,044	4,114	4,025	3,679
Discontinued Operations:					
Ecuador					
Production	76,872	76,235	76,567	78,376	76,320
Over/(under) lifting	1,121	1,641	(1,721)	(73)	4,662
Ecuador Sales *(bbls/d)*	77,993	77,876	74,846	78,303	80,982
United Kingdom *(BOE/d)*	20,973	13,927	20,222	26,728	22,755
Total Discontinued Operations ***(MMcfe/d)***	594	551	570	630	623
Total ***(MMcfe/d)***	4,560	4,595	4,684	4,655	4,302

Notes:

(1) Net divestitures total approximately 42 MMcf/day for the full year 2004.

(2)

Natural gas liquids include condensate volumes.

(3) Net divestitures total approximately 15,500 bbls/day for the full year 2004.

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 realized financial hedging.

	2006					2005					2004				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
	(percent)					(percent)					(percent)				
Continuing Operations:															
Produced Gas															
Canada	10.5	9.9	10.5	10.4	11.2	11.7	11.9	11.8	11.0	11.9	12.5	12.0	12.2	12.7	13.3
United States	18.5	18.3	18.4	18.7	18.7	18.6	18.6	19.9	17.9	18.1	19.6	19.8	18.3	21.1	19.3
Crude Oil															
Canada and United States	9.9	10.3	11.4	10.5	7.5	8.8	8.8	8.7	9.2	8.7	9.0	8.7	8.8	11.6	9.4
Natural Gas Liquids															
Canada	15.5	15.3	16.3	14.4	16.1	14.9	14.4	15.8	15.6	13.8	15.7	16.5	18.5	13.1	14.8
United States	18.7	18.8	17.7	20.1	18.3	18.2	19.4	20.1	12.7	20.0	18.7	21.4	13.6	20.7	19.2
Total North America	13.0	12.7	13.2	13.1	12.9	13.3	13.5	13.8	12.6	13.3	13.7	13.8	13.2	14.1	13.7
Discontinued Operations:															
Crude Oil Ecuador	25.2				25.2	27.2	29.4	26.3	26.3	26.9	27.1	27.8	26.5	26.5	27.4

Per-Unit Results

The following tables summarize net per-unit results for EnCana on a quarterly basis for the periods indicated. The results exclude the impact of realized financial hedging.

	Per-Unit Results 2006				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Produced Gas Canada ($/Mcf)					
Price	6.20	5.87	5.59	5.71	7.66
Production and mineral taxes	0.10	0.05	0.09	0.08	0.18
Transportation and selling	0.35	0.33	0.37	0.35	0.34
Operating	0.79	0.82	0.78	0.77	0.79
Netback	4.96	4.67	4.35	4.51	6.35
Produced Gas United States ($/Mcf)					
Price	6.35	5.65	6.04	6.08	7.70
Production and mineral taxes	0.49	0.50	0.43	0.22	0.85

	Per-Unit Results 2006				
Transportation and selling	0.54	0.60	0.57	0.50	0.49
Operating	0.65	0.68	0.59	0.70	0.64
Netback	4.67	3.87	4.45	4.66	5.72
Produced Gas Total North America ($/Mcf)					
Price	6.25	5.79	5.75	5.84	7.68
Production and mineral taxes	0.24	0.21	0.21	0.13	0.41
Transportation and selling	0.42	0.42	0.44	0.40	0.40
Operating	0.74	0.77	0.71	0.74	0.74
Netback	4.85	4.39	4.39	4.57	6.13

	Per-Unit Results 2006				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids Canada ($/bbl)					
Price	51.12	44.79	55.95	55.19	48.84
Production and mineral taxes					
Transportation and selling	0.67	0.58	0.74	0.73	0.61
Netback	50.45	44.21	55.21	54.46	48.23
Natural Gas Liquids United States ($/bbl)					
Price	56.33	51.04	61.76	58.25	54.07
Production and mineral taxes	4.19	4.62	4.42	2.60	5.18
Transportation and selling	0.01	0.01	0.01	0.01	0.01
Netback	52.13	46.41	57.33	55.64	48.88
Natural Gas Liquids Total North America ($/bbl)					
Price	53.81	47.97	58.99	56.80	51.50
Production and mineral taxes	2.16	2.35	2.31	1.36	2.63
Transportation and selling	0.33	0.29	0.36	0.35	0.31
Netback	51.32	45.33	56.32	55.09	48.56
Crude Oil Light and Medium North America ($/bbl)					
Price	51.76	43.28	56.50	61.62	45.31
Production and mineral taxes	2.16	2.15	2.13	2.47	1.92
Transportation and selling	0.98	0.61	1.32	0.65	1.29
Operating	8.62	9.01	10.00	7.36	8.06
Netback	40.00	31.51	43.05	51.14	34.04
Crude Oil Heavy Foster Creek/Christina Lake ($/bbl)					
Price	36.49	39.32	37.19	46.53	23.08
Production and mineral taxes					
Transportation and selling	2.64	2.74	2.64	3.38	1.80
Operating[(1)]	12.38	13.07	14.06	11.78	10.39
Netback	21.47	23.51	20.49	31.37	10.89
Crude Oil Total Heavy North America ($/bbl)					
Price	36.72	33.87	44.32	46.49	23.53
Production and mineral taxes	0.05	0.05	0.05	0.07	0.04
Transportation and selling	1.62	1.35	1.98	2.00	1.21
Operating	9.33	10.58	10.32	8.82	7.69
Netback	25.72	21.89	31.97	35.60	14.59
Crude Oil Total North America ($/bbl)					
Price	41.83	36.94	48.74	51.62	30.76
Production and mineral taxes	0.77	0.74	0.81	0.88	0.66
Transportation and selling	1.40	1.11	1.74	1.54	1.24
Operating	9.09	10.05	10.20	8.34	7.82
Netback	30.57	25.04	35.99	40.86	21.04

Per-Unit Results	2006				
Total Liquids Canada ($/bbl)					
Price	42.53	37.55	49.21	51.91	32.17
Production and mineral taxes	0.70	0.67	0.73	0.80	0.61
Transportation and selling	1.35	1.06	1.67	1.48	1.19
Operating	8.33	9.21	9.39	7.63	7.17
Netback	32.15	26.61	37.42	42.00	23.20

	Per-Unit Results 2006				
	Year	Q4	Q3	Q2	Q1
Total Liquids Total North America ($/bbl)					
Price	43.71	38.69	50.37	52.44	33.87
Production and mineral taxes	0.99	0.99	1.05	0.96	0.96
Transportation and selling	1.24	0.98	1.52	1.35	1.10
Operating	7.66	8.47	8.58	7.01	6.64
Netback	33.82	28.25	39.22	43.12	25.17
Total North America ($/Mcfe)					
Price	6.48	5.93	6.31	6.46	7.22
Production and mineral taxes	0.22	0.20	0.20	0.13	0.36
Transportation and selling	0.37	0.37	0.40	0.36	0.35
Operating(2)	0.86	0.90	0.87	0.84	0.82
Netback	5.03	4.46	4.84	5.13	5.69
Discontinued Operations:					
Crude Oil Ecuador ($/bbl)					
Price	44.35				44.35
Production and mineral taxes	5.03				5.03
Transportation and selling	2.25				2.25
Operating	5.55				5.55
Netback	31.52				31.52

Notes:

(1) Heavy oil operating costs now include costs related to the Foster Creek power cogeneration facility.

(2) Year-to-date operating costs include costs related to long-term incentives of $0.02/Mcfe.

	Per-Unit Results 2005				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Produced Gas Canada ($/Mcf)					
Price	7.27	10.00	7.18	6.08	5.70
Production and mineral taxes	0.10	0.10	0.10	0.10	0.09
Transportation and selling	0.36	0.36	0.36	0.36	0.37
Operating	0.67	0.72	0.68	0.62	0.65
Netback	6.14	8.82	6.04	5.00	4.59
Produced Gas United States ($/Mcf)					

	Per-Unit Results 2005				
Price	7.82	10.84	7.51	6.60	6.04
Production and mineral taxes	0.81	1.19	0.75	0.65	0.62
Transportation and selling	0.46	0.45	0.49	0.42	0.46
Operating	0.53	0.60	0.55	0.50	0.45
Netback	6.02	8.60	5.72	5.03	4.51
Produced Gas Total North America ($/Mcf)					
Price	7.46	10.29	7.29	6.25	5.81
Production and mineral taxes	0.34	0.48	0.32	0.28	0.27
Transportation and selling	0.40	0.39	0.41	0.38	0.40
Operating	0.62	0.68	0.64	0.58	0.58
Netback	6.10	8.74	5.92	5.01	4.56

	Per-Unit Results 2005				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids Canada ($/bbl)					
Price	44.24	49.51	47.39	39.55	40.04
Production and mineral taxes					
Transportation and selling	0.42	0.46	0.48	0.39	0.35
Netback	43.82	49.05	46.91	39.16	39.69
Natural Gas Liquids United States ($/bbl)					
Price	48.36	54.14	53.92	44.79	40.93
Production and mineral taxes	4.86	5.42	5.46	4.37	4.20
Transportation and selling	0.01	0.01	0.01	0.01	0.01
Netback	43.49	48.71	48.45	40.41	36.72
Natural Gas Liquids Total North America ($/bbl)					
Price	46.44	51.87	50.93	42.32	40.53
Production and mineral taxes	2.60	2.77	2.96	2.31	2.34
Transportation and selling	0.20	0.23	0.23	0.19	0.16
Netback	43.64	48.87	47.74	39.82	38.03
Crude Oil Light and Medium North America ($/bbl)					
Price	45.09	46.27	55.41	41.44	38.57
Production and mineral taxes	1.54	1.83	1.29	1.71	1.32
Transportation and selling	1.20	1.14	1.29	1.20	1.19
Operating	6.34	6.41	6.24	6.34	6.38
Netback	36.01	36.89	46.59	32.19	29.68
Crude Oil Heavy Foster Creek/Christina Lake ($/bbl)					
Price	22.02	20.17	33.11	19.28	15.92
Production and mineral taxes					
Transportation and selling	1.54	1.53	1.24	2.02	1.42
Operating(1)	10.94	11.93	10.74	11.71	9.25
Netback	9.54	6.71	21.13	5.55	5.25
Crude Oil Heavy North America ($/bbl)					
Price	27.92	28.27	39.69	22.77	20.76
Production and mineral taxes	0.04	0.05	0.04	0.02	0.03
Transportation and selling	1.20	1.11	1.08	1.13	1.52
Operating	7.74	8.50	7.95	7.43	6.97
Netback	18.94	18.61	30.62	14.19	12.24
Crude Oil Total North America ($/bbl)					
Price	34.15	34.41	45.16	29.83	27.60
Production and mineral taxes	0.58	0.66	0.48	0.66	0.53
Transportation and selling	1.20	1.12	1.15	1.15	1.39
Operating	7.23	7.79	7.35	7.02	6.74
Netback	25.14	24.84	36.18	21.00	18.94

	Per-Unit Results 2005				
Total Liquids Canada ($/bbl)					
Price	34.97	35.65	45.35	30.58	28.60
Production and mineral taxes	0.53	0.60	0.43	0.61	0.48
Transportation and selling	1.14	1.07	1.09	1.09	1.31
Operating	6.61	7.13	6.66	6.45	6.19
Netback	26.69	26.85	37.17	22.43	20.62

	Per-Unit Results 2005				
	Year	Q4	Q3	Q2	Q1
Total Liquids Total North America ($/bbl)					
Price	36.17	37.16	46.16	31.80	29.77
Production and mineral taxes	0.91	0.99	0.91	0.92	0.83
Transportation and selling	1.04	0.98	0.99	1.00	1.18
Operating	6.04	6.56	6.08	5.91	5.61
Netback	28.18	28.63	38.18	23.97	22.15
Total North America ($/Mcfe)					
Price	7.13	9.37	7.38	6.03	5.62
Production and mineral taxes	0.30	0.41	0.29	0.25	0.24
Transportation and selling	0.35	0.34	0.35	0.33	0.36
Operating(2)	0.71	0.77	0.72	0.67	0.66
Netback	5.77	7.85	6.02	4.78	4.36
Discontinued Operations:					
Crude Oil Ecuador ($/bbl)					
Price	39.36	37.82	47.76	36.37	35.80
Production and mineral taxes	5.04	4.63	7.66	4.53	3.42
Transportation and selling	2.25	1.86	2.45	2.48	2.21
Operating	5.32	5.82	6.05	5.18	4.26
Netback	26.75	25.51	31.60	24.18	25.91

Notes:

(1) Heavy oil operating costs now include costs related to the Foster Creek power cogeneration facility.

(2) Year-to-date operating costs include costs related to long-term incentives of $0.03/Mcfe.

	Per-Unit Results 2004				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Produced Gas Canada ($/Mcf)					
Price	5.34	5.86	5.10	5.20	5.21
Production and mineral taxes	0.08	0.10	0.09	0.07	0.08
Transportation and selling	0.39	0.39	0.37	0.35	0.44
Operating	0.52	0.55	0.50	0.49	0.56
Netback	4.35	4.82	4.14	4.29	4.13
Produced Gas United States ($/Mcf)					

	Per-Unit Results 2004				
Price	5.79	6.53	5.36	5.72	5.39
Production and mineral taxes	0.65	0.69	0.57	0.80	0.51
Transportation and selling	0.31	0.27	0.26	0.34	0.39
Operating	0.37	0.41	0.36	0.37	0.33
Netback	4.46	5.16	4.17	4.21	4.16
Produced Gas Total North America ($/Mcf)					
Price	5.47	6.08	5.18	5.34	5.26
Production and mineral taxes	0.25	0.29	0.24	0.27	0.19
Transportation and selling	0.36	0.35	0.33	0.35	0.43
Operating	0.48	0.50	0.46	0.46	0.50
Netback	4.38	4.94	4.15	4.26	4.14

	Per-Unit Results 2004				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids Canada ($/bbl)					
Price	31.43	36.73	33.46	28.48	27.27
Production and mineral taxes					
Transportation and selling	0.41	0.47	0.45	0.35	0.35
Netback	31.02	36.26	33.01	28.13	26.92
Natural Gas Liquids United States ($/bbl)					
Price	35.43	38.74	36.09	32.93	32.77
Production and mineral taxes	3.82	3.94	4.05	3.93	3.09
Transportation and selling					
Netback	31.61	34.80	32.04	29.00	29.68
Natural Gas Liquids Total North America ($/bbl)					
Price	33.36	37.75	34.85	30.63	29.46
Production and mineral taxes	1.84	2.00	2.14	1.90	1.23
Transportation and selling	0.21	0.23	0.21	0.18	0.21
Netback	31.31	35.52	32.50	28.55	28.02
Crude Oil Light and Medium North America ($/bbl)					
Price	34.67	39.57	37.40	32.43	29.92
Production and mineral taxes	0.96	1.38	0.85	0.79	0.86
Transportation and selling	1.01	1.04	1.08	0.76	1.19
Operating	5.85	6.41	6.49	4.84	5.87
Netback	26.85	30.74	28.98	26.04	22.00
Crude Oil Heavy Foster Creek/Christina Lake ($/bbl)					
Price	20.75	17.46	26.32	19.92	18.97
Production and mineral taxes					
Transportation and selling	1.15	1.03	1.26	1.15	1.15
Operating[1]	9.34	10.41	9.03	8.97	8.96
Netback	10.26	6.02	16.03	9.80	8.86
Crude Oil Total Heavy North America ($/bbl)					
Price	23.41	21.37	28.01	22.35	21.48
Production and mineral taxes	0.04	0.04	0.05	(0.01)	0.06
Transportation and selling	1.09	(0.57)	1.63	1.50	1.69
Operating	6.10	7.24	5.39	5.77	6.11
Netback	16.18	14.66	20.94	15.09	13.62
Crude Oil Total North America ($/bbl)					
Price	27.92	28.63	31.49	26.85	24.73
Production and mineral taxes	0.41	0.57	0.34	0.35	0.37
Transportation and selling	1.06	0.07	1.42	1.17	1.50
Operating	6.00	6.91	5.80	5.36	6.02
Netback	20.45	21.08	23.93	19.97	16.84

	Per-Unit Results	2004

36

	Per-Unit Results 2004				
	Year	Q4	Q3	Q2	Q1
Total Liquids Canada ($/bbl)					
Price	28.21	29.36	31.63	26.99	24.95
Production and mineral taxes	0.37	0.52	0.31	0.32	0.34
Transportation and selling	1.00	0.11	1.35	1.10	1.40
Operating	5.48	6.28	5.33	4.90	5.48
Netback	21.36	22.45	24.64	20.67	17.73
Total Liquids Total North America ($/bbl)					
Price	28.77	30.20	32.03	27.43	25.39
Production and mineral taxes	0.63	0.82	0.63	0.59	0.49
Transportation and selling	0.93	0.10	1.23	1.02	1.32
Operating	5.06	5.72	4.87	4.53	5.17
Netback	22.15	23.56	25.30	21.29	18.41
Total North America ($/Mcfe)					
Price	5.30	5.83	5.22	5.15	4.98
Production and mineral taxes	0.21	0.25	0.21	0.22	0.16
Transportation and selling	0.31	0.27	0.30	0.30	0.37
Operating(2)	0.57	0.61	0.54	0.54	0.60
Netback	4.21	4.70	4.17	4.09	3.85
<u>Discontinued Operations:</u>					
Crude Oil Ecuador ($/bbl)					
Price	28.68	29.97	33.47	27.78	23.82
Production and mineral taxes	2.13	2.73	2.62	1.84	1.37
Transportation and selling	2.12	1.57	2.36	1.92	2.63
Operating	4.39	5.02	4.35	4.14	4.04
Netback	20.04	20.65	24.14	19.88	15.78
Crude Oil United Kingdom ($/bbl)					
Price	36.92	46.19	40.88	34.68	31.11
Production and mineral taxes					
Transportation and selling	2.06	2.17	2.44	1.85	1.94
Operating	6.75	5.00	9.98	7.84	3.86
Netback	28.11	39.02	28.46	24.99	25.31

Notes:

(1) Heavy oil operating costs now include costs related to the Foster Creek power cogeneration facility.

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

The following tables show the impact of realized financial hedging on EnCana's per-unit results.

	2006				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Natural Gas ($/Mcf)	0.47	0.91	0.82	0.66	(0.53)
Liquids ($/bbl)	(3.32)	(3.30)	(3.45)	(3.43)	(3.12)
Total ($/Mcfe)	0.25	0.60	0.53	0.40	(0.53)
Discontinued Operations:					
Ecuador Oil ($/bbl)	(0.12)				(0.12)

	2005				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Natural Gas ($/Mcf)	(0.32)	(0.88)	(0.39)	(0.14)	0.18
Liquids ($/bbl)	(5.18)	(5.00)	(5.70)	(4.88)	(5.18)
Total ($/Mcfe)	(0.44)	(0.87)	(0.52)	(0.30)	(0.06)
Discontinued Operations:					
Ecuador Oil ($/bbl)	(4.92)	(3.57)	(7.81)	(4.90)	(3.48)

	2004				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Natural Gas ($/Mcf)	(0.22)	(0.37)	(0.15)	(0.25)	(0.08)
Liquids ($/bbl)	(7.08)	(8.24)	(8.75)	(6.53)	(4.79)
Total ($/Mcfe)	(0.46)	(0.61)	(0.48)	(0.47)	(0.27)
Discontinued Operations:					
Ecuador Oil ($/bbl)	(9.66)	(14.60)	(10.31)	(7.13)	(6.69)
United Kingdom Oil ($/bbl)[1]	(7.62)	(6.34)	(11.75)	(7.01)	(5.72)

Note:

(1) Excludes hedges unwound as a result of the United Kingdom divestiture.

Drilling Activity

The following tables summarize EnCana's gross participation and net interest in wells drilled for the periods indicated.

Exploration Wells Drilled

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
Continuing Operations:											
2006:											
Canada	281	230	7	7	7	6	295	243	128	423	243
United States	12	7			2	1	14	8		14	8
Other			2	1	4	1	6	2		6	2
Total	293	237	9	8	13	8	315	253	128	443	253
2005:											
Canada	605	540	8	8	7	7	620	555	99	719	555
United States	7	6			9	7	16	13	1	17	13
Other			3	1	3	2	6	3		6	3
Total	612	546	11	9	19	16	642	571	100	742	571
2004:											
Canada	566	534	48	47	9	6	623	587	51	674	587
United States	19	16	2				21	16		21	16
Other			3	2	5	2	8	4		8	4
Total	585	550	53	49	14	8	652	607	51	703	607
Discontinued Operations:											
Ecuador 2006											
Ecuador 2005			2	1	3	2	5	3		5	3
Ecuador 2004			6	3			6	3		6	3
United Kingdom 2004			1		4	2	5	2		5	2

Development Wells Drilled

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
Continuing Operations:											
2006:											
Canada	2,799	2,639	139	103	25	24	2,963	2,766	855	3,818	2,766
United States	779	625			7	6	786	631	22	808	631
Total	3,578	3,264	139	103	32	30	3,749	3,397	877	4,626	3,397
2005:											
Canada	3,503	3,229	277	243	12	11	3,792	3,483	932	4,724	3,483
United States	699	604					699	604	9	708	604
Total	4,202	3,833	277	243	12	11	4,491	4,087	941	5,432	4,087
2004:											
Canada	3,632	3,419	386	364	16	15	4,034	3,798	1,105	5,139	3,798
United States	600	515	1		3	3	604	518		604	518
Total	4,232	3,934	387	364	19	18	4,638	4,316	1,105	5,743	4,316
Discontinued Operations:											
Ecuador 2006			7	6	1	1	8	7		8	7
Ecuador 2005			28	15	3	1	31	16		31	16
Ecuador 2004			43	25	1	1	44	26		44	26
United Kingdom 2004			3	1			3	1		3	1

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.

(3) At December 31, 2006, EnCana was in the process of drilling 34 gross wells (32 net wells) in Canada, 46 gross wells (34 net wells) in the United States and one well outside of North America.

Location of Wells

The following table summarizes EnCana's interest in producing wells and wells capable of producing as at December 31, 2006:

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Continuing Operations:						
Alberta	35,826	33,764	3,956	3,593	39,782	37,357
British Columbia	1,950	1,758	16	10	1,966	1,768
Saskatchewan	477	451	1,244	544	1,721	995
Manitoba			1	1	1	1
Total Canada	38,253	35,973	5,217	4,148	43,470	40,121
Colorado	4,119	3,583			4,119	3,583
Texas	3,101	1,427	39	21	3,140	1,448
Wyoming	1,756	1,210	1		1,757	1,210
Utah	20	15	2	2	22	17
Oklahoma	1				1	
Total United States	8,997	6,235	42	23	9,039	6,258
Total	47,250	42,208	5,259	4,171	52,509	46,379

Notes:

(1) EnCana has varying royalty interests in 14,554 natural gas wells and 9,155 crude oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: 28,296 gross natural gas wells (26,945 net wells) and 1,314 gross crude oil wells (1,130 net wells).

Interest in Material Properties

The following table summarizes EnCana's developed, undeveloped and total landholdings as at December 31, 2006:

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
				(thousands of acres)			
Continuing Operations:							
Canada							
Alberta	Fee	4,415	4,415	2,708	2,707	7,123	7,122
	Crown	4,051	3,200	5,259	4,368	9,310	7,568
	Freehold	230	132	212	175	442	307
		8,696	7,747	8,179	7,250	16,875	14,997
British Columbia	Crown	1,053	900	4,353	3,653	5,406	4,553
	Freehold			7		7	
		1,053	900	4,360	3,653	5,413	4,553
Saskatchewan	Fee	62	62	457	457	519	519
	Crown	133	114	508	461	641	575
	Freehold	15	11	51	48	66	59
		210	187	1,016	966	1,226	1,153
Manitoba	Fee	3	3	263	263	266	266
		3	3	263	263	266	266
Newfoundland & Labrador	Crown			1,550	1,018	1,550	1,018
Nova Scotia	Crown			1,184	638	1,184	638
Northwest Territories	Crown			314	174	314	174
Yukon	Crown			5	2	5	2
Beaufort	Crown			125	4	125	4
Total Canada		9,962	8,837	16,996	13,968	26,958	22,805

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
		(thousands of acres)					
United States							
Colorado	Federal/State Lands	191	178	798	732	989	910
	Freehold	110	104	161	147	271	251
	Fee	3	3	37	37	40	40
		304	285	996	916	1,300	1,201
Washington	Federal/State Lands			638	626	638	626
	Freehold			185	185	185	185
				823	811	823	811
Texas	Federal/State Lands	8	3	441	423	449	426
	Freehold	172	113	1,216	988	1,388	1,101
	Fee			4	2	4	2
		180	116	1,661	1,413	1,841	1,529
Wyoming	Federal/State Lands	143	87	785	593	928	680
	Freehold	25	18	57	35	82	53
		168	105	842	628	1,010	733
Other	Federal/State Lands	9	7	336	199	345	206
	Freehold	12	5	1,031	1,026	1,043	1,031
		21	12	1,367	1,225	1,388	1,237
Total United States		673	518	5,689	4,993	6,362	5,511
Chad[7]				54,103	27,052	54,103	27,052
Oman				8,568	4,284	8,568	4,284
Qatar				2,160	1,081	2,160	1,081
Greenland				1,701	1,488	1,701	1,488
Brazil				1,662	522	1,662	522
Australia				1,053	357	1,053	357
France				859	859	859	859
Azerbaijan				346	17	346	17
Total International				70,452	35,660	70,452	35,660
Total		10,635	9,355	93,137	54,621	103,772	63,976

Notes:

(1)

This table excludes approximately 4.2 million gross acres under lease or sublease, reserving to EnCana royalties or other interests.

(2) Fee lands are those lands in which EnCana has a fee simple interest in the minerals rights and has either: (i) not leased out all of the mineral zones; or (ii) retained a working interest. The current fee lands acreage summary now includes all fee titles owned by EnCana that have one or more zones that remain unleased or available for development.

(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.

(7) In January 2007, a subsidiary of EnCana completed the sale of all its interests in its Chad exploration assets.

Acquisitions, Divestitures and Capital Expenditures

EnCana's growth in recent years has been achieved through a combination of internal growth and acquisitions. EnCana has a large inventory of internal growth opportunities and also continues to examine select acquisition opportunities to develop and expand its key resource plays. The acquisition opportunities may include corporate or asset acquisitions, and EnCana may finance any such acquisitions with debt, equity, cash generated from operations, proceeds from asset divestitures or a combination of these sources.

The following table summarizes EnCana's net capital investment for 2006 and 2005.

	2006	**2005**
	($ millions)	
Upstream		
Canada excluding Foster Creek / Christina Lake	3,383	3,757
Foster Creek / Christina Lake	632	393
Total Canada	4,015	4,150
United States	2,061	1,982
Other Countries	75	70
	6,151	6,202
Market Optimization	44	197
Corporate	74	78
Core Capital from Continuing Operations	6,269	6,477
Upstream		
Acquisitions		
Property		
Canada	47	30
United States(1)	284	418
Divestitures		
Property		
Canada	(59)	(447)
United States	(19)	(2,074)
Corporate(2)	(367)	
Market Optimization		
Corporate(3)	(244)	
Corporate		(2)
Net Acquisition and Divestiture Activity from Continuing Operations	(358)	(2,075)
Discontinued Operations		
Ecuador(4)	(1,116)	179
Midstream(5)	(1,531)	(484)
Net Capital Investment	3,264	4,097

Notes:

(1) The Corporation acquired additional operated interest in East Texas on June 29, 2006.

(2) The sale of shares of EnCanBrasil Limitada was completed on August 16, 2006.

(3) The sale of shares of Entrega Gas Pipeline LLC was completed on February 23, 2006.

(4) The sale of all of the Corporation's Ecuador interests was completed on February 28, 2006.

(5) The sale of Phase 1 of EnCana's Gas Storage interests was completed on May 12, 2006, followed by Phase 2 which was completed on November 17, 2006.

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. The Corporation has sufficient reserves of natural gas and crude oil to meet these commitments. More detailed information relating to such commitments can be found in Note 18 to EnCana's audited consolidated financial statements for the year ended December 31, 2006.

GENERAL

Competitive Conditions

All aspects of the oil and gas industry are highly competitive and EnCana actively competes with oil and natural gas and other companies, particularly in the following areas: (i) exploration for and development of new sources of oil and natural gas reserves; (ii) reserves and property acquisitions; (iii) transportation and marketing of oil, natural gas, NGLs, diluents and electricity; (iv) supply of refinery feedstock and the market for refined products (v) access to services and equipment to carry out exploration, development or operating activities; and (vi) attracting and retaining experienced industry personnel. The oil and gas industry also competes with other industries focused on providing alternative forms of energy to consumers. Competitive forces can lead to cost increases or result in an oversupply of oil and natural gas, both of which could have a negative impact on EnCana's financial results.

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 reviews and recommends to the Board of Directors for approval environmental policy and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety ("EH&S") 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 programs are in place and utilized to restore the environment.

EnCana expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2006, expenditures beyond normal compliance with environmental regulations were not material. EnCana does not anticipate making material expenditures beyond normal compliance with environmental regulations in 2007. 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 approximately $5.3 billion.

Social and Environmental Policies

In 2003, EnCana developed a Corporate Responsibility Policy (the "Policy") that translates its constitutional values and shared principles into policy commitments. The Policy applies to any activity undertaken by or on behalf of EnCana, anywhere in the world, associated with the finding, production, transmission and storage of the Corporation's products including decommissioning of facilities, marketing and other business and administrative functions. The Policy has specific requirements in areas related to: (i) leadership commitment, (ii) sustainable value creation, (iii) governance and business practices, (iv) human rights, (v) labour practices, (vi) environment, health and safety, (vii) stakeholder engagement, and (viii) socio-economic and community development.

Accountability for implementation of the Policy is at the operational level within EnCana's business units. Business units have established processes to evaluate risks, and programs are implemented to minimize that risk. Results related to the commitments outlined in the Corporate Constitution are tied to the individual performance assessment process.

With respect to human rights, the Policy states that: (i) while governments have the primary responsibility to promote and protect human rights, EnCana shares this goal and will support and respect human rights within its sphere of influence; (ii) EnCana will not take part in human rights abuse, and will not engage or be complicit in any activity that solicits or encourages human rights abuse; and (iii) in providing for the protection of company personnel and assets by public or private security forces, EnCana will promote respect for, and protection of, human rights.

The Policy states the following with respect to the environment: (i) EnCana will safeguard the environment, and will operate in a manner consistent with recognized global industry standards in environment, health and safety; (ii) in all of its operations, EnCana will strive to make efficient use of resources, to minimize its environmental footprint, and to conserve habitat diversity and the plant and animal populations that may be affected by its operations; and (iii) EnCana will strive to reduce its emissions intensity and increase its energy efficiency.

With respect to EnCana's relationship with the communities in which it does business, the Policy states that: (i) EnCana emphasizes collaborative, consultative and partnership approaches in its community investment and programs, recognizing that no corporation is solely responsible for changing the fundamental economic, environmental and social situation in a community or country; and (ii) through its activities, EnCana will assist in local capacity-building and develop mutually beneficial relationships, to make a positive difference in the communities and regions where it operates.

Some of the steps that EnCana has taken to embed the corporate responsibility approach throughout the organization include: (i) a comprehensive approach to training and communicating policies and practices; (ii) an EH&S management system; (iii) a security program to regularly assess security threats to business operations and manage the associated risks; (iv) a formalized approach to stakeholder relations with a standardized Stakeholder Engagement Guide; (v) corporate responsibility performance metrics to track the Corporation's progress; (vi) contribution of a minimum of one percent of EnCana's pre-tax domestic profits to charitable and non-profit organizations in the communities in which EnCana operates; (vii) an Investigations Practice and an Investigations Committee to review and resolve potential violations of EnCana policies or practices and other regulations; (viii) an Integrity Hotline that provides an additional avenue for EnCana's stakeholders to raise their concerns; (ix) an internal corporate EH&S audit program that evaluates EnCana's compliance with the expectations and requirements of the EH&S management system; and (x) related policies and practices such as an Alcohol and Drug Policy and Business Conduct and Ethics Practice. In addition, EnCana's Board of Directors approves such policies, and is advised of significant contraventions thereof, and receives updates on trends, issues or events which could have a significant impact on the Corporation.

Employees

At December 31, 2006, EnCana employed 4,678 full time equivalent ("FTE") employees as set forth in the following table:

	FTE Employees
Upstream	3,337
Midstream & Marketing	615
Corporate	726
Total	4,678

The Corporation also engages a number of contractors and service providers.

Foreign Operations

As at December 31, 2006, 100 percent of EnCana's reserves and 100 percent of its 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.

Reorganizations

As discussed under "Name and Incorporation" in this annual information form, EnCana was formed through the Merger of AEC and PanCanadian on April 5, 2002. AEC remained in existence as an indirect wholly owned subsidiary of EnCana, and on January 1, 2003, AEC was amalgamated with EnCana.

As a general matter, EnCana reorganizes its subsidiaries as required to maintain proper alignment of its businesses and facilitate acquisitions and divestitures. Between December 2005 and February 2006, the Corporation completed a restructuring of various Canadian subsidiaries in order to eliminate corporate entities that had become unnecessary.

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[12]	Principal Occupation
MICHAEL N. CHERNOFF[2,6] West Vancouver, British Columbia, Canada	1999	Corporate Director
RALPH S. CUNNINGHAM[2,3] Houston, Texas, United States	2003	Group Executive Vice President & Chief Operating Officer of the General Partner of Enterprise Products Partners L.P. (Enterprise Products GP, LLC) *(Midstream energy services)*
PATRICK D. DANIEL[1,5] Calgary, Alberta, Canada	2001	President & Chief Executive Officer Enbridge Inc. *(Energy delivery)*
IAN W. DELANEY[3,4] Toronto, Ontario, Canada	1999	Executive Chairman Sherritt International Corporation *(Nickel/cobalt mining, oil and natural gas production, electricity generation and coal mining)*
RANDALL K. ERESMAN Calgary, Alberta, Canada	2006	President & Chief Executive Officer EnCana Corporation
MICHAEL A. GRANDIN[3,4,6,8] Calgary, Alberta, Canada	1998	Chairman & Chief Executive Officer Fording Canadian Coal Trust *(Metallurgical coal producer)*

Name and Municipality of Residence	Director Since(12)	Principal Occupation
BARRY W. HARRISON(1,4,9) Calgary, Alberta, Canada	1996	Corporate Director and independent businessman
DALE A. LUCAS(1,5) Calgary, Alberta, Canada	1997	Corporate Director
KEN F. MCCREADY(2,5,10) Calgary, Alberta, Canada	1992	President K.F. McCready & Associates Ltd. *(Sustainable energy development consulting company)*
VALERIE A. A. NIELSEN(2,6) Calgary, Alberta, Canada	1990	Corporate Director
DAVID P. O'BRIEN(4,7,11) Calgary, Alberta, Canada	1990	Chairman EnCana Corporation Chairman Royal Bank of Canada
JANE L. PEVERETT(1,5) West Vancouver, British Columbia, Canada	2003	President & Chief Executive Officer British Columbia Transmission Corporation *(Electrical transmission)*
DENNIS A. SHARP(2,4) Calgary, Alberta, Canada & Montreal, Quebec, Canada	1998	Executive Chairman UTS Energy Corporation *(Oilsands company)*
JAMES M. STANFORD, O.C.(1,3,6) Calgary, Alberta, Canada	2001	President Stanford Resource Management Inc. *(Investment management)* Chairman OPTI Canada Inc. *(Oilsands company)*

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. 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.

(9) 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.

(10) 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. Mr. McCready was a director, Chairman and Chief Executive Officer of Etho Power Corporation, a small private company, when it was assigned into bankruptcy on April 7, 2003.

(11) 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. On September 30, 2004, Air Canada announced that it had successfully completed its restructuring process and implemented its Plan of Arrangement.

(12) Denotes the year each individual became a director of EnCana or one of its predecessor companies (AEC or PanCanadian).

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

At the date of this annual information form, there are 14 directors of the Corporation. At the next Annual Meeting of Shareholders, shareholders will be asked to elect as directors the 13 nominees listed in the above table (with the exception of Mr. Michael N. Chernoff who will be retiring) and two new nominees, Mr. Allan P. Sawin and Mr. Wayne G. Thomson, 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, whereby a director may not stand for re-election at the first annual meeting after reaching the age of 71, all of the directors shall be eligible for re-election.

Executive Officers

Name and Municipality of Residence	Corporate Office (Divisional Title)
DAVID P. O'BRIEN Calgary, Alberta, Canada	Chairman
RANDALL K. ERESMAN Calgary, Alberta, Canada	President & Chief Executive Officer
JOHN K. BRANNAN[(1)] Calgary, Alberta, Canada	Executive Vice-President *(President, Integrated Oilsands Division)*
SHERRI A. BRILLON[(2)] Calgary, Alberta, Canada	Executive Vice-President, Strategic Planning & Portfolio Management
BRIAN C. FERGUSON Calgary, Alberta, Canada	Executive Vice-President & Chief Financial Officer
MICHAEL M. GRAHAM Calgary, Alberta, Canada	Executive Vice-President *(President, Canadian Foothills Division)*
SHEILA M. MCINTOSH[(3)] Calgary, Alberta, Canada	Executive Vice-President, Corporate Communications
R. WILLIAM OLIVER[(4)] Calgary, Alberta, Canada	Executive Vice-President, Business Development *(President, Midstream & Marketing Division)*
GERARD J. PROTTI[(5)] Calgary, Alberta, Canada	Executive Vice-President, Corporate Relations *(President, Offshore & International Division)*
DONALD T. SWYSTUN[(6)] Calgary, Alberta, Canada	Executive Vice-President *(President, Canadian Plains Division)*
HAYWARD J. WALLS Calgary, Alberta, Canada	Executive Vice-President, Corporate Services
JEFF E. WOJAHN Denver, Colorado, USA	Executive Vice-President *(President, USA Division)*

Notes:

(1) John K. Brannan (formerly Managing Director, FINV) was appointed Executive Vice-President of EnCana and President, Integrated Oilsands Division effective January 1, 2007.

(2) Sherri A. Brillon (formerly Vice-President, Strategic Planning & Portfolio Management) was appointed Executive Vice-President, Strategic Planning & Portfolio Management of EnCana effective January 1, 2007.

(3) Sheila M. McIntosh (formerly Vice-President, Investor Relations) was appointed Executive Vice-President, Corporate Communications of EnCana effective January 1, 2007.

(4) R. William Oliver (formerly Executive Vice-President of EnCana and President Midstream & Marketing) was appointed Executive Vice-President, Business Development of EnCana effective January 1, 2007 and remains President, Midstream & Marketing Division.

(5) Gerard J. Protti (Executive Vice-President, Corporate Development) was, in addition to his current position, appointed President, Offshore & International Division effective January 1, 2007.

(6)

Donald T. Swystun (formerly Executive Vice-President, Corporate Development) was appointed Executive Vice-President of EnCana and President, Canadian Plains Division, effective January 1, 2007.

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. Cunningham was appointed Group Executive Vice President & Chief Operating Officer of the General Partner of Enterprise Products Partners L.P. (Enterprise Products GP, LLC) effective December 1, 2005, and a director on February 14, 2006. He was appointed as a director and Chairman of the Board of Texas Eastern Products Pipeline Company, LLC effective March 22, 2005 and resigned from the position effective November 23, 2005. Prior to March 2005, he was a Corporate Director.

Mr. Grandin served as Dean of the Haskayne School of Business, University of Calgary from April 2004 to January 2006. He 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 Vice President, Corporate Services and Chief Financial Officer of British Columbia Transmission Corporation (BCTC) from June 2003 to April 2005 when she was appointed President and Chief Executive Officer of BCTC. She was President of Union Gas Limited from April 2002 to May 2003, President and Chief Executive Officer from April 2001 to April 2002 and Senior Vice President Sales & Marketing from June 2000 to April 2001.

Mr. Sawin is being nominated for election as a director of the Corporation at the next Annual Meeting of Shareholders. Mr. Sawin is President of Bear Investments Inc., a private investment company. From 1990 until their sale to CCS Income Trust in May 2006, he was President, director and part owner of Grizzly Well Servicing Inc. and related companies. He is also a director of a number of private companies.

Mr. Sharp was Chairman and Chief Executive Officer of UTS Energy Corporation from July 1998 to October 2004.

Mr. Thomson is being nominated for election as a director of the Corporation at the next Annual Meeting of Shareholders. Since February 2005, Mr. Thomson has been President and a director of Virgin Resources Limited, a private junior international oil and gas exploration company, with activities focused in Yemen. He is a director of TG World Energy Corp. (TSX Venture listed international oil and gas exploration company) and a director of EcoMax Energy Services Ltd. (TSX Venture listed oil and gas service company). He is also a director of several private companies. Mr. Thomson was President and a director of Airborne Pollution Control from 2001 to 2003. Prior to 2001, he served as President and a director of private companies in the oil and gas sector, namely, Hadrian Energy Corp., Gardiner Exploration Limited and Petrocorp Exploration Limited (New Zealand oil and gas company), a division of Fletcher Challenge (public company), and was also President of Gardiner Oil and Gas Limited while it was a public company listed on the Toronto Stock Exchange.

All of the directors and executive officers of EnCana listed above beneficially owned, as of February 14, 2007, directly or indirectly, or exercised control or direction over an aggregate of 2,275,823 Common Shares representing 0.29 percent of the issued and outstanding voting shares of EnCana, and directors and executive officers held options to acquire an aggregate of 3,590,778 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.

AUDIT COMMITTEE INFORMATION

The full text of the Audit Committee mandate is included in Appendix C of this annual information form.

Composition of the Audit Committee

The Audit Committee consists of five members, all of whom are independent and financially literate in accordance with the definitions in Multilateral Instrument 52-110 *Audit Committees.* The relevant education and experience of each Audit Committee member is outlined below:

Patrick D. Daniel

Mr. Daniel holds a Bachelor of Science (University of Alberta) and a Masters of Science (University of British Columbia), both in chemical engineering. He also completed the Harvard Advanced Management Program. He is President and Chief Executive Officer and a director of Enbridge Inc. (energy delivery company). He is a director of a number of Enbridge subsidiaries. He is also a director and past member of the Audit Committee of Enerflex Systems Ltd. (compression systems manufacturer) and a director and Chair of the Finance Committee of Synenco Energy Inc. (oilsands mining).

Barry W. Harrison (Audit Committee Chair)

Mr. Harrison holds a Bachelor of Business Administration and Banking (Colorado College) and a Bachelor of Laws (University of British Columbia). He is a Corporate Director and an independent businessman. Mr. Harrison is a director and President of Eastgate Minerals Ltd. (oil and gas). He is also a director and Chairman (as well as past Chairman of the Audit Committees) of The Wawanesa Mutual Insurance Company (property and casualty insurer) and its related companies, The Wawanesa Life Insurance Company and its U.S. subsidiary, the Wawanesa General Insurance Company, headquartered in California. He was Managing Director of Goepel Shields & Partners Inc. in Calgary.

Dale A. Lucas

Mr. Lucas holds a Bachelor of Science in Chemical Engineering and a Bachelor of Arts in Economics (University of Alberta). Mr. Lucas is a Corporate Director and is President of D.A. Lucas Enterprises Inc., a private company owned by Mr. Lucas and through which he consulted internationally. During his 44-year career in the energy sector, he served the maximum 6-year term as a director of the New York Mercantile Exchange (NYMEX) and was past Chairman of the Alberta Petroleum Marketing Commission. He has held senior executive positions with J. Makowski Canada Ltd. (Calgary), J. Makowski Associates Inc. (Boston), BP Canada and BP Pipelines (San Francisco).

Jane L. Peverett

Ms. Peverett holds a Bachelor of Commerce (McMaster University) and a Masters of Business Administration (Queen's University), together with a designation as a Certified Management Accountant and a Canadian Security Analyst Certificate. She is also a Fellow of The Society of Management Accountants (FCMA). She was Vice President, Corporate Services and Chief Financial Officer of British Columbia Transmission Corporation (electrical transmission) from June 2003 to April 2005, when she was appointed President and Chief Executive Officer. In her 15-year career with the Westcoast Energy Inc./Duke Energy Corporation group of companies, she held senior executive positions with Union Gas Limited (Ontario), including President, President and Chief Executive Officer, Senior Vice President Sales & Marketing and Chief Financial Officer, among others.

James M. Stanford, O.C.

Mr. Stanford holds a Doctor of Laws (Hon.) and a Bachelor of Science in Petroleum Engineering (University of Alberta), and a Doctor of Laws (Hon.) and a Bachelor of Science in Mining (Concordia University). He is President of Stanford Resource Management Inc. (investment management). He is a director and Chairman of OPTI Canada Inc. (oilsands development and upgrading company). He is also a director of Kinder Morgan, Inc. (North American midstream energy company) and NOVA Chemicals Corporation (commodity chemical company). He was Chairman of the Audit Committee of Inco Limited from April 2002 until August 2005 when he retired from the Board. Mr. Stanford was a director, President and Chief Executive Officer of Petro-Canada (oil and gas company) from 1993 until his retirement in 2000. He also served as the President, Chief Operating Officer and a director of Petro-Canada from 1990 to 1993.

The above list does not include David P. O'Brien who is an ex officio member of the Audit Committee.

Pre-Approval Policies and Procedures

EnCana has adopted 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 which are 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 C$200,000, in the case of pre-approvals granted by the Chairman of the Audit Committee, and (ii) may not exceed C$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.

External Auditor Service Fees

The following table provides information about the fees billed to the Corporation for professional services rendered by PricewaterhouseCoopers LLP during fiscal 2006 and 2005:

($ thousands)	2006	2005
Audit Fees[1]	3,762	3,726
Audit-Related Fees[2]	401	894
Tax Fees[3]	1,215	1,021
All Other Fees[4]	34	26
Total	5,412	5,667

Notes:

(1) Audit fees consist of fees for the audit of the Corporation's annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

(2) 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 Corporation's financial statements and are not reported as Audit Fees. During fiscal 2006 and 2005, the services provided in this category included due diligence reviews in connection with acquisitions and divestitures, research of accounting and audit-related issues and review of reserves disclosure.

(3) Tax fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal 2006 and 2005, the services provided in this category included assistance and advice in relation to the preparation of corporate income tax returns and expatriate tax services.

(4) During fiscal 2006 and 2005, the services provided in this category included the payment of maintenance fees associated with a research tool that grants access to a comprehensive library of financial reporting and assurance literature and a working paper documentation package used by the Corporation's internal audit group.

EnCana did not rely on the *de minimus* exemption provided by Section (c)(7)(i)(C) of Rule 2-01 of SEC Regulation S-X in 2005 or 2006.

DESCRIPTION OF SHARE CAPITAL

The Corporation 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 of December 31, 2006 there were approximately 784 million Common Shares outstanding and no Preferred Shares outstanding.

At the annual and special meeting of EnCana's shareholders on April 27, 2005, the Corporation's shareholders approved the subdivision of EnCana's outstanding common shares on a two-for-one basis. Each shareholder received one additional common share for each common share held on the record date for the stock split of May 12, 2005. EnCana's common shares commenced trading on a subdivided basis on May 10, 2005.

Common Shares

The holders of the Common Shares are entitled to receive dividends if, as and when declared by the Board of Directors of the Corporation. The holders of the Common Shares are entitled to receive notice of and to attend all meetings of shareholders and are entitled to one vote per Common Share held at all such meetings. In the event of the liquidation, dissolution or winding up of the Corporation or other distribution of assets of the Corporation among its shareholders for the purpose of winding up its affairs, the holders of the Common Shares will be entitled to participate rateably in any distribution of the assets of the Corporation.

EnCana has stock-based compensation plans that allow employees to purchase Common Shares of the Corporation. 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 predecessor and/or related company replacement plans expire up to 10 years from the date the options were granted.

The Corporation has a shareholder rights plan (the "Plan") that was adopted to ensure, to the extent possible, that all shareholders of the Corporation are treated fairly in connection with any take-over bid for the Corporation. The Plan creates a right that attaches to each present and subsequently issued Common Share. Until the separation time, which typically occurs at the time of an unsolicited takeover bid, whereby a person acquires or attempts to acquire 20 percent or more of EnCana's Common Shares, the rights are not separable from the Common Shares, are not exercisable and no separate rights certificates are issued. Each right entitles the holder, other than the 20 percent acquiror, from and after the separation time and before certain expiration times, to acquire one Common Share at 50 percent of the market price at the time of exercise. The plan was reconfirmed at the 2004 annual meeting of shareholders and must be reconfirmed at every third annual meeting thereafter until it expires on July 30, 2011. It is anticipated that the Plan will be presented to shareholders for reconfirmation at the 2007 annual and special meeting of shareholders.

Preferred Shares

Preferred Shares may be issued in one or more series. The Board of Directors may determine the designation, rights, privileges, restrictions and conditions attached to each series of Preferred Shares before the issue of such series. Holders of the Preferred Shares are not entitled to vote at any meeting of the shareholders of the Corporation, but may be entitled to vote if the Corporation fails to pay dividends on that series of Preferred Shares. The First Preferred Shares are entitled to priority over the Second Preferred Shares and the Common Shares of the Corporation with respect to the payment of dividends and the distribution of assets of the Corporation in the event of any liquidation, dissolution or winding up of the Corporation's affairs.

CREDIT RATINGS

The following table outlines the ratings of the Corporation's debt as of December 31, 2006.

	Standard & Poor's Ratings Services ("S&P")	Moody's Investors Service ("Moody's")	Dominion Bond Rating Service ("DBRS")
Senior Unsecured/Long-Term Rating	A-	Baa2	A (low)
Commercial Paper/Short-Term Rating	A-1 (low)	P-2	R-1 (low)
Outlook	Negative	Positive	Stable

S&P's long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of A- by S&P is within the third highest of ten categories and indicates that the obligor has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher rated categories. The addition of a plus (+) or minus (-) designation after a rating indicates the relative standing within a particular rating category. The negative outlook status implies that the rating could remain the same or be lowered. S&P's Canadian commercial paper ratings scale ranges from A-1 (high) to D, representing the range from highest to lowest quality. A-1 (low) is the third highest of eight categories and indicates that the obligor has satisfactory capacity to meet its financial commitments.

Moody's long-term credit ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. A rating of Baa2 by Moody's is within the fourth highest of nine categories and is assigned to debt securities which are considered medium-grade obligations (i.e., they are subject to moderate credit risk). Such debt securities may possess certain speculative characteristics. The addition of a 1, 2 or 3 modifier after a rating indicates the relative standing within a particular rating category. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the issue ranks in the lower end of its generic rating category. The addition a ratings outlook of "Positive (POS)", "Negative (NEG)" or "Stable (STA)"is an opinion regarding the likely direction of a rating over the medium term. Moody's short-term ratings are on a scale ranging from P-1 (highest quality) to NP (lowest quality). P-2 is the second highest of four categories and indicates that the issuer has a strong ability to repay short-term debt obligations.

DBRS' long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of A (low) by DBRS is within the third highest of ten categories and is assigned to debt securities considered to be of satisfactory credit quality. Protection of interest and principal is still substantial, but the degree of strength is less than that of AA rated entities. While a respectable rating, entities in the A category are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher-rated securities. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category. DBRS' short-term ratings are on a scale ranging from R-1 (high) to D, representing the range from highest to lowest quality. R-1 (low) is the third highest of ten categories and indicates that the short-term debt is of satisfactory credit quality. The overall strength and outlook for key liquidity, debt and profitability ratios is not normally as favourable as with higher rating categories, but these considerations are still respectable. Any qualifying negative factors that exist are considered manageable, and the entity is normally of sufficient size to have some influence in its industry.

Credit ratings are intended to provide investors with an independent measure of credit quality of any issue of securities. The credit ratings assigned by the rating agencies are not recommendations to purchase, hold or sell the securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

MARKET FOR SECURITIES

All of the outstanding Common Shares of EnCana are listed and posted for trading on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") under the symbol ECA. The following table outlines the share price trading range and volume of shares traded by month in 2006.

	Toronto Stock Exchange Share Price Trading Range				New York Stock Exchange Share Price Trading Range			
	High	Low	Close	Share Volume	High	Low	Close	Share Volume
		(C$ per share)		(millions)		($ per share)		(millions)
2006								
January	57.10	51.70	56.75	90.0	49.93	44.68	49.86	83.2
February	57.08	44.96	47.00	88.0	50.05	39.54	41.31	90.8
March	57.00	46.55	54.50	95.2	49.04	40.92	46.73	84.4
April	59.25	53.45	55.88	57.6	52.33	46.54	50.05	59.0
May	59.20	49.51	55.56	61.2	53.70	44.02	50.54	72.3
June	59.38	49.91	58.78	65.5	53.31	45.15	52.64	76.4
July	62.52	53.61	61.04	48.6	55.43	46.88	54.06	53.8
August	62.49	58.00	58.00	46.0	55.93	52.24	52.74	50.1
September	59.51	48.35	52.01	65.5	53.68	43.32	46.69	63.4
October	55.47	48.28	53.33	72.0	49.20	42.75	47.49	74.5
November	61.00	51.83	59.36	58.2	53.44	45.77	52.21	61.4
December	61.90	53.55	53.66	58.7	53.90	45.95	45.95	61.5

In November 2006, EnCana received approval from the TSX to renew its normal course issuer bid. Under the renewed program, EnCana is entitled to purchase up to 10 percent of its outstanding common shares. Purchases may be made through the facilities of the TSX and the NYSE, in accordance with the policies and rules of each exchange.

During January 2007, EnCana purchased 10.8 million shares under the program for approximately $494 million.

In 2006, EnCana purchased 85.6 million shares under the program for an average price of $49.26 for approximately $4.2 billion.

DIVIDENDS

The declaration of dividends is at the discretion of the Board of Directors and is approved quarterly. In 2004, cash dividends were paid to common shareholders at a rate of $0.20 per share annually ($0.05 per share quarterly). In the second quarter of 2005, EnCana increased its dividend by 50 percent to $0.30 per share annually ($0.075 per share quarterly). In the second quarter of 2006, EnCana increased its dividend by 33 percent to $0.40 per share ($0.10 per share quarterly). EnCana's Board of Directors has declared a dividend of $0.20 per share payable on March 30, 2007 to common shareholders of record on March 15, 2007, a 100 percent increase over the previous dividend. All of the figures in this section have been adjusted to reflect the May 2005 share split.

LEGAL PROCEEDINGS

The Corporation is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in EnCana's favour, the Corporation does not currently believe that the outcome of any pending or threatened proceedings related to these or other matters, or the amounts which the Corporation may be required to pay by reason thereof, would have a material adverse impact on its financial position, results of operations or liquidity.

For information on legal proceedings related to EnCana's discontinued merchant energy trading operations refer to "Risk Factors" in this annual information form.

RISK FACTORS

If any event arising from the risk factors set forth below occurs, EnCana's business, prospects, financial condition, results of operation or cash flows could be materially adversely affected.

A substantial or extended decline in crude oil and natural gas prices could have a material adverse effect on EnCana.

EnCana's financial performance and condition are substantially dependent on the prevailing prices of crude oil and natural gas. Fluctuations in crude oil or natural gas prices could have an adverse effect on the Corporation's operations and financial condition and the value and amount of its proved reserves. Prices for crude oil and natural gas fluctuate in response to changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of additional factors beyond the Corporation's control. Crude oil prices are determined by international supply and demand. Factors which affect crude oil prices include the actions of the Organization of Petroleum Exporting Countries, world economic conditions, government regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil, the price of foreign imports, the availability of alternate fuel sources and weather conditions. Natural gas prices realized by EnCana are affected primarily by North American supply and demand, weather conditions and by prices of alternate sources of energy. Any substantial or extended decline in the prices of crude oil and natural gas could result in a delay or cancellation of existing or future drilling, development or construction programs or curtailment in production at some properties or could result in unutilized long-term transportation commitments, all of which could have an adverse effect on the Corporation's revenues, profitability and cash flows.

The market prices for heavy oil are lower than the established market indices for light and medium grades of oil, due principally to diluent prices and the higher transportation and refining costs associated with heavy oil. Also, the market for heavy oil is more limited than for light and medium grades, making it more susceptible to supply and demand fundamentals. Future price differentials are uncertain and any increase in the heavy oil differentials could have a material adverse effect on EnCana's business.

EnCana conducts an annual assessment of the carrying value of its assets in accordance with Canadian GAAP. If crude oil and natural gas prices decline, the carrying value of EnCana's assets could be subject to financial downward revisions, and the Corporation's earnings could be adversely affected.

If EnCana fails to acquire or find additional crude oil and natural gas reserves, the Corporation's reserves and production will decline materially from their current levels.

EnCana's future crude oil and natural gas reserves and production, and therefore its cash flows, are highly dependent upon its success in exploiting its current reserves base and acquiring, discovering or developing additional reserves. Without reserves additions through exploration, acquisition or development activities, the Corporation's reserves and production will decline over time as reserves are depleted. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited, EnCana's ability to make the necessary capital investments to maintain and expand its crude oil and natural gas reserves will be impaired. In addition, there can be no guarantee that EnCana will be able to find and develop or acquire additional reserves to replace production at acceptable costs.

EnCana's crude oil and natural gas reserves data and future net revenue estimates are uncertain.

There are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves, including many factors beyond the Corporation's control. The reserves data in this annual information form represents estimates only. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties and the assumed effects of regulation by governmental agencies, all of which may vary considerably from actual results. All such estimates are to some degree uncertain, and classifications of reserves are only attempts to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. EnCana's actual production, revenues, taxes and development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

EnCana's hedging activities could result in realized and unrealized losses.

The nature of the Corporation's operations results in exposure to fluctuations in commodity prices and interest rates. The Corporation monitors its exposure to such fluctuations and, where the Corporation deems it appropriate, utilizes derivative financial instruments and physical delivery contracts to mitigate the potential impact of declines in crude oil and natural gas prices and changes in interest rates. Under Canadian GAAP, derivative instruments that do not qualify as hedges, or are not designated as hedges, are marked-to-market with changes in fair value recognized in current period net earnings. The utilization of derivative financial instruments may therefore introduce significant volatility into the Corporation's reported net earnings.

The terms of the Corporation's various hedging agreements may limit the benefit to the Corporation of commodity price increases or changes in interest rates. The Corporation may also suffer financial loss because of hedging arrangements if:

- the Corporation is unable to produce oil or natural gas to fulfill delivery obligations;
- the Corporation is required to pay royalties based on market or reference prices that are higher than hedged prices; or
- counterparties to the Corporation's hedging agreements are unable to fulfill their obligations under the hedging agreements.

EnCana's ability to complete projects is dependent on factors outside of its control.

The Corporation undertakes a variety of projects including exploration and development projects and the construction or expansion of facilities, refineries and pipelines. Project delays may delay expected revenues and project cost overruns could make projects uneconomic. The Corporation's ability to complete projects depends upon numerous factors beyond the Corporation's control. These factors include:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of drilling and other equipment;
- the availability of diluents to transport crude oil;
- the ability to access lands;
- weather;
- unexpected cost increases;

accidents;

general business and market conditions;

the availability of skilled labour; and

environmental and regulatory matters.

All of EnCana's operations are subject to regulation and intervention by governments that can affect or prohibit the drilling, completion and tie-in of wells, production, the construction or expansion of facilities and the operation and abandonment of fields. Contract rights can be cancelled or expropriated. Changes to government regulation could impact the Corporation's existing and planned projects.

The Corporation's business is subject to environmental legislation in all jurisdictions in which it operates and any changes in such legislation could negatively affect its results of operations.

All phases of the crude oil, natural gas and refining businesses are subject to environmental regulation pursuant to a variety of Canadian, U.S. and other federal, provincial, territorial, state and municipal laws and regulations (collectively, "environmental legislation").

Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. It also imposes restrictions, liabilities and obligations in connection with the management of fresh or potable water sources that are being used, or whose use is contemplated, in connection with oil and gas operations. Environmental legislation also requires that wells, facility sites and other properties associated with EnCana's operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Compliance with environmental legislation can require significant expenditures, including expenditures for clean up costs and damages arising out of contaminated properties and failure to comply with environmental legislation may result in the imposition of fines and penalties. Although it is not expected that the costs of complying with environmental legislation will have a material adverse effect on EnCana's financial condition or results of operations, no assurance can be made that the costs of complying with environmental legislation in the future will not have such an effect.

The Canadian Federal Government has announced its intention to regulate greenhouse gases ("GHG") and other air pollutants. The Government is currently developing a framework that outlines its clean air and climate change action plan, including a target to reduce GHG emissions by 45 percent to 65 percent by 2050 and a commitment to regulate industry on an emissions intensity basis in the short-term. Currently there are few technical details regarding the implementation of the Government's plan to regulate industrial GHG emissions, but the Government has made a commitment to work with industry to develop the specifics.

As this federal program is under development, EnCana is unable to predict the total impact of the potential regulations upon its business. Therefore, it is possible that the Corporation could face increases in operating costs in order to comply with GHG emissions legislation. However, EnCana in cooperation with the Canadian Association of Petroleum Producers will continue to work with the Government to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

EnCana will continue its current activities to reduce emissions intensity and improve energy efficiency. The Corporation's efforts with respect to emissions management are founded on the following key elements:

- significant weighting in natural gas;
- recognition as an industry leader in CO_2 sequestration;
- focus on the development of technology to reduce GHG emissions;
- involvement in the creation of industry best practices; and
- industry leading oilsands steam to oil ratio, which translates directly into a lower emissions intensity.

EnCana's operations are subject to the risk of business interruption and casualty losses.

The Corporation's business is subject to all of the operating risks normally associated with the exploration for, development of and production of crude oil and natural gas and the operation of midstream and refining

facilities. These risks include blowouts, explosions, fire, gaseous leaks, migration of harmful substances and crude oil spills, any of which could cause personal injury, result in damage to, or destruction of, crude oil and natural gas wells or formations or production facilities and other property, equipment and the environment, as well as interrupt operations. In addition, all of EnCana's operations will be subject to all of the risks normally incident to the transportation, processing, storing, refining and marketing of crude oil, natural gas and other related products, drilling and completion of crude oil and natural gas wells, and the operation and development of crude oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoir pressure or productivity, blowouts, equipment failures and other accidents, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, adverse weather conditions, pollution and other environmental risks.

The occurrence of a significant event against which EnCana is not fully insured could have a material adverse effect on the Corporation's financial position.

Fluctuations in exchange rates could affect expenses or result in realized and unrealized losses.

Worldwide prices for crude oil, natural gas and refined products are set in U.S. dollars. However, many of the Corporation's expenses outside of the U.S. are denominated in Canadian dollars. Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar could impact the Corporation's expenses and have an adverse effect on the Corporation's financial performance and condition.

In addition, the Corporation has significant U.S. dollar denominated long-term debt. Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar could result in realized and unrealized losses on U.S. dollar denominated long-term debt.

EnCana does not operate all of its properties and assets.

Other companies operate a portion of the assets in which EnCana has interests. EnCana will have limited ability to exercise influence over operations of these assets or their associated costs. EnCana's dependence on the operator and other working interest owners for these properties and assets, and its limited ability to influence operations and associated costs could materially adversely affect the Corporation's financial performance. The success and timing of EnCana's activities on assets operated by others therefore will depend upon a number of factors that are outside of the Corporation's control, including:

- timing and amount of capital expenditures;
- timing and amount of operating and maintenance expenditures;
- the operator's expertise and financial resources;
- approval of other participants;
- selection of technology; and
- risk management practices.

All of the Corporation's downstream operations are operated by ConocoPhillips. The success of the Corporation's downstream operations is dependant on the ability of ConocoPhillips to successfully operate this business.

The volatility of downstream margins will have an impact on EnCana's results.

EnCana's downstream operations are sensitive to margins for refined products. Margin volatility is impacted by numerous conditions including: market competitiveness, the cost of crude oil, fluctuations in the supply and demand for refined products and weather. It is expected that all of these and other factors will continue to impact downstream margins for the foreseeable future. As a result, it can be reasonably expected that downstream results will fluctuate over time and from period to period.

The Corporation's foreign operations will expose it to risks from abroad which could negatively affect its results of operations.

Some of EnCana's operations and related assets are located in countries outside North America, some of which may be considered to be politically and economically unstable. Exploration or development activities in such countries may require protracted negotiations with host governments, national oil companies and third parties and are frequently subject to economic and political considerations, such as taxation, nationalization, expropriation, inflation, currency fluctuations, increased regulation and approval requirements, governmental regulation and the risk of actions by terrorist or insurgent groups, any of which could adversely affect the economics of exploration or development projects.

EnCana is exposed to risks associated with the use of current technology, and the pursuit of new technology, which could negatively affect its results of operations.

Current SAGD technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam that is used in the recovery process. The amount of steam required in the production process can also vary and affect costs. The performance of the reservoir can also affect the timing and levels of production using this technology. A large increase in recovery costs could cause certain projects that rely on SAGD technology to become uneconomical, which could have a negative effect on EnCana's results of operations.

There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations. The success of projects incorporating new technologies cannot be assured.

EnCana may be adversely affected by legal proceedings related to its discontinued merchant energy trading operations.

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. The lawsuits allege that the defendants engaged in a conspiracy with unnamed competitors in the natural gas markets in California in violation of U.S. and California anti-trust and unfair competition laws.

Without admitting any liability in the lawsuits, WD agreed to settle all of the class action lawsuits in both state and federal court, for payments of $20.5 million and $2.4 million, respectively. Court approval of the federal court class action settlement of $2.4 million is pending, court approval having been granted in the state court action. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission ("CFTC") and of a previously disclosed consolidated class action lawsuit in the United States District Court in New York for $8.2 million.

The remaining lawsuits were commenced by individual plaintiffs, one of which is E. & J. Gallo Winery ("Gallo"). The Gallo lawsuit claims damages in excess of $30 million. The other remaining lawsuits do not specify the precise amount of damages claimed. California law allows for the possibility that the amount of damages assessed could be tripled.

EnCana intends to vigorously defend against any claims of liability alleged in the remaining lawsuits; however, the Corporation cannot predict the outcome of these proceedings or the commencement or outcome of any future proceedings against EnCana or whether any such proceeding would lead to monetary damages which could have a material adverse effect on the Corporation's financial position, or whether there will be other proceedings arising out of these allegations.

TRANSFER AGENTS AND REGISTRARS

In Canada:	In the United States:
CIBC Mellon Trust Company	Mellon Investor Services LLC
320 Bay Street	44 Wall Street, 6th Floor
P.O. Box 1	New York, New York
Toronto, ON M5H 4A6	10005
Tel: 1-800-387-0825	Tel: 1-800-387-0825
Website: www.cibcmellon.com	Website: www.cibcmellon.com

INTERESTS OF EXPERTS

PricewaterhouseCoopers LLP, Chartered Accountants, are the Corporation's auditors and such firm has prepared an opinion with respect to the Corporation's consolidated financial statements as at and for the fiscal year ended December 31, 2006. PricewaterhouseCoopers LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta. Information relating to reserves in this annual information form dated February 23, 2007 was calculated by GLJ Petroleum Consultants Ltd., McDaniel & Associates Consultants Ltd., Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton as independent qualified reserves evaluators.

The principals of each of GLJ Petroleum Consultants Ltd., McDaniel & Associates Consultants Ltd., Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton, in each case, as a group own beneficially, directly or indirectly, less than one percent of any class of EnCana's securities.

ADDITIONAL INFORMATION

Additional information relating to EnCana is available via the System for Electronic Document Analysis and Retrieval (SEDAR) at www.sedar.com.

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 and Management's Discussion and Analysis for the year ended December 31, 2006.

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, 2006. The reserves data consist of the following:

   (i) estimated proved oil and gas reserves quantities as at December 31, 2006 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 reserves 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 reserves 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, 2006:

Evaluator and Preparation Date of Report	Reserves Location	Estimated Proved Reserves Quantities After Royalty		Related Estimates of Future Net Cash Flow BTax, 10% discount rate
		Gas	Liquids	
		(Bcf)	(MMbbl)	(US$MM)
McDaniel & Associates Consultants Ltd. January 25, 2007	Canada	4,280	983	13,674
GLJ Petroleum Consultants Ltd. January 18, 2007	Canada	2,748	96	6,627
Netherland, Sewell & Associates, Inc. January 18, 2007	United States	4,230	50	6,833
DeGolyer and MacNaughton January 18, 2007	United States	1,160	4	1,692
Totals		12,418	1,133	28,826

	Estimated Proved Reserves Quantities After Royalty

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 judgments 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) GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

(signed) Netherland, Sewell & Associates, Inc.
Dallas, Texas, U.S.A.
February 13, 2007

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

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 reserves quantities estimated as at December 31, 2006 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 reserves quantities.

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. A report from the independent qualified reserves evaluators dated February 13, 2007 (the "IQRE Report"), highlighting the standards they followed and their results, accompanies this Report.

The Reserves Committee of 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 of the Corporation (the "Board of Directors") has reviewed the standardized measure calculation with respect to the Corporation's proved oil and gas reserves 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 reserves 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) Randall K. Eresman
President & Chief Executive Officer

(signed) Donald T. Swystun
Executive Vice-President

(signed) David P. O'Brien

(signed) James M. Stanford, O.C.
Director and Chairman of the Reserves Committee

Director and Chairman of the Board
February 14, 2007

APPENDIX C

Audit Committee Mandate

Last Updated December 13, 2006

I. PURPOSE

The Audit Committee (the "Committee") is appointed by the Board of Directors of EnCana Corporation ("the Corporation") to assist the Board in fulfilling its oversight responsibilities.

The Committee's primary duties and responsibilities are to:

- Review and approve management's identification of principal financial risks and monitor the process to manage such risks.
- Oversee and monitor the Corporation's compliance with legal and regulatory requirements.
- Receive and review the reports of the Audit Committee of any subsidiary with public securities.
- Oversee and monitor the integrity of the Corporation's accounting and financial reporting processes, financial statements and system of internal controls regarding accounting and financial reporting and accounting compliance.
- Oversee audits of the Corporation's financial statements.
- Oversee and monitor the qualifications, independence and performance of the Corporation's external auditors and internal auditing department.
- Provide an avenue of communication among the external auditors, management, the internal auditing department, and the Board of Directors.
- Report to the Board of Directors regularly.

The Committee has the authority to conduct any review or investigation appropriate to fulfilling its responsibilities. The Committee shall have unrestricted access to personnel and information, and any resources necessary to carry out its responsibility. In this regard, the Committee may direct internal audit personnel to particular areas of examination.

II. COMPOSITION AND MEETINGS

Committee Member's Duties in addition to those of a Director

The duties and responsibilities of a member of the Committee are in addition to those duties set out for a member of the Board of Directors.

Composition

The Committee shall consist of not less than five and not more than eight directors as determined by the Board, all of whom shall qualify as independent directors pursuant to Multilateral Instrument 52-110 *Audit Committees* (as implemented by the Canadian Securities Administrators and as amended from time to time) ("MI 52-110").

All members of the Committee shall be financially literate, as defined in MI 52-110, and at least one member shall have accounting or related financial managerial expertise. In particular, at least one member shall have, through (i) education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that involve the performance of similar functions; (ii) experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions; (iii) experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or (iv) other relevant experience:

An understanding of generally accepted accounting principles and financial statements;

The ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves;

Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the registrant's financial statements, or experience actively supervising one or more persons engaged in such activities;

An understanding of internal controls and procedures for financial reporting; and

An understanding of audit committee functions.

Committee members may not, other than in their respective capacities as members of the Committee, the Board or any other committee of the Board, accept directly or indirectly any consulting, advisory or other compensatory fee from the Corporation or any subsidiary of the Corporation, or be an "affiliated person" (as such term is defined in the *United States Securities Exchange Act of 1934*, as amended, and the rules adopted by the SEC thereunder) of the Corporation or any subsidiary of the Corporation. For greater certainty, directors' fees and fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Corporation that are not contingent on continued service should be the only compensation an audit committee member receives from the Corporation.

At least one member shall have experience in the oil and gas industry.

Committee members shall not simultaneously serve on the audit committees of more than two other public companies, unless the Board first determines that such simultaneous service will not impair the ability of the relevant members to effectively serve on the Committee, and required public disclosure is made.

The non-executive Board Chairman shall be a non-voting member of the Committee.

Appointment of Members

Committee members shall be appointed at a meeting of the Board, effective after the election of directors at the annual meeting of shareholders, provided that any member may be removed or replaced at any time by the Board and shall, in any event, cease to be a member of the Committee upon ceasing to be a member of the Board.

The Nominating and Corporate Governance Committee will recommend for approval to the Board an unrelated Director to act as Chairman of the Committee. The Board shall appoint the Chairman of the Committee.

If the Chairman of the Committee is unavailable or unable to attend a meeting of the Committee, the Chair shall ask another member to chair the meeting, failing which a member of the Committee present at the meeting shall be chosen to preside over the meeting by a majority of the members of the Committee present at such meeting.

The Chairman of the Committee presiding at any meeting of the Committee shall not have a casting vote.

The items pertaining to the Chairman in this section should be read in conjunction with the Committee Chair section of the *Chair of the Board of Directors and Committee Chair General Guidelines*.

Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board.

The Corporate Secretary or one of the Assistant Corporate Secretaries of the Corporation or such other person as the Corporate Secretary of the Corporation shall designate from time to time shall be the Secretary of the Committee and shall keep minutes of the meetings of the Committee.

Meetings

Committee meetings may, by agreement of the Chairman of the Committee, be held in person, by video conference, by means of telephone or by a combination of any of the foregoing.

The Committee shall meet at least quarterly. The Chairman of the Committee may call additional meetings as required. In addition, a meeting may be called by the non-executive Board Chairman, the President & Chief Executive Officer, or any member of the Committee or by the external auditors.

The Committee shall have the right to determine who shall, and who shall not, be present at any time during a meeting of the Committee.

Directors, who are not members of the Committee, may attend Committee meetings, on an ad hoc basis, upon prior consultation and approval by the Committee Chairman or by a majority of the members of the Committee.

The Committee may, by specific invitation, have other resource persons in attendance.

The President & Chief Executive Officer, the Executive Vice-President & Chief Financial Officer, the Comptroller and the head of internal audit are expected to be available to attend the Committee's meetings or portions thereof.

Notice of Meeting

Notice of the time and place of each Committee meeting may be given orally, or in writing, or by facsimile, or by electronic means to each member of the Committee at least 48 hours prior to the time fixed for such meeting. Notice of each meeting shall also be given to the external auditors of the Corporation.

A member and the external auditors may, in any manner, waive notice of the Committee meeting. Attendance of a member at a meeting shall constitute waiver of notice of the meeting except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting was not lawfully called.

Quorum

A majority of Committee members, present in person, by video conference, by telephone, or by a combination thereof, shall constitute a quorum. In addition, if an ex officio, non-voting member's presence is required to attain a quorum of the Committee, then the said member shall be allowed to cast a vote at the meeting.

Minutes

Minutes of each Committee meeting should be succinct yet comprehensive in describing substantive issues discussed by the Committee. However, they should clearly identify those items of responsibilities scheduled by the Committee for the meeting that have been discharged by the Committee and those items of responsibilities that are outstanding.

Minutes of Committee meetings shall be sent to all Committee members and to the external auditors.

The full Board of Directors shall be kept informed of the Committee's activities by a report following each Committee meeting.

III. RESPONSIBILITIES

Review Procedures

Review and update the Committee's mandate annually, or sooner, where the Committee deems it appropriate to do so. Provide a summary of the Committee's composition and responsibilities in the Corporation's annual report or other public disclosure documentation.

Provide a summary of all approvals by the Committee of the provision of audit, audit-related, tax and other services by the external auditors for inclusion in the Corporation's annual report filed with the United States Securities and Exchange Commission.

Annual Financial Statements

1. Discuss and review with management and the external auditors the Corporation's and any subsidiary with public securities annual audited financial statements and related documents prior to their filing or distribution. Such review to include:

    a. The annual financial statements and related footnotes including significant issues regarding accounting principles, practices and significant management estimates and judgments, including any significant changes in the Corporation's selection or application of accounting principles, any major issues as to the adequacy of the Corporation's internal controls and any special steps adopted in light of material control deficiencies.

    b. Management's Discussion and Analysis.

    c. A review of the use of off-balance sheet financing including management's risk assessment and adequacy of disclosure.

    d. A review of the external auditors' audit examination of the financial statements and their report thereon.

    e. Review of any significant changes required in the external auditors' audit plan.

    f. A review of any serious difficulties or disputes with management encountered during the course of the audit, including any restrictions on the scope of the external auditors' work or access to required information.

    g. A review of other matters related to the conduct of the audit, which are to be communicated to the Committee under generally accepted auditing standards.

2. Review and formally recommend approval to the Board of the Corporation's:

    a. Year-end audited financial statements. Such review shall include discussions with management and the external auditors as to:

        (i) The accounting policies of the Corporation and any changes thereto.

        (ii) The effect of significant judgements, accruals and estimates.

        (iii) The manner of presentation of significant accounting items.

        (iv) The consistency of disclosure.

    b. Management's Discussion and Analysis.

    c. Annual Information Form as to financial information.

    d. All prospectuses and information circulars as to financial information.

The review shall include a report from the external auditors about the quality of the most critical accounting principles upon which the Corporation's financial status depends, and which involve the most complex, subjective or significant judgemental decisions or assessments.

Quarterly Financial Statements

3. Review with management and the external auditors and either approve (such approval to include the authorization for public release) or formally recommend for approval to the Board the Corporation's:

   a. Quarterly unaudited financial statements and related documents, including Management's Discussion and Analysis.

   b. Any significant changes to the Corporation's accounting principles.

   Review quarterly unaudited financial statements of any subsidiary of the Corporation with public securities prior to their distribution.

Other Financial Filings and Public Documents

4. Review and discuss with management financial information, including earnings press releases, the use of "pro forma" or non-GAAP financial information and earnings guidance, contained in any filings with the securities regulators or news releases related thereto (or provided to analysts or rating agencies) and consider whether the information is consistent with the information contained in the financial statements of the Corporation or any subsidiary with public securities. Such discussion may be done generally (consisting of discussing the types of information to be disclosed and the types of presentations to be made).

Internal Control Environment

5. Ensure that management, the external auditors, and the internal auditors provide to the Committee an annual report on the Corporation's control environment as it pertains to the Corporation's financial reporting process and controls.

6. Review and discuss significant financial risks or exposures and assess the steps management has taken to monitor, control, report and mitigate such risk to the Corporation.

7. Review significant findings prepared by the external auditors and the internal auditing department together with management's responses.

8. Review in consultation with the internal auditors and the external auditors the degree of coordination in the audit plans of the internal auditors and the external auditors and enquire as to the extent the planned scope can be relied upon to detect weaknesses in internal controls, fraud, or other illegal acts. The Committee will assess the coordination of audit effort to assure completeness of coverage and the effective use of audit resources. Any significant recommendations made by the auditors for the strengthening of internal controls shall be reviewed and discussed with management.

Other Review Items

9. Review policies and procedures with respect to officers' and directors' expense accounts and perquisites, including their use of corporate assets, and consider the results of any review of these areas by the internal auditor or the external auditors.

10. Review all related party transactions between the Corporation and any officers or directors, including affiliations of any officers or directors.

11. Review with the General Counsel, the head of internal audit and the external auditors the results of their review of the Corporation's monitoring compliance with each of the Corporation's published codes of business conduct and applicable legal requirements.

12. Review legal and regulatory matters, including correspondence with regulators and governmental agencies, that may have a material impact on the interim or annual financial statements, related corporation compliance policies, and programs and reports received from regulators or governmental agencies. Members from the Legal and Tax departments should be at the meeting in person to deliver their reports.

13. Review policies and practices with respect to off-balance sheet transactions and trading and hedging activities, and consider the results of any review of these areas by the internal auditors or the external auditors.

14. Ensure that the Corporation's presentations on net proved reserves have been reviewed with the Reserves Committee of the Board.

15.

Review procedures for the receipt, retention and treatment of complaints received by the Corporation, including confidential, anonymous submissions by employees of the Corporation, regarding accounting, internal accounting controls, or auditing matters.

16. Review with the President & Chief Executive Officer, the Executive Vice-President & Chief Financial Officer of the Corporation and the external auditors: (i) all significant deficiencies and material weaknesses in the design or operation of the Corporation's internal controls and procedures for financial reporting

which could adversely affect the Corporation's ability to record, process, summarize and report financial information required to be disclosed by the Corporation in the reports that it files or submits under the *United States Securities Exchange Act of 1934*, as amended (the "Exchange Act") or applicable Canadian federal and provincial legislation and regulations within the required time periods, and (ii) any fraud, whether or not material, that involves management of the Corporation or other employees who have a significant role in the Corporation's internal controls and procedures for financial reporting.

17. Meet on a periodic basis separately with management.

External Auditors

18. Be directly responsible, in the Committee's capacity as a committee of the Board and subject to the rights of shareholders and applicable law, for the appointment, compensation, retention and oversight of the work of the external auditors (including resolution of disagreements between management and the external auditors regarding financial reporting) for the purpose of preparing or issuing an audit report, or performing other audit, review or attest services for the Corporation. The external auditors shall report directly to the Committee.

19. Meet on a regular basis with the external auditors (without management present) and have the external auditors be available to attend Committee meetings or portions thereof at the request of the Chairman of the Committee or by a majority of the members of the Committee.

20. Review and discuss a report from the external auditors at least quarterly regarding:

    a. All critical accounting policies and practices to be used;

    b. All alternative treatments within generally accepted accounting principles for policies and practices related to material items that have been discussed with management, including the ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditors; and

    c. Other material written communications between the external auditors and management, such as any management letter or schedule of unadjusted differences.

21. Obtain and review a report from the external auditors at least annually regarding:

    a. The external auditors' internal quality-control procedures.

    b. Any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with those issues.

    c. To the extent contemplated in the following paragraph, all relationships between the external auditors and the Corporation.

22. Review and discuss with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation, (i) receiving and reviewing, as part of the report described in the preceding paragraph, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the Corporation and its affiliates, (ii) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors, and (iii) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence.

23. Review and evaluate:

a. The external auditors' and the lead partner of the external auditors' team's performance, and make a recommendation to the Board of Directors regarding the reappointment of the external auditors at the annual meeting of the Corporation's shareholders or regarding the discharge of such external auditors.

b. The terms of engagement of the external auditors together with their proposed fees.

c. External audit plans and results.

d. Any other related audit engagement matters.

e. The engagement of the external auditors to perform non-audit services, together with the fees therefor, and the impact thereof, on the independence of the external auditors.

24. Upon reviewing and discussing the information provided to the Committee in accordance with paragraphs 20 through 23, evaluate the external auditors' qualifications, performance and independence, including whether or not the external auditors' quality controls are adequate and the provision of permitted non-audit services is compatible with maintaining auditor independence, taking into account the opinions of management and the head of internal audit. The Committee shall present its conclusions with respect to the external auditors to the Board.

25. Ensure the rotation of partners on the audit engagement team in accordance with applicable law. Consider whether, in order to assure continuing external auditor independence, it is appropriate to adopt a policy of rotating the external auditing firm on a regular basis.

26. Set clear hiring policies for the Corporation's hiring of employees or former employees of the external auditors.

27. Consider with management and the external auditors the rationale for employing audit firms other than the principal external auditors.

28. Consider and review with the external auditors, management and the head of internal audit:

a. Significant findings during the year and management's responses and follow-up thereto.

b. Any difficulties encountered in the course of their audits, including any restrictions on the scope of their work or access to required information, and management's response.

c. Any significant disagreements between the external auditors or internal auditors and management.

d. Any changes required in the planned scope of their audit plan.

e. The resources, budget, reporting relationships, responsibilities and planned activities of the internal auditors.

f. The internal audit department mandate.

g. Internal audit's compliance with the Institute of Internal Auditors' standards.

Internal Audit Department and Legal Compliance

29. Meet on a periodic basis separately with the head of internal audit.

30. Review and concur in the appointment, compensation, replacement, reassignment, or dismissal of the head of internal audit.

31. Confirm and assure, annually, the independence of the internal audit department and the external auditors.

Approval of Audit and Non-Audit Services

32. Review and, where appropriate, approve the provision of all permitted non-audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors (subject to the de minimus exception for non-audit services described in the Exchange Act or applicable Canadian federal and provincial legislation and regulations which are approved by the Committee prior to the completion of the audit).

33. Review and, where appropriate and permitted, approve the provision of all audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors.

34. If the pre-approvals contemplated in paragraphs 32 and 33 are not obtained, approve, where appropriate and permitted, the provision of all audit and non-audit services promptly after the Committee or a member of the Committee to whom authority is delegated becomes aware of the provision of those services.

35. Delegate, if the Committee deems necessary or desirable, to subcommittees consisting of one or more members of the Committee, the authority to grant the pre-approvals and approvals described in paragraphs 32 through 34. The decision of any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

36. The Committee may establish policies and procedures for the pre-approvals described in paragraphs 32 and 33, so long as such policies and procedures are detailed as to the particular service, the Committee is informed of each service and such policies and procedures do not include delegation of the Committee's responsibilities under the Exchange Act or applicable Canadian federal and provincial legislation and regulations to management.

Other Matters

37. Review and concur in the appointment, replacement, reassignment, or dismissal of the Chief Financial Officer.

38. Upon a majority vote of the Committee outside resources may be engaged where and if deemed advisable.

39. Report Committee actions to the Board of Directors with such recommendations, as the Committee may deem appropriate.

40. Conduct or authorize investigations into any matters within the Committee's scope of responsibilities. The Committee shall be empowered to retain, obtain advice or otherwise receive assistance from independent counsel, accountants, or others to assist it in the conduct of any investigation as it deems necessary and the carrying out of its duties.

41. The Corporation shall provide for appropriate funding, as determined by the Committee in its capacity as a committee of the Board, for payment (i) of compensation to the external auditors for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation, (ii) of compensation to any advisors employed by the Committee and (iii) of ordinary administrative expenses of the Committee that are necessary or appropriate in carrying out its duties.

42. Obtain assurance from the external auditors that disclosure to the Committee is not required pursuant to the provisions of the Exchange Act regarding the discovery of illegal acts by the external auditors.

43. The Committee shall review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Board for approval.

44. The Committee's performance shall be evaluated annually by the Nominating and Corporate Governance Committee of the Board of Directors.

45. Perform such other functions as required by law, the Corporation's mandate or bylaws, or the Board of Directors.

46. Consider any other matters referred to it by the Board of Directors.

December 31, 2006

Management s Discussion and Analysis

Management s Discussion and Analysis

This Management s Discussion and Analysis (MD&A) for EnCana Corporation (EnCana or the Company) should be read with the audited Consolidated Financial Statements for the year ended December 31, 2006, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2005. Readers should also read the Forward-Looking Statements legal advisory contained at the end of this MD&A.

The Consolidated Financial Statements and comparative information have been prepared in United States dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles (GAAP). Production and sales volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This MD&A is dated February 22, 2007.

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

EnCana s Business

EnCana is a leading North American unconventional natural gas and integrated oilsands company.

At December 31, 2006, EnCana operated two continuing businesses:

Upstream includes the Company s exploration for, and development and production of, natural gas, crude oil and natural gas liquids (NGLs) and other related activities. The majority of the Company s Upstream operations are located in Canada and the United States (U.S.). International new ventures exploration is mainly focused on opportunities in Brazil, the Middle East, Greenland and France.

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

2006 Overview

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

In 2006 compared to 2005, EnCana:

Grew total North American sales volumes 3 percent to 4,295 million cubic feet (MMcf) of gas equivalent per day (MMcfe/d);

Grew natural gas sales by 4 percent to 3,367 MMcf/d;

Reported a 16 percent decrease in natural gas prices to $6.25 per thousand cubic feet (Mcf). Realized natural gas prices, including the impact of financial hedging, averaged $6.72 per Mcf, a decrease of 6 percent;

Reported average North American crude oil prices of $41.83 per barrel (bbl), an increase of 22 percent over 2005. Realized crude oil prices, including the impact of financial hedging, averaged $38.51 per bbl, an increase of 33 percent;

Achieved sales of approximately 48,000 barrels per day (bbls/d) at EnCana s three steam-assisted gravity drainage (SAGD) projects (Foster Creek, Christina Lake and Senlac). Production at Foster Creek in 2006 was approximately 37,000 bbls/d compared to approximately 29,000 bbls/d in 2005;

Increased production from key resource plays by 12 percent;

Reported operating costs of $0.86 per Mcfe, a 21 percent increase mainly due to the higher U.S./Canadian dollar, increased industry activity and electricity costs;

Completed the sale of EnCana s Ecuador assets for approximately $1.4 billion before indemnifications and both stages of the sale of EnCana s natural gas storage operations for approximately $1.5 billion;

Completed the sale of its interest in the Chinook heavy oil discovery offshore Brazil for proceeds of approximately $367 million;

Reported net earnings of $5,652 million (up 65 percent from 2005) mainly due to after-tax unrealized mark-to-market gains of $1,370 million and the after-tax gain on sale of the discontinued operations of $554 million;

Purchased 85.6 million, or 10 percent, of its Common Shares at an average price of $49.26 per share under the Normal Course Issuer Bid (NCIB) for a total cost of $4.2 billion; and

Reduced Net Debt to Capitalization to 27 percent from 33 percent and Net Debt to Adjusted EBITDA to 0.6x from 1.1x at December 31, 2005.

On January 2, 2007, EnCana became a 50 percent partner in an integrated, North American heavy oil business with ConocoPhillips, which consists of an upstream and a downstream entity. In creating the integrated venture, EnCana contributed its Foster Creek and Christina Lake oilsands properties, while ConocoPhillips contributed its Wood River and Borger refineries located in Illinois and Texas, respectively.

Business Environment

NATURAL GAS

Natural Gas Price Benchmarks Year ended December 31 (Average for the period)		**2006**	**2006 vs 2005**		2005	2005 vs 2004		2004
AECO Price *(C$/Mcf)*	**$**	**6.98**	**-18%**	$	8.48	25%	$	6.79
NYMEX Price *($/MMBtu)*		**7.22**	**-16%**		8.62	40%		6.14
Rockies (Opal) Price *($/MMBtu)*		**5.65**	**-19%**		6.96	33%		5.23
Basis Differential *($/MMBtu)*								
AECO/NYMEX		**1.06**	**-33%**		1.59	75%		0.91
Rockies/NYMEX		**1.57**	**-5%**		1.66	82%		0.91

NYMEX gas prices decreased in 2006 due to:

a warmer than normal January and February;

an aggressive industry drilling program that increased U.S. supply;

an uneventful hurricane season compared to expectations and 2005; and

a warmer than normal December.

All of the above contributed to an increase in industry levels of natural gas in storage throughout the year. Natural gas in storage for the industry ended 2006 at 408 billion cubic feet (Bcf) above the five year average.

The lower average AECO gas price in 2006 is attributed to the decrease in the NYMEX gas price and a stronger Canadian dollar partially offset by the narrowing of the AECO/NYMEX basis differential. A lower average Rockies (Opal) gas price in 2006 resulted from a lower NYMEX gas price partially offset by a reduced Rockies/NYMEX basis differential. Increased demand in the Rockies region during the second half of 2006 relieved some of the pressure that supply growth in the Rockies had exerted on an already highly utilized pipeline grid. This allowed the Rockies basis differential to narrow in 2006 compared to 2005. However, continued supply growth in the Rockies is expected to put further pressure on Rockies basis in the future. Until the Rockies Express Pipeline comes into service, expected in early 2008, EnCana has taken steps to mitigate its projected Rockies price risk from the impact of further deterioration in the Rockies basis differential through the use of financial basis hedges, the details of which are disclosed in Note 16 of the Consolidated Financial Statements.

CRUDE OIL

Crude Oil Price Benchmarks		**2006 vs**		2005 vs	
Year ended December 31 (Average for the period) ($/bbl)	**2006**	**2005**	2005	2004	2004 (1)
WTI	**$ 66.25**	**17%**	$ 56.70	37%	$ 41.47
WCS	**44.69**	**23%**	36.39	-	n/a
Differential - WTI/WCS	**21.56**	**6%**	20.31	-	n/a

(1) WCS was first posted by EnCana in October 2004, thus there is no annual average rate for WCS or WTI/WCS differential available for 2004.

Concerns over Iran s nuclear program, Nigerian production shut-in due to militant attacks, ongoing instability in Iraq and a lack of U.S. gasoline supply combined to propel the West Texas Intermediate (WTI) price above the $70 per bbl level for most of the second and third quarters. By the end of 2006, WTI prices had fallen back to the $60 per bbl level as overall crude oil and refined product market balances continued to demonstrate there was adequate supplies of crude oil.

Canadian heavy oil differentials were comparable with 2005 owing to strength in asphalt and residual fuel oil markets supporting prices for Canadian heavy crude oil. The Western Canadian Select (WCS) average sales price was 67 percent of WTI for 2006 compared to 64 percent of WTI in 2005.

U.S./CANADIAN DOLLAR EXCHANGE RATES

The impacts of currency fluctuations on EnCana s results should be considered when analyzing the Consolidated Financial Statements. The value of the Canadian dollar compared to the U.S. dollar increased by 6.9 percent, or $0.057, to an average of US$0.882 in 2006 from an average of US$0.825 in 2005, which was approximately 7.4 percent, or $0.057, higher than the 2004 average.

As a result, EnCana reported an additional $5.70 of costs for every one hundred Canadian dollars spent on capital projects, operating expenses and administrative expenses in 2006 relative to 2005. However, revenues were relatively unaffected by fluctuations in the U.S./Canadian dollar exchange rate because the commodity prices received by EnCana are largely based in U.S. dollars or in Canadian dollars at prices that are closely tied to the value of the U.S. dollar.

U.S./Canadian Dollar Exchange Rates

Year ended December 31		2006		2005		2004
Average U.S./Canadian dollar exchange rate	**$**	**0.882**	**$**	**0.825**	$	0.768
Average U.S./Canadian dollar exchange rate for prior year	**$**	**0.825**	**$**	**0.768**	$	0.716
Increase in reported capital, operating and administrative expenditures caused solely by fluctuations in exchange rates, for every hundred Canadian dollars spent	**$**	**5.70**	**$**	**5.70**	$	5.20

Acquisitions and Divestitures

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

The sale of the Entrega Pipeline, located in Colorado, on February 23 for approximately $244 million;

The sale of its interests in Ecuador on February 28 for approximately $1.4 billion before indemnifications, which is discussed in Note 4 to the Consolidated Financial Statements;

The sale of its natural gas storage operations in Canada and the U.S. in two separate transactions with a single purchaser for total proceeds of approximately $1.5 billion resulting in an after-tax gain on sale of $829 million; and

The sale of its 50 percent interest in the Chinook heavy oil discovery offshore Brazil on August 16 for approximately $367 million, resulting in an after-tax gain on sale of $255 million.

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

Consolidated Financial Results

Year ended December 31 ($ millions, except per share[1] amounts)		2006	2006 vs 2005		2005	2005 vs 2004		2004
Total Consolidated								
Cash Flow [2]	**$**	**7,161**	**-4%**	$	7,426	49%	$	4,980
- per share diluted		**8.56**	**3%**		8.35	57%		5.32
Net Earnings		**5,652**	**65%**		3,426	-2%		3,513
- per share basic		**6.89**	**74%**		3.95	3%		3.82
- per share diluted		**6.76**	**76%**		3.85	3%		3.75
Operating Earnings [3]		**3,271**	**1%**		3,241	64%		1,976
- per share diluted		**3.91**	**7%**		3.64	73%		2.11
Total Assets		**35,106**	**3%**		34,148	9%		31,213
Long-Term Debt		**6,577**	**-2%**		6,703	-13%		7,742
Cash Dividends		**304**	**28%**		238	30%		183
Continuing Operations								
Cash Flow from Continuing Operations [2]		**7,043**	**1%**		6,962	55%		4,502
Net Earnings from Continuing Operations		**5,051**	**79%**		2,829	35%		2,093
- per share basic		**6.16**	**89%**		3.26	44%		2.27
- per share diluted		**6.04**	**90%**		3.18	42%		2.24
Operating Earnings from Continuing Operations [3]		**3,237**	**6%**		3,048	63%		1,872
Revenues, Net of Royalties		**16,399**	**13%**		14,573	39%		10,491

(1) Per share amounts have been restated for the effect of the Common Share split in 2005.

(2) Cash Flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations and net change in non-cash working capital from discontinued operations, all of which are defined on the Consolidated Statement of Cash Flows.

(3) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under Operating Earnings , all of which are defined on the Consolidated Statement of Cash Flows.

CASH FLOW

While cash flow measures are considered non-GAAP, they are commonly used in the oil and gas industry and are used by EnCana to assist management and investors in measuring the Company s ability to finance capital programs and meet financial obligations.

2006 vs 2005

EnCana s 2006 cash flow was $7,161 million, a decrease of 4 percent from 2005 mainly due to the decline in cash flow from discontinued operations of $346 million year over year.

Cash flow from continuing operations in 2006 was $7,043 million (2005 - $6,962 million).

The increase in cash flow from continuing operations was positively impacted by:

Average North American liquids prices, excluding financial hedges, increased 21 percent to $43.71 per bbl in 2006 compared to $36.17 per bbl in 2005;

North American natural gas sales volumes in 2006 increased 4 percent to 3,367 MMcf/d from 3,227 MMcf/d in 2005; and

Realized financial natural gas and crude oil commodity hedging gains were $263 million after-tax (natural gas $386 million gain; crude oil and other $123 million loss) in 2006 compared with losses of $441 million after-tax (natural gas $261 million loss; crude oil and other $180 million loss) in 2005.

The increase in cash flow from continuing operations was negatively impacted by:

Average North American natural gas prices, excluding financial hedges, decreased 16 percent to $6.25 per Mcf in 2006 compared to $7.46 per Mcf in 2005;

Operating expenses, which increased 15 percent to $1,655 million in 2006 compared with $1,438 million in 2005; and

The current tax provision, excluding income tax on the sale of the Brazil assets, increased $267 million to $893 million in 2006 compared to $626 million in 2005, excluding income tax on the sale of the Gulf of Mexico assets.

2005 vs 2004

EnCana s 2005 cash flow was $7,426 million, an increase of $2,446 million or 49 percent from 2004. This increase reflects higher commodity prices in 2005 partially reduced by increased costs. EnCana s discontinued operations contributed $464 million to cash flow compared with $478 million in 2004.

EnCana s 2005 cash flow from continuing operations was $6,962 million (2004 - $4,502 million), an increase of $2,460 million or 55 percent.

The increase in cash flow from continuing operations was positively impacted by:

Average North American natural gas prices, excluding financial hedges, increased 36 percent to $7.46 per Mcf in 2005 compared to $5.47 per Mcf for 2004;

North American natural gas sales volumes increased 9 percent to 3,227 MMcf/d; and

Average North American liquids prices, excluding financial hedges, increased 26 percent to $36.17 per bbl in 2005 compared to $28.77 per bbl in 2004.

The increase in cash flow was negatively impacted by:

Operating expenses, which increased 31 percent to $1,438 million in 2005 compared with $1,099 million in 2004;

Interest expense, which increased $126 million to $524 million in 2005. Almost all of this increase represents the cost to redeem certain notes in 2005; and

The current tax provision, excluding income tax on the sale of the Gulf of Mexico assets, increased $67 million to $626 million compared with $559 million in 2004.

Realized financial natural gas and crude oil commodity hedging losses were $441 million after-tax in 2005, relatively unchanged from $430 million after-tax in 2004.

NET EARNINGS

EnCana s 2006 net earnings were $5,652 million (2005 - $3,426 million). Net earnings for the year include unrealized after-tax mark-to-market gains of $1,370 million (2005 after-tax losses of $277 million) and the effect of the tax rate reduction of $457 million (2005 - nil). Net earnings from discontinued operations increased slightly to $601 million, mainly due to the gain on sale of the gas storage assets in 2006 offset partially by the loss on sale of Ecuador assets (discussed in the Discontinued Operations section of this MD&A).

2006 vs 2005

EnCana s 2006 net earnings from continuing operations were $5,051 million, an increase of $2,222 million compared with 2005. In addition to the items affecting cash flow as detailed previously, significant items affecting net earnings were:

Unrealized mark-to-market gains of $1,357 million after-tax (natural gas $1,256 million gain; crude oil and other $101 million gain) in 2006 compared with losses of $311 million after-tax (natural gas $326 million loss; crude oil and other $15 million gain) in 2005;

A gain on sale of approximately $255 million after-tax from the sale of a 50 percent interest in the Chinook heavy oil discovery offshore Brazil; and

An increase in depreciation, depletion and amortization (DD&A) of $343 million as a result of the higher U.S./Canadian dollar, higher DD&A rates and increased sales volumes.

2005 vs 2004

EnCana s 2005 net earnings were $3,426 million (2004 - $3,513 million). Net earnings from discontinued operations decreased $823 million to $597 million; most of this decrease results from the 2005 after-tax gain of $370 million on the sale of substantially all of EnCana s natural gas processing business being less than the 2004 after-tax gain on the sale of EnCana s United Kingdom (U.K.) operations.

EnCana s 2005 net earnings from continuing operations were $2,829 million, an increase of $736 million, or 35 percent compared with 2004. In addition to the items affecting cash flow as detailed previously, significant items affecting earnings were:

An increase in DD&A of $390 million as a result of the higher U.S./Canadian dollar, higher DD&A rates and increased sales volumes; and

Unrealized mark-to-market losses of $311 million after-tax in 2005 compared with losses of $117 million in 2004.

OPERATING EARNINGS

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

Summary of Total Operating Earnings

Year Ended December 31 ($ millions)		2006	2006 vs 2005		2005	2005 vs 2004		2004
Net Earnings, as reported	**$**	**5,652**	**65%**	$	3,426	-2%	$	3,513
Add back (losses) and deduct gains:								
- Unrealized mark-to-market accounting gain (loss), after-tax		**1,370**			(277)			(165)
- Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt, after-tax (1)		**-**			92			229
- Gain on sale of discontinued operations, after-tax		**554**			370			1,364
- Future tax recovery due to tax rate reductions		**457**			-			109
Operating Earnings (2) (3)	**$**	**3,271**	**1%**	$	3,241	64%	$	1,976

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

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

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

Summary of Total Operating Earnings (continued)

Year Ended December 31 ($ per Common Share Diluted)	**2006**	**2006 vs 2005**	2005	2005 vs 2004	2004
Net Earnings, as reported	**$ 6.76**	**76%**	$ 3.85	3%	$ 3.75
Add back (losses) and deduct gains:					
- Unrealized mark-to-market accounting gain (loss), after-tax	**1.64**		(0.31)		(0.18)
- Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt, after-tax [1]	**-**		0.10		0.24
- Gain on sale of discontinued operations, after-tax	**0.66**		0.42		1.46
- Future tax recovery due to tax rate reductions	**0.55**		-		0.12
Operating Earnings [2] [3]	**$ 3.91**	**7%**	$ 3.64	73%	$ 2.11

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

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

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

The 2006 operating earnings per share have increased mainly due to share purchases under the NCIB program.

Summary of Operating Earnings from Continuing Operations

Year Ended December 31 ($ millions)	**2006**	**2006 vs 2005**	2005	2005 vs 2004	2004
Net Earnings from Continuing Operations, as reported	**$ 5,051**	**79%**	$ 2,829	35%	$ 2,093
Add back (losses) and deduct gains:					
- Unrealized mark-to-market accounting gain (loss), after-tax	**1,357**		(311)		(117)
- Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt, after-tax [1]	**-**		92		229
- Future tax recovery due to tax rate reductions	**457**		-		109
Operating Earnings from Continuing Operations [2] [3]	**$ 3,237**	**6%**	$ 3,048	63%	$ 1,872

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

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

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

RESULTS OF OPERATIONS Continuing Operations

Upstream Operations

Financial Results from Continuing Operations

Year Ended December 31

($ millions)	2006				2005				2004			
	Produced Gas	Crude Oil & NGLs	Other	Total	Produced Gas	Crude Oil & NGLs	Other	Total	Produced Gas	Crude Oil & NGLs	Other	Total
Revenues, Net of Royalties	**$ 8,294**	**$ 2,738**	**$ 310**	**$ 11,342**	$ 8,418	$ 2,071	$ 283	$ 10,772	$ 5,704	$ 1,552	$ 232	$ 7,488
Expenses												
Production and mineral taxes	**293**	**56**	**-**	**349**	401	52	-	453	270	41	-	311
Transportation and selling	**526**	**528**	**-**	**1,054**	465	367	-	832	416	288	-	704
Operating	**912**	**400**	**293**	**1,605**	733	305	313	1,351	519	285	222	1,026
Operating Cash Flow	**$ 6,563**	**$ 1,754**	**$ 17**	**$ 8,334**	$ 6,819	$ 1,347	$ (30)	$ 8,136	$ 4,499	$ 938	$ 10	$ 5,447
Depreciation, depletion and amortization				**3,025**				2,688				2,271
Segment Income				**$ 5,309**				$ 5,448				$ 3,176

Upstream Revenues

2006 vs 2005

Revenues, net of royalties, 2006 compared with 2005:

-increased due to

A 21 percent increase in North American liquids prices and a 4 percent increase in North American natural gas volumes; and

Realized financial natural gas and crude oil commodity hedging gains of $397 million in 2006 compared to losses of $672 million for 2005;

-were lower due to

A 16 percent decrease in North American natural gas prices.

2005 vs 2004

Revenues, net of royalties, 2005 compared with 2004:

-increased due to

- A 36 percent increase in natural gas prices combined with a 9 percent increase in natural gas sales volumes; and
- A 26 percent increase in liquids prices;

-were lower due to

- A 6 percent decrease in liquids volumes mainly as a result of property divestitures in the first and third quarters of 2004 and in June 2005.

Realized financial natural gas and crude oil commodity hedging losses totaled $672 million in 2005, relatively unchanged from $669 million in 2004.

Revenue Variances for 2006 Compared to 2005 from Continuing Operations

Year Ended December 31 ($ millions)	2005 Revenues, Net of Royalties	Revenue Variances in: Price (1)	Volume	**2006 Revenues, Net of Royalties**
Produced Gas				
Canada	$ 5,486	$ (178)	$ 132	**$ 5,440**
United States	2,932	(288)	210	**2,854**
Total Produced Gas	$ 8,418	$ (466)	$ 342	**$ 8,294**
Crude Oil and NGLs				
Canada	$ 1,826	$ 651	$ (6)	**$ 2,471**
United States	245	41	(19)	**267**
Total Crude Oil and NGLs	$ 2,071	$ 692	$ (25)	**$ 2,738**

(1) Includes the impact of realized financial hedging.

The increase in liquids sales prices and natural gas realized financial commodity hedging gains account for the majority of the approximately 5 percent increase in revenues, net of royalties, in 2006 compared with 2005. The balance of the increase in revenues results from an increase in natural gas sales volumes.

Produced gas volumes in Canada increased 2 percent in 2006, mainly due to drilling success in the key resource plays of Coalbed Methane Integrated (CBM) in central and southern Alberta, Cutbank Ridge in northeast British Columbia and Bighorn in west-central Alberta and additional well tie-ins and recompletions in several areas. CBM is the commingled gas volumes from the coal and sand intervals based on regulatory approval. Offsetting the increase were unscheduled maintenance, natural declines, planned turnarounds and weather related delays for the Shallow Gas key resource play and conventional properties, which resulted in lower production volumes.

Produced gas volumes in the U.S. increased 8 percent in 2006 as a result of drilling success at Fort Worth, Jonah, Piceance and East Texas as well as the impact of property acquisitions in the Fort Worth Basin in late 2005.

North American crude oil and NGLs volumes were basically unchanged as a result of production increases at Foster Creek offset by the Pelican Lake royalty payout, lower production due to unscheduled maintenance, delays in capital programs in southern Alberta and natural declines. EnCana s Pelican Lake property reached payout in April 2006, which increased the royalty payments to the Government of Alberta and reduced EnCana s net revenue interest crude oil volumes by approximately 6,000 bbls/d at the point of payout.

Upstream Sales Volumes

Sales Volumes Year Ended December 31	**2006**	**2006 vs 2005**	2005	2005 vs 2004	2004

Produced Gas *(MMcf/d)*	**3,367**	4%	3,227	9%	2,968
Crude Oil *(bbls/d)*	**130,497**	-	130,418	-7%	140,379
NGLs *(bbls/d)*	**24,207**	-5%	25,582	-2%	26,038
Continuing Operations *(MMcfe/d)* (1)	**4,295**	3%	4,163	5%	3,966
Discontinued Operations					
Ecuador *(bbls/d)* (2)	**12,366**	-83%	71,065	-9%	77,993
United Kingdom *(BOE/d)* (3)	-	-	-	-100%	20,973
Discontinued Operations *(MMcfe/d)* (1)	**74**	-83%	426	-28%	594
Total *(MMcfe/d)* (1)	**4,369**	-5%	4,589	1%	4,560

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

(2) As the Ecuador sale closed on February 28, 2006 only two months of volumes are included in 2006.

(3) Includes natural gas and liquids (converted to BOE).

Sales volumes from continuing operations in 2006 increased 3 percent or 132 MMcfe/d from 2005 due to:

Production from EnCana s key resource plays increased 12 percent;

Drilling success in the key resource gas plays of CBM, Cutbank Ridge, Bighorn, Fort Worth, Jonah, Piceance and East Texas offset somewhat by unscheduled maintenance, natural declines, planned turnarounds and weather related delays for the Shallow Gas key resource play and conventional properties; and

Expansion of Foster Creek facilities partially offset by the Pelican Lake royalty payout in April 2006 and natural declines for conventional properties.

Key Resource Plays	Daily Production					Drilling Activity (number of net wells drilled)		
	2006	**2006 vs 2005**	2005	2005 vs 2004	2004	**2006**	2005	2004
Natural Gas *(MMcf/d)*								
Jonah	**464**	**7%**	435	12%	389	**163**	104	70
Piceance	**326**	**6%**	307	18%	261	**220**	266	250
East Texas	**99**	**10%**	90	80%	50	**59**	84	50
Fort Worth	**101**	**44%**	70	159%	27	**97**	59	36
Greater Sierra	**213**	**-3%**	219	-5%	230	**115**	164	187
Cutbank Ridge	**170**	**85%**	92	130%	40	**116**	135	50
Bighorn	**91**	**65%**	55	31%	42	**52**	51	20
CBM Integrated [(1)]	**194**	**73%**	112	300%	28	**729**	1,245	1,086
Shallow Gas	**600**	**-4%**	625	6%	592	**1,164**	1,267	1,552
Oil *(Mbbls/d)*								
Foster Creek	**37**	**28%**	29	-	29	**6**	39	11
Christina Lake	**6**	**20%**	5	25%	4	**2**	-	2
Pelican Lake	**24**	**-8%**	26	37%	19	**-**	52	92
Total *(MMcfe/d)*	**2,656**	**12%**	2,366	20%	1,971	**2,723**	3,466	3,406

(1) CBM Integrated s 2005 and 2004 volumes and net wells drilled restated to report commingled gas volumes from the coal and sand intervals based on regulatory approval.

Per Unit Results Produced Gas	Canada					United States				
Year Ended December 31										
($ per thousand cubic feet)	**2006**	**2006 vs 2005**	2005	2005 vs 2004	2004	**2006**	**2006 vs 2005**	2005	2005 vs 2004	2004
Price (1)	**$ 6.20**	**-15%**	$ 7.27	36%	$ 5.34	**$ 6.35**	**-19%**	$ 7.82	35%	$ 5.79
Expenses										
Production and mineral taxes	**0.10**	**-**	0.10	25%	0.08	**0.49**	**-40%**	0.81	25%	0.65

Transportation and selling	**0.35**	**-3%**	0.36	-8%	0.39	**0.54**	**17%**	0.46	48%	0.31
Operating	**0.79**	**18%**	0.67	29%	0.52	**0.65**	**23%**	0.53	43%	0.37
Netback	**$ 4.96**	**-19%**	$ 6.14	41%	$ 4.35	**$ 4.67**	**-22%**	$ 6.02	35%	$ 4.46
Gas Sales Volumes *(MMcf/d)*	**2,185**	**2%**	2,132	2%	2,099	**1,182**	**8%**	1,095	26%	869

(1) Excludes the impact of realized financial hedging.

2006 vs 2005

EnCana s North American natural gas price for 2006, excluding the impact of financial hedges, was $6.25 per Mcf, a decrease of 16 percent compared to 2005, which is consistent with the decline in the AECO price of 18 percent and the NYMEX price of 16 percent. North American realized financial commodity hedging gains on natural gas for 2006 were approximately $584 million or $0.47 per Mcf compared to losses of approximately $377 million or $0.32 per Mcf in 2005. The hedging gains in 2006 were a result of put hedging instruments transacted at higher price levels than in 2005, coupled with a decline in North American natural gas prices in 2006 compared to 2005.

Natural gas per unit production and mineral taxes, which are generally calculated as a percentage of revenues, have remained flat in Canada for 2006 mainly due to lower natural gas prices offset partially by the higher U.S./Canadian dollar. Natural gas per unit production and mineral taxes in the U.S. decreased $0.32 per Mcf or 40 percent in 2006 mainly as a result of a reduction in the effective production and severance tax rates for Colorado properties and lower natural gas prices.

Natural gas per unit transportation and selling costs for the U.S. increased $0.08 per Mcf or 17 percent for 2006 primarily as a result of higher transportation costs on operated wells from Piceance, East Texas and certain Colorado properties.

Natural gas per unit operating expenses in Canada for 2006 were 18 percent or $0.12 per Mcf higher as a result of the higher U.S./Canadian dollar, increased industry activity, property taxes and lease rentals, electricity rates and salaries and benefits. Natural gas per unit operating expenses in the U.S. increased 23 percent or $0.12 per Mcf for 2006 mainly as a result of increased industry activity, chemicals, salaries, workovers and repairs and maintenance expenses. Increases in operating costs in both Canada and the U.S. were offset partially by lower long-term compensation costs in 2006 compared to 2005.

2005 vs 2004

EnCana s realized natural gas prices for 2005 were $7.46 per Mcf, an increase of 36 percent compared with 2004, which is consistent with the increase in the AECO price of 25 percent and the NYMEX price of 40 percent. North American realized financial commodity hedging losses on natural gas for 2005 were approximately $377 million or $0.32 per Mcf compared to losses of approximately $238 million or $0.22 per Mcf in 2004.

Natural gas per unit production and mineral taxes in the U.S. increased $0.16 per Mcf or 25 percent in 2005 as a result of higher natural gas prices.

Natural gas per unit transportation and selling costs for the U.S. increased 48 percent or $0.15 per Mcf for 2005 primarily as a result of marketing certain gas volumes downstream of the wellhead in 2005, which were marketed at the wellhead in 2004.

Canadian natural gas per unit operating expenses for 2005 were 29 percent or $0.15 per Mcf higher as a result of increased industry activity, the higher U.S./Canadian dollar, higher repairs and maintenance and long-term compensation expenses. Natural gas per unit operating expenses in the U.S. increased 43 percent or $0.16 per Mcf for 2005 mainly as a result of increased staffing levels, higher long-term compensation expenses, increased industry activity and higher workovers.

Per Unit Results Crude Oil

Year Ended December 31	North America				
($ per barrel)	**2006**	**2006 vs 2005**	2005	2005 vs 2004	2004
Price [1]	**$ 41.83**	**22%**	$ 34.15	22%	$ 27.92
Expenses					
Production and mineral taxes	**0.77**	**33%**	0.58	41%	0.41
Transportation and selling	**1.40**	**17%**	1.20	13%	1.06
Operating	**9.09**	**26%**	7.23	21%	6.00
Netback	**$ 30.57**	**22%**	$ 25.14	23%	$ 20.45
Crude Oil Sales Volumes *(bbls/d)*	**130,497**	**-**	130,418	-7%	140,379

(1) Excludes the impact of realized financial hedging.

2006 vs 2005

The increase in EnCana s North American crude oil price for 2006, excluding the impact of financial hedges, reflects the 23 percent increase in the benchmark WCS crude oil price compared to 2005. North American realized financial commodity hedging losses on crude oil were approximately $187 million or $3.32 per bbl for 2006 compared to losses of approximately $295 million or $5.18 per bbl for 2005. The reduced hedging losses in 2006 were a result of fixed price and put hedging instruments transacted at higher price levels than in 2005, coupled with an increase in North American oil prices in 2006 compared to 2005.

Heavy oil sales in 2006 have increased slightly from 2005, representing approximately 66 percent of total oil sales in 2006 versus 64 percent of total oil sales in 2005. The percentage increase is a result of the increase in heavy oil production from Foster Creek, offset slightly by the Pelican Lake royalty payout in April 2006 and declining conventional production.

North American crude oil per unit production and mineral taxes increased 33 percent or $0.19 per bbl in 2006 primarily due to increased production from the Weyburn and Senlac properties in Saskatchewan, which are subject to freehold production tax and Saskatchewan resource tax, the higher U.S./Canadian dollar and the impact of higher overall prices.

North American crude oil per unit transportation and selling costs increased 17 percent or $0.20 per bbl in 2006 primarily due to a higher proportion of Canadian heavy crude oil volumes being delivered to the U.S. Gulf Coast to capture higher selling prices and the higher U.S./Canadian dollar. Crude oil transportation and selling costs also include costs of condensate purchased for blending of bitumen, totaling $458 million (2005 - $307 million; 2004 - $232 million), which are not included in the transportation and selling per unit calculations.

North American crude oil per unit operating costs for 2006 increased 26 percent or $1.86 per bbl mainly due to workovers at Foster Creek, the higher U.S./Canadian dollar, increased electricity rates, a prior period adjustment for a non-operated property, increased industry activity and lower production from Pelican Lake as a result of the royalty payout in the second quarter of 2006. The increased proportion of crude oil volumes from SAGD projects, which have higher operating costs compared to EnCana s other properties, also increased the overall crude oil per unit operating costs.

2005 vs 2004

The increase in the average crude oil price in 2005, excluding the impact of financial hedges, reflects the 37 percent increase in the benchmark WTI in 2005. This increase was partially offset by the increased WTI/Bow River crude oil price differential (up approximately 53 percent). North American realized financial commodity hedging losses on crude oil were approximately $295 million or $5.18 per bbl of liquids in 2005 compared to losses of approximately $431 million or $7.08 per bbl of liquids in 2004.

Heavy oil sales in 2005 increased to 64 percent of total oil sales from 60 percent in 2004. This increase was mainly due to an increase in heavy oil production from the Pelican Lake property combined with divestitures of non-core conventional assets in 2004 and 2005 that produced light/medium oil.

North American crude oil per unit production and mineral taxes increased by 41 percent or $0.17 per bbl in 2005 primarily due to the impact of higher prices.

The 2005 crude oil per unit transportation and selling expenses in North America increased 13 percent or $0.14 per bbl mainly due to the higher U.S./Canadian dollar and increased tariff rates as of July 2005.

North American crude oil per unit operating costs for 2005 increased 21 percent or $1.23 per bbl mainly due to the higher U.S./Canadian dollar, workovers, repairs and maintenance, fuel costs and long-term compensation expenses. In addition, the increased proportion of crude oil volumes from SAGD projects, which have higher operating costs compared to EnCana s other properties, increased the overall crude oil per unit operating costs.

Per Unit Results NGLs

Year Ended December 31	Canada					United States				
($ per barrel)	**2006**	**2006 vs 2005**	2005	2005 vs 2004	2004	**2006**	**2006 vs 2005**	2005	2005 vs 2004	2004
Price [1]	**$ 51.12**	**16%**	$ 44.24	41%	$ 31.43	**$ 56.33**	**16%**	$ 48.36	36%	$ 35.43
Expenses										
Production and mineral taxes	**-**	**-**	-	-	-	**4.19**	**-14%**	4.86	27%	3.82
Transportation and selling	**0.67**	**60%**	0.42	2%	0.41	**0.01**	**-**	0.01	-	-
Netback	**$ 50.45**	**15%**	$ 43.82	41%	$ 31.02	**$ 52.13**	**20%**	$ 43.49	38%	$ 31.61
NGLs Sales Volumes *(bbls/d)*	**11,713**	**-2%**	11,907	-11%	13,452	**12,494**	**-9%**	13,675	9%	12,586

(1) Excludes the impact of realized financial hedging.

2006 vs 2005

The increase in NGLs realized prices in 2006 compared to 2005 generally correlates with higher WTI oil prices.

NGLs per unit transportation and selling costs in Canada increased 60 percent or $0.25 per bbl in 2006 due to an increase in volumes being trucked and higher trucking rates due to inflation at Bighorn and certain B.C. properties.

U.S. NGLs per unit production and mineral taxes in the U.S. decreased 14 percent or $0.67 per bbl in 2006 mainly as a result of a reduction in the effective production and severance tax rates for Colorado properties.

U.S. NGLs sales volumes decreased 9 percent as a result of declines at certain Colorado properties that have a high liquids component.

2005 vs 2004

The increase in NGLs realized prices in 2005 generally correlates with increased WTI oil prices.

U.S. NGLs per unit production and mineral taxes for 2005 increased 27 percent or $1.04 per bbl as a result of the increase in NGLs prices.

Upstream Depreciation, Depletion and Amortization

2006 vs 2005

DD&A expenses in 2006 increased $337 million or 13 percent from 2005 due to:

North American sales volumes increased 3 percent;

Unit of production DD&A rates were $1.91 per Mcfe in 2006 compared to $1.72 per Mcfe in 2005. Rates were higher as a result of the higher U.S./Canadian dollar and an increase in future development costs partially reduced by the effect of the Gulf of Mexico sale in May 2005; and

DD&A expense in 2006 included impairments of $6 million related to exploration prospects in the Middle East compared to $7 million in 2005.

2005 vs 2004

DD&A expenses in 2005 increased by $417 million or 18 percent from 2004 due to:

North American sales volumes increased 5 percent;

Unit of production DD&A rates were $1.72 per Mcfe in 2005 compared to $1.53 per Mcfe in 2004. Rates increased as a result of the higher U.S./Canadian dollar and increased future development costs reduced by the effect of the 2005 Gulf of Mexico sale; and

DD&A expense in 2005 included impairments of $7 million related to exploration prospects in Yemen and other areas.

Market Optimization

Financial Results Year Ended December 31 ($ millions)		**2006**	**2006 vs 2005**		2005	2005 vs 2004		2004
Revenues	**$**	**3,007**	**-30%**	$	4,267	33%	$	3,200
Expenses								
Transportation and selling		**16**	**23%**		13	-28%		18
Operating		**62**	**-27%**		85	15%		74
Purchased product		**2,862**	**-31%**		4,159	35%		3,092
Operating Cash Flow		**67**	**570%**		10	-38%		16
Depreciation, depletion and amortization		**12**	**50%**		8	-83%		47
Segment Income (Loss)	**$**	**55**	**2,650%**	$	2	106%	$	(31)

2006 vs 2005

Market Optimization results for 2006 include power generation income of $21 million (2005 - $1 million; 2004 - $(6) million), reflecting very high Alberta power pool prices realized by the Company s 100 percent owned Cavalier and 50 percent owned Balzac power plants.

On January 1, 2006, EnCana adopted Emerging Issues Task Force (EITF) Abstract No. 04-13 Accounting for Purchases and Sales of Inventory with the Same Counterparty. The effect is to record purchases and sales of inventory that are entered into in contemplation of each other with the same counterparty on a net basis in the Consolidated Statement of Earnings. This change has been adopted prospectively and has no effect on the net earnings of the reported periods. These purchases and sales are used to optimize transportation or fulfil marketing arrangements. As a result of the adoption of this policy, reported revenues and purchased product costs for 2006 included offsets of $3,238 million.

Purchased product and revenues before the netting increased in 2006 due to third party purchases and sales as a result of our sale of the Empress NGL plant to a third party at the end of 2005. For 2006, this incremental activity to facilitate the movement of our gas through the Empress plant totaled approximately $1.9 billion.

2005 vs 2004

Revenues and purchased product expenses increased in 2005 as a result of increases in commodity prices while third party optimization volumes remained relatively flat year over year.

Corporate

Financial Results

Year Ended December 31 ($ millions)		**2006**		2005		2004
Revenues	**$**	**2,050**	$	(466)	$	(197)
Expenses						
Operating		**(12)**		2		(1)
Depreciation, depletion and amortization		**75**		73		61
Segment Income (Loss)	**$**	**1,987**	$	(541)	$	(257)
Administrative		**271**		268		197
Interest, net		**396**		524		398
Accretion of asset retirement obligation		**50**		37		22
Foreign exchange (gain) loss, net		**14**		(24)		(412)
Stock-based compensation options		**-**		15		17
(Gain) on divestitures		**(323)**		-		(59)

The 2006 corporate revenues of $2,050 million are unrealized mark-to-market gains related to financial natural gas and crude oil commodity hedge contracts compared with $466 million unrealized mark-to-market losses in 2005 (2004 $198 million loss). The operating expense recovery of $12 million for 2006 is due to unrealized mark-to-market gains related to long-term financial power commodity hedge contracts entered into in the fourth quarter of 2006.

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

Financial Results

Year Ended December 31 ($ millions)		**2006**		2005		2004
Continuing Operations						
Natural Gas	**$**	**1,910**	$	(494)	$	(21)
Crude Oil		**140**		28		(177)
		2,050		(466)		(198)
Expenses		**(10)**		3		(7)
		2,060		(469)		(191)
Income Tax Expense		**703**		158		74
Unrealized Mark-to-Market Gains (Losses), after-tax	**$**	**1,357**	$	(311)	$	(117)

Price volatility has impacted net earnings as a result of EnCana s price risk management activities. As a means of managing this commodity price volatility, EnCana enters into various financial instrument agreements and physical contracts. The financial instrument agreements are recorded at the date of the financial statements based on mark-to-market accounting. On December 31, 2006, the forward price curve for 2007 for WTI was basically unchanged from December 31, 2005 at $65.02 per bbl, while NYMEX gas decreased by 32 percent to $6.97 per Mcf.

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

2006 vs 2005

Administrative expenses in 2006 were comparable with 2005 due to increases for office expenses, the higher U.S./Canadian dollar and increased general costs offset by lower long-term compensation expenses, which are tied to EnCana s Common Share price. Administrative expenses in 2006 were $0.17 per Mcfe compared with $0.18 per Mcfe in 2005.

Interest expense in 2006 decreased by $128 million mainly as a result of a $121 million one time charge incurred in 2005 to retire certain medium term notes, and lower average outstanding debt in 2006 due to repayments using the sales proceeds from the Entrega Pipeline, Ecuador, Brazil and gas storage divestitures.

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

2005 vs 2004

Administrative expenses increased $71 million compared to 2004. The increase results from higher long-term compensation expenses that are tied to EnCana s Common Share price and the change in the U.S./Canadian dollar exchange rate. Administrative costs in 2005 were $0.18 per Mcfe compared with $0.14 per Mcfe in 2004.

Interest expense in 2005 increased as a result of a $121 million ($79 million after-tax) charge to retire certain medium term notes. EnCana s total long-term debt decreased by $1,154 million to $6,776 million at December 31, 2005 compared with $7,930 million at December 31, 2004.

The foreign exchange gain of $24 million in 2005 includes $113 million ($92 million after-tax), resulting from the change in the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada. Under Canadian GAAP, EnCana is required to translate long-term debt issued from Canada and denominated in U.S. dollars into Canadian dollars at the period end exchange rate. Resulting unrealized foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings. Other foreign exchange gains and losses result from the settlement of foreign currency transactions and the translation of EnCana s monetary assets and liabilities.

Income Tax

2006 vs 2005

The effective tax rate for 2006 is 27.3 percent compared to 30.8 percent for 2005. The decrease is largely due to a decrease in future income tax expense of $457 million as a result of reductions in the Canadian federal and Alberta corporate tax rates, which were enacted in the second quarter of 2006. The Canadian federal tax rate of 22.1 percent is to be reduced to 19 percent over the 2008 - 2010 period. The Alberta tax rate was reduced from 11.5 percent to 10 percent effective April 1, 2006.

Cash taxes included in cash flow for 2006 were $893 million compared to $626 million in 2005. The increase in cash tax expense over 2005 primarily reflects higher Canadian income resulting from higher prices in 2005, which is recognized for income tax purposes in 2006. An additional $49 million of cash tax was incurred in 2006, resulting from the divestiture of the Brazil operations, compared to $578 million of cash tax in the second quarter of 2005 as a result of the divestiture of the Gulf of Mexico operations. These amounts are included in investing activities in the Consolidated Statement of Cash Flows.

2005 vs 2004

The effective tax rate for 2005 was 30.8 percent compared with 23.2 percent in 2004. The 2005 income tax provision has been reduced by the net benefit of tax basis retained on divestitures of $68 million compared to $169 million in 2004. The 2004 effective tax rate included a reduction of $109 million in future income taxes, resulting from the reduction in the Alberta tax rate from 12.5 percent to 11.5 percent.

Current tax expense was $1,204 million in 2005 compared to $559 million in 2004; $578 million of this increase relates to the sale of Gulf of Mexico assets and has been shown as cash outflow from investing activities in the Consolidated Statement of Cash Flows. The balance of $626 million has been included in cash flow.

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

The effects of asset divestitures where the tax values of the assets sold differ from their accounting values;

Adjustments for the impact of legislative tax changes, which have a prospective impact on future income tax obligations;

The non-taxable half of Canadian capital gains or losses; and

Items, such as resource allowance and non-deductible Crown payments, where the income tax treatment is different from the accounting treatment.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

Capital Expenditures

Capital Summary

Year Ended December 31 ($ millions)		2006		2005		2004
Upstream	**$**	**6,151**	$	6,202	$	4,343
Market Optimization		**44**		197		10
Corporate		**74**		78		46
Total Core Capital Expenditures	**$**	**6,269**	$	6,477	$	4,399
Acquisitions		**331**		448		2,699
Divestitures		**(689)**		(2,523)		(1,456)
Discontinued Operations		**(2,647)**		(305)		(1,436)
Net Capital Investment	**$**	**3,264**	$	4,097	$	4,206

EnCana s capital investment for the year ended December 31, 2006 was funded by cash flow.

Upstream Capital Expenditures

2006 vs 2005

Capital spending during 2006 was primarily focused on continued development of our North American key resource plays. Natural gas capital expenditures were focused on continued development of the Company s key resource plays in Cutbank Ridge and Bighorn in Canada and Piceance, Jonah, East Texas and Fort Worth in the United States. Crude oil capital spending in 2006 was concentrated on expansion of the Company s SAGD projects located at Foster Creek and Christina Lake and developing the new resource play at Borealis.

The $51 million decrease in Upstream core capital expenditures in 2006 was primarily due to:

Canadian core capital expenditures decreased by $392 million offset by an increase in foreign exchange of $257 million for a net reported decrease of $135 million. The overall decrease is due to:

Crown land sales and other land costs were $260 million or 68 percent lower than the prior year mainly due to large land purchases in 2005;

Total drilling and completion costs decreased $307 million or 13 percent due to a decrease in the total number of wells drilled compared to 2005;

Facility costs increased $199 million or 16 percent mainly due to the costs resulting from the continued expansion of Foster Creek and Christina Lake facilities and the construction of the Steeprock and Kakwa gas plants at Cutbank Ridge and Bighorn respectively;

In Canada, the Company drilled 3,009 net wells in 2006 compared to 4,038 net wells in 2005. The decrease resulted from the Company s decision to decrease drilling activity in response to higher industry costs and new regulations related to CBM water well testing, which delayed drilling. In various locations, the Company redirected capital spending to recompletion and tie-in of existing wells instead of drilling new wells in the current price environment.

U.S. core capital expenditures increased $79 million to $2,061 million primarily due to additional drilling and completion costs at Fort Worth related to the development of the Barnett Shale play, increased activity at Jonah after receipt of the Bureau of Land Management Record of Decision approving further development of the field and the drilling of several deep gas wells in the Deep Bossier play in East Texas. The number of net wells drilled increased slightly to 639 from 617 in 2005.

2005 vs 2004

Capital spending during 2005 was primarily focused on North American resource play land capture, drilling programs and facility expansion. Natural gas capital expenditures were focused on continued development of the Company s key resource plays in Greater Sierra, Cutbank Ridge, CBM Integrated and Shallow Gas in Canada, and Piceance, Jonah, East Texas and Fort Worth in the United States. Crude oil capital spending in 2005 was concentrated on expansion of the Company s SAGD projects located at Foster Creek and Christina Lake, the waterflood program at Pelican Lake in Alberta and Weyburn in Saskatchewan. In addition, capital was directed at identifying and developing new resource plays at Bighorn and Borealis.

The $1.9 billion increase in Upstream core capital expenditures in 2005 was primarily due to:

Canadian core capital expenditures increased approximately $1.1 billion to $4.2 billion. This includes approximately $219 million related to the change in the U.S./Canadian dollar exchange rate as well as the following factors:

Crown land sales and other land costs in 2005 were $274 million higher than the prior year mainly due to significantly higher land prices;

Drilling and completion costs increased $608 million in 2005 due to service cost increases as a result of industry activity levels;

Facility costs increased $113 million in 2005 mainly due to the Foster Creek expansion, which was completed in the fourth quarter of 2005; and

In Canada, the Company drilled 4,038 net wells in 2005 compared to 4,385 net wells in 2004. This decrease of 8 percent relates mainly to decreased drilling of shallow gas wells in southern and west-central Alberta due to weather related delays during the summer and service sector shortages as a result of record levels of activity in the industry.

U.S. core capital expenditures increased $0.7 billion in 2005 to $2 billion primarily due to increases in drilling and completion costs. In the U.S. the Company drilled 617 net wells in 2005 compared to 534 net wells in 2004, an increase of 16 percent. Drilling was focused on continued development of the four key resource plays of Jonah, Piceance, Fort Worth and East Texas.

Canadian East Coast

EnCana continues to advance its plans for the Deep Panuke project. In June 2006, EnCana and the Province of Nova Scotia reached an Offshore Strategic Energy Agreement that established the framework for the potential development of Deep Panuke. In November 2006, EnCana filed the Development Plan Application with the Canada-Nova Scotia Offshore Petroleum Board, which included an Environmental Assessment Report and an application to the National Energy Board for approval of the construction and operation of an offshore pipeline. The hearings for the project before the Canada-Nova Scotia Offshore Petroleum Board and the National Energy Board are scheduled to commence on March 5, 2007 in Halifax, Nova Scotia. The hearings are expected to last a few weeks.

Brazil

EnCana has non-operated interests in 10 deep and ultra-deep water exploration blocks offshore Brazil, nine of which are operated by Petrobras, the Brazilian national oil company. EnCana and its partners drilled one gross exploration well in 2006 in the Campos Basin.

Chad

In 2006, EnCana s capital program in Chad included drilling five gross exploratory wells and conducting several seismic surveys. In the third quarter of 2006, EnCana made the decision to divest of these assets. On January 12, 2007, EnCana announced that it had sold its interests in all its exploration assets in Chad for approximately $203 million, subject to post-closing adjustments, which will result in a gain on sale.

France

In February 2006, a subsidiary of EnCana was granted a 100 percent interest in the Foix exploration permit in the onshore Aquitaine Basin in southwest France. EnCana has plans for a two well exploration drilling program in 2007 to identify the potential for the development of a natural gas resource play.

Market Optimization Capital Expenditures

Expenditures in 2006 and 2005 were mostly focused on the completion of construction for the Entrega Pipeline prior to the sale in February 2006.

Corporate Capital Expenditures

Corporate capital expenditures have generally been directed to business information systems and leasehold improvements. In addition, 2006 ($37 million) and 2005 ($36 million) include land purchases and costs related to the development of a Calgary office complex. On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of project assets and is entering into a 25 year lease agreement with a third party developer. EnCana expects to account for the agreement as a capital lease.

Acquisitions, Divestitures and Discontinued Operations

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

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

Proved Oil and Gas Reserves

Proved Reserves by Country

Constant Prices After Royalties	Natural Gas (billions of cubic feet)					Crude Oil and NGLs[1] (millions of barrels)				
As at December 31	**2006**	**2006 vs 2005**	2005	2005 vs 2004	2004	**2006**	**2006 vs 2005**	2005	2005 vs 2004[2]	2004
Canada	**7,028**	**8%**	6,517	12%	5,824	**1,079.4**	**16%**	932.5	48%	629.6
United States	**5,390**	**2%**	5,267	14%	4,636	**54.0**	**2%**	53.1	-42%	91.0
Ecuador	**-**	**-**	-	-	-	**-**	**-100%**	135.0	-6%	143.3
Total	**12,418**	**5%**	11,784	13%	10,460	**1,133.4**	**1%**	1,120.6	30%	863.9

(1) Crude Oil and NGLs include condensate.

(2) Prices at year-end 2005 allowed the reinstatement of 362.7 million barrels that were deducted as a revision due to the bitumen price at year-end 2004.

Each year, EnCana engages independent qualified reserve evaluators to prepare reports on 100 percent of the Corporation s oil and natural gas reserves. The Company has a Reserves Committee of independent Board members, which reviews the qualifications and appointment of the independent qualified reserve evaluators. The Committee also reviews the procedure for providing information to the evaluators. EnCana s disclosure of reserves data is covered by NI 51-101 as amended by a Mutual Reliance Review System Decision Document dated December 16, 2003 permitting the adoption of U.S. reporting standards, including compliance with the practices and procedures of the U.S. Securities and Exchange Commission (SEC) and Financial Accounting Standards Board (FASB) reserve reporting requirements. These standards require that reserves be estimated employing the single day field price of the commodity at the effective date of the valuation – in this case, December 31, 2006.

Proved Reserves Reconciliation by Country

Constant Prices After Royalties	Natural Gas (billions of cubic feet)			Crude Oil and NGLs[1] (millions of barrels)			
As at December 31, 2006	**Canada**	**USA**	**Total**	**Canada**	**USA**	**Ecuador[3]**	**Total**
Beginning of year	6,517	5,267	11,784	932.5	53.1	135.0	1,120.6
Revisions and improved recovery	301	(88)	213	(39.0)	(1.1)	-	(40.1)
Extensions and discoveries	1,014	606	1,620	238.7	6.4	-	245.1
Acquisitions	-	68	68	-	0.3	-	0.3
Divestitures	(6)	(32)	(38)	(0.1)	-	(130.6)	(130.7)

Production	(798)	(431)	(1,229)	(52.7)	(4.7)	(4.4)	(61.8)
End of year	7,028	5,390	12,418	1,079.4[(2)]	54.0	-	1,133.4

(1) Crude Oil and NGLs include condensate.

(2) Effective January 2, 2007, the Corporation s Foster Creek and Christina Lake operations were contributed to a 50/50 upstream partnership with ConocoPhillips. The Corporation s ownership in reserves associated with these properties were reduced by 398 million barrels.

(3) Ecuador operations sold February 28, 2006.

Natural Gas

EnCana s proved natural gas reserves as at December 31, 2006, totaled 12,418 Bcf. Approximately 152 percent of production was replaced by reserves additions during 2006. Extensions and discoveries resulting from successful exploration and development capital programs amounted to 1,620 Bcf. Positive revisions of 213 Bcf were less than 2 percent of natural gas reserves at the beginning of 2006. In Canada, positive revisions of 301 Bcf (or 5 percent of the opening balance) were largely associated with CBM Integrated. Downward revisions in the United States amounted to 88 Bcf (or less than 2 percent of natural gas reserves at the beginning of 2006), mainly due to proved undeveloped reserves being removed consistent with planned moderation in drilling activity. Acquisitions and divestitures account for less than 1 percent of the opening natural gas reserves balance.

Crude Oil and NGLs

EnCana s proved crude oil and NGLs reserves as at December 31, 2006 totaled 1,133 MMbbls. Reserve additions from continuing operations replaced over 357 percent of production. Extensions and discoveries amounted to 245 MMbbls, while revisions were negative 40 MMbbls (or 4 percent of the opening balance). Christina Lake and Foster Creek accounted for 226 MMbbls or more than 90 percent of the extensions and discoveries. A negative revision in net oil reserves at Foster Creek of approximately 67 MMBbls was due to a higher average royalty rate as a direct result of an almost two-fold increase in the December 31, 2006 field price in comparison to the previous year. This was partially offset by positive revisions elsewhere in Canada. Reserve changes due to acquisitions and divestitures in continuing operations during 2006 were not significant. With the creation of the integrated oilsands business, effective January 2, 2007, ConocoPhillips and EnCana each own a 50 percent interest in the Foster Creek and Christina Lake upstream operations and the Wood River and Borger refineries. As a result of this transaction, the Corporation s estimated proved oil reserves were reduced by 398 MMbbls in exchange for a 50 percent interest in the two refineries.

Discontinued Operations

Discontinued operations in the Consolidated Financial Statements include:

Ecuador

United Kingdom

Midstream

EnCana s 2006 net earnings from discontinued operations were $601 million compared to $597 million in 2005 and include realized financial hedge gains of $7 million after-tax and unrealized financial hedge gains of $13 million after-tax.

Ecuador

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

Year Ended December 31		**2006**		2005		2004
Sales Volumes						
Crude Oil *(bbls/d)*		**12,366**		71,065		77,993
($ millions)						
Net Earnings (Loss) from Discontinued Operations [1]	**$**	**(279)**	$	131	$	(33)
Capital Investment [2]		**(1,116)**		179		240

(1) In accordance with Canadian generally accepted accounting principles, DD&A expense for Ecuador has not been recorded in the Consolidated Statement of Earnings for discontinued operations. Amounts recorded as DD&A expense in 2006 and 2005 represent provisions that were recorded against the net book value of the Ecuador operations to recognize Management s best estimate of the difference between the selling price and the underlying accounting value of the related investments, as required by Canadian generally accepted accounting principles.

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

2006 vs 2005

Ecuador s Net Loss from discontinued operations in 2006 is a result of the sale and the 2005 Net Earnings are the result of operations.

2005 vs 2004

Production volumes in 2005 averaged 72,916 bbls/d, down 5 percent from 2004. Sales volumes in 2005 decreased 9 percent to average 71,065 bbls/d due to declining production in Tarapoa and Block 15 as well as the shift to an underlift position at December 31, 2005 from an overlift position at the end of 2004.

Production and mineral taxes were $70 million higher in 2005 compared to 2004 as a result of higher realized prices on the Tarapoa block sales volumes partially offset by lower Tarapoa sales volumes. EnCana is required to pay a percentage of revenue from this block to the Ecuador government based on realized prices over a base price.

United Kingdom

Year Ended December 31		**2006**		2005		2004
Sales Volumes						
Produced Gas *(MMcf/d)*		**-**		-		30
Crude Oil *(bbls/d)*		**-**		-		14,128
NGLs *(bbls/d)*		**-**		-		1,845
Total *(BOE/d)*		**-**		-		20,973
($ millions)						
Net Earnings from Discontinued Operations [1]	**$**	**5**	$	35	$	1,338
Capital Investment		**-**		-		488

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

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

Midstream

On March 6, 2006, EnCana announced it had reached an agreement to sell its gas storage business interests for approximately $1.5 billion. The sale, to a single purchaser, closed in two stages. The first stage of the sale closed on May 12, 2006 for proceeds of approximately $1.3 billion. On November 17, 2006, EnCana closed the second and final phase with its sale of the Wild Goose storage facility interests in California for proceeds of approximately $0.2 billion after the receipt of the California Public Utilities Commission approval.

Year Ended December 31		**2006**		2005		2004
($ millions)						
Net Earnings from Discontinued Operations [1]	$	875	$	431	$	118
Capital Investment		(1,531)		(484)		(20)

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

2006 vs 2005

Midstream s net earnings from discontinued operations in 2006 mainly result from the gain on sale of the gas storage operations in May and November 2006, which totaled $829 million after-tax. The 2005 amount also includes the NGLs processing business, which was sold in December 2005 for an after-tax gain on sale of $370 million.

2005 vs 2004

On December 13, 2005, EnCana sold substantially all of its NGLs processing business for proceeds of approximately $625 million subject to post-closing adjustments.

Net earnings in 2005 for the discontinued Midstream businesses were $431 million, an increase of $313 million over 2004. Included in 2005 net earnings is a $370 million after-tax gain on the sale of the NGLs processing business. 2005 net earnings have been reduced by $30 million as a result of agreements by WD Energy Services Inc., one of EnCana s indirect subsidiaries, to settle certain California and New York lawsuits, as further described in this MD&A under the heading Contractual Obligations and Contingencies.

Liquidity and Capital Resources

Year Ended December 31 ($ millions)		**2006**		2005		2004
Net cash provided by (used in)						
Operating activities	**$**	**7,973**	$	7,430	$	4,591
Investing activities		**(3,382)**		(4,520)		(4,259)
Financing activities		**(4,294)**		(3,396)		163
Deduct: Foreign exchange gain on cash and cash equivalents held in foreign currency		**-**		2		6
Increase (decrease) in cash and cash equivalents	**$**	**297**	$	(488)	$	489

Operating Activities

Cash flow from continuing operations was $7,043 million in 2006 compared to $6,962 million in 2005. The $81 million increase in cash flow from continuing operations in 2006 was primarily due to increased revenues driven by higher liquids prices, realized financial commodity hedge gains and natural gas sales volumes partially reduced by lower natural gas prices, increased operating expenses and higher cash taxes. The working capital surplus at December 31, 2006 was $11 million compared to a deficit of $1,267 million at December 31, 2005 mainly as a result of a net change in risk management of $2,121 million. Cash flow from continuing operations comprises most of EnCana s cash provided by operating activities.

Investing Activities

Net cash of $3,382 million was used for investing activities in 2006, a decrease of $1,138 million compared to 2005. Capital expenditures, including property acquisitions, decreased $325 million and cash tax on divestitures of assets decreased by $529 million for the year ended December 31, 2006.

Financing Activities

Total long-term debt as at December 31, 2006 increased by $58 million over 2005 primarily due to net revolving long-term debt issuances of $134 million offset by a fixed rate long-term debt repayment of $73 million. EnCana s net debt adjusted for working capital was $6,566 million as at December 31, 2006 compared with $7,970 million at December 31, 2005. During 2006, EnCana purchased 85.6 million of its Common Shares for total consideration of $4,219 million.

On June 9, 2006, an indirect wholly owned subsidiary, EnCana Holdings Finance Corp., filed a debt shelf prospectus in the amount of $2 billion under the multijurisdictional disclosure system (MJDS). This shelf prospectus replaces EnCana Holdings Finance Corp. s previous $2 billion shelf prospectus, which expired in April 2006. 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. Debt securities issued under this shelf prospectus are fully and unconditionally guaranteed by EnCana Corporation.

On September 22, 2006, EnCana filed a debt shelf prospectus in the amount of $2 billion under the MJDS. This shelf prospectus replaces EnCana s previous $2 billion shelf prospectus, which expired on October 16, 2006. 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. At December 31, 2006, EnCana had available unused committed bank credit facilities in the amount of $2.8 billion and unused capacity under shelf prospectuses for up to $4.4 billion, the availability of which is dependent upon market conditions.

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

Financial Metrics

Year Ended December 31	**2006**	2005
Net Debt to Capitalization	**27%**	33%
Net Debt to Adjusted EBITDA (1)	**0.6x**	1.1x

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

Net Debt to Capitalization and Net Debt to Adjusted EBITDA are two ratios Management uses to steward the Company s overall debt position as measures of the Company s overall financial strength.

Outstanding Share Data

(millions)	2006	2005[1]	2004[1]
Common Shares outstanding, beginning of year	**854.9**	**900.6**	921.2
Issued under option plans	**8.6**	15.0	19.4
Shares purchased (Normal Course Issuer Bid)	**(85.6)**	(55.2)	(40.0)
Shares purchased (Performance Share Unit Plan)	**-**	(5.5)	-
Common Shares outstanding, end of year	**777.9**	854.9	900.6
Weighted average Common Shares outstanding diluted	**836.5**	889.2	936.0

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

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares. There were no Preferred Shares outstanding as at December 31, 2006.

Employees and directors have been granted options to purchase Common Shares under various plans. At December 31, 2006, 11.8 million options without Tandem Share Appreciation Rights (TSAR) attached were outstanding, all of which are exercisable.

Long-term incentives may be granted to EnCana employees in the form of stock options and Performance Share Units (PSUs). Stock options granted after December 31, 2003 have an associated TSAR attached and employees may elect to exercise either the stock option or the associated Share Appreciation Right (SAR). Stock option exercises result in the issuance of new Common Shares while TSAR exercises result in cash payments by the Company. PSUs will not result in the issuance of new Common Shares by the Company as shares are purchased through a trust for payment, should performance considerations be met. At December 31, 2006, there were 5.5 million shares held in trust for issuance upon vesting of PSUs.

EnCana has obtained regulatory approval under Canadian securities laws to purchase Common Shares under five consecutive NCIBs. During 2006, EnCana purchased 85.6 million Common Shares for total consideration of $4,219 million ($49.26 per Common Share). As of December 31, 2006, the number of Common Shares that EnCana will be permitted to purchase in 2007 under the current NCIB is 55.7 million.

EnCana pays quarterly dividends to shareholders at the discretion of the Board of Directors. These dividends totaled $304 million in 2006, $238 million for 2005, and $183 million for 2004. These dividends were funded by cash flow. At December 31, 2006, the quarterly dividend paid to shareholders was $0.100 per Common Share (2005 - $0.075; 2004 - $0.050).

Normal Course Issuer Bid

(millions)	Share Purchases 2006	2005
Bid expired October 2005	**-**	55.2
Bid expired October 2006	**61.1**	-
Bid expiring November 2007	**24.5**	-
	85.6	55.2

Contractual Obligations and Contingencies

Contractual Obligations (1)	Expected Payment Date				
($ millions)	2007	2008 to 2009	2010 to 2011	2012+	Total
Long-Term Debt (2)	$ 257	$ 857	$ 2,260	$ 3,400	$ 6,774
Asset Retirement Obligations	44	75	58	5,155	5,332
Pipeline Transportation	431	836	791	2,144	4,202
Purchase of Goods and Services	427	509	281	790	2,007
Operating Leases (3)	52	92	97	237	478
Product Purchases	54	47	24	98	223
Capital Commitments	75	35	-	38	148
Other Long-Term Commitments	13	10	3	-	26
Total	$ 1,353	$ 2,461	$ 3,514	$ 11,862	$ 19,190
Product Sales	$ 41	$ 84	$ 85	$ 252	$ 462
Other Commitments	$ (36)	$ -	$ -	$ -	$ (36)

(1) In addition, the Company has made commitments related to its risk management program. See Note 18 to the Consolidated Financial Statements. The Company has an obligation to fund its Pension Plan and other Post-Employment Benefits as disclosed in Note 15 to the Consolidated Financial Statements.

(2) Excludes interest component. See Note 12 to the Consolidated Financial Statements.

(3) Related to office space.

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

Included in EnCana s total long-term debt commitments of $6,774 million at December 31, 2006 are $1,560 million in commitments related to Bankers Acceptances and Commercial Paper. These amounts are fully supported and Management expects they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year. Further details regarding EnCana s long-term debt are described in Note 12 to the Consolidated Financial Statements.

As at December 31, 2006, EnCana remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 38 MMcf/d, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 125 Bcf at a weighted average price of $3.72 per Mcf. At December 31, 2006, these transactions had an unrealized loss of $267 million.

Leases

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

Legal Proceedings

EnCana is involved in various legal claims associated with the normal course of operations and believes it has made adequate provision for such legal claims.

Discontinued Merchant Energy Operations

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. (WD), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits relating to sales of natural gas from 1999 to 2002. The lawsuits allege that the defendants engaged in a conspiracy with unnamed competitors in the natural gas markets in California in violation of U.S. and California antitrust and unfair competition laws.

Without admitting any liability in the lawsuits, WD agreed to settle all of the class action lawsuits in both state and federal court, for payments of $20.5 million and $2.4 million, respectively. Court approval of the federal court class action settlement of $2.4 million is pending, court approval having been granted in the state court action. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission (CFTC) and of a previously disclosed consolidated class action lawsuit in the United States District Court in New York for $8.2 million.

The remaining lawsuits were commenced by individual plaintiffs, one of which is E. & J. Gallo Winery (Gallo). The Gallo lawsuit claims damages in excess of $30 million. The other remaining lawsuits do not specify the precise amount of damages claimed. California law allows for the possibility that the amount of damages assessed could be tripled.

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

Accounting Policies and Estimates

Changes in Accounting Principles

On January 1, 2006, the Company adopted Emerging Issues Task Force (EITF) Abstract No. 04-13 *Accounting for Purchases and Sales of Inventory with the Same Counterparty* . As of January 1, 2006, purchases and sales of inventory with the same counterparty that are entered into in contemplation of each other are recorded on a net basis in the Consolidated Statement of Earnings. This change has been adopted prospectively and has no effect on the net earnings of the reported periods. As a result of the adoption of this policy, reported Market Optimization revenues and purchased product costs for the year ended December 31, 2006 include offsets of $3,238 million.

Recent Accounting Pronouncements

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Company:

As of January 1, 2007, the Company is required to adopt the Canadian Institute of Chartered Accountants (CICA) Section 1530 *Comprehensive Income* , Section 3251 *Equity* , Section 3855 *Financial Instruments Recognition and Measurement* , and Section 3865 *Hedges* , which were issued in January 2005. Under the new standards, a new financial statement, the Consolidated Statement of Comprehensive Income, has been introduced that will provide for certain gains and losses, including foreign currency translation adjustments and other amounts arising from changes in fair value, to be temporarily recorded outside the income statement. In addition, all financial instruments, including derivatives, are to be included in the Company s Consolidated Balance Sheet and measured, in most cases, at fair values, and requirements for hedge accounting have been further clarified. The Company does not expect the Financial Instruments and Hedges standards to have a material impact on its Consolidated Financial Statements as EnCana currently uses mark-to-market accounting for derivative instruments that do not qualify or are not designated as hedges.

As of January 1, 2007, EnCana is required to adopt revised CICA Section 1506, *Accounting Changes* , which provides expanded disclosures for changes in accounting polices, accounting estimates and corrections of errors, which were issued in July 2006. Under the new standard, accounting changes should be applied retrospectively unless otherwise permitted or where impracticable to determine. As well, voluntary changes in accounting policy are made only when required by a primary source of GAAP or the change results in more relevant and reliable information. EnCana does not expect application of this revised standard to have a material impact on its Consolidated

Financial Statements.

As of January 1, 2008, EnCana will be required to adopt two new CICA standards, Section 3862 *Financial Instruments Disclosures* and Section 3863 *Financial Instruments Presentation*, which will replace Section 3861 *Financial Instruments Disclosure and Presentation*. The new disclosure standard increases the emphasis on the risks associated with both recognized and unrecognized financial instruments and how those risks are managed. The new presentation standard carries forward the former presentation requirements. The new financial instruments presentation and disclosure requirements were issued in December 2006 and the Company is assessing the impact on its Consolidated Financial Statements.

As of January 1, 2008, EnCana will be required to adopt CICA Section 1535 *Capital Disclosures*, which will require companies to disclose their objectives, policies and processes for managing capital. In addition, disclosures are to include whether companies have complied with externally imposed capital requirements. The new capital disclosure requirements were issued in December 2006 and the Company is assessing the impact on its Consolidated Financial Statements.

In January 2006, the Accounting Standards Board (AcSB) adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards (IFRS) by the end of 2011. The Company continues to monitor and assess the impact of convergence of Canadian GAAP and IFRS.

Critical Accounting Policies and Estimates

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. A summary of EnCana s significant accounting policies can be found in Note 1 to the Consolidated Financial Statements. The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to determining EnCana s financial results.

Full Cost Accounting

EnCana follows the CICA guideline on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs including internal costs and asset retirement costs, directly associated with the acquisition of, exploration for and 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, including estimated future development 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 DD&A. 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 divestiture, 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.

Oil and Gas Reserves

All of EnCana s oil and gas reserves are evaluated and reported on by independent qualified reserve evaluators. 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. 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 the carrying amount, the impairment loss is limited to an 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.

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 initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. 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. Amounts recorded for asset retirement obligations are based on estimates of reserves and on retirement costs, which will not be incurred for several years. Actual payments to settle the obligations may differ from estimated amounts.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed by EnCana for impairment at least annually. Goodwill was allocated to the business segments 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.

Derivative Financial Instruments

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

The Company enters into financial transactions to help reduce its exposure to price fluctuations with respect to commodity purchase and sale transactions to achieve targeted investment returns and growth objectives, while maintaining prescribed financial metrics. These transactions generally are swaps, collars, or options and are generally entered into with major financial institutions or commodities trading institutions.

EnCana may also use derivative financial instruments, such as interest rate swap agreements, to manage the fixed and floating interest rate mix of its 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.

EnCana 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.

EnCana also may purchase 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.

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from the Company s natural gas and crude oil financial derivatives are recognized in natural gas and crude oil revenues as the related sales occur. Unrealized gains and losses are recognized in revenues at the end of each respective reporting period. The estimate of fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indicators. In 2004, 2005, and 2006, the Company elected not to designate any of its current price risk management activities as accounting hedges and, accordingly, accounts for all derivatives using the mark-to-market accounting method.

Pensions and Other Post-Employment Benefits

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

The cost of pensions and other employment 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 percent of the greater of the benefit obligation and the fair value of plan assets. The amortization period covers the expected average remaining service 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.

Performance Share Units (PSUs)

The PSU plans provide for a range of payouts, based on EnCana s performance relative to certain peers. EnCana expenses the cost of PSUs based on expected payouts; however, the amounts to be paid, if any, may vary from the current estimate.

Risk Management

EnCana s results are affected by:

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

Financial Risks

Sensitivity of 2007 Net Earnings from Continuing Operations and Cash Flow from Continuing Operations (Including Hedges) [1]

($ millions)	Net Earnings from Continuing Operations	Cash Flow from Continuing Operations
$1.00 per million British thermal units increase in the NYMEX gas price	$ 320	$ 330
$8.00 per barrel increase in the WTI oil price	100	90
$1.00 per barrel increase in the 3-2-1 U.S. Gulf Coast Crack Spread	30	30
$0.01 decrease in the U.S./Canadian dollar exchange rate	(5)	10

(1) Hedge position as at December 31, 2006. Based on forward curve commodity price and forward curve estimates dated December 31, 2006.

Sensitivity of 2007 Net Earnings from Continuing Operations and Cash Flow from Continuing Operations (Excluding Hedges) (1)

($ millions)	Net Earnings from Continuing Operations	Cash Flow from Continuing Operations
$1.00 per million British thermal units increase in the NYMEX gas price	$ 660	$ 700
$8.00 per barrel increase in the WTI oil price	180	170
$1.00 per barrel increase in the 3-2-1 U.S. Gulf Coast Crack Spread	30	30
$0.01 decrease in the U.S./Canadian dollar exchange rate	(5)	10

(1) Based on forward curve commodity price and forward curve estimates dated December 31, 2006.

EnCana partially mitigates its exposure to financial risks through the use of various financial instruments and physical contracts. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. As a means of mitigating exposure to commodity price risk volatility, the Company has entered into various financial instrument agreements. The details of these instruments, including any unrealized gains or losses, as of December 31, 2006, are disclosed in Note 16 to the Consolidated Financial Statements.

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

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

Commodity Price

To partially mitigate the natural gas commodity price risk, the Company enters into swaps, which fix the AECO and NYMEX prices, and put and collar options, which fix the range of AECO and NYMEX prices. To help protect against widening natural gas price differentials in various production areas, EnCana has entered into swaps to fix the AECO and Rockies price differential from the NYMEX price. Physical contracts relating to these activities had an unrecognized gain of $35 million at December 31, 2006.

EnCana has also entered into contracts to purchase and sell natural gas as part of its daily ongoing operations of the Company s proprietary production management. Physical contracts associated with this activity had an unrecognized gain of $47 million at December 31, 2006.

For crude oil price risk, the Company has partially mitigated its exposure to the WTI NYMEX price for approximately 92 percent of its expected 2007 oil production with fixed price swaps and put options.

To manage its electricity consumption costs, EnCana has entered into two derivative contracts for a term of 11 years.

Foreign Exchange

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

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

Interest Rates

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

Credit Risk

EnCana is exposed to credit related losses in the event of default by counterparties. This credit exposure is mitigated through the use of Board-approved credit policies governing the Company s credit portfolio and with credit practices that limit transactions according to counterparties credit quality and transactions that are fully collateralized. A substantial portion of EnCana s accounts receivable is with customers in the oil and gas industry.

Operational Risks

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

A peer review process is used to ensure that capital projects are appropriately risked and that knowledge is shared across the Company. Peer reviews are undertaken primarily for exploration projects and early stage resource plays, although they may occur for any type of project.

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

Environment, Health, Safety and Security Risks

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

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

Climate Change

The Canadian federal government has announced its intention to regulate greenhouse gases and other air pollutants. It is currently developing a framework that outlines its clean air and climate change action plan, including a target to reduce greenhouse gas (GHG) emissions by 45 percent - 65 percent by 2050 and a commitment to regulate industry on an emissions intensity basis in the short term. Currently, there are few technical details regarding the implementation of the government s plan to regulate industrial GHG emissions, but they have made a commitment to work with industry to develop the specifics.

As this federal program is under development, EnCana is unable to predict the total impact of the potential regulations upon its business; therefore, it is possible that the Corporation could face increases in operating costs in order to comply with GHG emissions legislation. However, EnCana, in cooperation with the Canadian Association of Petroleum Producers, will continue to work with the government to develop an approach to deal with climate change issues that protects the industry s competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

EnCana intends to continue its activity to reduce its emissions intensity and improve its energy efficiency. The Company s efforts with respect to emissions management are founded on five key elements:

- our significant weighting in natural gas and our high quality in-situ oilsands assets;
- our recognition as an industry leader in CO_2 sequestration;
- our focus on the development of technology to reduce GHG emissions;
- our involvement in the creation of industry best practices; and
- our industry leading oilsands steam-oil ratio, which translates directly into lower emissions intensity.

EnCana is committed to transparency with its stakeholders and will keep them apprised of how these issues affect operations. Additional detail on EnCana s GHG emissions is available in the Corporate Responsibility Report that is available on our website at www.encana.com.

Reputational Risks

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

Quarterly Results

Quarterly Summary

($ millions, except per share [1] amounts)	2006 Q4	2006 Q3	2006 Q2	2006 Q1	2005 Q4	2005 Q3	2005 Q2	2005 Q1
Cash Flow [2]	**$ 1,761**	**$ 1,894**	**$ 1,815**	**$ 1,691**	$ 2,510	$ 1,931	$ 1,572	$ 1,413
- per share diluted	**2.18**	**2.30**	**2.15**	**1.96**	2.88	2.20	1.76	1.55
Net Earnings	**663**	**1,358**	**2,157**	**1,474**	2,366	266	839	(45)
- per share basic	**0.84**	**1.68**	**2.60**	**1.74**	2.77	0.31	0.96	(0.05)
- per share diluted	**0.82**	**1.65**	**2.55**	**1.70**	2.71	0.30	0.94	(0.05)
Operating Earnings [3]	**675**	**1,078**	**824**	**694**	1,271	704	655	611
- per share diluted	**0.84**	**1.31**	**0.98**	**0.80**	1.46	0.80	0.73	0.67
Continuing Operations								
Cash Flow from Continuing Operations [2]	**1,742**	**1,883**	**1,839**	**1,579**	2,390	1,823	1,502	1,247
Net Earnings from Continuing Operations	**643**	**1,343**	**1,593**	**1,472**	1,869	348	774	(162)
- per share basic	**0.81**	**1.66**	**1.92**	**1.74**	2.19	0.41	0.89	(0.18)
- per share diluted	**0.80**	**1.63**	**1.88**	**1.70**	2.14	0.40	0.87	(0.18)
Operating Earnings from Continuing Operations [3]	**672**	**1,064**	**841**	**660**	1,229	733	611	475
Revenues, Net of Royalties	**3,676**	**4,029**	**3,922**	**4,772**	5,933	3,061	3,461	2,118

(1) Per share amounts have been restated for the effect of the Common Share split in 2005.

(2) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are defined under Cash Flow .

(3) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are defined under Operating Earnings .

Average North American natural gas prices in the fourth quarter of 2006 were 44 percent lower than the same period in 2005. A warm November and December in the Northeast U.S. combined with no significant supply losses from hurricane damage compared to 2005 caused NYMEX gas prices to drop in the fourth quarter.

The WTI crude oil price remained unchanged in the fourth quarter of 2006 compared to the same period in 2005. Concerns over Iran s nuclear program, Nigerian production shut-in due to militant attacks, ongoing instability in Iraq and U.S. gasoline supply partially offset by an uneventful hurricane season, resulted in WTI remaining flat from 2005, when there was significant oil supply disruptions. Fourth quarter Canadian heavy oil differentials were narrower in dollar terms relative to the fourth quarter of 2005, primarily due to the strength in asphalt and residual fuel oil markets supporting prices for Canadian heavy crude oil.

EnCana s net earnings for the fourth quarter of 2006 were $663 million, down $1,703 million from 2005. Net earnings from discontinued operations decreased $477 million to $20 million.

EnCana s net earnings from continuing operations in the fourth quarter of 2006 decreased $1,226 million or 66 percent to $643 million compared with the same period in 2005.

The decrease in net earnings from continuing operations was due to:

Average North American natural gas prices, excluding financial hedges, decreased 44 percent to $5.79 per Mcf compared to $10.29 per Mcf in 2005;

Unrealized mark-to-market gains of $99 million after-tax in 2006 compared with $661 million after-tax in 2005; and

A $128 million after-tax unrealized foreign exchange loss on Canadian issued U.S. dollar debt in 2006 compared to a $21 million after-tax unrealized foreign exchange loss in 2005; this reflects the decrease in the U.S./Canadian dollar in the fourth quarter of 2006 compared to an increase in the Canadian dollar in the same period in 2005.

The decrease in net earnings from continuing operations was offset by:

Realized financial natural gas and crude oil commodity hedging gains of $160 million after-tax compared with losses of $229 million after-tax in 2005;

Average North American liquids prices, excluding financial hedges, increased 4 percent to $38.69 per bbl in 2006 compared to $37.16 per bbl in 2005; and

Natural gas sales volumes increased 2 percent from the comparable period in 2005 to 3,406 MMcf/d.

During the fourth quarter of 2006, EnCana:

Announced on October 5, 2006, an agreement that EnCana and ConocoPhillips were to create an integrated, North American heavy oil business consisting of upstream and downstream assets. This transaction closed on January 3, 2007; and

Received regulatory approval to renew its NCIB. EnCana purchased 24.5 million shares at an average price of $50.74 in the fourth quarter of 2006 for a total cost of $1.2 billion under this renewed Bid.

Quarterly Sales Volumes		**2006**				2005		
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Produced Gas *(MMcf/d)*	**3,406**	**3,359**	**3,361**	**3,343**	3,326	3,222	3,212	3,146
Crude Oil *(bbls/d)*	**128,048**	**126,658**	**129,070**	**138,370**	134,178	124,402	132,294	130,826
NGLs *(bbls/d)*	**24,106**	**23,907**	**24,400**	**24,421**	25,111	26,055	24,814	26,358
Continuing Operations *(MMcfe/d)* [1]	**4,319**	**4,262**	**4,282**	**4,320**	4,282	4,125	4,155	4,089
Discontinued Operations								
Ecuador *(bbls/d)*	**-**	**-**	**-**	**50,150**	69,943	68,710	73,176	72,487
Discontinued Operations *(MMcfe/d)* [1]	**-**	**-**	**-**	**301**	419	412	439	435
Total *(MMcfe/d)* [1]	**4,319**	**4,262**	**4,282**	**4,621**	4,701	4,537	4,594	4,524

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

Outlook

EnCana plans to continue to focus principally on growing natural gas and crude oil production from unconventional resource plays in North America and to developing its high quality in-situ oilsands resources and expanding the Company s downstream heavy oil processing capacity.

Volatility in crude oil prices is expected to continue throughout 2007 as a result of market uncertainties over supply and refining disruptions, continued demand growth in China, OPEC actions, demand destruction from high energy prices and the overall state of the world economies. In the near term, the new pipeline capacity to the U.S. Gulf Coast should reduce the volatility on Canadian crude oil relative to world oil prices.

Natural gas prices are primarily driven by North American supply and demand, with weather being the key factor in the short term. EnCana believes that North American conventional gas supply has peaked in the past two years and that unconventional resource plays can at least partially offset conventional gas production declines. The industry s ability to respond to the constrained gas supply situation in North America remains challenged by land access and regulatory issues.

The Company expects its 2007 core capital investment program to be funded from cash flow.

Consistent with the Company s focus on shareholder value creation, EnCana s Board of Directors intends to double the quarterly dividend in 2007 to $0.20 per share. On February 14, 2007 the Company s Board of Directors declared a dividend for the first quarter of 2007 in the amount of $0.20 per share.

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

Advisories

FORWARD-LOOKING STATEMENTS

In the interest of providing EnCana shareholders and potential investors with information regarding the Company and its subsidiaries, including Management s assessment of EnCana s and its subsidiaries future plans and operations, certain statements contained in this MD&A constitute forward-looking statements or information (collectively referred to herein as forward-looking statements) within the meaning of the safe harbour provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as anticipate , believe , expect , plan , intend , forecast , target , project or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: projections with respect to growth of natural gas production from unconventional resource plays and in-situ oilsands resources; projections relating to the volatility of crude oil prices in 2007 and beyond and the reasons therefor; projections of common share dividends for 2007; projections with respect to capital investments for 2007 and the source of funding therefor; the effect of the Company s risk management program, including the impact of derivative financial instruments and the percentage of oil production impacted by fixed price swaps and put options; the potential impact of revised accounting pronouncements on the Company; the Company s defence of lawsuits; the impact of climate change initiatives on operating costs; the adequacy of the Company s provision for taxes; the impact of new pipeline capacity to the U.S. Gulf Coast on future Canadian crude oil prices; projections that the Company s Bankers Acceptances and Commercial Paper Program will continue to be fully supported by committed credit facilities and term loan facilities; and projections relating to North American conventional natural gas supplies and the ability of unconventional resource plays to partially offset future conventional gas production declines. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company s actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things, volatility of and assumptions regarding oil and gas prices; assumptions based upon EnCana s current guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company s and its subsidiaries marketing operations, including credit risks; imprecision of reserve estimates and estimates of recoverable quantities of oil, bitumen, natural gas and liquids from resource plays and other sources not currently classified as proved; the Company s and its subsidiaries ability to replace and expand oil and gas reserves; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining synthetic crude oil; risks associated with technology; the Company s ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company s ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company s and its subsidiaries ability to secure adequate product transportation; changes in environmental and other regulations or the interpretations of such regulations; political and economic conditions in the countries in which the Company and its subsidiaries operate; the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company and its subsidiaries operate and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company and its subsidiaries; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Statements relating to reserves or resources or resource potential are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A and, except as required by law, EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

OIL AND GAS INFORMATION

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

Crude Oil, Natural Gas Liquids and Natural Gas Conversions

In this MD&A, certain crude oil and natural gas liquids (NGLs) volumes have been converted to millions of cubic feet equivalent (MMcfe) or thousands of cubic feet equivalent (Mcfe) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). Also, certain natural gas volumes have been converted to barrels of oil equivalent (BOE), thousands of BOE (MBOE) or millions of BOE (MMBOE) on the same basis. MMcfe, Mcfe, BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the well head.

Resource Play, Estimated Ultimate Recovery, and Unbooked Resource Potential

EnCana uses the terms resource play, estimated ultimate recovery and unbooked resource potential. Resource play is a term used by EnCana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate. As used by EnCana, estimated ultimate recovery (EUR) has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom. EnCana defines Unbooked Resource Potential as quantities of oil and gas on existing landholdings that are not yet classified as proved reserves, but which EnCana believes may be moved into the proved reserves category and produced in the future. EnCana employs a probability-weighted approach in the calculation of these quantities, including statistical distributions of resource play potential and areal extent. Consequently, EnCana s unbooked resource potential necessarily includes quantities of probable and possible reserves and contingent resources, as these terms are defined in the Canadian Oil and Gas Evaluation Handbook.

CURRENCY, NON-GAAP MEASURES AND REFERENCES TO ENCANA

All information included in this MD&A and the Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after royalties basis unless otherwise noted. Sales forecasts reflect current public guidance on an after royalties basis. Current Corporate Guidance assumes a U.S. dollar exchange rate of $0.89 for every Canadian dollar.

Non-GAAP Measures

Certain measures in this MD&A do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles (Canadian GAAP) such as Cash Flow from Continuing Operations, Cash Flow, Cash Flow per share-diluted, Operating Earnings and Operating Earnings per share-diluted, Operating Earnings from Continuing Operations and Adjusted EBITDA and therefore are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this MD&A in order to provide shareholders and potential investors with additional information regarding the Company s liquidity and its ability to generate funds to finance its operations. Management s use of these measures has been disclosed further in this MD&A as these measures are discussed and presented.

References to EnCana

For convenience, references in this MD&A to EnCana , the Company , we , us and our may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships (Subsidiaries) of EnCana Corporation, and the assets, activities and initiatives of such Subsidiaries.

ADDITIONAL INFORMATION

Further information regarding EnCana Corporation can be accessed under the Company s public filings found at www.sedar.com and on the Company s website at www.encana.com.

EnCana Corporation

CONSOLIDATED FINANCIAL STATEMENTS

Prepared in US$

For the Year Ended December 31, 2006

Management Report

Management s Responsibility for Consolidated Financial Statements

The accompanying Consolidated Financial Statements of EnCana Corporation (the Company) are the responsibility of Management. The Consolidated 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 judgments. Financial information contained throughout the annual report is consistent with these financial statements.

The Company s Board of Directors has approved the information contained in the Consolidated 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 Canadian securities legislation and the United States Sarbanes-Oxley Act of 2002 and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange. The Audit Committee meets at least on a quarterly basis.

Management s Assessment of Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over the Company s financial reporting. The internal control system was designed to provide reasonable assurance to the Company s Management regarding the preparation and presentation of the Consolidated Financial Statements.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has assessed the effectiveness of the Company s internal control over financial reporting as at December 31, 2006. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework in Internal Control Integrated Framework to evaluate the effectiveness of the Company s internal control over financial reporting. Based on our evaluation, Management has concluded that the Company s internal control over financial reporting was effective as at that date.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, was appointed by a vote of shareholders at the Company s last annual meeting to audit and provide independent opinions on both the Consolidated Financial Statements and Management s assessment of the effectiveness of the Company s internal control over financial reporting as at December 31, 2006, as stated in their Auditor s Report. PricewaterhouseCoopers LLP has provided such opinions.

(signed)	(signed)
Randall K. Eresman	Brian C. Ferguson
President &	Executive Vice-President &
Chief Executive Officer	Chief Financial Officer

February 22, 2007

Auditors   Report

To the Shareholders of EnCana Corporation

We have completed an integrated audit of the Consolidated Financial Statements and internal control over financial reporting of EnCana Corporation (the   Company   ) as of December 31, 2006 and audits of its December 31, 2005 and December 31, 2004 Consolidated Financial Statements. Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

We have audited the accompanying Consolidated Balance Sheets of the Company as at December 31, 2006 and December 31, 2005, and the related Consolidated Statements of Earnings, Retained Earnings and Cash Flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company   s Management. Our responsibility is to express an opinion on these Consolidated Financial Statements based on our audits.

We conducted our audit of the Company   s Consolidated Financial Statements as at December 31, 2006 and for the year then ended in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). We conducted our audits of the Company   s Consolidated Financial Statements as at December 31, 2005 and for each of the two years in the period ended December 31, 2005 in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation.

In our opinion, the Consolidated Financial Statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and December 31, 2005 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006 in accordance with Canadian generally accepted accounting principles.

Internal Control over Financial Reporting

We have also audited management   s assessment, included in the accompanying Management Report, that the Company maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company   s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management   s assessment and on the effectiveness of the Company   s internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

2

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and divestitures of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or divestiture of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that the Company maintained effective internal control over financial reporting as at December 31, 2006 is fairly stated, in all material respects, based on criteria established in Internal Control - Integrated Framework issued by the COSO. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006 based on criteria established in Internal Control - Integrated Framework issued by the COSO.

(signed)

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

Canada

February 22, 2007

EnCana Corporation

Consolidated Statement of Earnings

For the years ended December 31 (US$ millions, except per share amounts)		**2006**	2005	2004
Revenues, Net of Royalties	*(Note 3)*			
Upstream		**$ 11,342**	$ 10,772	$ 7,488
Market Optimization		**3,007**	4,267	3,200
Corporate - Unrealized gain (loss) on risk management	*(Note 16)*	**2,050**	(466)	(198)
- Other		**-**	-	1
		16,399	14,573	10,491
Expenses	*(Note 3)*			
Production and mineral taxes		**349**	453	311
Transportation and selling		**1,070**	845	722
Operating		**1,655**	1,438	1,099
Purchased product		**2,862**	4,159	3,092
Depreciation, depletion and amortization		**3,112**	2,769	2,379
Administrative		**271**	268	197
Interest, net	*(Note 6)*	**396**	524	398
Accretion of asset retirement obligation	*(Note 13)*	**50**	37	22
Foreign exchange (gain) loss, net	*(Note 7)*	**14**	(24)	(412)
Stock-based compensation options	*(Note 14)*	**-**	15	17
(Gain) on divestitures	*(Note 5)*	**(323)**	-	(59)
		9,456	10,484	7,766
Net Earnings Before Income Tax		**6,943**	4,089	2,725
Income tax expense	*(Note 8)*	**1,892**	1,260	632
Net Earnings From Continuing Operations		**5,051**	2,829	2,093
Net Earnings From Discontinued Operations	*(Note 4)*	**601**	597	1,420
Net Earnings		**$ 5,652**	$ 3,426	$ 3,513
Net Earnings From Continuing Operations per Common Share	*(Note 17)*			
Basic		**$ 6.16**	$ 3.26	$ 2.27
Diluted		**$ 6.04**	$ 3.18	$ 2.24
Net Earnings per Common Share	*(Note 17)*			
Basic		**$ 6.89**	$ 3.95	$ 3.82
Diluted		**$ 6.76**	$ 3.85	$ 3.75

Consolidated Statement of Retained Earnings

For the years ended December 31 (US$ millions)		**2006**	2005	2004
Retained Earnings, Beginning of Year		**$ 9,481**	$ 7,935	$ 5,276
Net Earnings		**5,652**	3,426	3,513
Dividends on Common Shares		**(304)**	(238)	(183)
Charges for Normal Course Issuer Bid	*(Note 14)*	**(3,485)**	(1,642)	(671)
Retained Earnings, End of Year		**$ 11,344**	$ 9,481	$ 7,935

See accompanying Notes to Consolidated Financial Statements

EnCana Corporation

Consolidated Balance Sheet

As at December 31 (US$ millions)			**2006**		2005
Assets					
Current Assets					
Cash and cash equivalents		**$**	**402**	$	105
Accounts receivable and accrued revenues			**1,721**		1,851
Risk management	*(Note 16)*		**1,403**		495
Inventories	*(Note 9)*		**176**		103
Assets of discontinued operations	*(Note 4)*		**-**		1,050
			3,702		3,604
Property, Plant and Equipment, net	*(Notes 3, 10)*		**28,213**		24,881
Investments and Other Assets	*(Note 11)*		**533**		496
Risk Management	*(Note 16)*		**133**		530
Assets of Discontinued Operations	*(Note 4)*		**-**		2,113
Goodwill			**2,525**		2,524
	(Note 3)	**$**	**35,106**	$	34,148
Liabilities and Shareholders Equity					
Current Liabilities					
Accounts payable and accrued liabilities		**$**	**2,494**	$	2,741
Income tax payable			**926**		392
Risk management	*(Note 16)*		**14**		1,227
Liabilities of discontinued operations	*(Note 4)*		**-**		438
Current portion of long-term debt	*(Note 12)*		**257**		73
			3,691		4,871
Long-Term Debt	*(Note 12)*		**6,577**		6,703
Other Liabilities			**79**		93
Risk Management	*(Note 16)*		**2**		102
Asset Retirement Obligation	*(Note 13)*		**1,051**		816
Liabilities of Discontinued Operations	*(Note 4)*		**-**		267
Future Income Taxes	*(Note 8)*		**6,240**		5,289
			17,640		18,141
Commitments and Contingencies	*(Note 18)*				
Shareholders Equity					
Share capital	*(Note 14)*		**4,587**		5,131
Paid in surplus	*(Note 14)*		**160**		133
Retained earnings			**11,344**		9,481
Foreign currency translation adjustment			**1,375**		1,262
			17,466		16,007
		$	**35,106**	$	34,148

See accompanying Notes to Consolidated Financial Statements

Approved by the Board

(signed)
David P. O Brien

(signed)
Barry W. Harrison

Director	Director

EnCana Corporation

Consolidated Statement of Cash Flows

For the years ended December 31 (US$ millions)		**2006**	2005	2004
Operating Activities				
Net earnings from continuing operations		**$ 5,051**	$ 2,829	$ 2,093
Depreciation, depletion and amortization		**3,112**	2,769	2,379
Future income taxes	*(Note 8)*	**950**	56	73
Cash tax on sale of assets	*(Note 8)*	**49**	578	-
Unrealized (gain) loss on risk management	*(Note 16)*	**(2,060)**	469	191
Unrealized foreign exchange (gain) loss		**76**	(50)	(285)
Accretion of asset retirement obligation	*(Note 13)*	**50**	37	22
(Gain) on divestitures	*(Note 5)*	**(323)**	-	(59)
Other		**138**	274	88
Cash flow from discontinued operations		**118**	464	478
Net change in other assets and liabilities		**138**	(281)	(176)
Net change in non-cash working capital from continuing operations	*(Note 17)*	**3,343**	497	1,565
Net change in non-cash working capital from discontinued operations		**(2,669)**	(212)	(1,778)
Cash From Operating Activities		**7,973**	7,430	4,591
Investing Activities				
Business combinations		**-**	-	(2,335)
Capital expenditures	*(Note 3)*	**(6,600)**	(6,925)	(4,763)
Proceeds on disposal of assets	*(Note 5)*	**689**	2,523	1,456
Cash tax on sale of assets	*(Note 8)*	**(49)**	(578)	-
Equity investments		**-**	-	47
Net change in investments and other		**2**	(109)	44
Net change in non-cash working capital from continuing operations	*(Note 17)*	**19**	330	(29)
Discontinued operations		**2,557**	239	1,321
Cash (Used in) Investing Activities		**(3,382)**	(4,520)	(4,259)
Financing Activities				
Net issuance (repayment) of revolving long-term debt		**134**	(538)	72
Repayment of long-term debt		**(73)**	(1,104)	(2,759)
Issuance of long-term debt		**-**	429	3,761
Issuance of common shares	*(Note 14)*	**179**	294	281
Purchase of common shares	*(Note 14)*	**(4,219)**	(2,114)	(1,004)
Dividends on common shares		**(304)**	(238)	(183)
Other		**(11)**	(125)	(5)
Cash (Used in) From Financing Activities		**(4,294)**	(3,396)	163
Deduct: Foreign Exchange Loss on Cash and Cash Equivalents Held in Foreign Currency		**-**	2	6
Increase (Decrease) in Cash and Cash Equivalents		**297**	(488)	489
Cash and Cash Equivalents, Beginning of Year		**105**	593	104
Cash and Cash Equivalents, End of Year		**$ 402**	$ 105	$ 593
Supplemental Cash Flow Information	*(Note 17)*			

See accompanying Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

NOTE 1. Summary of Significant Accounting Policies

In these Consolidated Financial Statements, unless otherwise indicated, all dollar amounts are expressed in United States (U.S.) dollars. EnCana has adopted the U.S. 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. All references to US$ or to $ are to United States dollars and references to C$ are to Canadian dollars.

EnCana s continuing operations are in the business of exploration for, production and marketing of, natural gas, crude oil and natural gas liquids (NGLs) and power generation operations.

A) Principles of Consolidation

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. Information prepared in accordance with generally accepted accounting principles in the United States is included in Note 20.

Investments in jointly controlled partnerships and unincorporated joint ventures carry on EnCana s exploration and production business and are accounted for using the proportionate consolidation method, whereby EnCana s proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Investments in companies and partnerships in which EnCana 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 period-end exchange rates, while revenues and expenses are translated using average rates over the period. 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 Consolidated Financial Statements in conformity with Canadian generally accepted accounting principles requires that Management make estimates and assumptions and use judgement regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated 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 natural gas and crude oil reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and the related future cash flows are subject to measurement uncertainty, and the impact in the Consolidated Financial Statements of future periods could be material.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

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.

The amount of compensation expense accrued for long-term performance-based compensation arrangements are subject to Management s best estimate of whether or not the performance criteria will be met and what the ultimate payout will be.

D) Revenue Recognition

Revenues associated with the sales of EnCana s natural gas, crude oil and NGLs are recognized when title passes from the Company to its customer. Natural gas and crude oil produced and sold by EnCana 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. Realized gains and losses from the Company s natural gas and crude oil commodity price risk management activities are recorded in revenue when the product is sold.

Market optimization revenues and purchased product are recorded on a gross basis when EnCana takes title to product and has risks and rewards of ownership. Purchases and sales of inventory with the same counterparty that are entered into in contemplation of each other are recorded on a net basis. Revenues associated with the services provided where EnCana 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 power is provided to the customer.

Unrealized gains and losses from the Company s natural gas and crude oil commodity price risk management activities are recorded as revenue based on the related mark-to-market calculations at the end of the respective period.

E) Production and Mineral Taxes

Costs paid by EnCana to non-mineral interest owners based on production of natural gas, crude oil and NGLs are recognized when the product is produced.

F) Transportation and Selling Costs

Costs paid by EnCana for the transportation and selling of natural gas, crude oil and NGLs, including diluent, are recognized when the product is delivered and the services provided.

G) Employee Benefit Plans

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

The cost of pensions and other retirement and post-employment 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Pension expense for the defined benefit pension plan 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 percent of the greater of the benefit obligation and the fair value of plan assets. Amortization is done on a straight-line basis over a period covering the expected average remaining service 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 plans.

H) Income Taxes

EnCana follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded 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 net earnings in the period that the change occurs. Investment tax credits are recorded as an offset to the related expenditures.

I) 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 share amounts are calculated giving effect to the potential dilution that would occur if stock options without tandem share appreciation rights attached 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 without tandem share appreciation rights attached and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options without tandem share appreciation rights attached are used to repurchase common shares at the average market price.

J) 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.

K) 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.

L) Property, Plant and Equipment

Upstream

EnCana accounts for natural gas and crude oil 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, including internal costs and asset retirement costs, directly 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. 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 divestiture 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 percent 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 the costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties, or impairment has occurred. Costs that have been impaired are included in the costs subject to depreciation, depletion and amortization.

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 the 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.

Market Optimization

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.

Corporate

Costs associated with office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 3 to 25 years. Land is carried at cost.

M) 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.

N) 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

O) Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed 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.

P) Asset Retirement Obligation

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 initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

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 in 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.

Q) Stock-based Compensation

EnCana records compensation expense in the Consolidated Financial Statements for stock options that do not have tandem share appreciation rights attached to them granted to employees and directors using the fair value method. Fair values are determined using the Black-Scholes-Merton option-pricing model. Compensation costs are recognized over the vesting period.

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

11

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

R) Derivative Financial Instruments

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from financial derivatives related to natural gas and crude oil commodity prices are recognized in natural gas and crude oil revenues as the related sales occur. Realized gains or losses from financial derivatives related to power commodity prices are recognized in operating costs as the related power costs are incurred. Unrealized gains and losses are recognized at the end of each respective reporting period. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

Derivative financial instruments are used by EnCana to manage economic 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.

EnCana has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of 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 identifies relationships between financial instruments and anticipated transactions, as well as its risk management objective and the strategy for undertaking the economic hedge transaction. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

S) Recent Accounting Pronouncements

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Company:

As of January 1, 2007, the Company is required to adopt the Canadian Institute of Chartered Accountants (CICA) Section 1530 *Comprehensive Income* , Section 3251 *Equity* , Section 3855 *Financial Instruments Recognition and Measurement* , and Section 3865 *Hedges* , which were issued in January 2005. Under the new standards, comprehensive income has been introduced which will provide for certain gains and losses, including foreign currency translation adjustments and other amounts arising from changes in fair value, to be temporarily recorded outside of net earnings. In addition, all financial instruments, including derivatives, are to be included in the Company s Consolidated Balance Sheet and measured, in most cases, at fair values, and requirements for hedge accounting have been further clarified.

The Company does not expect the Financial Instruments and Hedges standards to have a material impact on its Consolidated Financial Statements as EnCana currently uses mark-to-market accounting for derivative instruments that do not qualify or are not designated as hedges. As a result of these new standards, the Company s financial statement presentation will change to be similar to the presentation under the United States Accounting Principles and Reporting included in Note 20.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

As of January 1, 2007, EnCana is required to adopt revised CICA Section 1506, *Accounting Changes*, which provides expanded disclosures for changes in accounting polices, accounting estimates and corrections of errors. Under the new standard, accounting changes should be applied retrospectively unless otherwise permitted or where impracticable to determine. As well, voluntary changes in accounting policy are made only when required by a primary source of GAAP or the change results in more relevant and reliable information. EnCana does not expect application of this revised standard to have a material impact on its Consolidated Financial Statements.

As of January 1, 2008, EnCana will be required to adopt two new CICA standards, Section 3862 *Financial Instruments Disclosures* and Section 3863 *Financial Instruments Presentation*, which will replace Section 3861 *Financial Instruments Disclosure and Presentation*. The new disclosure standard increases the emphasis on the risks associated with both recognized and unrecognized financial instruments and how those risks are managed. The new presentation standard carries forward the former presentation requirements. The new financial instruments presentation and disclosure requirements were issued in December 2006 and the Company is assessing the impact on its Consolidated Financial Statements.

As of January 1, 2008, EnCana will be required to adopt CICA Section 1535 *Capital Disclosures*, which will require companies to disclose their objectives, policies and processes for managing capital. In addition, disclosures are to include whether companies have complied with externally imposed capital requirements. The new capital disclosure requirements were issued in December 2006 and the Company is assessing the impact on its Consolidated Financial Statements.

In January 2006, the CICA Accounting Standards Board (AcSB) adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards (IFRS) by the end of 2011. The Company continues to monitor and assess the impact of convergence of Canadian GAAP and IFRS.

T) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2006.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

NOTE 2. Changes in Accounting Policies and Practices

On January 1, 2006, the Company adopted Emerging Issues Task Force (EITF) Abstract No. 04-13 *Accounting for Purchases and Sales of Inventory with the Same Counterparty* . In 2006, purchases and sales of inventory with the same counterparty that are entered into in contemplation of each other are recorded on a net basis in the Consolidated Statement of Earnings. This change has been adopted prospectively and has no effect on the net earnings of the reported periods. As a result of the adoption of this policy, reported Market Optimization revenues and purchased product costs for the year ended December 31, 2006 include offsets of $3,238 million.

NOTE 3. Segmented Information

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

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

Market Optimization is conducted by the Midstream & Marketing division. The Marketing groups primary responsibility is the sale of the Company s proprietary production. The results are included in the Upstream segment. Correspondingly, the Marketing groups also undertake market optimization activities which comprise third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment.

Corporate includes unrealized gains or losses recorded on derivative instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

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

Operations that have been discontinued are disclosed in Note 4.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Results of Continuing Operations

	Upstream			Market Optimization		
For the years ended December 31	**2006**	2005	2004	**2006**	2005	2004
Revenues, Net of Royalties	**$ 11,342**	$ 10,772	$ 7,488	**$ 3,007**	$ 4,267	$ 3,200
Expenses						
Production and mineral taxes	**349**	453	311	**-**	-	-
Transportation and selling	**1,054**	832	704	**16**	13	18
Operating	**1,605**	1,351	1,026	**62**	85	74
Purchased product	**-**	-	-	**2,862**	4,159	3,092
Depreciation, depletion and amortization	**3,025**	2,688	2,271	**12**	8	47
Segment Income (Loss)	**$ 5,309**	$ 5,448	$ 3,176	**$ 55**	$ 2	$ (31)

	Corporate			Consolidated		
	2006	2005	2004	**2006**	2005	2004
Revenues, Net of Royalties	**$ 2,050**	$ (466)	$ (197)	**$ 16,399**	$ 14,573	$ 10,491
Expenses						
Production and mineral taxes	**-**	-	-	**349**	453	311
Transportation and selling	**-**	-	-	**1,070**	845	722
Operating	**(12)**	2	(1)	**1,655**	1,438	1,099
Purchased product	**-**	-	-	**2,862**	4,159	3,092
Depreciation, depletion and amortization	**75**	73	61	**3,112**	2,769	2,379
Segment Income (Loss)	**$ 1,987**	$ (541)	$ (257)	**7,351**	4,909	2,888
Administrative				**271**	268	197
Interest, net				**396**	524	398
Accretion of asset retirement obligation				**50**	37	22
Foreign exchange (gain) loss, net				**14**	(24)	(412)
Stock-based compensation options				**-**	15	17
(Gain) on divestitures				**(323)**	-	(59)
				408	820	163
Net Earnings Before Income Tax				**6,943**	4,089	2,725
Income tax expense				**1,892**	1,260	632
Net Earnings From Continuing Operations				**$ 5,051**	$ 2,829	$ 2,093

Upstream

	Canada			United States		
For the years ended December 31	**2006**	2005	2004	**2006**	2005	2004
Revenues, Net of Royalties	**$ 7,911**	$ 7,312	$ 5,315	**$ 3,121**	$ 3,177	$ 1,941
Expenses						
Production and mineral taxes	**116**	104	87	**233**	349	224
Transportation and selling	**806**	650	584	**248**	182	120
Operating	**1,029**	826	685	**283**	212	119
Depreciation, depletion and amortization	**2,142**	1,927	1,751	**848**	682	475

Segment Income	**$ 3,818**	$ 3,805	$ 2,208	**$ 1,509**	$ 1,752	$ 1,003

	Other			Total Upstream		
	2006	2005	2004	**2006**	2005	2004
Revenues, Net of Royalties	**$ 310**	$ 283	$ 232	**$ 11,342**	$ 10,772	$ 7,488
Expenses						
Production and mineral taxes	**-**	-	-	**349**	453	311
Transportation and selling	**-**	-	-	**1,054**	832	704
Operating	**293**	313	222	**1,605**	1,351	1,026
Depreciation, depletion and amortization	**35**	79	45	**3,025**	2,688	2,271
Segment Income (Loss)	**$ (18)**	$ (109)	$ (35)	**$ 5,309**	$ 5,448	$ 3,176

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Upstream Geographic and Product Information (Continuing Operations)

	Produced Gas								
	Canada			United States			Total		
For the years ended December 31	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Revenues, Net of Royalties	**$ 5,440**	$ 5,486	$ 3,928	**$ 2,854**	$ 2,932	$ 1,776	**$ 8,294**	$ 8,418	$ 5,704
Expenses									
Production and mineral taxes	**80**	76	65	**213**	325	205	**293**	401	270
Transportation and selling	**278**	283	296	**248**	182	120	**526**	465	416
Operating	**629**	521	400	**283**	212	119	**912**	733	519
Operating Cash Flow	**$ 4,453**	$ 4,606	$ 3,167	**$ 2,110**	$ 2,213	$ 1,332	**$ 6,563**	$ 6,819	$ 4,499

	Oil and NGLs								
	Canada			United States			Total		
	2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Revenues, Net of Royalties	**$ 2,471**	$ 1,826	$ 1,387	**$ 267**	$ 245	$ 165	**$ 2,738**	$ 2,071	$ 1,552
Expenses									
Production and mineral taxes	**36**	28	22	**20**	24	19	**56**	52	41
Transportation and selling	**528**	367	288	**-**	-	-	**528**	367	288
Operating	**400**	305	285	**-**	-	-	**400**	305	285
Operating Cash Flow	**$ 1,507**	$ 1,126	$ 792	**$ 247**	$ 221	$ 146	**$ 1,754**	$ 1,347	$ 938

	Other			Total Upstream		
	2006	2005	2004	**2006**	2005	2004
Revenues, Net of Royalties	**$ 310**	$ 283	$ 232	**$ 11,342**	$ 10,772	$ 7,488
Expenses						
Production and mineral taxes	**-**	-	-	**349**	453	311
Transportation and selling	**-**	-	-	**1,054**	832	704
Operating	**293**	313	222	**1,605**	1,351	1,026
Operating Cash Flow	**$ 17**	$ (30)	$ 10	**$ 8,334**	$ 8,136	$ 5,447

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Capital Expenditures (Continuing Operations)

For the years ended December 31	**2006**	2005	2004
Upstream Core Capital			
Canada	**$ 4,015**	$ 4,150	$ 3,015
United States	**2,061**	1,982	1,249
Other Countries	**75**	70	79
	6,151	6,202	4,343
Upstream Acquisition Capital			
Canada	**47**	30	64
United States	**284**	418	300
	331	448	364
Market Optimization	**44**	197	10
Corporate	**74**	78	46
Total	**$ 6,600**	$ 6,925	$ 4,763

On December 17, 2004, EnCana acquired certain natural gas and crude oil properties in Texas for approximately $251 million. The purchase was facilitated by an unrelated party, Brown Ranger LLC, which held the assets in trust for the Company. Pursuant to the agreement with Brown Ranger LLC, EnCana operated the properties, received all the revenue and paid all of the expenses associated with the properties. EnCana determined that the relationship with Brown Ranger LLC represented an interest in a variable interest entity (VIE) and that EnCana was the primary beneficiary of the VIE. EnCana consolidated Brown Ranger LLC from the date of acquisition to the date the properties were transferred to EnCana in 2005.

Additions to Goodwill

There were no additions to goodwill during 2006 or 2005. All goodwill included in continuing operations relates to the Upstream segment.

Property, Plant and Equipment and Total Assets

	Property, Plant and Equipment		Total Assets	
As at December 31	**2006**	2005	**2006**	2005
Upstream	**$ 27,781**	$ 24,247	**$ 32,299**	$ 28,858
Market Optimization	**154**	371	**469**	597
Corporate	**278**	263	**2,338**	1,530

Assets of Discontinued Operations	*(Note 4)*						**-**		3,163
Total		**$**	**28,213**	$	24,881	**$**	**35,106**	$	34,148

Export Sales

Sales of natural gas, crude oil and NGLs produced or purchased in Canada delivered to customers outside of Canada were $1,814 million (2005 - $1,784 million; 2004 - $1,747 million).

Major Customers

In connection with the marketing and sale of EnCana s own and purchased natural gas and crude oil, for the year ended December 31, 2006, the Company had one customer (2005 - one) which individually accounted for more than 10 percent of its consolidated revenues, net of royalties. Sales to this customer, a major international integrated energy company with a high quality investment grade credit rating, were approximately $1,951 million (2005 - $2,056 million).

17

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

NOTE 4. Discontinued Operations

As EnCana has focused its continuing operations on North American Upstream operations, a number of divestitures have been made which are accounted for as discontinued operations.

Midstream

During 2006, EnCana completed, in two separate transactions with a single purchaser, the sale of its natural gas storage operations in Canada and the United States. Total proceeds received were approximately $1.5 billion and an after-tax gain on sale of $829 million was recorded.

On December 13, 2005, EnCana completed the sale of its natural gas liquids processing operations for proceeds of $625 million (C$720 million) and recorded an after-tax gain on sale of $370 million.

Upstream

Ecuador

On February 28, 2006, EnCana completed the sale of its Ecuador operations for proceeds of $1.4 billion before indemnifications. A loss of $279 million, including the impact of indemnifications, was recorded. Indemnifications are discussed further in this note.

Amounts recorded as depreciation, depletion and amortization in 2006 and 2005 represent provisions which were recorded against the net book value of the Ecuador operations to recognize management s best estimate of the difference between the selling price and the underlying accounting value of the related investments, as required by Canadian generally accepted accounting principles.

United Kingdom

On December 1, 2004, EnCana completed the sale of its 100 percent interest in EnCana (U.K.) Limited, holder of its U.K. operations, for net cash consideration of approximately $2.1 billion. A gain on sale of approximately $1.4 billion was recorded.

Consolidated Statement of Earnings

The following tables present the effect of the discontinued operations in the Consolidated Statement of Earnings:

Midstream

For the years ended December 31		**2006**		2005		2004
Revenues	**$**	**482**	$	1,570	$	1,551
Expenses						
Transportation and selling		**-**		9		9
Operating		**37**		301		251
Purchased product		**356**		1,100		1,184
Depreciation, depletion and amortization		**-**		28		23
Administrative		**-**		30		-
Interest, net		**-**		(2)		(1)
Foreign exchange (gain) loss, net		**4**		(2)		(5)
(Gain) on discontinuance		**(807)**		(364)		(54)
		(410)		1,100		1,407
Net Earnings Before Income Tax		**892**		470		144
Income tax expense		**17**		39		26
Net Earnings From Discontinued Operations	**$**	**875**	$	431	$	118

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Upstream Ecuador

For the years ended December 31		**2006**		2005		2004
Revenues, Net of Royalties	**$**	**200**	$	965	$	471
Expenses						
Production and mineral taxes		**23**		131		61
Transportation and selling		**10**		58		60
Operating		**25**		138		125
Depreciation, depletion and amortization		**84**		234		263
Interest, net		**(2)**		(2)		(3)
Accretion of asset retirement obligation		**-**		1		1
Foreign exchange (gain) loss, net		**1**		(4)		5
Loss on discontinuance		**279**		-		-
		420		556		512
Net Earnings (Loss) Before Income Tax		**(220)**		409		(41)
Income tax expense (recovery)		**59**		278		(8)
Net Earnings (Loss) From Discontinued Operations	**$**	**(279)**	$	131	$	(33)

Upstream United Kingdom

For the years ended December 31		**2006**		2005		2004
Revenues, Net of Royalties	**$**	**-**	$	-	$	153
Expenses						
Transportation and selling		**-**		-		36
Operating		**-**		-		36
Depreciation, depletion and amortization		**-**		-		118
Interest, net		**-**		-		(9)
Accretion of asset retirement obligation		**-**		-		3
Foreign exchange (gain) loss, net		**(1)**		(40)		(2)
(Gain) on discontinuance		**-**		-		(1,365)
		(1)		(40)		(1,183)
Net Earnings (Loss) Before Income Tax		**1**		40		1,336
Income tax expense (recovery)		**(4)**		5		(2)
Net Earnings From Discontinued Operations	**$**	**5**	$	35	$	1,338

Upstream Syncrude

For the years ended December 31		**2006**		2005		2004
Revenues, Net of Royalties	**$**	**-**	$	-	$	(1)
Expenses						
Loss on discontinuance		**-**		-		2

		-		-		2
Net (Loss) Before Income Tax		**-**		-		(3)
Income tax expense		**-**		-		-
Net (Loss) From Discontinued Operations	**$**	**-**	$	-	$	(3)

19

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Consolidated Total

For the years ended December 31	**2006**	2005	2004
Revenues, Net of Royalties	**$ 682**	$ 2,535	$ 2,174
Expenses			
Production and mineral taxes	**23**	131	61
Transportation and selling	**10**	67	105
Operating	**62**	439	412
Purchased product	**356**	1,100	1,184
Depreciation, depletion and amortization	**84**	262	404
Administrative	**-**	30	-
Interest, net	**(2)**	(4)	(13)
Accretion of asset retirement obligation	**-**	1	4
Foreign exchange (gain) loss, net	**4**	(46)	(2)
(Gain) on discontinuance	**(528)**	(364)	(1,417)
	9	1,616	738
Net Earnings Before Income Tax	**673**	919	1,436
Income tax expense	**72**	322	16
Net Earnings From Discontinued Operations	**$ 601**	$ 597	$ 1,420
Net Earnings from Discontinued Operations per Common Share			
Basic	**$ 0.73**	$ 0.69	$ 1.55
Diluted	**$ 0.72**	$ 0.67	$ 1.51

Consolidated Balance Sheet

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

As at December 31	**2006**	2005
Assets		
Cash and cash equivalents	**$ -**	$ 208
Accounts receivable and accrued revenues	**-**	408
Risk management	**-**	21
Inventories	**-**	413
	-	1,050
Property, plant and equipment, net	**-**	1,686
Investments and other assets	**-**	360
Goodwill	**-**	67
	$ -	$ 3,163
Liabilities		
Accounts payable and accrued liabilities	**$ -**	$ 167
Income tax payable	**-**	230
Risk management	**-**	41

		-		438
Asset retirement obligation		-		21
Future income taxes		-		246
		-		705
Net Assets of Discontinued Operations	**$**	**-**	$	2,458

Included in Midstream is $nil (2005 - $117 million) related to cushion gas, required to operate the gas storage facilities, which is not subject to depletion.

Divestitures

On December 22, 2004, EnCana completed the divestiture of its interest in the Alberta Ethane Gathering System Joint Venture for approximately $108 million, including working capital. A $54 million pre-tax gain was recorded on this sale.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Commitments and Contingencies

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

During the second quarter of 2006, the Government of Ecuador seized the Block 15 assets, in relation to which EnCana previously held a 40 percent economic interest, from the operator which is an event requiring indemnification under the terms of EnCana s sale agreement with the purchaser. The purchaser requested payment and EnCana paid the maximum amount calculated in accordance with the terms of the agreements, approximately $265 million. EnCana does not expect that any further significant indemnification payments relating to any other business matters addressed in the share sale agreements will be required to be made to the purchaser.

NOTE 5. Divestitures

For the years ended December 31		**2006**		2005		2004
Upstream	**$**	**445**	$	2,521	$	1,430
Market Optimization		**244**		-		26
Other		**-**		2		44
	$	**689**	$	2,523	$	1,500

Proceeds received on the sale of assets and investments in 2006 were $689 million (2005 - $2,523 million; 2004 - $1,500 million) as described below:

Upstream

In 2006, EnCana completed the divestiture of various mature conventional oil and natural gas assets for proceeds of $78 million (2005 - $471 million; 2004 - $1,430 million).

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

In May 2005, EnCana completed the sale of its Gulf of Mexico assets for approximately $2.1 billion resulting in net proceeds of approximately $1.5 billion after deducting $578 million in tax plus other adjustments. In accordance with full cost accounting for oil and gas activities, proceeds were credited to property, plant and equipment.

Market Optimization

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

In December 2004, EnCana sold its 25 percent limited partnership interest in the Kingston CoGen Limited Partnership (Kingston) for net cash consideration of $25 million. A pre-tax gain of $28 million was recorded on this sale.

Other

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

NOTE 6. Interest, Net

For the years ended December 31	**2006**	2005	2004
Interest Expense Long-Term Debt	**$ 366**	$ 417	$ 385
Early Retirement of Long-Term Debt	**-**	121	(16)
Interest Expense Other	**76**	18	42
Interest Income	**(46)**	(32)	(13)
	$ 396	$ 524	$ 398

During 2005, EnCana redeemed a number of unsecured notes with a principal of C$1,150 million. The $121 million before tax ($79 million after-tax) charge is due to the early retirement of these medium term notes.

EnCana has entered into a series of one or more interest rate swaps, foreign exchange swaps and option transactions detailed below (see Note 12). The net effect of these transactions reduced interest costs in 2006 by $7 million (2005 - $16 million; 2004 - $22 million).

Swap Positions

As at December 31, 2006	Principal Amount	Indenture Interest	Net Swap To	Effective Rate
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

* This instrument has been subject to multiple swap transactions.

NOTE 7. Foreign Exchange (Gain) Loss, Net

For the years ended December 31	**2006**	2005	2004
	$ -	$ (113)	$ (285)

Unrealized Foreign Exchange (Gain) on Translation of U.S. Dollar Debt Issued from Canada						
Other Foreign Exchange (Gain) Loss		**14**		89		(127)
	$	**14**	$	(24)	$	(412)

NOTE 8. Income Taxes

The provision for income taxes is as follows:

For the years ended December 31		**2006**		2005		2004
Current						
Canada	**$**	**764**	$	493	$	586
United States		**128**		719		(12)
Other		**50**		(8)		(15)
Total Current Tax		**942**		1,204		559
Future		**1,407**		56		182
Future Tax Rate Reductions		**(457)**		-		(109)
Total Future Tax		**950**		56		73
	$	**1,892**	$	1,260	$	632

Included in current tax for 2006 is $49 million related to the sale of assets in Brazil (2005 - $578 million related to the sale of the Gulf of Mexico assets).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

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

For the years ended December 31	**2006**	2005	2004
Net Earnings Before Income Tax	**$ 6,943**	$ 4,089	$ 2,725
Canadian Statutory Rate	**34.7%**	37.9%	39.1%
Expected Income Tax	**2,407**	1,550	1,066
Effect on Taxes Resulting from:			
Non-deductible Canadian Crown payments	**97**	207	192
Canadian resource allowance	**(16)**	(202)	(256)
Statutory and other rate differences	**(98)**	(235)	(50)
Effect of tax rate changes	**(457)**	-	(109)
Non-taxable capital gains	**(1)**	(24)	(91)
Previously unrecognized capital losses	**-**	-	17
Tax basis retained on divestitures	**-**	(68)	(169)
Large corporations tax	**-**	25	24
Other	**(40)**	7	8
	$ 1,892	$ 1,260	$ 632
Effective Tax Rate	**27.3%**	30.8%	23.2%

The net future income tax liability is comprised of:

As at December 31	**2006**	2005
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	**$ 4,695**	$ 4,461
Timing of partnership items	**1,251**	1,226
Other	**305**	-
Future Tax Assets		
Non-capital and net operating losses carried forward	**(11)**	(47)
Other	**-**	(351)
Net Future Income Tax Liability	**$ 6,240**	$ 5,289

The approximate amounts of tax pools available are as follows:

As at December 31	**2006**	2005
Canada	**$ 9,352**	$ 8,575
United States	**3,409**	2,978
	$ 12,761	$ 11,553

Included in the above tax pools are $39 million (2005 - $133 million) related to non-capital and net operating losses available for carry forward to reduce taxable income in future years. These losses expire between 2008 and 2016.

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 year end that is after that of EnCana Corporation.

NOTE 9. Inventories

As at December 31		**2006**		2005
Product				
Upstream	**$**	**50**	$	70
Market Optimization		**126**		31
Parts and Supplies		**-**		2
	$	**176**	$	103

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

NOTE 10. Property, Plant and Equipment, Net

As at December 31	**2006**			2005		
	Cost	**Accumulated DD&A***	**Net**	Cost	Accumulated DD&A*	Net
Upstream						
Canada	**$ 33,289**	**$ (14,265)**	**$ 19,024**	$ 29,199	$ (12,144)	$ 17,055
United States	**11,105**	**(2,611)**	**8,494**	8,707	(1,763)	6,944
Other Countries	**360**	**(97)**	**263**	470	(222)	248
Total Upstream	**44,754**	**(16,973)**	**27,781**	38,376	(14,129)	24,247
Market Optimization	**207**	**(53)**	**154**	419	(48)	371
Corporate	**616**	**(338)**	**278**	544	(281)	263
	$ 45,577	**$ (17,364)**	**$ 28,213**	$ 39,339	$ (14,458)	$ 24,881

* Depreciation, depletion and amortization

Upstream property, plant and equipment include internal costs directly related to exploration, development and construction activities of $365 million (2005 - $347 million). Costs classified as Administrative expenses 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 at the end of the year were:

As at December 31	**2006**	2005	2004
Canada	**$ 1,449**	$ 1,689	$ 1,444
United States	**956**	870	1,119
Other Countries	**263**	248	177
	$ 2,668	$ 2,807	$ 2,740

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. For the year ended December 31, 2006, the Company completed its impairment review of pre-production cost centres and determined that $6 million of costs should be charged to the Consolidated Statement of Earnings (2005 - $7 million; 2004 - $23 million).

The prices used in the ceiling test evaluation of the Company s crude oil and natural gas reserves at December 31, 2006 were:

	2007	2008	2009	2010	2011	Cumulative % Increase to 2018
Natural Gas ($/Mcf)						
Canada	$ 5.93	$ 6.09	$ 5.65	$ 5.71	$ 5.77	16%
United States	$ 6.75	$ 6.43	$ 6.27	$ 6.40	$ 6.36	14%
Crude Oil ($/barrel)						
Canada	$ 28.99	$ 28.00	$ 27.58	$ 28.12	$ 28.48	5%
Natural Gas Liquids ($/barrel)						
Canada	$ 46.80	$ 47.09	$ 49.36	$ 50.41	$ 51.40	15%
United States	$ 43.12	$ 42.84	$ 45.06	$ 45.95	$ 47.12	14%

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

NOTE 11. Investments and Other Assets

As at December 31		**2006**		2005
Prepaid Capital	**$**	**401**	$	334
Deferred Pension Plan and Savings Plan		**58**		60
Deferred Financing Costs		**52**		59
Marketing Contracts		**-**		10
Equity Investment		**6**		7
Other		**16**		26
	$	**533**	$	496

NOTE 12. Long-Term Debt

As at December 31	Note		**2006**		2005
Canadian Dollar Denominated Debt					
Revolving credit and term loan borrowings	*B*	**$**	**1,456**	$	1,425
Unsecured notes	*C*		**793**		793
			2,249		2,218
U.S. Dollar Denominated Debt					
Revolving credit and term loan borrowings	*D*		**104**		-
Unsecured notes	*E*		**4,421**		4,494
			4,525		4,494
Increase in Value of Debt Acquired	*F*		**60**		64
Current Portion of Long-Term Debt	*G*		**(257)**		(73)
		$	**6,577**	$	6,703

A) Overview

Revolving Credit and Term Loan Borrowings

At December 31, 2006, EnCana Corporation had in place a revolving credit facility for C$4.5 billion or its equivalent amount in U.S. dollars ($3.9 billion). The facility, which matures in October 2011, is fully revolving for a period of five years. The facility is extendible from time to time, but not more than once per year, for a period not longer than five years plus ninety days from the date of the extension request, at the option of the lenders and upon notice from EnCana. The facility is unsecured and bears interest at the lenders rates for Canadian prime, U.S. base rate, Bankers Acceptances rates plus applicable margins, or at LIBOR plus applicable margins.

At December 31, 2006, one of EnCana s subsidiaries had in place a credit facility totaling $600 million. The facility, which matures in February 2012, is guaranteed by EnCana Corporation, and is fully revolving for five years. The facility is extendible from time to time, but not more than once per year, for a period not longer than five years plus ninety days from the date of the extension request, 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.

Revolving credit and term loan borrowings include Bankers Acceptances and Commercial Paper of $1,560 million (2005 - $1,425 million) maturing at various dates with a weighted average interest rate of 4.58 percent (2005 - 3.52 percent). 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 2006 relating to revolving credit and term loan agreements were approximately $5 million (2005 - $4 million; 2004 - $5 million).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Unsecured Notes

Unsecured notes include medium term notes and senior notes that are issued from time to time under trust indentures.

EnCana has in place a debt shelf prospectus for Canadian unsecured medium term notes in the amount of C$1 billion. The shelf prospectus provides that debt securities in Canadian 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 maturity dates are determined by reference to market conditions at the date of issue. At December 31, 2006, C$500 million ($429 million) of the shelf prospectus, which expires in September 2007, remains unutilized, the availability of which is dependent upon market conditions.

EnCana has in place a debt shelf prospectus for U.S. unsecured notes in the amount of $2 billion under the multijurisdictional disclosure system (MJDS). 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. The shelf prospectus was renewed in 2006 and expires in October 2008. At December 31, 2006, $2 billion of the shelf prospectus remains unutilized, the availability of which is dependent upon market conditions.

EnCana has an indirect wholly owned subsidiary, EnCana Holdings Finance Corp., which has in place a debt shelf prospectus for U.S. unsecured notes in the amount of $2 billion under the MJDS. 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. The debt securities issued under this shelf prospectus are fully and unconditionally guaranteed by EnCana Corporation. EnCana has also obtained certain exemption orders from Canadian securities regulatory authorities that allow the filing of certain financial and other information of EnCana to satisfy certain continuous disclosure obligations of EnCana Holdings Finance Corp. The shelf prospectus was renewed in 2006 and expires in July 2008. At December 31, 2006, $2 billion of the shelf prospectus remains unutilized, the availability of which is dependent upon market conditions.

B) Canadian Revolving Credit and Term Loan Borrowings

	C$ Principal Amount	2006	2005
Bankers Acceptances	**$ 390**	**$ 335**	$ 369
Commercial Paper	**1,306**	**1,121**	1,056
	$ 1,696	**$ 1,456**	$ 1,425

C) Canadian Unsecured Notes

	C$ Principal Amount	2006	2005
5.30% due December 3, 2007	**$ 300**	**$ 257**	$ 257
5.80% due June 2, 2008	**125**	**107**	107
3.60% due September 15, 2008	**500**	**429**	429
	$ 925	**$ 793**	$ 793

D) U.S. Revolving Credit and Term Loan Borrowings

	2006	2005
Commercial Paper	**$ 104**	$ -

26

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

E) U.S. Unsecured Notes

	C$ Amount	**2006**	2005
7.50% due August 25, 2006	**$ -**	**$ -**	$ 73
5.80% due June 2, 2008	**83***	**71**	71
4.60% due August 15, 2009		**250**	250
7.65% due September 15, 2010		**200**	200
6.30% due November 1, 2011		**500**	500
4.75% due October 15, 2013		**500**	500
5.80% due May 1, 2014		**1,000**	1,000
8.125% due September 15, 2030		**300**	300
7.20% due November 1, 2031		**350**	350
7.375% due November 1, 2031		**500**	500
6.50% due August 15, 2034		**750**	750
		$ 4,421	$ 4,494

* The Company has entered into a cross-currency and interest rate swap transaction that effectively converts a portion of the Canadian dollar denominated note to U.S. dollars. The effective U.S. dollar principal is shown in the table.

The 5.80% note due May 1, 2014 was issued by the Company s indirect wholly owned subsidiary, EnCana Holdings Finance Corp. This note is fully and unconditionally guaranteed by EnCana Corporation.

F) Increase in Value of Debt Acquired

Certain of the notes and debentures of the Company were acquired in business combinations 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 21 years.

G) Current Portion of Long-Term Debt

	C$ Principal Amount	**2006**	2005
7.50% medium term note due August 25, 2006	**$ -**	**$ -**	$ 73

5.30% medium term note due December 3, 2007	**300**	**257**	-
	$ 300	**$ 257**	$ 73

H) Mandatory Debt Payments

	C$ Principal Amount	US$ Principal Amount	**Total US$ Equivalent**
2007	$ 300	$ -	**$ 257**
2008	625	71	**607**
2009	-	250	**250**
2010	-	200	**200**
2011	1,696	604	**2,060**
Thereafter	-	3,400	**3,400**
Total	$ 2,621	$ 4,525	**$ 6,774**

The amount due in 2007 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.

27

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

NOTE 13. 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	**2006**	2005
Asset Retirement Obligation, Beginning of Year	**$ 816**	$ 611
Liabilities Incurred	**68**	77
Liabilities Settled	**(51)**	(42)
Liabilities Divested	**-**	(23)
Change in Estimated Future Cash Flows	**172**	135
Accretion Expense	**50**	37
Other	**(4)**	21
Asset Retirement Obligation, End of Year	**$ 1,051**	$ 816

The total undiscounted amount of estimated cash flows required to settle the obligation is $5,334 million (2005 - $4,944 million), which has been discounted using a weighted average credit-adjusted risk free rate of 5.66 percent (2005 5.74 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 that time.

NOTE 14. 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

As at December 31	**2006**			2005		
	Number (millions)		**Amount**	Number (millions)		Amount
Common Shares Outstanding, Beginning of Year	**854.9**	**$**	**5,131**	900.6	$	5,299
Common Shares Issued under Option Plans	**8.6**		**179**	15.0		283
Stock-based Compensation	**-**		**11**	-		11
Common Shares Purchased	**(85.6)**		**(734)**	(60.7)		(462)
Common Shares Outstanding, End of Year	**777.9**	**$**	**4,587**	854.9	$	5,131

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

Normal Course Issuer Bid

In 2006, the Company purchased 85.6 million Common Shares for total consideration of $4,219 million. Of the amount paid, $734 million was charged to Share capital and $3,485 million was charged to Retained earnings. Included in the 2005 Common Shares Purchased are 5.5 million Common Shares which have been purchased by an EnCana Employee Benefit Plan Trust and are held for issuance upon vesting under EnCana s Performance Share Unit Plan (see Note 15).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

EnCana has received regulatory approval each year under Canadian securities laws to purchase Common Shares under five consecutive Normal Course Issuer Bids (Bids). EnCana is entitled to purchase, for cancellation, up to approximately 80.2 million Common Shares under the renewed Bid which commenced on November 6, 2006 and terminates on November 5, 2007. During January 2007, EnCana purchased approximately 10.8 million Common Shares under the Bid for total consideration of $494 million.

Stock Options

EnCana has stock-based compensation plans that allow employees and directors to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the plans are generally fully exercisable after three years and expire five years after the date granted. Options granted under predecessor and/or related company replacement plans expire up to 10 years from the date the options were granted. All options issued subsequent to December 31, 2003 have an associated Tandem Share Appreciation Right (TSAR) attached to them (see Note 15).

EnCana Plan

Pursuant to the terms of a stock option plan, options may be granted to certain key employees to purchase EnCana Common Shares. 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 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.

Canadian Pacific Limited Replacement Plan

As part of the 2001 reorganization of Canadian Pacific Limited (CPL), EnCana s former parent company, 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 and on October 25, 2005, the Company terminated the plan.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

The following tables summarize the information about options to purchase Common Shares that do not have a TSAR attached to them:

As at December 31	**2006**		2005		2004	
	Stock Options *(millions)*	**Weighted Average Exercise Price*(C$)***	Stock Options *(millions)*	Weighted Average Exercise Price *(C$)*	Stock Options *(millions)*	Weighted Average Exercise Price *(C$)*
Outstanding, Beginning of Year	**20.7**	**23.36**	36.2	23.15	57.6	21.57
Exercised	**(8.6)**	**23.60**	(14.9)	22.90	(19.4)	18.32
Forfeited	**(0.3)**	**23.80**	(0.6)	21.71	(2.0)	23.75
Outstanding, End of Year	**11.8**	**23.17**	20.7	23.36	36.2	23.15
Exercisable, End of Year	**11.8**	**23.17**	16.8	23.21	21.6	22.55

As at December 31, 2006	**Outstanding Options**			**Exercisable Options**	
Range of Exercise Price *(C$)*	Number of Options Outstanding *(millions)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *(C$)*	Number of Options Outstanding *(millions)*	Weighted Average Exercise Price *(C$)*
11.00 to 16.99	0.8	2.3	11.89	0.8	11.89
17.00 to 22.99	0.2	1.0	22.32	0.2	22.32
23.00 to 23.99	5.4	1.3	23.87	5.4	23.87
24.00 to 24.99	5.2	0.4	24.19	5.2	24.19
25.00 to 25.99	0.2	1.7	25.58	0.2	25.58
	11.8	1.0	23.17	11.8	23.17

At December 31, 2006, there were 20.7 million common shares reserved for issuance under stock option plans (2005 - 29.3 million; 2004 - 16.0 million).

EnCana has recorded stock-based compensation expense in the Consolidated Statement of Earnings for stock options granted to employees and directors in 2003 using the fair value method. Stock options granted subsequent to December 31, 2003 have an associated TSAR attached. Compensation expense has not been recorded in the Consolidated Statement of Earnings related to stock options granted prior to 2003. If the Company had applied the fair value method to options granted prior to 2003, pro forma Net Earnings and Net Earnings per Common Share in 2006 and 2005 would have been unchanged (2004 - $3,476 million; $3.77 per common share - basic; $3.71 per common share - diluted).

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

For the year ended December 31		2003
Weighted Average Fair Value of Options Granted *(C$)*	$	6.11
Risk-Free Interest Rate		3.87%
Expected Lives *(years)*		3.00
Expected Volatility		0.33
Annual Dividend per Share *(C$/common share)*	$	0.20

At December 31, 2006 and 2005, the balance in Paid in surplus relates to stock-based compensation programs.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

NOTE 15. Compensation Plans

Where applicable, the amounts below have been restated to reflect the effect of the common share split approved in April 2005.

A) Pensions and Post-Employment Benefits

The most recent actuarial valuation completed for the Company s pension plans is dated December 31, 2005. The next required valuation will be as at December 31, 2008.

The Company sponsors both defined benefit and defined contribution plans, providing pension and post-employment benefits (OPEB) to substantially all of its employees.

For the years ended December 31		**2006**		2005		2004
Total Expense for Defined Contribution Plans	$	28	$	22	$	19

Information about defined benefit and OPEB plans, in aggregate, is as follows:

Accrued Benefit Obligation

	Pension Benefits				OPEB			
As at December 31		**2006**		2005		**2006**		2005
Accrued Benefit Obligation, Beginning of Year	**$**	**294**	$	246	**$**	**39**	$	19
Amendments		**-**		-		**-**		13
Current service cost		**9**		6		**7**		5
Interest cost		**15**		14		**2**		2
Benefits paid		**(18)**		(12)		**(1)**		(1)
Actuarial (gain) loss		**7**		29		**(2)**		-
Contributions		**1**		1		**-**		-
Foreign exchange		**-**		10		**-**		1
Accrued Benefit Obligation, End of Year	**$**	**308**	$	294	**$**	**45**	$	39

The amendments made January 1, 2005 related to obligations for OPEB related to the acquisition of Tom Brown, Inc. and changes made to one of the Company s Plans which increased the Company s OPEB obligation.

Plan Assets

As at December 31	Pension Benefits **2006**	2005	OPEB **2006**	2005
Fair Value of Plan Assets, Beginning of Year	**$ 284**	$ 247	**$ -**	$ -
Actual return on plan assets	**27**	29	**-**	-
Employer contributions	**10**	9	**-**	-
Employees contributions	**1**	1	**-**	-
Benefits paid	**(18)**	(12)	**-**	-
Foreign exchange	**-**	10	**-**	-
Fair Value of Plan Assets, End of Year	**$ 304**	$ 284	**$ -**	$ -

Accrued Benefit Asset (Liability)

As at December 31	Pension Benefits **2006**	2005	OPEB **2006**	2005
Funded Status Plan Assets (less) than Benefit Obligation	**$ (4)**	$ (10)	**$ (45)**	$ (39)
Amounts Not Recognized:				
Unamortized net actuarial loss	**54**	64	**2**	4
Unamortized past service cost	**7**	9	**1**	1
Net transitional asset	**(6)**	(8)	**13**	14
Accrued Benefit Asset (Liability)	**$ 51**	$ 55	**$ (29)**	$ (20)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

	Pension Benefits		OPEB	
As at December 31	**2006**	2005	**2006**	2005
Prepaid Benefit Cost	**$ 51**	$ 55	**$ -**	$ -
Accrued Benefit Cost	**-**	-	**(29)**	(20)
Net Amount Recognized	**$ 51**	$ 55	**$ (29)**	$ (20)

The Company s OPEB plans are funded on an as required basis.

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

	Pension Benefits		OPEB	
As at December 31	**2006**	2005	**2006**	2005
Discount Rate	**5.00%**	5.00%	**5.375%**	5.25%
Rate of Compensation Increase	**4.30%**	4.50%	**5.65%**	5.65%

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

	Pension Benefits		OPEB	
For the years ended December 31	**2006**	2005	**2006**	2005
Discount Rate	**5.00%**	5.75%	**5.25%**	5.75%
Expected Long-Term Rate of Return on Plan Assets:				
Registered pension plans	**6.75%**	6.75%	**n/a**	n/a
Supplemental pension plans	**3.375%**	3.375%	**n/a**	n/a
Rate of Compensation Increase	**4.50%**	4.60%	**5.65%**	5.65%

The periodic expense for benefits is as follows:

	Pension Benefits			OPEB		
For the years ended December 31	**2006**	2005	2004	**2006**	2005	2004
Current Service Cost	**$ 9**	$ 6	$ 5	**$ 7**	$ 5	$ 1
Interest Cost	**15**	14	13	**2**	2	1
Actual Return on Plan Assets	**(27)**	(29)	(19)	**-**	-	-
Actuarial Loss on Accrued Benefit Obligation	**6**	29	8	**-**	-	1
Difference Between Actual and:						

Expected return on plan assets	**11**	15	7	**-**	-	-
Recognized actuarial gain (loss)	**-**	(24)	(4)	**-**	-	(1)
Difference Between Amortization of Past Service Costs and Actual Plan Amendments	**2**	2	2	**-**	-	-
Amortization of Transitional Obligation	**(3)**	(3)	(2)	**2**	1	-
Expense for Defined Contribution Plan	**28**	22	19	**-**	-	-
Net Benefit Plan Expense	**$ 41**	$ 32	$ 29	**$ 11**	$ 8	$ 2

The average remaining service period of the active employees covered by the defined benefit pension plan is seven years. The average remaining service period of the active employees covered by the OPEB plan is 12 years.

Assumed health care cost trend rates are as follows:

As at December 31	**2006**	2005
Health Care Cost Trend Rate for Next Year	**11.00%**	11.00%
Rate that the Trend Rate Gradually Trends To	**5.00%**	5.00%
Year that the Trend Rate Reaches the Rate which it is Expected to Remain At	**2015**	2015

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Assumed health care cost trend rates have an effect on the amounts reported for the OPEB 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	$1	$(1)
Effect on Post Retirement Benefit Obligation	$4	$(4)

The Company s pension plan asset allocations are as follows:

Asset Category	Target Allocation %		% of Plan Assets at December 31		Expected Long-Term Rate of Return
	Normal	Range	**2006**	2005	
Domestic Equity	35	25-45	**39**	41	
Foreign Equity	30	20-40	**30**	27	
Bonds	30	20-40	**25**	25	
Real Estate and Other	5	0-20	**6**	7	
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 Supplemental Pension Plan is funded through a retirement compensation arrangement and is subject to the applicable Canada Revenue Agency regulations.

The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investment, credit rating categories and foreign currency exposure.

The Company s contributions to the pension plans are subject to direction by the Pension Committee. Contributions by the participants to the pension and other benefits plans were $1 million for the year ended December 31, 2006 (2005 - $1 million; 2004 - $1 million).

Estimated future payment of pension and other benefits are as follows:

	Pension Benefits	OPEB
2007	$ 14	$ 1
2008	15	1
2009	16	2
2010	17	2
2011	18	3
2012 2016	104	29
Total	$ 184	$ 38

B) Share Appreciation Rights

EnCana 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 EnCana s Common Shares at the time of exercise over the exercise price of the right. SAR s granted generally expire after five years with the exception of a limited number that expire after seven years.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

The following tables summarize the information about the SAR s:

	2006		2005	
As at December 31	**Outstanding SAR s**	**Weighted Average Exercise Price**	Outstanding SAR s	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**246,739**	**23.13**	930,510	18.31
Exercised	**(246,739)**	**23.13**	(682,241)	16.55
Forfeited	**-**	**-**	(1,530)	23.14
Outstanding, End of Year	**-**	**-**	246,739	23.13
Exercisable, End of Year	**-**	**-**	246,739	23.13
U.S. Dollar Denominated (US$)				
Outstanding, Beginning of Year	**319,511**	**14.33**	771,860	14.40
Exercised	**(317,423)**	**14.33**	(452,349)	14.45
Outstanding, End of Year	**2,088**	**14.21**	319,511	14.33
Exercisable, End of Year	**2,088**	**14.21**	319,511	14.33

As at December 31, 2006	**SAR s Outstanding and Exercisable**		
Range of Exercise Price	**Number of SAR s**	**Weighted Average Remaining Contractual Life (years)**	**Weighted Average Exercise Price**
U.S. Dollar Denominated (US$)			
10.00 to 19.99	**2,088**	**1.12**	**14.21**
	2,088	**1.12**	**14.21**

During the year, the Company recorded a reduction of $1 million to compensation costs related to the outstanding SAR s (2005 - compensation costs of $17 million; 2004 - compensation costs of $17 million).

C) Tandem Share Appreciation Rights

Subsequent to December 31, 2003, all options to purchase Common Shares issued under the share option plans described in Note 14 have an associated Tandem Share Appreciation Right (TSAR) attached to them whereby the option holder has the right to receive a cash payment equal to the excess of the market price of EnCana s Common Shares at the time of exercise over the exercise price of the right in lieu of exercising the option. The TSAR s vest and expire under the same terms and conditions as the underlying option.

The following tables summarize the information about the TSAR s:

As at December 31	**2006**		2005	
	Outstanding TSAR s	**Weighted Average Exercise Price**	Outstanding TSAR s	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**8,403,967**	**38.41**	1,735,000	27.77
Granted	**11,180,800**	**49.01**	7,581,412	40.14
Exercised SAR s	**(700,418)**	**34.54**	(151,610)	27.51
Exercised Options	**(32,948)**	**34.46**	(104,735)	27.60
Forfeited	**(1,575,210)**	**43.21**	(656,100)	34.44
Outstanding, End of Year	**17,276,191**	**44.99**	8,403,967	38.41
Exercisable, End of Year	**1,971,467**	**38.31**	229,705	28.00

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

As at December 31, 2006	Outstanding TSAR s			Exercisable Options with TSAR s Attached	
Range of Exercise Price (C$)	**Number of TSAR s**	**Weighted Average Remaining Contractual Life (years)**	**Weighted Average Exercise Price**	**Number of TSAR s**	**Weighted Average Exercise Price**
20.00 to 29.99	**698,118**	**2.35**	**27.41**	**293,718**	**27.44**
30.00 to 39.99	**5,253,063**	**3.12**	**38.12**	**1,427,189**	**38.07**
40.00 to 49.99	**9,645,615**	**4.09**	**48.11**	**85,780**	**44.73**
50.00 to 59.99	**1,476,335**	**4.21**	**55.04**	**143,930**	**55.22**
60.00 to 69.99	**203,060**	**4.33**	**61.93**	**20,850**	**64.19**
	17,276,191	**3.74**	**44.99**	**1,971,467**	**38.31**

During the year, the Company recorded compensation costs of $52 million related to the outstanding TSAR s (2005 - $60 million; 2004 - $3 million).

D) 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 2002 vest over a three year period. DSU s expire on December 15th of the year following the employee s retirement or death.

As at December 31	**2006**		2005	
	Outstanding DSU s	**Average Share Price**	Outstanding DSU s	Average Share Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**836,561**	**26.81**	750,612	24.81
Granted, Directors	**70,000**	**56.71**	80,765	43.75
Units, in Lieu of Dividends	**12,578**	**54.69**	5,184	52.34
Exercised	**(52,562)**	**27.92**	-	-
Outstanding, End of Year	**866,577**	**29.56**	836,561	26.81
Exercisable, End of Year	**866,577**	**29.56**	836,561	26.81

During the year, the Company recorded compensation costs of $5 million related to the outstanding DSU s (2005 - $16 million; 2004 - $10 million).

E) Performance Share Units

EnCana has in place a program whereby employees may be granted Performance Share Units (PSU s) which entitle the employee to receive, upon vesting, either a common share of EnCana or a cash payment equal to the value of one common share of EnCana depending upon the terms of the PSU granted. PSU s vest at the end of a three year period. Their ultimate value will depend upon EnCana s performance measured over three calendar years. Performance will be measured by total shareholder return relative to a fixed comparison group of North American oil and gas companies. If EnCana s performance is below the specified level compared to the comparison group, the units awarded will be forfeited. If EnCana s performance is at or above the specified level compared to the comparison group, the value of the PSU s shall be determined by EnCana s relative ranking, with payments ranging from one half to two times the PSU s granted for the 2004 and 2005 grant. These will be paid in common shares.

PSU s granted in 2003 were paid out in cash at 75 percent of the number granted.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

The following table summarizes the information about the PSU s:

As at December 31	**2006**		2005	
	Outstanding PSU s	**Average Share Price**	Outstanding PSU s	Average Share Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**4,704,348**	**30.65**	3,294,206	26.71
Granted	**36,599**	**54.82**	1,734,089	38.13
Paid out	**(239,794)**	**23.26**	-	-
Forfeited	**(309,313)**	**31.35**	(323,947)	30.48
Outstanding, End of Year	**4,191,840**	**31.24**	4,704,348	30.65
U.S. Dollar Denominated (US$)				
Outstanding, Beginning of Year	**739,649**	**25.22**	449,230	20.56
Granted	**4,860**	**48.07**	390,171	30.92
Forfeited	**(170,020)**	**24.13**	(99,752)	26.50
Outstanding, End of Year	**574,489**	**25.74**	739,649	25.22

During the year, the Company recorded compensation costs of $27 million related to the outstanding PSU s (2005 - $91 million; 2004 - $25 million).

At December 31, 2006, EnCana had approximately 5.5 million Common Shares held in trust for issuance upon vesting of the PSU s (2005 - 5.5 million).

NOTE 16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

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

		Realized Gain (Loss)	
For the years ended December 31	**2006**	2005	2004
Revenues, Net of Royalties	**$ 393**	$ (684)	$ (662)
Operating Expenses and Other	**5**	31	28

Gain (Loss) on Risk Management	Continuing Operations		**398**		(653)		(634)
Gain (Loss) on Risk Management	Discontinued Operations		**12**		(155)		(410)
		$	**410**	$	(808)	$	(1,044)

			Unrealized Gain (Loss)				
For the years ended December 31			**2006**		2005		2004
Revenues, Net of Royalties		**$**	**2,050**	$	(466)	$	(198)
Operating Expenses and Other			**10**		(3)		7
Gain (Loss) on Risk Management	Continuing Operations		**2,060**		(469)		(191)
Gain (Loss) on Risk Management	Discontinued Operations		**20**		50		(70)
		$	**2,080**	$	(419)	$	(261)

Amounts Recognized on Transition

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

At December 31, 2006, a net unrealized gain of approximately $16 million remains to be recognized over the next two years.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Fair Value of Outstanding Risk Management Positions

The following table presents a reconciliation of the change in the unrealized amounts during 2006:

		Fair Market Value		Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**$**	**(640)**		
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During 2006		**2,466**	**$**	**2,466**
Fair Value of Contracts in Place at Transition that Expired During 2006		**-**		**24**
Fair Value of Contracts Realized During 2006		**(410)**		**(410)**
Fair Value of Contracts Outstanding	**$**	**1,416**	**$**	**2,080**
Unamortized Premiums Paid on Options		**104**		
Fair Value of Contracts and Premiums Paid, End of Year	**$**	**1,520**		
Amounts Allocated to Continuing Operations	**$**	**1,520**	**$**	**2,060**
Amounts Allocated to Discontinued Operations		**-**		**20**
	$	**1,520**	**$**	**2,080**

At December 31, 2006, the risk management amounts are recorded in the Consolidated Balance Sheet as follows:

As at December 31			**2006**		2005
Risk Management					
Current asset		**$**	**1,403**	$	495
Long-term asset			**133**		530
Current liability			**14**		1,227
Long-term liability			**2**		102
Net Risk Management Asset (Liability)	Continuing Operations		**1,520**		(304)
Net Risk Management Asset (Liability)	Discontinued Operations		**-**		(20)
		$	**1,520**	$	(324)

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

As at December 31	Note		**2006**		2005
Commodity Price Risk	*A*				
Natural gas		**$**	**1,431**	$	(247)
Crude oil			**74**		(66)

Power				**13**		-
Interest Rate Risk		*B*		**4**		10
Credit Derivatives		*C*		**(2)**		(1)
Total Fair Value Positions	Continuing Operations			**1,520**		(304)
Total Fair Value Positions	Discontinued Operations			**-**		(20)
			$	**1,520**	$	(324)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

A) Commodity Price Risk

Natural Gas

At December 31, 2006 the Company s natural gas risk management activities from financial contracts had an unrealized gain of $1,410 million and a fair market value position of $1,431 million. Details of the contracts are as follows:

	Notional Volumes (MMcf/d)	Term	Average Price		Fair Market Value
Sales Contracts					
Fixed Price Contracts					
NYMEX Fixed Price	1,487	2007	8.56	US$/Mcf	$ **861**
Other	8	2007	8.97	US$/Mcf	**7**
NYMEX Fixed Price	222	2008	8.45	US$/Mcf	**34**
Options					
Purchased NYMEX Put Options	240	2007	6.00	US$/Mcf	**15**
Basis Contracts					
Fixed NYMEX to AECO basis	747	2007	(0.72)	US$/Mcf	**39**
Fixed NYMEX to Rockies basis	538	2007	(0.65)	US$/Mcf	**223**
Fixed NYMEX to CIG basis	390	2007	(0.76)	US$/Mcf	**144**
Fixed Rockies to CIG basis	12	2007	(0.10)	US$/Mcf	**(1)**
Fixed NYMEX to AECO basis	191	2008	(0.78)	US$/Mcf	**10**
Fixed NYMEX to Rockies basis	162	2008	(0.59)	US$/Mcf	**46**
Fixed NYMEX to CIG basis	60	2008	(0.67)	US$/Mcf	**15**
Fixed NYMEX to Rockies basis (NYMEX Adjusted)	329	2008	17% of NYMEX	US$/Mcf	**14**
Fixed NYMEX to Mid-Continent basis (NYMEX Adjusted)	120	2008	12% of NYMEX	US$/Mcf	**4**
Fixed NYMEX to CIG basis	20	2009	(0.71)	US$/Mcf	**1**
Fixed NYMEX to AECO basis	12	2010	(0.40)	US$/Mcf	**-**
Purchase Contracts					
Fixed Price Contracts					
Other	8	2007	7.84	US$/Mcf	**(4)**
					1,408
Other Financial Positions (1)					**2**
Total Unrealized Gain on Financial Contracts					**1,410**
Unamortized Premiums Paid on Options					**21**
Total Fair Value Positions					$ **1,431**

(1) Other financial positions are part of the daily ongoing operations of the Company s proprietary production management.

Crude Oil

As at December 31, 2006, the Company s crude oil risk management activities from financial contracts had an unrealized loss of $9 million and a fair market value position of $74 million. Details of the contracts are as follows:

	Notional Volumes (bbls/d)	Term		Average Price		Fair Market Value
Fixed WTI NYMEX Price	34,500	2007	64.40	US$/bbl	**$**	**(8)**
Purchased WTI NYMEX Put Options	91,500	2007	55.34	US$/bbl		**(1)**
						(9)
Other Financial Positions [1]	**-**					
Total Unrealized (Loss) on Financial Contracts						**(9)**
Unamortized Premiums Paid on Options						**83**
Total Fair Value Positions					**$**	**74**

(1) Other financial positions are part of the daily ongoing operations of the Company s proprietary production management.

38

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Power

In November 2006, the Company entered into two derivative contracts, commencing January 1, 2007 for a period of 11 years, to manage its electricity consumption costs. At December 31, 2006, these contracts had an unrealized gain of $13 million.

B) 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 6.

The unrealized gains on the outstanding financial instruments were as follows:

	Unrealized Gain	
As at December 31	**2006**	2005
7.50% medium term note due August 25, 2006	**$ -**	$ 3
5.80% medium term note due June 2, 2008	**4**	7
	$ 4	$ 10

At December 31, 2006, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $11 million (2005 - $10 million; 2004 - $13 million).

C) 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 and net settlements where appropriate. At December 31, 2006, EnCana had three counterparties whose net settlement position individually account for more than 10 percent of the fair value of the outstanding in-the-money net financial instrument contracts by counterparty.

All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

D) Fair Value of Financial Assets and Liabilities

The fair values of financial instruments not recorded at their fair values 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.

As at December 31	**2006**		2005	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets				
Cash and cash equivalents	**$ 402**	**$ 402**	$ 105	$ 105
Accounts receivable	**1,721**	**1,721**	1,851	1,851
Financial Liabilities				
Accounts payable, income tax payable	**$ 3,420**	**$ 3,420**	$ 3,133	$ 3,133
Long-term debt	**6,834**	**6,965**	6,776	7,180

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

NOTE 17. 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	**2006**	2005	2004
Weighted Average Common Shares Outstanding Basic	**819.9**	868.3	920.8
Effect of Stock Options and Other Dilutive Securities	**16.6**	20.9	15.2
Weighted Average Common Shares Outstanding Diluted	**836.5**	889.2	936.0

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

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

For the years ended December 31		**2006**		2005		2004
Operating Activities						
Accounts receivable and accrued revenues	**$**	**3,128**	$	(146)	$	825
Inventories		**(75)**		(34)		(22)
Accounts payable and accrued liabilities		**(260)**		654		585
Income tax payable		**550**		23		177
	$	**3,343**	$	497	$	1,565
Investing Activities						
Accounts payable and accrued liabilities	**$**	**19**	$	330	$	(29)

C) Supplementary Cash Flow Information Continuing Operations

For the years ended December 31	**2006**	2005	2004

Interest Paid	**$**	**341**	$	522	$	402
Income Taxes Paid	**$**	**450**	$	1,096	$	136

NOTE 18. Commitments and Contingencies

Commitments

As at December 31, 2006	2007	2008	2009	2010	2011	Thereafter	**Total**
Pipeline Transportation	$ 431	$ 412	$ 424	$ 409	$ 382	$ 2,144	**$ 4,202**
Purchases of Goods and Services	427	282	228	161	119	790	**2,007**
Product Purchases	54	23	24	24	-	98	**223**
Operating Leases	52	46	46	50	47	237	**478**
Capital Commitments	75	29	6	-	-	38	**148**
Other Long-Term Commitments	13	7	3	2	1	-	**26**
Total	$ 1,052	$ 799	$ 731	$ 646	$ 549	$ 3,307	**$ 7,084**
Product Sales	$ 41	$ 44	$ 40	$ 42	$ 43	$ 252	**$ 462**

In addition to the above, the Company has made commitments related to its risk management program (see Note 16).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

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

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. (WD), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. The lawsuits allege that the defendants engaged in a conspiracy with unnamed competitors in the natural gas markets in California in violation of U.S. and California anti-trust and unfair competition laws.

Without admitting any liability in the lawsuits, WD agreed to settle all of the class action lawsuits in both state and federal court, for payment, of $20.5 million and $2.4 million, respectively. Court approval of the federal court class action settlement of $2.4 million is pending, court approval having been granted in the state court action. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission (CFTC) and of a previously disclosed consolidated class action lawsuit in the United States District Court in New York for $8.2 million.

The remaining lawsuits were commenced by individual plaintiffs, one of which is E. & J. Gallo Winery (Gallo). The Gallo lawsuit claims damages in excess of $30 million. The other remaining lawsuits do not specify the precise amount of damages claimed. California law allows for the possibility that the amount of damages assessed could be tripled.

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

Asset Retirement

EnCana 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 $1,051 million based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

Income Tax Matters

The operations of the Company are complex, and related tax interpretations, regulations and legislation in the various jurisdictions that EnCana 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

NOTE 19. Subsequent Events

Integrated Oilsands Business

On January 2, 2007, EnCana became a 50 percent partner in an integrated, North American heavy oil business with ConocoPhillips which consists of an upstream and a downstream entity. In creating the integrated venture, EnCana contributed its Foster Creek and Christina Lake oilsands properties while ConocoPhillips contributed its Wood River and Borger refineries, located in Illinois and Texas respectively. On a go forward basis, EnCana will show a separate business segment for the Integrated Oilsands business. In accordance with the Canadian generally accepted accounting principles, these entities will be accounted for using the proportionate consolidation method.

Sale of Chad Operations

On January 12, 2007, EnCana announced that it had completed the sale of its interests in Chad, properties that are considered to be in the pre-production stage, for proceeds of $203 million which will result in a gain on sale.

The Bow

On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of project assets and is entering into a 25 year lease agreement with a third party developer. EnCana expects to account for the agreement as a capital lease.

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 GAAP 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*	**2006**	2005	2004
Net Earnings Canadian GAAP		**$ 5,652**	$ 3,426	$ 3,513
Less:				
Net Earnings From Discontinued Operations Canadian GAAP		**601**	597	1,420
Net Earnings From Continuing Operations Canadian GAAP		**5,051**	2,829	2,093
Increase (Decrease) in Net Earnings From Continuing Operations Under U.S. GAAP:				
Revenues, net of royalties	*A*	**179**	(217)	345
Operating	*A, D*	**(15)**	1	(3)
Depreciation, depletion and amortization	*B, D*	**95**	55	31
Administrative	*D*	**(8)**	-	-
Interest, net	*A*	**(15)**	(16)	(41)
Stock-based compensation options	*C*	**-**	(12)	(5)
Income tax expense	*F*	**(80)**	59	(105)
Net Earnings From Continuing Operations U.S. GAAP		**5,207**	2,699	2,315
Net Earnings From Discontinued Operations U.S. GAAP		**644**	553	1,418
Net Earnings Before Change in Accounting Policy U.S. GAAP		**5,851**	3,252	3,733
Cumulative Effect of Change in Accounting Policy, net of tax	*D*	**(15)**	-	-
Net Earnings U.S. GAAP		**$ 5,836**	$ 3,252	$ 3,733
Net Earnings per Common Share Before Change in Accounting Policy U.S. GAAP				
Basic		**$ 7.14**	$ 3.75	$ 4.05
Diluted		**$ 6.99**	$ 3.66	$ 3.99
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy U.S. GAAP				
Basic		**$ 7.12**	$ 3.75	$ 4.05
Diluted		**$ 6.98**	$ 3.66	$ 3.99

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Consolidated Statement of Earnings - U.S. GAAP

For the years ended December 31	*Note*		**2006**		2005		2004
Revenues, Net of Royalties	*A*	**$**	**16,578**	$	14,356	$	10,836
Expenses							
Production and mineral taxes			**349**		453		311
Transportation and selling			**1,070**		845		722
Operating	*A, D*		**1,670**		1,437		1,102
Purchased product			**2,862**		4,159		3,092
Depreciation, depletion and amortization	*B, D*		**3,017**		2,714		2,348
Administrative	*D*		**279**		268		197
Interest, net	*A*		**411**		540		439
Accretion of asset retirement obligation			**50**		37		22
Foreign exchange (gain) loss, net			**14**		(24)		(412)
Stock-based compensation options	*C*		**-**		27		22
(Gain) on divestitures			**(323)**		-		(59)
Net Earnings Before Income Tax			**7,179**		3,900		3,052
Income tax expense	*F*		**1,972**		1,201		737
Net Earnings From Continuing Operations U.S. GAAP			**5,207**		2,699		2,315
Net Earnings From Discontinued Operations U.S. GAAP			**644**		553		1,418
Net Earnings Before Change in Accounting Policy U.S. GAAP			**5,851**		3,252		3,733
Cumulative Effect of Change in Accounting Policy, net of tax	*D*		**(15)**		-		-
Net Earnings U.S. GAAP		**$**	**5,836**	$	3,252	$	3,733
Net Earnings From Continuing Operations per Common Share - U.S. GAAP							
Basic		**$**	**6.35**	$	3.11	$	2.51
Diluted		**$**	**6.22**	$	3.04	$	2.47
Net Earnings From Discontinued Operations per Common Share - U.S. GAAP							
Basic		**$**	**0.79**	$	0.64	$	1.54
Diluted		**$**	**0.77**	$	0.62	$	1.52
Net Earnings per Common Share Before Change in Accounting Policy U.S. GAAP							
Basic		**$**	**7.14**	$	3.75	$	4.05
Diluted		**$**	**6.99**	$	3.66	$	3.99
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy U.S. GAAP							
Basic		**$**	**7.12**	$	3.75	$	4.05
Diluted		**$**	**6.98**	$	3.66	$	3.99

Consolidated Statement of Comprehensive Income - U.S. GAAP

For the years ended December 31	*Note*		**2006**		2005		2004
Net Earnings U.S. GAAP		**$**	**5,836**	$	3,252	$	3,733
Change in Fair Value of Financial Instruments	*A, G*		**4**		-		-
Foreign Currency Translation Adjustment	*E*		**(224)**		573		420
Compensation Plans - Adoption of FAS 158	*D*		**(48)**		-		-

Comprehensive Income		**$ 5,568**	$ 3,825	$ 4,153

Consolidated Statement of Accumulated Other Comprehensive Income - U.S. GAAP

For the years ended December 31	*Note*	**2006**	2005	2004
Balance, Beginning of Year		**$ 1,598**	$ 1,025	$ 605
Change in Fair Value of Financial Instruments	*A, G*	**4**	-	-
Foreign Currency Translation Adjustment	*E*	**(224)**	573	420
Compensation Plans - Adoption of FAS 158	*D*	**(48)**	-	-
Balance, End of Year		**$ 1,330**	$ 1,598	$ 1,025

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Consolidated Statement of Retained Earnings - U.S. GAAP

For the years ended December 31	**2006**	2005	2004
Retained Earnings, Beginning of Year	**$ 9,327**	$ 7,955	$ 5,076
Net Earnings	**5,836**	3,252	3,733
Dividends on Common Shares	**(304)**	(238)	(183)
Charges for Normal Course Issuer Bid	**(3,485)**	(1,642)	(671)
Retained Earnings, End of Year	**$ 11,374**	$ 9,327	$ 7,955

Condensed Consolidated Balance Sheet

As at December 31		**2006**		2005	
	Note	**As Reported**	**U.S GAAP**	As Reported	U.S. GAAP
Assets					
Current Assets	D	**$ 3,702**	**$ 3,703**	$ 3,604	$ 3,603
Property, Plant and Equipment (includes unproved properties of $2,668 and $2,807 as of December 31, 2006 and 2005, respectively)	B, D	**45,577**	**45,496**	39,339	39,224
Accumulated Depreciation, Depletion and Amortization		**(17,364)**	**(17,197)**	(14,458)	(14,383)
Property, Plant and Equipment, net (Full Cost Method for Oil and Gas Activities)		**28,213**	**28,299**	24,881	24,841
Investments and Other Assets	*D*	**533**	**488**	496	491
Risk Management		**133**	**133**	530	530
Assets of Discontinued Operations		**-**	**-**	2,113	2,113
Goodwill		**2,525**	**2,525**	2,524	2,524
		$ 35,106	**$ 35,148**	$ 34,148	$ 34,102
Liabilities and Shareholders Equity					
Current Liabilities	*A, D*	**$ 3,691**	**$ 3,742**	$ 4,871	$ 4,821
Long-Term Debt		**6,577**	**6,577**	6,703	6,703
Other Liabilities	*A, D*	**79**	**106**	93	22
Risk Management		**2**	**2**	102	102
Asset Retirement Obligation		**1,051**	**1,051**	816	816
Liabilities of Discontinued Operations		**-**	**-**	267	267
Future Income Taxes	*F*	**6,240**	**6,189**	5,289	5,153
		17,640	**17,667**	18,141	17,884
Share Capital	*C*				
Common Shares, no par value		**4,587**	**4,617**	5,131	5,160
Outstanding: 2006 777.9 million shares					
2005 854.9 million shares					
Paid in Surplus		**160**	**160**	133	133
Retained Earnings		**11,344**	**11,374**	9,481	9,327
Foreign Currency Translation Adjustment	*E*	**1,375**	**-**	1,262	-

Accumulated Other Comprehensive Income		**-**		**1,330**		-		1,598
		17,466		**17,481**		16,007		16,218
	$	**35,106**	**$**	**35,148**	$	34,148	$	34,102

The following table summarizes the assets and liabilities of discontinued operations included in current assets and current liabilities:

As at December 31		**2006**				2005		
		As Reported		**U.S GAAP**		As Reported		U.S. GAAP
Assets of Discontinued Operations	**$**	**-**	**$**	**-**	$	1,050	$	1,050
Liabilities of Discontinued Operations		**-**		**-**		438		438

44

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Condensed Consolidated Statement of Cash Flows U.S. GAAP

For the years ended December 31	**2006**	2005	2004
Operating Activities			
Net earnings from continuing operations	**$ 5,207**	$ 2,699	$ 2,315
Depreciation, depletion and amortization	**3,017**	2,714	2,348
Future income taxes	**1,030**	(4)	178
Unrealized (gain) loss on risk management	**(2,229)**	668	(116)
Unrealized foreign exchange (gain) loss	**76**	(50)	(285)
Accretion of asset retirement obligation	**50**	37	22
(Gain) on divestitures	**(323)**	-	(59)
Other	**166**	174	99
Cash flow from discontinued operations	**118**	464	478
Net change in other assets and liabilities	**138**	(281)	(176)
Net change in non-cash working capital from continuing operations	**3,343**	497	1,565
Net change in non-cash working capital from discontinued operations	**(2,669)**	(187)	(1,778)
Cash From Operating Activities	**$ 7,924**	$ 6,731	$ 4,591
Cash (Used in) Investing Activities	**$ (3,333)**	$ (3,942)	$ (4,259)
Cash (Used in) From Financing Activities	**$ (4,294)**	$ (3,275)	$ 163

Notes:

A) Derivative Instruments and Hedging

On January 1, 2004, the Company implemented under Canadian GAAP, EIC 128 *Accounting For Trading, Speculative or Non-Hedging Derivative Financial Instruments* which requires derivatives not designated as hedges to be recorded in 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. Under the transitional rules any gain or loss at the implementation date is deferred and recognized into revenue once realized. Currently, Management has not designated any of the financial instruments as hedges.

The adoption of EIC 128 at January 1, 2004 resulted in the recognition of a $235 million deferred loss which will be recognized into earnings when realized. As at December 31, 2006, under Canadian GAAP, a $16 million deferred gain remains.

For U.S. GAAP, the Company adopted Statement of Financial Accounting Standards (SFAS) 133 effective January 1, 2001. SFAS 133 requires that all derivatives be recorded in 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 SFAS 133.

Unrealized gain (loss) on derivatives relate to:

For the years ended December 31		**2006**		2005		2004
Commodity Prices (Revenues, net of royalties)	**$**	**2,327**	$	(703)	$	76
Interest and Currency Swaps (Interest, net)		**(11)**		(9)		(29)
Total Unrealized Gain (Loss)	**$**	**2,316**	$	(712)	$	47
Amounts Allocated to Continuing Operations	**$**	**2,229**	$	(668)	$	116
Amounts Allocated to Discontinued Operations		**87**		(44)		(69)
	$	**2,316**	$	(712)	$	47

As at December 31, 2006, it is estimated that over the following 12 months, $0.07 million ($0.05 million, net of tax) will be reclassified into net earnings from other comprehensive income.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

B) Full Cost Accounting

The full cost method of accounting for crude oil and natural gas operations under Canadian GAAP and U.S. GAAP differ in the following respects. 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 percent, 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. Depletion charges under U.S. GAAP are calculated by reference to proved reserves estimated using constant prices. Under Canadian GAAP, a similar ceiling test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize forecast pricing to determine whether impairment exists. Any impairment amount is measured using the fair value of proved and probable reserves. Depletion charges under Canadian GAAP are calculated by reference to proved reserves estimated using estimated future prices and costs.

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.

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 financial statements, which would be the same adjustment under U.S. GAAP, see Note 14.

Under Financial Accounting Standards Board (FASB) Interpretation (FIN) 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 of Canadian Pacific Limited (CPL), an equity restructuring occurred which resulted in CPL stock options being replaced with stock options granted by EnCana, as described in Note 14. 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) Compensation Plans

Pensions and Other Post-Employment Benefits

For the year ended December 31, 2006, the Company adopted, for U.S. GAAP purposes, SFAS 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)*. SFAS 158 requires EnCana to recognize the over-funded or under-funded status of defined benefit and post-employment plans on the balance sheet as an asset or liability and to recognize changes in the funded status through other comprehensive income. Canadian GAAP currently does not require the Company to recognize the funded status of these plans on its balance sheet.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

Tandem Share Appreciation Rights and Deferred Share Units

Under Canadian GAAP, obligations for liability-based stock compensation plans are recorded using the intrinsic-value method of accounting. For U.S. GAAP purposes, the Company adopted SFAS 123(R) *Share-Based Payment* for the year ended December 31, 2006 using the modified-prospective approach. Under SFAS 123(R), the intrinsic-method of accounting for liability-based stock compensation plans is no longer an alternative. Liability-based stock compensation plans, including tandem share appreciation rights and deferred share units, are now required to be re-measured at fair value at each reporting period up until the settlement date.

To the extent compensation cost relates to employees directly involved in natural gas and crude oil exploration and development activities, such amounts are capitalized to property, plant and equipment. Amounts not capitalized are recognized as administrative expenses or operating expenses. As the Company adopted SFAS 123(R) using the modified prospective approach, prior periods have not been restated, as required by the standard.

SFAS 123(R), under the modified prospective approach, requires the cumulative impact of a change in an accounting policy to be presented in the current year Consolidated Statement of Earnings. The cumulative effect, net of tax, of initially adopting SFAS 123(R) January 1, 2006 was a loss of $15 million.

E) 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.

F) 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		**2006**		2005		2004
Net Earnings Before Income Tax U.S. GAAP	**$**	**7,179**	$	3,900	$	3,052
Canadian Statutory Rate		**34.7%**		37.9%		39.1%
Expected Income Tax		**2,491**		1,478		1,193
Effect on Taxes Resulting from:						
Non-deductible Canadian Crown payments		**97**		207		192
Canadian resource allowance		**(16)**		(202)		(256)
Statutory and other rate differences		**(98)**		(235)		(50)
Effect of tax rate reductions		**(457)**		-		(109)
Non-taxable capital gains		**(1)**		(24)		(91)
Previously unrecognized capital losses		**-**		-		17
Tax basis retained on divestitures		**-**		(68)		(169)
Large corporations tax		**-**		25		24
Other		**(44)**		20		(14)
Income Tax U.S. GAAP	**$**	**1,972**	$	1,201	$	737
Effective Tax Rate		**27.5%**		30.7%		24.1%

47

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

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The net future income tax liability is comprised of:

As at December 31	**2006**	2005
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	**$ 4,632**	$ 4,407
Timing of partnership items	**1,251**	1,226
Other	**317**	-
Future Tax Assets		
Net operating losses carried forward	**(11)**	(47)
Other	**-**	(433)
Net Future Income Tax Liability	**$ 6,189**	$ 5,153

G) 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 SFAS 133. At December 31, 2006, accumulated other comprehensive income related to these items was a loss of $2.1 million, net of tax.

H) Consolidated Statement of Cash Flows

Certain items presented as investing or financing activities under Canadian GAAP are required to be presented as operating activities under U.S. GAAP.

I) Dividends Declared on Common Stock

For the years ended December 31	**2006**	2005	2004
Dividends per share	**$** 0.39	$ 0.28	$ 0.20

J) Recent Accounting Pronouncements

As of January 1, 2006, the Company adopted, for U.S. GAAP purposes, SFAS 154 *Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and SFAS 3*. SFAS 154 requires retrospective application of voluntary changes in accounting principles, unless it is impracticable. This standard has not had a material impact on the Company s Consolidated Financial Statements.

As of January 1, 2006, the Company adopted EITF 04-13 *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. This change was adopted for Canadian and U.S. GAAP purposes. This change has no effect on the net earnings of the reported periods. Refer to Note 2 for further information.

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Company:

As of January 1, 2007, EnCana will be required to adopt, for U.S. GAAP purposes, FASB Interpretation No. 48 *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109*. This Interpretation clarifies financial statement recognition and disclosure requirements for uncertain tax positions taken or expected to be taken in a tax return. Guidance is also provided on the derecognition of previously recognized tax benefits and the classification of tax liabilities on the balance sheet. The Company is assessing the impact this Interpretation will have on our Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PREPARED USING CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

ALL AMOUNTS IN US$ MILLIONS, UNLESS OTHERWISE INDICATED

As of January 1, 2008, EnCana will be required to adopt, for U.S. GAAP purposes, SFAS 157 *Fair Value Measurements*. SFAS 157 provides a common definition of fair value, establishes a framework for measuring fair value under U.S. GAAP and expands disclosures about fair value measurements. This Statement applies when other accounting pronouncements require fair value measurements and does not require new fair value measurements. The Company is assessing the impact this Statement will have on our Consolidated Financial Statements.

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, 2006, 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 management with the participation of the 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 (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and (ii) accumulated and communicated to the registrant s management, including its principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

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) Management s Annual Report on Internal Control Over Financial Reporting. The required disclosure is included in the Management Report that accompanies the registrant s Consolidated Financial Statements for the fiscal year ended December 31, 2006, filed as part of this Annual Report on Form 40-F.

(d) Attestation Report of the Registered Public Accounting Firm. The required disclosure is included in the Auditors Report that accompanies the registrant s Consolidated Financial Statements for the fiscal year ended December 31, 2006, filed as part of this Annual Report on Form 40-F.

(e) Changes in Internal Control Over Financial Reporting. During the fiscal year ended December 31, 2006, 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.

40-F2

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), and is independent as that term is defined in the rules of the New York Stock Exchange.

Code of Ethics.

The registrant has adopted a code of ethics (as that term is defined in Form 40-F), entitled the Business Conduct & 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.

The Code of Ethics is available for viewing on the registrant s website at www.encana.com, and is available in print to any shareholder who requests it. Requests for copies of the Code of Ethics should be made by contacting: Kerry D. Dyte, Vice-President, General Counsel & Corporate Secretary, EnCana Corporation, 1800, 855-2nd Street S.W., P.O. Box 2850, Calgary, Alberta, Canada T2P 2S5. Alternatively, requests for a copy of the Code of Ethics may be made by contacting the registrant s Corporate Secretarial Department at (403) 645-2000 (Fax: (403) 645-4617).

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 required disclosure is included under the heading Audit Committee Information External Auditor Service Fees in the registrant s Annual Information Form for the fiscal year ended December 31, 2006, filed as part of this Annual Report on Form 40-F.

Pre-Approval Policies and Procedures.

The required disclosure is included under the heading Audit Committee Information Pre-Approval Policies and Procedures in the registrant s Annual Information Form for the fiscal year ended December 31, 2006, filed as part of this Annual Report on Form 40-F.

Off-Balance Sheet Arrangements.

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

Tabular Disclosure of Contractual Obligations.

The required disclosure is included under the heading Contractual Obligations and Contingencies in the registrant s Management s Discussion and Analysis for the fiscal year ended December 31, 2006, filed as part of this Annual Report on Form 40-F.

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, 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, Vice-President, General Counsel & Corporate Secretary, EnCana Corporation, 1800, 855 - 2nd Street S.W., P.O. Box 2850, 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 2007 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, Vice-President, General Counsel & 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 Secretarial 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 registrant 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 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 February 23, 2007.

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

40-F6

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	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350
99.4	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350
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 DeGolyer and MacNaughton
99.9	Consent of GLJ Petroleum Consultants Ltd.

QuickLinks