ENCANA CORP
Form 40-F
February 20, 2009

U.S. SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(Check One)
o Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934

or

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

For the fiscal year ended **December 31, 2008**

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:

ý Annual Information Form ý 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: 750,906,824

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

Yes o No ý

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 ý No o

The Annual Report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, each of the registrant's Registration Statements under the Securities Act of 1933: Form F-3 (File No. 333-150453), Form S-8 (File Nos. 333-124218, 333-13956 and 333-140856) and Form F-9 (File No. 333-149370).

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, 2008;

(b) Management's Discussion and Analysis for the fiscal year ended December 31, 2008; and

(c) Consolidated Financial Statements for the fiscal year ended December 31, 2008 *(Note 23 to the Consolidated Financial Statements relates to United States Accounting Principles and Reporting (U.S. GAAP)).*

ANNUAL INFORMATION FORM

February 20, 2009

ENCANA CORPORATION

ANNUAL INFORMATION FORM

This is the annual information form of EnCana Corporation ("EnCana" or the "Corporation") for the year ended December 31, 2008. 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 "US$" are to U.S. dollars and all references to "C$" are to Canadian dollars. All production and reserves information is presented on an after royalties basis consistent with U.S. reporting protocol.

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.

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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: the proposed arrangement transaction and expected future attributes of EnCana and Cenovus Energy Inc. following such transaction, bitumen strategy and the benefits of this strategy, drilling and development plans and the timing and location thereof, production capacity and levels and the timing of achieving such capacity and levels, the anticipated date of production for the Deep Panuke natural gas project, 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 refinery and the capital expenditures for such expansions, anticipated capacity for expansion of the Steeprock natural gas plant, reserves estimates, the level of expenditures for compliance with environmental regulations, including estimates of potential costs of carbon, site restoration costs including abandonment and reclamation costs, pending litigation, exploration plans, acquisition and divestiture 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 assumptions, 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: risks associated with the ability to obtain any necessary approvals, waivers, consents, court orders and other requirements necessary or desirable to permit or facilitate the proposed arrangement transaction (including regulatory and shareholder approvals), the risk that any applicable condition of the proposed arrangement transaction may not be satisfied, volatility of and assumptions regarding oil and natural gas prices as well as refined product 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 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, and the application thereof to the business of EnCana and Cenovus Energy Inc. after the proposed arrangement transaction, 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 royalty, tax, environmental and other laws or regulations or the interpretations of such laws or 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 assumptions, risks and uncertainties described from time to time in EnCana's reports and filings with the Canadian securities authorities and the U.S. 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. Forward-looking statements respecting the proposed arrangement transaction are based upon the assumption that financial and other markets will stabilize. Assumptions relating to forward-looking statements generally include EnCana's current expectations and projections made by the Corporation in light of, and generally consistent with, its historical experience and its perception of historical trends, as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this document.

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. 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. This facilitates comparability of oil and gas disclosure with that provided by the U.S. and other international issuers, given that EnCana is active in the U.S. capital markets. 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 current 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 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 U.S. 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").

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, 2008. 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, 2008.

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
FCCL Oil Sands Partnership	50	Alberta
EnCana Downstream Holdings ULC	100	Alberta
EnCana US Refinery Holdings	100	Delaware
WRB Refining LLC	50	Delaware
EnCana US Refineries, LLC	100	Delaware
EnCana USA Investment Holdings	100	Delaware

Note:

(1) Includes indirect ownership.

The above table does not include all of the subsidiaries and partnerships of EnCana. The assets and revenues of unnamed subsidiaries and partnerships in the aggregate did not exceed 20 percent of the total consolidated assets or total consolidated revenues of EnCana as at and for the year ended December 31, 2008.

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 bitumen. EnCana's other operations include the transportation and marketing of crude oil, natural gas and NGLs, 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 U.S. All of EnCana's proved reserves and production come from North America.

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.

In January of 2007, EnCana, with ConocoPhillips, completed the creation of an integrated oil business. This venture provides greater certainty of execution for EnCana's in-situ projects and allows EnCana to participate in the North American refining industry.

EnCana is organized into Operating Divisions and Corporate Groups. The Operating Divisions are:

- Canadian Plains Division, which includes natural gas production assets in southern Alberta and southern Saskatchewan as well as crude oil development and production assets in Alberta and Saskatchewan. Three key resource plays are located in the Division: (i) Shallow Gas in southeast Alberta and Saskatchewan; (ii) Pelican Lake in northeast Alberta; and (iii) Weyburn in Saskatchewan;

- Canadian Foothills Division, which includes natural gas development and production assets located in Alberta and British Columbia and the management of the Deep Panuke natural gas project offshore Nova Scotia. Four key resource plays are located in the Division: (i) Greater Sierra in northeast British Columbia; (ii) Cutbank Ridge on the Alberta and British Columbia border; (iii) Bighorn in west central Alberta; and (iv) Coalbed Methane ("CBM") in Alberta;

- USA Division, which includes the natural gas development and production assets located in the U.S. Four key resource plays are located in the Division: (i) Jonah in southwest Wyoming; (ii) Piceance in northwest Colorado; (iii) East Texas; and (iv) Fort Worth; and

- Integrated Oil Division, which includes all of the Canadian upstream and U.S. downstream assets within the integrated oil business with ConocoPhillips, as well as other bitumen interests and the Athabasca natural gas assets. Two key crude oil resource plays are located in the Integrated Oil Division: (i) Foster Creek; and (ii) Christina Lake.

For 2008 financial reporting purposes, EnCana's reportable segments are: (i) Canada; (ii) USA; (iii) Downstream Refining; (iv) Market Optimization; and (v) Corporate and Other. The Canada reportable segment comprises the Canadian Plains Division, the Canadian Foothills Division and the Canadian upstream operations of the Integrated Oil Division. Market Optimization activities are managed by EnCana's Business Development, Canadian Gas Marketing and Power Corporate Group and by divisional marketing groups. Market Optimization is focused on enhancing the netback price of the Corporation's proprietary production. Market Optimization activities include third party purchases and sales of product to provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

On May 11, 2008, EnCana announced its plans to split into two independent energy companies one a North American natural gas company and the other a fully integrated oil company with in-situ oil properties and refineries supplemented by reliable production from various natural gas and crude oil resource plays.

The proposed corporate reorganization (the "Arrangement") would be implemented through a court approved Plan of Arrangement and is subject to shareholder approval. The Arrangement would result in two publicly traded entities with the names of Cenovus Energy Inc. ("Cenovus") (prior working name "IOCo") and EnCana Corporation (prior working name "GasCo"). Each EnCana shareholder would receive one share of

each entity in exchange for each EnCana Common Share held. On October 15, 2008, EnCana announced that the proposed Arrangement would be delayed until financial markets regain stability.

EnCana's operating divisions, post-Arrangement, would include Canadian Foothills and USA. Cenovus' operating divisions, post-Arrangement, would include Canadian Plains and Integrated Oil.

The following describes the significant events in the development of EnCana's business over the last three years. In this section, all divestiture proceeds are provided on a before-tax basis unless otherwise noted.

2008 Projects:

In the third quarter of 2008, the Wood River refinery received regulatory approvals to start construction on the Coker and Refinery Expansion ("CORE") project. EnCana's 50 percent share of the CORE project is expected to cost approximately $1.8 billion and is anticipated to be completed and in full operation by 2011. The expansion is expected to increase crude oil refining capacity by 50,000 barrels per day to approximately 356,000 barrels per day (on a 100 percent basis) and is expected to more than double heavy crude oil refining capacity to approximately 240,000 barrels per day.

2008 Acquisitions:

In 2008, EnCana acquired, in several transactions, certain land and mineral interests in the Haynesville Shale in Louisiana and Texas for approximately $1,010 million, net to EnCana. These acquisitions increased EnCana's land position to approximately 435,000 net acres, including approximately 63,000 net mineral acres. Of these transactions, the most significant was the purchase made on July 23, 2008, when EnCana acquired certain land and mineral interests in Louisiana for approximately $457 million before closing adjustments. On November 12, 2008, an unrelated party exercised an option to purchase certain interests as part of the above acquisition for approximately $157 million which reduced EnCana's total share of the purchase price to approximately $300 million.

2008 Divestitures:

In 2008, EnCana completed the divestiture of mature, non-core conventional oil and natural gas assets for proceeds of approximately $39 million in the Canadian Plains Division, $400 million in the Canadian Foothills Division and $251 million in the USA Division.

In September 2008, EnCana completed the sale of all its remaining interests in Brazil for net proceeds of approximately $164 million, before closing adjustments, resulting in an after-tax gain on sale of approximately $99 million. EnCana's Brazil interests included ten offshore exploration blocks.

In 2008, EnCana completed the sale of all of its interests in France and withdrew from Qatar.

2007 Projects:

In November 2005, EnCana announced plans to examine a number of proposals from other companies which were interested in participating in the development of EnCana's bitumen assets. In October 2006, EnCana announced it had entered into agreements with ConocoPhillips to create equally owned integrated oil business consisting of upstream and downstream assets. The integrated oil business provides greater certainty of execution for EnCana's in-situ bitumen projects and allows EnCana to participate in the North American refining industry.

The creation of this business was completed on January 3, 2007. It comprises 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.

In October 2007, EnCana's Board of Directors authorized funding for the development of the Deep Panuke natural gas project. The Deep Panuke natural gas project involves the installation of the facilities required to produce natural gas from the Deep Panuke field, located approximately 175 kilometres offshore Nova

Scotia. Produced gas is expected to be transported to shore by subsea pipeline and EnCana expects to transport this natural gas via the Maritimes & Northeast Pipeline to a delivery point in eastern Canada.

2007 Acquisitions:

In November 2007, a subsidiary of EnCana acquired all of the Deep Bossier natural gas and land interests of the privately-owned Leor Energy group in Texas for approximately $2.55 billion before closing adjustments. EnCana first entered the Deep Bossier play in 2005 by acquiring a 30 percent interest in the Amoruso field from Leor Energy, and then increased its interest to 50 percent in June 2006. The November 2007 transaction brought EnCana's interest in the Amoruso field to 100 percent and added an additional 75 million cubic feet per day of natural gas production in 2007.

2007 Divestitures:

In January 2007, a subsidiary of EnCana completed the sale of all of its interests in its Chad exploration assets for approximately $208 million. The Chad assets included a 50 percent working interest in approximately 54 million gross acres in seven sedimentary basins.

In February 2007, EnCana completed the sale of The Bow office project assets for approximately $57 million. As part of the transaction, EnCana, as tenant, has signed a 25-year tenant lease agreement for 100 percent of the office space.

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 in 2006.

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 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 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.

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

NARRATIVE DESCRIPTION OF THE BUSINESS

The following map outlines EnCana's onshore North America landholdings and key resource plays as of December 31, 2008. The map also identifies the Borger and Wood River refineries.

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The vast majority of EnCana's operations are located in Canada and the U.S. All of EnCana's proved reserves and production come from North America.

At December 31, 2008, EnCana had net proved reserves of approximately 13.7 trillion cubic feet of natural gas and 1.0 billion barrels of crude oil, bitumen and NGLs, as estimated by independent qualified reserves evaluators. Proved developed reserves comprise approximately 63 percent of total natural gas reserves, approximately 72 percent of crude oil and NGLs reserves excluding bitumen and approximately 19 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 21.0 million gross acres (18.3 million net acres, of which approximately 9.3 million net acres are undeveloped). The mineral rights on approximately 41 percent of the total net acreage are 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 2008, EnCana had capital investment in western Canada of approximately $3,737 million and drilled approximately 2,578 net wells.

In the U.S., EnCana's landholdings are approximately 5.4 million gross acres (4.4 million net acres, of which approximately 3.9 million net acres are undeveloped), with the majority in Texas, Colorado, Wyoming and Louisiana. In 2008, EnCana had capital investment of approximately $2,615 million, not including refineries, and drilled approximately 750 net wells within the USA Division.

The following narrative describes EnCana's operations in greater detail.

Canadian Plains Division

The Canadian Plains Division encompasses legacy natural gas production activities in southern Alberta and southern Saskatchewan as well as crude oil development and production activities in Alberta and Saskatchewan. Three key resource plays are located in the Canadian Plains Division: (i) Shallow Gas; (ii) Pelican Lake; and (iii) Weyburn. The Shallow Gas key resource play is contained within the Suffield, Brooks North and Langevin areas.

In 2008, the Canadian Plains Division had capital investment of approximately $847 million and drilled approximately 1,476 net wells. Plans for 2009 include continued infill drilling, well recompletions and well optimizations as well as enhanced oil recovery initiatives and investment in facility infrastructure necessary for continued progression of development plans.

As at December 31, 2008, the Canadian Plains Division had an established land position of approximately 6.9 million gross acres (6.5 million net acres). Approximately 2.6 million gross acres (2.5 million net acres) are undeveloped. The mineral rights on approximately 48 percent of the total net acreage are owned in fee title by EnCana.

The following table summarizes landholdings for the Canadian Plains Division as at December 31, 2008.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Suffield	924	910	70	69	994	979	98%
Brooks North	560	558	9	9	569	567	100%
Langevin	1,215	1,096	853	773	2,068	1,869	90%
Drumheller	363	351	16	13	379	364	96%
Pelican Lake	133	133	280	266	413	399	97%
Weyburn	95	83	393	386	488	469	96%
Other	973	909	1,013	934	1,986	1,843	93%
Canadian Plains Total	4,263	4,040	2,634	2,450	6,897	6,490	94%

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

Production (annual average)	Natural Gas (MMcf/d) 2008	2007	Crude Oil and NGLs (bbls/d) 2008	2007	Total Production (MMcfe/d) 2008	2007
Suffield	231	245	12,971	15,563	309	338
Brooks North	273	271	838	742	278	275
Langevin	203	219	9,111	9,542	258	277
Drumheller	93	97	2,276	2,190	107	110
Pelican Lake	1	1	21,975	23,253	132	141
Weyburn			14,056	14,774	84	89
Other	41	42	6,111	6,136	78	78
Canadian Plains Total	842	875	67,338	72,200	1,246	1,308

Note:

(1) The Shallow Gas key resource play, contained within the Suffield, Brooks North and Langevin areas, had 2008 average production of approximately 700 million cubic feet per day (726 million cubic feet per day in 2007). Shallow Gas volumes and net wells drilled are reported with commingled volumes from multiple zones within the same geographic area as a result of regulatory approval which was received in late 2006.

The following table summarizes EnCana's interests in producing wells in the Canadian Plains Division as at December 31, 2008. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2008.

Producing Wells (number of wells)	Producing Gas Wells Gross	Net	Producing Oil Wells Gross	Net	Total Producing Wells Gross	Net
Suffield	9,989	9,971	725	725	10,714	10,696
Brooks North	7,123	7,018	53	53	7,176	7,071
Langevin	6,791	6,216	244	238	7,035	6,454
Drumheller	1,547	1,487	97	94	1,644	1,581
Pelican Lake	7	7	453	453	460	460
Weyburn			773	485	773	485
Other	1,177	1,153	660	622	1,837	1,775
Canadian Plains Total	26,634	25,852	3,005	2,670	29,639	28,522

Note:

(1) At December 31, 2008, the Shallow Gas key resource play had approximately 23,903 gross producing gas wells (23,205 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 in cooperation with the Canadian military according to guidelines established under agreements presently entered into with the Government of Canada. On October 6, 2008, an ERCB joint panel hearing as part of the *Canadian Environmental Assessment Act* was commenced in connection with EnCana's ongoing application to continue shallow gas infill drilling in the National Wildlife Area. The hearing was completed in late October. On January 27, 2009, the joint panel released a report in respect of its findings. In its report, the joint panel concluded that this project could proceed provided two key pre-conditions were met. The first is that critical habitat assessments for certain specific species of plants and animals be finalized. The second is that the role of the Suffield Environmental Advisory Committee be clarified, and that this Committee be resourced adequately to provide proper regulatory oversight of the project. EnCana will now work with necessary interested parties to proceed to the next stage of this project.

In 2008, approximately 516 net wells were drilled in the Suffield area and production averaged approximately 231 million cubic feet per day of natural gas and approximately 12,971 barrels per day of crude oil.

Brooks North

EnCana produces natural gas, crude oil and NGLs from the Cretaceous horizons and has begun development of the coals of the Cretaceous Belly River formation in the Brooks North area of southern Alberta. This area is another core area of the Shallow Gas key resource play and is largely composed of fee title lands. Development in the area focuses on infill drilling, recompletions and optimization of existing wells. In 2008, approximately 481 net wells were drilled in the area and production averaged approximately 273 million cubic feet per day of natural gas.

Langevin

EnCana produces shallow gas predominantly from the Upper Cretaceous formations in the Langevin area of southeast Alberta and southwest Saskatchewan and has begun development of the coals of the Cretaceous Belly River formation. Natural gas production in this area is from a mix of fee title and Crown lands and is included in the Shallow Gas key resource play. Crude oil production in the area is predominantly from fee title lands located in southern Alberta. Development of this area focuses on infill drilling, recompletions and optimization of existing wells. In 2008, approximately 271 net wells were drilled in the area and production averaged approximately 203 million cubic feet per day of natural gas and approximately 9,111 barrels per day of crude oil.

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 natural gas play, and is largely composed of fee title lands. In 2008, approximately 174 net wells were drilled in the area and production averaged approximately 93 million cubic feet per day of natural gas.

Pelican Lake

Pelican Lake is one of EnCana's key resource plays producing heavy crude oil from the Cretaceous Wabiskaw formation in northeast Alberta. Facility infrastructure expansion in this area was continued in 2008 to accommodate higher total fluid production volumes associated with its waterflood and polymer projects. The polymer flood program was expanded by 35 injection wells during 2008.

In addition to the heavy crude oil in the Wabiskaw formation, large deposits of bitumen have been identified in the Cretaceous Grand Rapids and the Devonian Grosmont formations in the Pelican Lake area which EnCana continues to evaluate.

EnCana 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.

In August 2008, EnCana entered into an agreement with Pembina Pipeline Corporation ("Pembina") to transport blended heavy oil from Utikuma, Alberta to Edmonton, Alberta via Pembina's pipeline with 100,000 barrels per day capacity. This pipeline will be used to transport heavy oil from EnCana's Pelican Lake property to crude oil markets. The parties also agreed to transport condensate, used as diluent for transporting heavy oil, from Whitecourt, Alberta to Utikuma, Alberta via a 22,000 barrel per day capacity pipeline. The initial term of the agreement is ten years from the in-service date, which is estimated to be in mid-2011.

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 is increasing ultimate recovery in the enhanced oil recovery area of the field with a carbon dioxide ("CO_2") miscible flood project. Weyburn is currently recognized as the world's largest CO_2 sequestration project. The CO_2 is pipelined directly to the Weyburn facility from a coal gasification project in North Dakota. The 2008 development program included an infill drilling program which resulted in 34 new gross wells in the unit, the addition of eight new CO_2 injection patterns and facilities related to pattern development. As at December 31, 2008, there were 46 patterns completed, with an additional eight awaiting CO_2 injection out of a current planned total of 75 patterns. In 2009, EnCana plans to focus on flood development with the roll out of additional CO_2 patterns along with CO_2 injector conversions, and waterflood pattern realignments.

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) CBM. The CBM key resource play (Horseshoe Canyon CBM and commingled shallow gas) is located within the Clearwater business unit. In addition, EnCana has established a leading land position in the emerging Horn River Devonian shale, located adjacent to the Greater Sierra key resource play. In late 2008, the management of the offshore Deep Panuke natural gas project in Atlantic Canada was transferred to the Canadian Foothills Division.

In 2008, the Canadian Foothills Division had capital investment in western Canada of approximately $2,234 million and drilled approximately 1,064 net wells.

As at December 31, 2008, the Canadian Foothills Division had an established land position in western Canada of approximately 12.1 million gross acres (10.2 million net acres); of these, approximately 6.8 million gross acres (5.8 million net acres) are undeveloped. The mineral rights on approximately 43 percent of the total net acreage are owned in fee title by EnCana.

The following table summarizes landholdings for the Canadian Foothills Division as at December 31, 2008.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Greater Sierra	641	599	1,718	1,428	2,359	2,027	86%
Cutbank Ridge	341	264	957	860	1,298	1,124	87%
Bighorn	304	179	509	324	813	503	62%
Clearwater	3,540	3,127	2,783	2,613	6,323	5,740	91%
Other	461	292	847	554	1,308	846	65%
Canadian Foothills Total[1]	5,287	4,461	6,814	5,779	12,101	10,240	85%

Note:

(1) Excluding offshore landholdings.

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)	
	2008	2007	2008	2007	2008	2007
Greater Sierra	220	211	1,044	852	226	216
Cutbank Ridge[1]	296	258	617	457	300	261
Bighorn[1]	167	126	3,734	2,123	189	139
Clearwater[2]	495	497	10,777	10,595	560	561
Other	122	163	3,808	4,245	145	188

	Natural Gas (MMcf/d)		Crude Oil and NGLs (bbls/d)		Total Production (MMcfe/d)	
Canadian Foothills Total	1,300	1,255	19,980	18,272	1,420	1,365

Notes:

(1) Key resource play production information for Cutbank Ridge and Bighorn has been restated to include the addition of new areas and zones that now qualify for key resource play inclusion based on EnCana's internal criteria.

(2) The CBM key resource play, located within the Clearwater area, had 2008 average production of approximately 304 million cubic feet per day (259 million cubic feet per day in 2007).

The following table summarizes EnCana's interests in producing wells as at December 31, 2008. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2008.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Greater Sierra	1,006	970	3	3	1,009	973
Cutbank Ridge(1)	693	599	16	2	709	601
Bighorn(1)	435	303	8	4	443	307
Clearwater(2)	8,976	8,188	151	109	9,127	8,297
Other	595	461	243	153	838	614
Canadian Foothills Total	11,705	10,521	421	271	12,126	10,792

Notes:

(1) Key resource play production information for Cutbank Ridge and Bighorn has been restated to include the addition of new areas and zones that now qualify for key resource play inclusion based on EnCana's internal criteria.

(2) At December 31, 2008, the CBM key resource play had approximately 5,426 gross producing gas wells (5,072 net gas wells).

The following describes the Canadian Foothills Division major producing areas or activities.

Greater Sierra

The Greater Sierra area in northeast British Columbia is one of EnCana's key natural gas resource plays. The primary focus in this area is on the continued development of the Devonian Jean Marie formation and the pilot commercial demonstration development of the Horn River Devonian Shale formation.

In 2008, EnCana drilled approximately 106 net natural gas wells in the area and production averaged approximately 220 million cubic feet per day of natural gas. Production has remained relatively constant over the past four years.

As at December 31, 2008, EnCana held an average 99 percent interest in 13 production facilities in the area that were capable of processing approximately 500 million cubic feet per day of natural gas. EnCana also held 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.

As at December 31, 2008, EnCana controlled approximately 436,000 undeveloped gross acres (260,000 net acres) in the emerging Devonian Shale formation of the Horn River Basin in northeast British Columbia. The shales in the basin (Muskwa, Otter Park and Evie) within EnCana's focus area are upwards of 500 feet thick. As at December 31, 2008, these shales were evaluated with 15 wells (five vertical and ten horizontal), nine of which have been placed on long-term production (one vertical and eight horizontal). In 2009, EnCana and its partner plan to drill a larger program of horizontal wells in the Two Island Lake area, and construct a compressor station and 24-inch raw gas transmission pipeline.

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 Montney, Cadomin, and Doig zones. The majority of EnCana's lands in this area were purchased in 2003. The Montney and Cadomin formations are almost exclusively being developed with horizontal well technology. In 2007, significant improvements were achieved with respect to horizontal well completions with the application of multi-stage hydraulic fracturing. In 2008, EnCana drilled approximately 82 net natural gas wells in the area and production averaged approximately 296 million cubic feet per day of natural gas.

EnCana holds approximately 731,000 net acres covering the unconventional deep basin Montney formation, with approximately 244,000 net acres located within EnCana's core development area near Dawson Creek,

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British Columbia. EnCana has tested the deep basin Montney play extensively over the last several years and, by applying advanced technology, has reduced overall development costs significantly, achieving a greater than 70 percent reduction in costs on a completed interval basis over the past two years.

EnCana's Steeprock plant had a capacity of approximately 70 million cubic feet per day at year-end 2007. An expansion was completed in July 2008 to bring total processing capacity to approximately 175 million cubic feet per day.

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. The primary producing properties in Bighorn are Resthaven, Kakwa, Wild River, Berland and Aurora. In 2008, EnCana drilled approximately 64 net wells in the area and production averaged approximately 167 million cubic feet per day of sweet natural gas.

EnCana has a working interest in a number of natural gas plants within Bighorn. The Resthaven plant, in which EnCana has a 60.8 percent working interest, has a capacity of approximately 100 million cubic feet per day. The Kakwa gas plant has a capacity of approximately 60 million cubic feet per day. EnCana owns 75 percent of this plant and has firm processing capacity for the remaining 25 percent. The Wild River plant, in which EnCana holds a 70 percent working interest, has a capacity of approximately 30 million cubic feet per day and the Berland River plant, in which EnCana holds a 24 percent working interest, has a capacity of approximately 40 million cubic feet per day.

Clearwater

The Clearwater area extends from the U.S. border to central Alberta. The primary focus of Clearwater is the CBM key natural gas resource play; however, Clearwater is also responsible for the development of the Mannville CBM fairway, and deeper Cretaceous reservoirs. Within Clearwater, EnCana holds approximately 5.7 million net acres with approximately 2.1 million net acres on the Horseshoe Canyon trend. Approximately 77 percent of the total net acreage landholdings are owned in fee title. In 2008, EnCana drilled approximately 698 net CBM wells and production averaged approximately 304 million cubic feet per day of natural gas from the CBM key resource play.

Atlantic Canada

As at December 31, 2008, EnCana held an interest in approximately 76,000 gross acres (31,000 net acres) in Atlantic Canada, which includes Nova Scotia, Newfoundland and Labrador. EnCana operates five of its eight licenses in these areas and has an average working interest of approximately 40 percent.

EnCana is the operator of the Deep Panuke natural gas field, located offshore Nova Scotia, and owned substantially the entire Deep Panuke field at December 31, 2008, after acquiring all of the interests in one of the licenses making up the Deep Panuke field in August 2008. EnCana is currently moving forward with the development of the Deep Panuke natural gas project. Work has been progressing on budget and on schedule in anticipation of first production in the fourth quarter of 2010.

USA Division

EnCana's operations in the U.S. are focused on exploiting long-life unconventional natural gas formations in the Jonah field in southwest Wyoming, the Piceance Basin in northwest Colorado, the East Texas and Fort Worth basins in Texas, and the Haynesville Shale in Texas and Louisiana. The majority of the production in the U.S. 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 2008, the USA Division had capital investment of approximately $2,615 million and drilled approximately 750 net wells.

As at December 31, 2008, EnCana's landholdings in the U.S. were approximately 5.4 million gross acres (4.4 million net acres), of which approximately 4.7 million gross acres (3.9 million net acres) were undeveloped, with the majority in Texas, Colorado and Wyoming.

The following table summarizes landholdings for the USA Division as at December 31, 2008.

Landholdings (thousands of acres)	**Developed Acreage**		**Undeveloped Acreage**		**Total Acreage**		**Average Working Interest**
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Jonah	12	11	145	131	157	142	90%
Piceance	261	235	784	686	1,045	921	88%
East Texas	105	73	290	263	395	336	85%
Fort Worth	55	52	81	51	136	103	76%
Haynesville	15	13	585	422	600	435	73%
Maverick Basin	106	20	264	235	370	255	69%
Delaware Basin	4	2	731	598	735	600	82%
Other	157	154	1,794	1,479	1,951	1,633	84%
USA Total	715	560	4,674	3,865	5,389	4,425	82%

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)**	
	2008	**2007**	**2008**	**2007**	**2008**	**2007**
Jonah	603	557	5,273	5,345	635	589
Piceance	385	348	2,513	2,755	400	364
East Texas	334	143	134	207	335	145
Fort Worth	142	124	500	497	145	127
Other	169	173	4,930	5,376	198	205
USA Total	1,633	1,345	13,350	14,180	1,713	1,430

The following table summarizes EnCana's interests in producing wells as at December 31, 2008. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2008.

Producing Wells (number of wells)	**Producing Gas Wells**		**Producing Oil Wells**		**Total Producing Wells**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Jonah	655	587			655	587
Piceance	2,907	2,547	3	1	2,910	2,548
East Texas	739	430	6	3	745	433
Fort Worth	711	613	21	20	732	633
Other	2,233	1,473	16	10	2,249	1,483
USA Total	7,245	5,650	46	34	7,291	5,684

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 13,000 feet. The wells are stimulated with multi-stage advanced hydraulic fracturing techniques. Historically, EnCana's operations have been conducted in the over-pressured core portion of the field. In 2008, EnCana commenced developing the adjacent normally pressured lands.

Within the over-pressured area, EnCana plans to drill the field to ten acre spacing, with higher densities in some areas. As at December 31, 2008, approximately 300 net ten acre locations remain, with approximately 255 additional net locations available. Outside the over-pressured area, EnCana owns approximately 55,000 gross acres, where 40 acre and possibly 20 acre drilling potential exists.

During 2008, EnCana drilled 151 net wells within the core area with 30 day initial production rates averaging 3.5 million to 4.5 million cubic feet per day and 24 net wells in the adjacent lands at initial rates averaging 0.8 million to 1.3 million cubic feet per day. During 2008, the Jonah field averaged approximately 603 million cubic feet per day of natural gas production.

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. EnCana's May 2004 acquisition of Tom Brown, Inc. included properties and natural gas production in the basin. In 2008, EnCana drilled approximately 328 net wells in the basin and net production of natural gas averaged approximately 385 million cubic feet per day.

In 2006 and 2007, EnCana finalized five agreements to jointly develop portions of the Piceance Basin. In 2008, EnCana finalized another two agreements to jointly develop additional portions of the Piceance Basin that encompassed approximately 28,867 net acres. For the period 2008 to 2011, it is expected that EnCana will drill approximately 336 net wells with third party funds. During 2008, EnCana drilled approximately 113 net wells with third party funds and its partners drilled approximately seven net wells.

East Texas

EnCana produces natural gas and associated NGLs in the East Texas Basin, one of EnCana's key resource plays. EnCana first entered East Texas in 2004 with the acquisition of Tom Brown, Inc. In 2005, EnCana entered the Deep Bossier play through an acquisition of a 30 percent interest in the Leor Energy group's Deep Bossier assets. Subsequently, in 2006, EnCana increased this interest to 50 percent. In November 2007, EnCana acquired the Leor Energy group's remaining interests in the Deep Bossier play as well as additional East Texas acreage. This tight gas, multi-zone play targets the Bossier and Cotton Valley zones. During 2008, EnCana drilled approximately 78 net wells in the basin and production averaged approximately 334 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, EnCana has assembled a significant land position in the Barnett Shale play in this basin. EnCana is applying both horizontal drilling and multi-stage reservoir stimulation to improve performance in this play. EnCana drilled approximately 83 net wells in the basin in 2008 and production averaged approximately 142 million cubic feet per day of natural gas.

Haynesville Shale

EnCana has established a land and resource position in the Haynesville Shale in Texas and Louisiana. EnCana acquired its first leases in 2005, drilled its first three vertical wells in 2006, and has continued to acquire land. In 2007, EnCana signed a 50/50 joint exploration agreement with an unrelated party. As at December 31, 2008, the companies had drilled eight vertical and six horizontal wells and are currently operating nine rigs in the area. EnCana and its joint venture partner are now drilling horizontal wells exclusively.

In 2008, EnCana increased its leased acreage in the Haynesville Shale play to approximately 435,000 net acres through a series of transactions totalling approximately $1,010 million. Included in this land position is approximately 63,000 net acres of mineral interests that were purchased by EnCana in July 2008 for approximately $300 million, net to EnCana.

Maverick Basin

EnCana holds approximately 264,000 undeveloped gross acres (235,000 net acres) in the Maverick Basin in southwest Texas. This acreage, acquired in September 2005, contains exploratory potential in the Pearsall Shale, plus multi-zone potential in the uphole section. In 2007, EnCana entered into a joint venture agreement to drill from three to seven wells, with an option to drill more. EnCana's partner has elected to continue the joint venture agreement and has committed to drilling four additional horizontal wells in 2009.

Delaware Basin

EnCana holds approximately 731,000 undeveloped gross acres (598,000 net acres) in the Delaware Basin of West Texas. This acreage, acquired in September 2004, contains exploratory potential in the Barnett and Woodford Shale, plus multi-zone potential in the uphole section. In 2007, EnCana entered into a joint venture agreement to drill 12 wells, with an option to drill more. As at December 31, 2008, ten exploratory wells were drilled and completed, and two wells were still being drilled as of year end.

Gulf Coast Jurassic Trend

During 2007 and 2008, EnCana acquired a land position of approximately 470,000 net acres in several projects in the Gulf Coast Jurassic Trend located in Texas, Louisiana and Mississippi.

Gathering & Processing Facilities

EnCana owns and operates various natural gas gathering and processing facilities within the U.S. The Corporation's gathering, compression and processing facilities in the Piceance Basin include over 2,500 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 approximately 794 kilometres of pipeline. 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 550 kilometres of pipelines and a refrigeration facility with a capacity of approximately 70 million cubic feet per day. During 2008, two pipelines were sold for approximately $132 million.

Integrated Oil Division

The Integrated Oil Division includes all of the assets within the integrated oil business with ConocoPhillips, as well as other bitumen interests and the Athabasca natural gas assets. For 2008 financial reporting purposes, the Integrated Oil Division's Canadian upstream assets are included in the Canada reportable segment and the U.S. downstream refining assets are included in the Downstream Refining reportable segment.

The Integrated Oil Division contains two key crude oil resource plays: (i) Foster Creek; and (ii) Christina Lake. As at December 31, 2008, EnCana held bitumen rights of approximately 1,056,000 gross acres (761,000 net acres) within the Athabasca and Cold Lake areas, as well as the exclusive rights to lease an additional 629,000 net acres on behalf of itself and/or its assignees on the Cold Lake Air Weapons Range.

In 2008, the Integrated Oil Division invested capital of approximately $1,134 million and drilled approximately 38 net wells.

The following table summarizes landholdings for the Integrated Oil Division as at December 31, 2008.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Foster Creek	24	12	48	24	72	36	50%
Christina Lake	1		24	12	25	12	50%
Athabasca	538	461	383	312	921	773	84%
Borealis			37	37	37	37	100%
Other	35	16	942	687	977	703	72%
Integrated Oil Total	598	489	1,434	1,072	2,032	1,561	77%

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)	
	2008	2007	2008	2007	2008	2007
Foster Creek			25,947	24,262	156	146
Christina Lake			4,236	2,552	25	15
Athabasca	63	91			63	91
Other			2,729	2,688	16	16
Integrated Oil Total	63	91	32,912	29,502	260	268

The following table summarizes EnCana's interests in producing wells as at December 31, 2008. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2008.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Foster Creek			114	57	114	57
Christina Lake	9	5	16	8	25	13
Athabasca	706	665			706	665
Other	2	1	20	17	22	18
Integrated Oil Total	717	671	150	82	867	753

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

Integrated Oil Business

On January 3, 2007, the creation of the integrated oil business with ConocoPhillips was completed. The integrated oil business includes Canadian upstream assets contributed by EnCana and U.S. downstream assets contributed by ConocoPhillips. The business comprises two 50/50 operating entities, one Canadian upstream entity managed by EnCana and one U.S. downstream enterprise managed by ConocoPhillips.

The upstream portion of the integrated oil business is currently conducted through the FCCL Oil Sands Partnership ("FCCL") which owns the Foster Creek and Christina Lake in-situ oil recovery projects. EnCana and ConocoPhillips each own 50 percent of FCCL. EnCana's wholly-owned subsidiary is the operating and managing partner of FCCL. The downstream portion of the integrated oil business is conducted through the 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 held a disproportionate economic interest in the Borger refinery of 85 percent in 2007 and 65 percent in 2008, before reverting to 50 percent in 2009. ConocoPhillips is the operator and manager of WRB. FCCL has a Management

Committee, while WRB has a Board of Directors; both are composed of three EnCana and three ConocoPhillips representatives, with each company holding equal voting rights. The current plan of FCCL is to increase production capacity to approximately 218,000 barrels of bitumen per day with the completion of current expansion phases at Foster Creek and Christina Lake. The current plan of WRB is to refine approximately 135,000 barrels per day of bitumen equivalent to primarily motor fuels with the completion of the CORE project in 2011. As at December 31, 2008, WRB had processing capability to refine up to approximately 70,000 barrels per day of bitumen equivalent.

Foster Creek

Through its interest in FCCL, EnCana has a 50 percent interest in Foster Creek, a key crude oil resource play. EnCana holds surface access rights from the Governments of Canada and Alberta and bitumen 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 holds exclusive rights to lease several hundred thousand acres of bitumen rights in other areas on the Cold Lake Air Weapons Range on behalf of itself and/or its assignees. An in-situ oil recovery project is currently being operated 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 production capacity of approximately 30,000 gross barrels of bitumen per day and increased production capacity at Foster Creek to approximately 60,000 gross barrels of bitumen per day. Further expansions are currently underway and are expected to increase production capacity to approximately 120,000 gross barrels of bitumen per day in 2009.

EnCana researches and develops technologies to increase recovery and decrease costs of extracting oil. One focus area is alternate methods of artificial lift where EnCana utilizes new pump designs that are expected to enable it to optimize SAGD performance by operating at lower pressures, thereby realizing lower steam-oil ratios and decreasing facility capital and operating costs. As at December 31, 2008, 83 wells were on electrical submersible pumps at Foster Creek, and EnCana expects to continue to utilize this technology on new SAGD wells. In addition, EnCana has successfully piloted another technology at Foster Creek whereby an additional production well is drilled between two producer well pairs to produce bitumen that is heated by proximity to a steam chamber, but is not recoverable by the adjacent production wells. A number of these "wedge wells" (patent pending) are on production and there are plans to complete and produce from additional wedge wells.

EnCana also focuses on reducing its reliance on natural gas for the generation of steam used in bitumen production operations. Two technologies using solvents have been piloted 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 process pilot project 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 operates an 80 megawatt natural gas-fired cogeneration facility in conjunction with the SAGD operation at Foster Creek. The steam and power generated by the facility is presently being used within the SAGD operation and the excess power generated is being sold into the Alberta Power Pool grid.

Christina Lake

Through its interest in FCCL, EnCana has a 50 percent interest in a SAGD oil recovery project at Christina Lake, a key crude oil resource play. During 2008, EnCana completed an expansion that increased production capacity to approximately 18,000 gross barrels of bitumen per day. Further expansions are currently underway and are expected to increase production to approximately 98,000 gross barrels of bitumen per day.

At Christina Lake, EnCana is focusing on a number of innovations, including a pilot SAP program that was commenced in 2004. This process mixes a small amount of solvent with steam to enhance recovery. EnCana has completed testing the SAP technology on several wells associated with the initial demonstration project and has achieved promising results. An additional SAP pilot well is planned within the 2009 to 2010 timeframe. Business cases are being evaluated for the potential use of this technology in the Christina Lake development plan.

Another innovation was undertaken in 2007, whereby a remote water disposal system was utilized to successfully manage bottom water pressures and improve the steam-oil ratio.

Borger Refinery

Through its interest in WRB, EnCana has a 50 percent interest in the Borger refinery, located in Borger, Texas. As at December 31, 2008, the Borger refinery had a processing capacity of approximately 146,000 barrels per day of crude oil and approximately 45,000 barrels per day of NGLs. It processes mainly medium, high-sulphur and heavy, high-sulphur crude oil and NGLs that it receives from North American pipeline systems to produce gasoline, diesel and jet fuel along with NGLs and solvents. The refined products are transported via pipelines to markets in Texas, New Mexico, Colorado and the Mid-Continent. In July 2007, a new coker with a capacity of approximately 25,000 barrels per day was brought into service along with a new vacuum unit and revamped gas oil and distillate hydrotreaters. This project has enabled the refinery to process heavy oil blends, particularly heavy oil blends, and comply with clean fuel regulations for ultra-low sulphur diesel and low-sulphur gasoline. The project has also enabled compliance with required reductions of sulphur dioxide emissions.

Wood River Refinery

Through its interest in WRB, EnCana has a 50 percent interest in the Wood River refinery, located in Roxana, Illinois. As at December 31, 2008, the Wood River refinery had a processing capacity of approximately 306,000 barrels per day of crude oil. It processes mainly light, low-sulphur and heavy, high-sulphur crude oil that it receives from North American crude oil pipelines to produce gasoline, diesel and jet fuel, petrochemical feedstocks and asphalt. The gasoline and diesel are transported via pipelines to markets in the upper Midwest. Other products are transported via pipeline, truck, barge and railcar to markets in the Midwest. In early 2007, the refinery completed the construction of a facility utilizing sulphur removal technology for the production of low-sulphur gasoline. In September 2008, regulatory approval was received to proceed with the CORE project at Wood River, which will increase crude oil refining capacity by approximately 50,000 barrels per day, coking capacity by approximately 65,000 barrels per day, more than double heavy crude oil refining capacity to approximately 240,000 barrels per day, increase the clean transportation fuels yield by approximately 10 percent to approximately 89 percent and will eliminate approximately 40,000 barrels per day of asphalt production. Capital expenditures for the CORE project are estimated at $3.6 billion ($1.8 billion net to EnCana) and the project is scheduled to be completed in 2011.

The following table summarizes the combined refineries' key operational results for the periods indicated.

Refinery Operations[(1)]	**2008**	**2007**
Crude Oil Capacity (Mbbls/d)	452	452
Crude Oil Runs (Mbbls/d)	423	432
Crude Utilization	93%	96%
Refined Products (Mbbls/d)		
Gasoline	230	246
Distillates	139	128
Other	79	83
Total	448	457

Note:

(1) Represents 100 percent of the Wood River and Borger refinery operations.

Athabasca

EnCana produces natural gas from the Cold Lake Air Weapons Range and several surrounding landholdings located in northeast Alberta and holds surface access and natural gas rights for exploration, development and transportation from areas within the Cold Lake Air Weapons Range that 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 2008, natural gas production was impacted by the September 2003, July 2004, September 2004 and July 2007 Energy Resource Conservation Board ("ERCB") decisions to shut-in McMurray, Wabiskaw and Clearwater natural gas production that may put at risk the recovery of bitumen resources in the area. The decisions resulted in a decrease in annualized natural gas production of approximately 26 million cubic feet per day in 2008 (20 million cubic feet per day in 2007). The Alberta Government's Department of Energy 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.

Borealis

EnCana holds a 100 percent working interest in the Borealis area, which is located approximately 90 kilometres north of Fort McMurray. Borealis is not included in the integrated oil business with ConocoPhillips. Approximately 198 delineation wells have been drilled in the greater Borealis area as at December 31, 2008. A joint application for development has been submitted to the ERCB and Alberta Environment that would allow for the construction of a SAGD facility with production capacity of approximately 35,000 barrels of bitumen per day. EnCana continues to evaluate the greater Borealis area. In 2008, seven wells were drilled to test specific reservoir properties of the McMurray formation and to test for potential water disposal zones in support of the joint application. The use of nitrogen injection to displace top water was successfully tested as part of the program.

Market Optimization

Market Optimization activities are managed by EnCana's Business Development, Canadian Gas Marketing & Power Corporate Group and by divisional marketing groups. Market Optimization is focused on enhancing the netback price of the Corporation's proprietary production. Market Optimization activities 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.

EnCana seeks to mitigate the market risk associated with forecasted cash flows by entering into various risk management contracts relating to produced products. Details of those transactions related to EnCana's various risk management positions for natural gas, crude oil and power are found in Note 20 to EnCana's audited consolidated financial statements for the year ended December 31, 2008.

Natural Gas Marketing

In 2008, approximately 94 percent of EnCana's sales of produced natural gas were directly marketed by EnCana to local distribution companies, industrials, other producers and energy marketing companies. The remaining 6 percent of sales of produced natural gas 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 seeks to mitigate the market risk associated with forecasted cash flows by entering into various risk management contracts relating to produced natural gas. For 2009, after taking into account its risk management contracts, EnCana's natural gas sales price portfolio exposure consists of approximately 2.6 billion cubic feet per day for January to October 2009 at an average fixed NYMEX equivalent price of approximately $9.13 per thousand cubic feet with the remainder unhedged.

Crude Oil Marketing

EnCana sells and manages the transportation of its western Canadian crude oil to markets in Canada and the U.S. (86,560 barrels per day in 2008 and 95,082 barrels per day in 2007). Crude oil sales are normally executed under spot, monthly evergreen and term 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. As part of a portfolio approach to its transportation and market needs, EnCana expects to increase its sales to the U.S. Gulf Coast in the future.

EnCana also has a founding position in the Western Canadian Select ("WCS") crude oil stream. Participation in WCS is important from the perspective of creating a transparent heavy oil benchmark, enhancing the liquidity of the heavy oil market and as a reference for Crown royalty determination.

In order to meet pipeline viscosity specifications, EnCana must blend certain of its heavy oil production with diluent. Security of supply is critical and EnCana has diversified sourcing of diluent since 2006 by obtaining supply both domestically and from offshore via the west coast of British Columbia.

EnCana markets blend oil on behalf of FCCL through an agency agreement (80,866 barrels per day in 2008 and 71,415 barrels per day in 2007). This agency agreement became effective on January 2, 2007.

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 operations 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 147 megawatts and its generation capacity is approximately 159 megawatts, excluding both the electricity requirements and generation capacity of the Integrated Oil Division.

RESERVES AND OTHER OIL AND GAS INFORMATION

Since inception, 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. In 2008, 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 by approximately 3 percent in 2008 as a result of successful exploration and development drilling, which resulted in extensions and discoveries of 1,966 billion cubic feet. Changes in the revisions and improved recovery category for natural gas reserves were negative at 18 billion cubic feet, or less than 1 percent of proved natural gas reserves at the beginning of 2008, primarily as a consequence of relatively low natural gas prices in the U.S. Rockies on December 31, 2008. Approximately two-thirds of extensions and discoveries were in Canada with the balance being in the U.S. Purchase and sale of reserves in place were not material.

In 2007 and 2006, natural gas reserves increased primarily from development and exploration drilling.

EnCana's crude oil and NGLs reserves increased approximately 8 percent at year-end 2008 in comparison to year-end 2007, largely as a result of positive revisions associated with the Corporation's interests in Foster Creek and Christina Lake.

As at December 31, 2007, EnCana's crude oil and NGLs reserves were approximately 18 percent lower than at year-end 2006 as a consequence of the contribution of the Corporation's interests in Foster Creek and Christina Lake into the integrated oil business effective January 2, 2007. Subsequent to this transaction, EnCana's crude oil and NGLs reserves increased approximately 26 percent over the balance of the year, mainly due to bookings at Foster Creek and Christina Lake.

In 2006, significant increases in proved reserves primarily at Foster Creek and Christina Lake 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 resulting from an almost two-fold increase in field prices relative to the prior year end.

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 2008 prices were as follows: crude oil (WTI) $44.60/bbl, (Edmonton Light) C$44.27/bbl, decreases of 54 percent and 53 percent from year-end 2007, respectively; Foster Creek field price C$30.39/bbl, a decrease of 39 percent from year-end 2007; natural gas (Henry Hub) $5.71/MMbtu, a decrease of 16 percent from year-end 2007; and natural gas (AECO) C$6.22/MMbtu, a decrease of 6 percent from year-end 2007.

Each year, EnCana reviews the methodologies employed to arrive at year-end prices to ensure that they are determined in a manner which is most consistent with SEC standards. At year-end 2007, this review resulted in EnCana changing its methodology with respect to bitumen price determination, placing greater emphasis on spot prices for the Western Canadian Select marker. The same methodology was used at year-end 2008.

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	Total	Canada	United States	Ecuador[3]	Total
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)
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[4]	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[4]	54.0		1,133.4
2007							
Beginning of year	7,028	5,390	12,418	1,079.4	54.0		1,133.4
Revisions and improved recovery	87	78	165	75.5	3.6		79.1
Extensions and discoveries	949	827	1,776	155.8	5.9		161.7
Purchase of reserves in place	63	211	274	0.2	0.0		0.2
Sale of reserves in place	(24)	(7)	(31)	(398.2)[5]	(0.0)		(398.2)
Production	(811)	(491)	(1,302)	(43.8)	(5.2)		(49.0)
End of year	7,292	6,008	13,300	868.9	58.3		927.2
Developed	4,868	3,368	8,236	289.5	37.0		326.5
Undeveloped	2,424	2,640	5,064	579.4	21.3		600.7
Total	7,292	6,008	13,300	868.9	58.3		927.2
2008							
Beginning of year	7,292	6,008	13,300	868.9	58.3		927.2
Revisions and improved recovery	148	(166)	(18)	112.8	(3.6)		109.2
Extensions and discoveries	1,311	655	1,966	17.0	3.8		20.8
Purchase of reserves in place	32	7	39	0.2	0.0		0.2
Sale of reserves in place	(129)	(75)	(204)	(0.9)	(2.0)		(2.9)
Production	(807)	(598)	(1,405)	(44.0)	(4.9)		(48.9)
End of year	7,847	5,831	13,678	954.0	51.6		1,005.6
Developed	4,945	3,720	8,665	334.4	33.9		368.3
Undeveloped	2,902	2,111	5,013	619.6	17.7		637.3
Total	7,847	5,831	13,678	954.0	51.6		1,005.6

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) The Corporation divested its Ecuadorian operations in 2006.

(4) 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 FCCL 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.

(5) Includes approximately 398 million barrels attributable to the contribution of interests to FCCL.

(6) Reserves estimates at December 31, 2008 for properties located in Alberta have been prepared using the Alberta royalty framework which came into effect on January 1, 2009.

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 to the extent provided by contractual arrangements such as price risk management activities, in existence at year end and to account for 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		
	2008	**2007**	**2006**	**2008**	**2007**	**2006**
			($ millions)			
Future cash inflows	64,308	95,778	72,262	26,620	38,398	27,165
Less future:						
Production costs	23,017	25,089	20,471	6,079	5,869	4,123
Development costs	9,800	10,171	9,355	5,227	6,943	4,715
Asset retirement obligation payments	2,995	3,320	2,397	488	532	396
Income taxes	5,746	12,871	8,816	2,961	7,375	5,349
Future net cash flows	22,750	44,327	31,223	11,865	17,679	12,582
Less 10% annual discount for estimated timing of cash flows	10,036	21,663	14,627	5,218	8,196	6,128
Discounted future net cash flows	12,714	22,664	16,596	6,647	9,483	6,454

	Total		
	2008	**2007**	**2006**
		($ millions)	
Future cash inflows	90,928	134,176	99,427
Less future:			
Production costs	29,096	30,958	24,594
Development costs	15,027	17,114	14,070
Asset retirement obligation payments	3,483	3,852	2,793
Income taxes	8,707	20,246	14,165
Future net cash flows	34,615	62,006	43,805
Less 10% annual discount for estimated timing of cash flows	15,254	29,859	20,755

	Total		
Discounted future net cash flows	19,361	32,147	23,050

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

	Canada			United States		
	2008	2007	2006	2008	2007	2006
			($ millions)			
Balance, beginning of year	22,664	16,596	20,137	9,483	6,454	11,472
Changes resulting from:						
Sales of oil and gas produced during the period	(7,346)	(6,055)	(5,970)	(4,125)	(3,281)	(2,373)
Discoveries and extensions, net of related costs	2,031	3,632	2,429	904	1,591	877
Purchases of proved reserves in place	58	120		14	372	69
Sales of proved reserves in place	(321)	(1,283)	(19)	(197)	(15)	(85)
Net change in prices and production costs	(14,632)	9,671	(6,260)	(4,204)	4,818	(7,636)
Revisions to quantity estimates	1,736	603	1,486	667	830	265
Accretion of discount	2,905	2,087	2,809	1,346	924	1,714
Previously estimated development costs incurred net of change in future development costs	1,923	(259)	(910)	315	(907)	(350)
Other	321	(341)	(782)	88	(113)	(381)
Net change in income taxes	3,375	(2,107)	3,676	2,356	(1,190)	2,882
Balance, end of year	12,714	22,664	16,596	6,647	9,483	6,454

	Ecuador			Total		
	2008	2007	2006	2008	2007	2006
			($ millions)			
Balance, beginning of year			1,568	32,147	23,050	33,177
Changes resulting from:						
Sales of oil and gas produced during the period			(142)	(11,471)	(9,336)	(8,485)
Discoveries and extensions, net of related costs				2,935	5,223	3,306
Purchases of proved reserves in place				72	492	69
Sales of proved reserves in place			(1,359)	(518)	(1,298)	(1,463)
Net change in prices and production costs				(18,836)	14,489	(13,896)
Revisions to quantity estimates				2,403	1,433	1,751
Accretion of discount				4,251	3,011	4,523
Previously estimated development costs incurred net of change in future development costs			(46)	2,238	(1,166)	(1,306)
Other				409	(454)	(1,163)
Net change in income taxes			(21)	5,731	(3,297)	6,537
Balance, end of year				19,361	32,147	23,050

Results of Operations, Capitalized Costs and Costs Incurred

Results of Operations

	Canada			United States			Ecuador[1]		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
				($ millions)					
Oil and gas revenues, net of royalties, transportation and selling costs	8,848	7,361	7,190	5,127	4,065	3,096			190
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	1,502	1,306	1,220	1,002	784	723			48
Depreciation, depletion and amortization	2,198	2,298	2,146	1,691	1,181	869			84
Operating income (loss)	5,148	3,757	3,824	2,434	2,100	1,504			58
Income taxes	1,502	1,114	1,235	937	809	556			21
Results of operations	3,646	2,643	2,589	1,497	1,291	948			37

	Other			Total		
	2008	2007	2006	2008	2007	2006
			($ millions)			
Oil and gas revenues, net of royalties, transportation and selling costs	2		2	13,977	11,426	10,478
Less:						
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	(2)	19	11	2,502	2,109	2,002
Depreciation, depletion and amortization	39	69	10	3,928	3,548	3,109
Operating income (loss)	(35)	(88)	(19)	7,547	5,769	5,367
Income taxes				2,439	1,923	1,812
Results of operations	(35)	(88)	(19)	5,108	3,846	3,555

Note:

(1) The sale of EnCana's Ecuador operations was completed in February 2006, and a loss on sale of approximately $279 million, including indemnities, was recorded. Depreciation, depletion and amortization in 2006 represent 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.

Capitalized Costs

	Canada			United States		
	2008	2007	2006	2008	2007	2006
			($ millions)			
Proved oil and gas properties	33,159	36,780	31,546	15,653	13,738	9,796
Unproved oil and gas properties	870	1,380	1,700	3,399	1,852	1,221
Total Capital cost	34,029	38,160	33,246	19,052	15,590	11,017
Accumulated DD&A	17,434	19,286	14,261	5,511	3,783	2,595

	Canada			United States		
Net capitalized costs	16,595	18,874	18,985	13,541	11,807	8,422

	Other			Total		
	2008	2007	2006	2008	2007	2006
			($ millions)			
Proved oil and gas properties				48,812	50,518	41,342
Unproved oil and gas properties	122	297	361	4,391	3,529	3,282
Total Capital cost	122	297	361	53,203	54,047	44,624
Accumulated DD&A	112	160	98	23,057	23,229	16,954
Net capitalized costs	10	137	263	30,146	30,818	27,670

Costs Incurred

	Canada			United States			Ecuador		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
	($ millions)								
Acquisitions									
Unproved	32	28		1,006	1,048	278			
Proved	119	61	47	17	1,565	6			
Total acquisitions	151	89	47	1,023	2,613	284			
Exploration costs	474	427	403	197	48	236			1
Development costs	3,328	3,309	3,611	2,418	1,871	1,826			46
Total costs incurred	3,953	3,825	4,061	3,638	4,532	2,346			47

	Other			Total		
	2008	2007	2006	2008	2007	2006
	($ millions)					
Acquisitions						
Unproved				1,038	1,076	278
Proved				136	1,626	53
Total acquisitions				1,174	2,702	331
Exploration costs	17	60	75	688	535	715
Development costs				5,746	5,180	5,483
Total costs incurred	17	60	75	7,608	8,417	6,529

Production Volumes and Per-Unit Results

Production Volumes

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

	Production Volumes 2008				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
PRODUCTION VOLUMES					
Continuing Operations:					
Produced Gas *(MMcf/d)*					
Canada	2,205	2,181	2,243	2,212	2,181
USA	1,633	1,677	1,674	1,629	1,552
Total Produced Gas	3,838	3,858	3,917	3,841	3,733
Oil and Natural Gas Liquids[(1)] *(bbls/d)*					
Canada	120,230	123,019	119,703	114,121	124,056
USA	13,350	12,831	13,853	13,482	13,232
Total Oil and Natural Gas Liquids	133,580	135,850	133,556	127,603	137,288
Total *(MMcfe/d)*					
Canada	2,926	2,919	2,961	2,897	2,926
USA	1,713	1,754	1,757	1,710	1,631
Total Continuing Operations *(MMcfe/d)*	4,639	4,673	4,718	4,607	4,557

	Production Volumes 2008				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
PRODUCTION VOLUMES					
Continuing Operations:					
Produced Gas *(MMcf/d)*					
Canadian Plains	842	820	831	856	860
Canadian Foothills	1,300	1,302	1,351	1,289	1,256
USA	1,633	1,677	1,674	1,629	1,552
Integrated Oil Other	63	59	61	67	65
Total Produced Gas	3,838	3,858	3,917	3,841	3,733
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil					

	Production Volumes 2008				
Canadian Plains	31,128	32,147	30,134	30,479	31,752
Canadian Foothills	8,473	8,437	8,217	8,376	8,867
Heavy Oil					
Canadian Plains	35,029	32,843	34,655	34,618	38,029
Foster Creek/Christina Lake	30,183	35,068	31,547	24,671	29,376
Integrated Oil Other	2,729	2,133	2,273	3,009	3,514
Natural Gas Liquids[1]					
Canadian Plains	1,181	1,126	1,147	1,189	1,262
Canadian Foothills	11,507	11,265	11,730	11,779	11,256
USA	13,350	12,831	13,853	13,482	13,232
Total Oil and Natural Gas Liquids	133,580	135,850	133,556	127,603	137,288
Total Continuing Operations *(MMcfe/d)*	4,639	4,673	4,718	4,607	4,557

Note:

(1) Natural gas liquids include condensate volumes.

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

	Production Volumes 2007				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
PRODUCTION VOLUMES					
Continuing Operations:					
Produced Gas *(MMcf/d)*					
Canada	2,221	2,258	2,243	2,203	2,178
USA	1,345	1,464	1,387	1,303	1,222
Total Produced Gas	3,566	3,722	3,630	3,506	3,400
Oil and Natural Gas Liquids[(1)] *(bbls/d)*					
Canada	119,974	121,346	120,805	119,607	118,087
USA	14,180	14,791	15,578	13,809	12,503
Total Oil and Natural Gas Liquids	134,154	136,137	136,383	133,416	130,590
Total *(MMcfe/d)*					
Canada	2,941	2,986	2,968	2,920	2,887
USA	1,430	1,553	1,480	1,386	1,297
Total Continuing Operations *(MMcfe/d)*	4,371	4,539	4,448	4,306	4,184

	Production Volumes 2007				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
PRODUCTION VOLUMES					
Continuing Operations:					
Produced Gas *(MMcf/d)*					
Canadian Plains	875	876	858	874	891
Canadian Foothills	1,255	1,313	1,280	1,231	1,196
USA	1,345	1,464	1,387	1,303	1,222
Integrated Oil Other	91	69	105	98	91
Total Produced Gas	3,566	3,722	3,630	3,506	3,400
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil					
Canadian Plains	32,156	31,706	32,064	31,740	33,129
Canadian Foothills	8,216	8,441	7,978	7,959	8,489
Heavy Oil					
Canadian Plains	38,784	38,581	38,647	38,408	39,510
Foster Creek/Christina Lake	26,814	27,190	28,740	27,994	23,269

	Production Volumes 2007				
Integrated Oil Other	2,688	3,040	2,235	2,489	2,990
Natural Gas Liquids[(1)]					
Canadian Plains	1,260	1,422	1,209	1,206	1,203
Canadian Foothills	10,056	10,966	9,932	9,811	9,497
USA	14,180	14,791	15,578	13,809	12,503
Total Oil and Natural Gas Liquids	134,154	136,137	136,383	133,416	130,590
Total Continuing Operations *(MMcfe/d)*	4,371	4,539	4,448	4,306	4,184

Note:

(1) Natural gas liquids include condensate volumes.

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

	Production Volumes 2006				
	Year	Q4	Q3	Q2	Q1
PRODUCTION VOLUMES					
Continuing Operations:					
Produced Gas *(MMcf/d)*					
Canada	2,185	2,205	2,162	2,192	2,182
USA	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[1] *(bbls/d)*					
Canada	144,315	142,085	143,410	138,506	153,391
USA	12,958	12,584	13,311	13,353	12,582
Total Oil and Natural Gas Liquids	157,273	154,669	156,721	151,859	165,973
Total *(MMcfe/d)*					
Canada	3,051	3,057	3,022	3,023	3,103
USA	1,260	1,277	1,277	1,249	1,236
Total Continuing Operations *(MMcfe/d)*	4,311	4,334	4,299	4,272	4,339

	Production Volumes 2006				
	Year	Q4	Q3	Q2	Q1
PRODUCTION VOLUMES					
Continuing Operations:					
Produced Gas *(MMcf/d)*					
Canadian Plains	906	901	899	894	932
Canadian Foothills	1,166	1,207	1,155	1,177	1,128
USA	1,182	1,201	1,197	1,169	1,161
Integrated Oil Other	113	97	108	121	122
Total Produced Gas	3,367	3,406	3,359	3,361	3,343
Oil and Natural Gas Liquids *(bbls/d)*					
Light and Medium Oil					
Canadian Plains	34,939	32,995	36,948	33,949	35,543
Canadian Foothills	9,037	8,643	8,717	9,163	9,970
Heavy Oil					
Canadian Plains	40,673	36,572	39,332	39,101	48,356
Foster Creek/Christina Lake	42,768	46,678	43,073	39,215	42,050

	Production Volumes 2006				
Integrated Oil Other	5,185	5,341	3,953	5,471	5,466
Natural Gas Liquids[1]					
Canadian Plains	1,380	1,397	1,326	1,318	1,479
Canadian Foothills	10,333	10,459	10,061	10,289	10,527
USA	12,958	12,584	13,311	13,353	12,582
Total Oil and Natural Gas Liquids	157,273	154,669	156,721	151,859	165,973
Total Continuing Operations *(MMcfe/d)*	4,311	4,334	4,299	4,272	4,339
Discontinued Operations:					
Ecuador *(bbls/d)*	11,996				48,650
Total Discontinued Operations *(MMcfe/d)*	72				292
Total *(MMcfe/d)*	4,383	4,334	4,299	4,272	4,631

Note:

(1) Natural gas liquids include condensate volumes.

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 2008				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Continuing Operations:					
Produced Gas Canadian Plains ($/Mcf)					
Price	7.77	5.65	8.67	9.50	7.19
Production and mineral taxes	0.12	0.06	0.17	0.17	0.06
Transportation and selling	0.23	0.21	0.24	0.22	0.25
Operating	0.78	0.65	0.59	0.96	0.93
Netback	6.64	4.73	7.67	8.15	5.95
Produced Gas Canadian Foothills ($/Mcf)					
Price	8.12	5.87	9.03	9.94	7.61
Production and mineral taxes	0.06	0.03	0.09	0.09	0.03
Transportation and selling	0.42	0.37	0.43	0.43	0.47
Operating	1.15	0.98	0.87	1.39	1.41
Netback	6.49	4.49	7.64	8.03	5.70
Produced Gas Canada ($/Mcf)					
Price	7.97	5.78	8.88	9.76	7.44
Production and mineral taxes	0.08	0.04	0.12	0.12	0.04
Transportation and selling	0.35	0.31	0.36	0.35	0.38
Operating	1.03	0.87	0.77	1.23	1.25
Netback	6.51	4.56	7.63	8.06	5.77
Produced Gas USA ($/Mcf)					
Price	7.89	5.01	8.54	9.93	8.19
Production and mineral taxes	0.56	0.35	0.56	0.72	0.62
Transportation and selling	0.84	0.87	0.86	0.81	0.81
Operating	0.59	0.56	0.38	0.71	0.71
Netback	5.90	3.23	6.74	7.69	6.05
Produced Gas Total ($/Mcf)					
Price	7.94	5.44	8.74	9.83	7.75
Production and mineral taxes	0.28	0.17	0.31	0.37	0.28
Transportation and selling	0.56	0.55	0.57	0.55	0.56
Operating	0.84	0.74	0.61	1.01	1.02
Netback	6.26	3.98	7.25	7.90	5.89
Natural Gas Liquids Canadian Plains ($/bbl)					
Price	78.91	45.13	98.35	96.34	75.09
Production and mineral taxes					
Transportation and selling			0.01		

	Per-Unit Results 2008				
Netback	78.91	45.13	98.34	96.34	75.09
Natural Gas Liquids Canadian Foothills ($/bbl)					
Price	80.22	42.03	95.49	101.23	80.80
Production and mineral taxes					
Transportation and selling	1.33	1.33	1.20	1.73	1.04
Netback	78.89	40.70	94.29	99.50	79.76

	Per-Unit Results 2008				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids Canada ($/bbl)					
Price	80.10	42.31	95.74	100.78	80.23
Production and mineral taxes					
Transportation and selling	1.21	1.21	1.10	1.57	0.94
Netback	78.89	41.10	94.64	99.21	79.29
Natural Gas Liquids USA[1] ($/bbl)					
Price	83.18	45.39	97.63	105.73	82.22
Production and mineral taxes	7.25	3.79	8.19	9.75	7.13
Transportation and selling					
Netback	75.93	41.60	89.44	95.98	75.09
Natural Gas Liquids Total ($/bbl)					
Price	81.67	43.88	96.72	103.29	81.24
Production and mineral taxes	3.70	1.93	4.25	4.94	3.63
Transportation and selling	0.59	0.59	0.53	0.78	0.46
Netback	77.38	41.36	91.94	97.57	77.15
Crude Oil Light and Medium Canadian Plains ($/bbl)					
Price	84.84	41.60	107.59	107.08	85.90
Production and mineral taxes	3.33	2.05	4.70	3.97	2.72
Transportation and selling	1.20	0.96	1.41	1.27	1.16
Operating	10.56	8.28	9.40	13.05	11.60
Netback	69.75	30.31	92.08	88.79	70.42
Crude Oil Light and Medium Canadian Foothills ($/bbl)					
Price	91.78	47.51	112.73	114.28	93.42
Production and mineral taxes	1.48	1.11	1.65	2.05	1.16
Transportation and selling	2.07	1.55	2.12	2.70	1.92
Operating	12.75	11.68	10.02	15.39	13.84
Netback	75.48	33.17	98.94	94.14	76.50
Crude Oil Heavy Canadian Plains ($/bbl)					
Price	74.08	31.30	95.86	98.65	70.44
Production and mineral taxes	0.03	0.06	0.07	(0.10)	0.07
Transportation and selling	1.60	1.13	2.42	1.60	1.29
Operating	9.04	7.17	7.62	11.30	9.93
Netback	63.41	22.94	85.75	85.85	59.15
Crude Oil Total excluding Foster Creek/Christina Lake ($/bbl)					
Price	80.31	37.20	102.66	103.40	78.82
Production and mineral taxes	1.56	1.02	2.16	1.81	1.28
Transportation and selling	1.52	1.13	2.00	1.61	1.36
Operating	10.43	8.28	8.99	13.00	11.39
Netback	66.80	26.77	89.51	86.98	64.79

	Per-Unit Results 2008				
Crude Oil Heavy Foster Creek/Christina Lake ($/bbl)					
Price(2)	62.44	19.86	91.21	93.64	59.67
Production and mineral taxes					
Transportation and selling	2.36	2.04	2.10	2.77	2.72
Operating	15.53	10.73	15.53	21.41	16.62
Netback	44.55	7.09	73.58	69.46	40.33

	Per-Unit Results 2008				
	Year	Q4	Q3	Q2	Q1
Crude Oil Total[3] ($/bbl)					
Price	75.36	31.58	99.39	100.99	74.10
Production and mineral taxes	1.13	0.69	1.54	1.36	0.96
Transportation and selling	1.75	1.43	2.03	1.90	1.69
Operating	11.84	9.08	10.86	15.08	12.68
Netback	60.64	20.38	84.96	82.65	58.77
Total Liquids Canada ($/bbl)					
Price	75.85	32.63	98.99	100.97	74.69
Production and mineral taxes	1.01	0.62	1.37	1.20	0.86
Transportation and selling	1.70	1.41	1.93	1.86	1.62
Operating	10.57	8.19	9.68	13.34	11.30
Netback	62.57	22.41	86.01	84.57	60.91
Total Liquids ($/bbl)					
Price	76.58	33.81	98.85	101.46	75.44
Production and mineral taxes	1.63	0.92	2.09	2.09	1.46
Transportation and selling	1.53	1.28	1.72	1.67	1.46
Operating	9.55	7.43	8.66	12.00	10.30
Netback	63.87	24.18	86.38	85.70	62.22
Total ($/Mcfe)					
Price	8.77	5.48	10.04	11.02	8.61
Production and mineral taxes	0.28	0.17	0.32	0.37	0.28
Transportation and selling	0.50	0.49	0.53	0.50	0.50
Operating[4]	0.97	0.83	0.75	1.17	1.15
Netback	7.02	3.99	8.44	8.98	6.68

Notes:

(1) The Natural Gas Liquids USA netback is equivalent to the Total Liquids USA netback.

(2) 2008 price includes the impact of the write-down of condensate inventories to net realizable value (2008 $4.26/bbl; Q4 2008 $11.21/bbl; Q3 2008 $3.07/bbl).

(3) The Crude Oil Total netback is equivalent to the Crude Oil Canada netback.

(4) Operating costs for the year include a recovery of costs related to long-term incentives of $0.01/Mcfe.

	Per-Unit Results 2007				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Produced Gas Canadian Plains ($/Mcf)					
Price	6.10	6.21	5.26	6.66	6.25
Production and mineral taxes	0.11	0.04	0.13	0.14	0.12
Transportation and selling	0.26	0.25	0.25	0.26	0.27
Operating	0.69	0.81	0.62	0.69	0.65
Netback	5.04	5.11	4.26	5.57	5.21
Produced Gas Canadian Foothills ($/Mcf)					
Price	6.30	6.44	5.46	6.86	6.46
Production and mineral taxes	0.08	0.04	0.08	0.11	0.10
Transportation and selling	0.42	0.41	0.41	0.43	0.43
Operating	1.05	1.14	0.96	1.02	1.09
Netback	4.75	4.85	4.01	5.30	4.84
Produced Gas Canada ($/Mcf)					
Price	6.20	6.35	5.36	6.76	6.36
Production and mineral taxes	0.09	0.03	0.10	0.11	0.10
Transportation and selling	0.35	0.35	0.34	0.36	0.36
Operating	0.92	1.03	0.83	0.90	0.91
Netback	4.84	4.94	4.09	5.39	4.99
Produced Gas USA ($/Mcf)					
Price	5.38	5.03	4.68	5.73	6.24
Production and mineral taxes	0.34	0.29	0.38	0.17	0.53
Transportation and selling	0.62	0.64	0.60	0.65	0.61
Operating	0.65	0.70	0.52	0.71	0.67
Netback	3.77	3.40	3.18	4.20	4.43
Produced Gas Total ($/Mcf)					
Price	5.89	5.83	5.10	6.38	6.32
Production and mineral taxes	0.18	0.14	0.21	0.14	0.26
Transportation and selling	0.45	0.46	0.44	0.47	0.45
Operating	0.82	0.90	0.72	0.83	0.82
Netback	4.44	4.33	3.73	4.94	4.79
Natural Gas Liquids Canadian Plains ($/bbl)					
Price	59.98	73.12	61.29	56.08	46.69
Production and mineral taxes					
Transportation and selling					
Netback	59.98	73.12	61.29	56.08	46.69
Natural Gas Liquids Canadian Foothills ($/bbl)					
Price	59.26	73.42	63.06	55.10	42.82
Production and mineral taxes					

	Per-Unit Results 2007				
Transportation and selling	1.14	1.08	2.02	0.83	0.61
Netback	58.12	72.34	61.04	54.27	42.21
Natural Gas Liquids Canada ($/bbl)					
Price	59.34	73.39	62.87	55.21	43.26
Production and mineral taxes					
Transportation and selling	1.01	0.96	1.80	0.74	0.54
Netback	58.33	72.43	61.07	54.47	42.72

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	Per-Unit Results 2007				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids USA[1] ($/bbl)					
Price	59.83	73.45	60.17	55.43	47.77
Production and mineral taxes	4.28	6.12	1.95	4.71	4.56
Transportation and selling	0.01		0.01	0.01	0.01
Netback	55.54	67.33	58.21	50.71	43.20
Natural Gas Liquids Total ($/bbl)					
Price	59.61	73.42	61.31	55.33	45.66
Production and mineral taxes	2.36	3.30	1.13	2.59	2.43
Transportation and selling	0.46	0.44	0.76	0.34	0.26
Netback	56.79	69.68	59.42	52.40	42.97
Crude Oil Light and Medium Canadian Plains ($/bbl)					
Price	56.41	68.78	59.68	52.43	44.81
Production and mineral taxes	2.37	2.36	2.16	2.37	2.59
Transportation and selling	1.33	1.22	1.39	1.27	1.43
Operating	9.20	10.34	8.84	9.10	8.55
Netback	43.51	54.86	47.29	39.69	32.24
Crude Oil Light and Medium Canadian Foothills ($/bbl)					
Price	64.63	81.51	67.07	57.00	52.31
Production and mineral taxes	1.05	1.59	0.76	1.47	0.37
Transportation and selling	1.77	1.66	2.16	1.79	1.49
Operating	10.84	12.72	11.21	9.31	10.03
Netback	50.97	65.54	52.94	44.43	40.42
Crude Oil Heavy Canadian Plains ($/bbl)					
Price	43.91	49.52	48.22	40.70	37.22
Production and mineral taxes	0.05	0.07	0.06	0.06	(0.01)
Transportation and selling	1.18	1.13	1.36	1.19	1.03
Operating	7.59	9.06	7.27	7.56	6.48
Netback	35.09	39.26	39.53	31.89	29.72
Crude Oil Total excluding Foster Creek/Christina Lake ($/bbl)					
Price	50.76	59.93	54.68	47.02	41.42
Production and mineral taxes	1.09	1.12	1.01	1.16	1.06
Transportation and selling	1.32	1.23	1.47	1.31	1.27
Operating	9.03	10.52	8.68	8.85	8.06
Netback	39.32	47.06	43.52	35.70	31.03
Crude Oil Heavy Foster Creek/Christina Lake ($/bbl)					
Price	40.14	45.58	42.86	39.40	33.28
Production and mineral taxes					
Transportation and selling	2.88	2.75	2.10	3.62	3.07
Operating[2]	14.46	14.05	12.55	14.02	17.12

	Per-Unit Results	**2007**			
Netback	22.80	28.78	28.21	21.76	13.09

	Per-Unit Results 2007				
	Year	Q4	Q3	Q2	Q1
Crude Oil Total[3] ($/bbl)					
Price	47.90	56.23	51.50	44.92	39.19
Production and mineral taxes	0.79	0.83	0.74	0.84	0.77
Transportation and selling	1.74	1.62	1.64	1.94	1.75
Operating	10.49	11.43	9.72	10.27	10.54
Netback	34.88	42.35	39.40	31.87	26.13
Total Liquids Canada ($/bbl)					
Price	48.92	57.92	52.50	45.83	39.50
Production and mineral taxes	0.72	0.74	0.66	0.76	0.70
Transportation and selling	1.68	1.56	1.66	1.84	1.67
Operating	9.47	10.20	8.78	9.29	9.60
Netback	37.05	45.42	41.40	33.94	27.53
Total Liquids ($/bbl)					
Price	50.05	59.60	53.37	46.81	40.25
Production and mineral taxes	1.08	1.32	0.81	1.16	1.04
Transportation and selling	1.51	1.39	1.47	1.65	1.51
Operating	8.57	9.19	7.87	8.41	8.81
Netback	38.89	47.70	43.22	35.59	28.89
Total ($/Mcfe)					
Price	6.35	6.57	5.80	6.65	6.40
Production and mineral taxes	0.18	0.15	0.19	0.15	0.24
Transportation and selling	0.42	0.42	0.41	0.43	0.42
Operating[4]	0.93	1.02	0.83	0.93	0.95
Netback	4.82	4.98	4.37	5.14	4.79

Notes:

(1) The Natural Gas Liquids USA netback is equivalent to the Total Liquids USA netback.

(2) First quarter operating costs include a prior year under accrual of approximately $1.82/bbl.

(3) The Crude Oil Total netback is equivalent to the Crude Oil Canada netback.

(4) Operating costs for the year include costs of $0.05/Mcfe related to long-term incentives.

	Per-Unit Results 2006				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Produced Gas Canadian Plains ($/Mcf)					
Price	6.11	5.73	5.49	5.61	7.60
Production and mineral taxes	0.12	0.05	0.11	0.09	0.23
Transportation and selling	0.23	0.23	0.26	0.23	0.21
Operating	0.59	0.61	0.54	0.58	0.62
Netback	5.17	4.84	4.58	4.71	6.54
Produced Gas Canadian Foothills ($/Mcf)					
Price	6.30	5.99	5.68	5.81	7.81
Production and mineral taxes	0.09	0.05	0.08	0.07	0.16
Transportation and selling	0.44	0.40	0.46	0.45	0.45
Operating	0.92	0.96	0.94	0.89	0.88
Netback	4.85	4.58	4.20	4.40	6.32
Produced Gas Canada ($/Mcf)					
Price	6.20	5.87	5.59	5.71	7.66
Production and mineral taxes	0.10	0.05	0.09	0.08	0.18
Transportation and selling	0.35	0.33	0.37	0.35	0.34
Operating	0.79	0.82	0.78	0.77	0.79
Netback	4.96	4.67	4.35	4.51	6.35
Produced Gas USA ($/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
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 ($/Mcf)					
Price	6.25	5.79	5.75	5.84	7.68
Production and mineral taxes	0.24	0.21	0.21	0.13	0.41
Transportation and selling	0.42	0.42	0.44	0.40	0.40
Operating	0.74	0.77	0.71	0.74	0.74
Netback	4.85	4.39	4.39	4.57	6.13
Natural Gas Liquids Canadian Plains ($/bbl)					
Price	51.10	46.03	57.46	54.24	47.35
Production and mineral taxes					
Transportation and selling					
Netback	51.10	46.03	57.46	54.24	47.35
Natural Gas Liquids Canadian Foothills ($/bbl)					
Price	51.12	44.63	55.75	55.31	49.05
Production and mineral taxes					

	Per-Unit Results 2006				
Transportation and selling	0.75	0.66	0.84	0.82	0.70
Netback	50.37	43.97	54.91	54.49	48.35
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

	Per-Unit Results 2006				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids USA[1] ($/bbl)					
Price	56.33	51.04	61.76	58.25	54.07
Production and mineral taxes	4.19	4.62	4.42	2.60	5.18
Transportation and selling	0.01	0.01	0.01	0.01	0.01
Netback	52.13	46.41	57.33	55.64	48.88
Natural Gas Liquids Total ($/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 Canadian Plains ($/bbl)					
Price	50.04	42.27	54.56	60.08	42.96
Production and mineral taxes	2.39	2.45	2.42	2.73	1.98
Transportation and selling	0.88	0.58	1.18	0.59	1.12
Operating	8.18	8.37	9.70	6.74	7.81
Netback	38.59	30.87	41.26	50.02	32.05
Crude Oil Light and Medium Canadian Foothills ($/bbl)					
Price	57.74	46.27	63.26	68.08	53.43
Production and mineral taxes	1.27	0.96	0.83	1.54	1.69
Transportation and selling	1.41	0.72	2.05	0.89	1.95
Operating	10.21	11.13	11.85	9.37	8.72
Netback	44.85	33.46	48.53	56.28	41.07
Crude Oil Heavy Canadian Plains ($/bbl)					
Price	37.20	26.28	54.68	45.98	24.28
Production and mineral taxes	0.06	0.08	0.06	0.04	0.05
Transportation and selling	0.71	(0.30)	1.36	0.65	1.05
Operating	5.99	7.48	5.50	5.70	5.46
Netback	30.44	19.02	47.76	39.59	17.72
Crude Oil Total excluding Foster Creek/Christina Lake ($/bbl)					
Price	44.83	37.65	51.37	55.58	35.39
Production and mineral taxes	1.11	1.11	1.14	1.28	0.92
Transportation and selling	0.91	0.60	1.27	0.76	1.00
Operating	7.69	8.59	8.73	6.84	6.67
Netback	35.12	27.35	40.23	46.70	26.80
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	12.38	13.07	14.06	11.78	10.39

	Per-Unit Results 2006				
Netback	21.47	23.51	20.49	31.37	10.89

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	Per-Unit Results 2006				
	Year	Q4	Q3	Q2	Q1
Crude Oil Total[2] ($/bbl)					
Price	41.83	36.94	48.74	51.62	30.76
Production and mineral taxes	0.77	0.74	0.81	0.88	0.66
Transportation and selling	1.40	1.11	1.74	1.54	1.24
Operating	9.09	10.05	10.20	8.34	7.82
Netback	30.57	25.04	35.99	40.86	21.04
Total Liquids Canada ($/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
Total Liquids ($/bbl)					
Price	43.71	38.69	50.37	52.44	33.87
Production and mineral taxes	0.99	0.99	1.05	0.96	0.96
Transportation and selling	1.24	0.98	1.52	1.35	1.10
Operating	7.66	8.47	8.58	7.01	6.64
Netback	33.82	28.25	39.22	43.12	25.17
Total ($/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[3]	0.86	0.90	0.87	0.84	0.82
Netback	5.03	4.46	4.84	5.13	5.69
<u>Discontinued Operations</u>					
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

Note:

(1) The Natural Gas Liquids USA netback is equivalent to the Total Liquids USA netback.

(2) The Crude Oil Total netback is equivalent to the Crude Oil Canada netback.

(3) Operating costs for the year include costs related to long-term incentives of $0.02/Mcfe.

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

	2008				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Natural Gas ($/Mcf)	(0.02)	1.74	(0.80)	(1.29)	0.27
Liquids ($/bbl)	(5.46)	2.35	(7.97)	(10.99)	(5.85)
Total ($/Mcfe)	(0.17)	1.50	(0.89)	(1.38)	0.05

	2007				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Natural Gas ($/Mcf)	1.33	1.49	1.65	1.24	0.92
Liquids ($/bbl)	(3.05)	(8.76)	(4.36)	(1.34)	2.34
Total ($/Mcfe)	0.99	0.96	1.21	0.96	0.82

	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)

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
<u>Continuing Operations:</u>											
2008:											
Canada											
Canadian Plains	5	3	1	1	2	1	8	5	34	42	5
Canadian Foothills	70	54	8	5			78	59	69	147	59
USA	26	14					26	14		26	14
Other					3	1	3	1		3	1
Total	101	71	9	6	5	2	115	79	103	218	79
2007:											
Canada											
Canadian Plains	4	4	3	3			7	7	89	96	7
Canadian Foothills	116	92	4	3			120	95	91	211	95
USA	2	2					2	2		2	2
Other					4	3	4	3		4	3
Total	122	98	7	6	4	3	133	107	180	313	107
2006:											
Canada											
Canadian Plains	19	18	2	2			21	20	108	129	20
Canadian Foothills	262	212	5	5	7	6	274	223	20	294	223
USA	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

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:											
2008:											
Canada											
Canadian Plains	1,489	1,372	105	92	7	7	1,601	1,471	503	2,104	1,471
Canadian Foothills	1,088	989	17	16			1,105	1,005	329	1,434	1,005
Integrated Oil Canada	13	13	41	21	4	4	58	38	41	99	38
USA	904	736					904	736	378	1,282	736
Total	3,494	3,110	163	129	11	11	3,668	3,250	1,251	4,919	3,250
2007:											
Canada											
Canadian Plains	2,215	2,115	161	138	4	3	2,380	2,256	466	2,846	2,256
Canadian Foothills	1,528	1,425	20	18	1	1	1,549	1,444	325	1,874	1,444
Integrated Oil Canada	6	2	55	29	6	4	67	35	43	110	35
USA	809	641			1	1	810	642	36	846	642
Total	4,558	4,183	236	185	12	9	4,806	4,377	870	5,676	4,377
2006:											
Canada											
Canadian Plains	1,546	1,525	118	88	1	1	1,665	1,614	822	2,487	1,614
Canadian Foothills	1,187	1,048	13	7			1,200	1,055	32	1,232	1,055
Integrated Oil Canada	66	66	8	8	24	23	98	97	1	99	97
USA	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
Discontinued Operations:											
Ecuador 2006			7	6	1	1	8	7		8	7

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, 2008, EnCana was in the process of drilling 26 gross wells (19 net wells) in Canada and 47 gross wells (38 net wells) in the U.S.

Location of Wells

The following table summarizes EnCana's interest in producing wells and wells capable of producing as at December 31, 2008.

	Gas		Oil		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Continuing Operations:						
Alberta	40,458	38,224	4,032	3,567	44,490	41,791
British Columbia	2,023	1,894	17	12	2,040	1,906
Saskatchewan	452	419	917	600	1,369	1,019
Manitoba			1	1	1	1
Total Canada	42,933	40,537	4,967	4,180	47,900	44,717
Colorado	4,741	4,159	6	2	4,747	4,161
Texas	1,741	1,213	40	29	1,781	1,242
Wyoming	2,151	1,488	4	3	2,155	1,491
Utah	35	31	12	12	47	43
Louisiana	27	18			27	18
Kansas	1	1			1	1
Montana	1	1			1	1
Total United States	8,697	6,911	62	46	8,759	6,957
Total	51,630	47,448	5,029	4,226	56,659	51,674

Notes:

(1) EnCana has varying royalty interests in 16,437 natural gas wells and 10,364 crude oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: 34,582 gross natural gas wells (32,807 net wells) and 1,498 gross crude oil wells (1,345 net wells).

Interest in Material Properties

The following table summarizes EnCana's developed, undeveloped and total landholdings as at December 31, 2008.

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
				(thousands of acres)			
Continuing Operations:							
Canada							
Alberta	Fee	4,524	4,524	2,258	2,258	6,782	6,782
	Crown	4,130	3,213	4,148	3,251	8,278	6,464
	Freehold	275	164	163	141	438	305
		8,929	7,901	6,569	5,650	15,498	13,551
British Columbia	Crown	1,005	901	3,095	2,533	4,100	3,434
	Freehold			7		7	
		1,005	901	3,102	2,533	4,107	3,434
Saskatchewan	Fee	64	64	447	447	511	511
	Crown	133	111	410	352	543	463
	Freehold	14	10	48	46	62	56
		211	185	905	845	1,116	1,030
Manitoba	Fee	3	3	261	261	264	264
Newfoundland and Labrador	Crown			35	2	35	2
Nova Scotia	Crown			41	29	41	29
Northwest Territories	Crown			45	12	45	12
Total Canada		10,148	8,990	10,958	9,332	21,106	18,322

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
		(thousands of acres)					
United States							
Colorado	Federal/State Lands	199	184	668	614	867	798
	Freehold	102	93	166	153	268	246
	Fee	1	1	4	4	5	5
		302	278	838	771	1,140	1,049
Texas	Federal/State Lands	12	7	460	441	472	448
	Freehold	227	166	1,091	873	1,318	1,039
	Fee			4	2	4	2
		239	173	1,555	1,316	1,794	1,489
Wyoming	Federal/State Lands	137	82	546	393	683	475
	Freehold	17	10	31	16	48	26
		154	92	577	409	731	501
Other	Federal/State Lands	8	7	360	220	368	227
	Freehold	12	10	1,257	1,062	1,269	1,072
	Fee			87	87	87	87
		20	17	1,704	1,369	1,724	1,386
Total United States		715	560	4,674	3,865	5,389	4,425
Greenland				1,700	808	1,700	808
Azerbaijan				346	17	346	17
Australia				104	40	104	40
Qatar(7)							
Brazil(8)							
France(9)							
Total International				2,150	865	2,150	865
Total		10,863	9,550	17,782	14,062	28,645	23,612

Notes:

(1) This table excludes approximately 4.9 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 October 2008, EnCana relinquished its interests in Qatar.

(8) In September 2008, EnCana sold its remaining interests in Brazil.

(9) In December 2008, EnCana completed the sale of all of its interests in France.

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. 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 2008 and 2007.

	2008	**2007**
	($ millions)	
Capital Investment		
Canada		
Canadian Plains	847	846
Canadian Foothills	2,299	2,439
Integrated Oil - Canada	656	451
USA	2,615	1,919
Downstream Refining	478	220
Market Optimization	17	6
Corporate & Other	168	154
Capital Investment	7,080	6,035
Acquisitions		
Property		
Canada		
Canadian Foothills	151	75
Integrated Oil - Canada		14
USA[(1)]	1,023	2,613
Divestitures		
Property		
Canada		
Canadian Plains	(39)	
Canadian Foothills[(2)]	(400)	(213)
Integrated Oil - Canada	(8)	
USA	(251)	(10)
Corporate & Other[(3)]	(41)	(47)
Corporate		
Corporate & Other[(4)]	(165)	(211)
Net Acquisition and Divestiture Activity	270	2,221
Net Capital Investment	7,350	8,256

Notes:

(1) In 2008, mainly includes Haynesville properties. In 2007, mainly includes the Deep Bossier natural gas and land interests of the privately-owned Leor Energy group in East Texas acquired November 20, 2007.

(2) In 2007, consists primarily of the sale of Mackenzie Delta assets which was completed on May 30, 2007.

(3)

In 2007, consists primarily of the sale of EnCana's office building project assets, The Bow, which was completed on February 9, 2007, and the sale of Australia assets which was completed on August 15, 2007.

(4)

In 2008, mainly includes the sale of interests in Brazil which was completed on September 18, 2008. In 2007, sale of interests in Chad was completed on January 12, 2007 and sale of interests in Oman was completed on November 28, 2007.

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 22 to EnCana's audited consolidated financial statements for the year ended December 31, 2008.

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 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 incorporates the potential costs of carbon into future planning. The Corporate Responsibility, Environment, Health and Safety Committee of EnCana's Board of Directors reviews the impact of a variety of carbon constrained scenarios on EnCana's strategy with a current price range from $15 to $65 per tonne of emissions, applied to a range of emissions coverage levels. A major benefit of applying a range of carbon prices at the strategic level is that it provides direct guidance to the capital allocation process. EnCana also examines the impact of carbon regulation on its major projects. Although uncertainty remains regarding potential future emissions regulation, EnCana's plan is to continue to assess and evaluate the cost of carbon relative to its investments across a range of scenarios.

EnCana expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2008, expenditures beyond normal compliance with environmental regulations were not material. EnCana does not anticipate making material expenditures beyond normal compliance with environmental regulations in 2009. 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 $6.6 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) EH&S; (vii) stakeholder engagement; and (viii) socio-economic and community development.

The Policy and any revisions are approved by EnCana's Executive Team and its Board of Directors. 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. Coordination and oversight of the Policy resides with the Environment, Health, Safety and Security Group within Corporate Relations.

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 EH&S; (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.

With respect to human rights, the Policy states that 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.

Through the Policy, EnCana is committed to protecting the health and safety of all individuals affected by its activities, including its workforce and the public. EnCana will not compromise the health and safety of any individual in the conduct of its activities. EnCana will strive to provide a safe and healthy working environment, and will expect its workers to comply with the health and safety practices established for their protection and that of the public.

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 and a requirement for acknowledgement and sign-off on key policies from the Board of Directors and employees; (ii) an EH&S management system; (iii) a security program to regularly assess security threats to business operations and to manage the associated risks; (iv) a formalized approach to stakeholder relations with a standardized Stakeholder Engagement Guide and specific Aboriginal Community Engagement Guide; (v) corporate responsibility performance metrics to track the Corporation's progress; (vi) an energy efficiency program that focuses on reducing energy use at EnCana's operations and supports initiatives at the community level while also incenting employees to reduce energy use in their homes; (vii) contribution of a minimum of 1 percent of EnCana's pre-tax domestic profits to charitable and non-profit organizations in the communities in which EnCana operates; (viii) an Investigations Practice and an Investigations Committee to review and resolve potential violations of EnCana policies or practices and other regulations; (ix) an Integrity Hotline that provides an additional avenue for EnCana's stakeholders to raise their concerns as well as the corporate responsibility website which allows people to write to the Corporation about non-financial issues of concern; (x) an internal corporate EH&S audit program that evaluates EnCana's compliance with the expectations and requirements of the EH&S management system; and (xi) related policies and practices such as an Alcohol and Drug Policy, a Business Conduct & Ethics Practice and guidelines for correct behaviours with respect to the acceptance of gifts, conflicts of interest and the appropriate use of EnCana equipment and technology in a manner that is consistent with leading ethical business practices. 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, 2008, EnCana employed 6,048 full time equivalent employees as set forth in the following table.

	FTE Employees
Canadian Plains Division	1,101
Canadian Foothills Division	1,765
USA Division	1,665
Integrated Oil Division	884
Corporate	633
Total	6,048

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

Foreign Operations

As at December 31, 2008, 100 percent of EnCana's reserves and production were located in North America, which limits EnCana's exposure to risks and uncertainties in countries considered politically and economically unstable. EnCana's operations and related assets outside North America may be adversely affected by changes in governmental policy, social instability or other political or economic developments which are not within the control of EnCana, including the expropriation of property, the cancellation or modification of contract rights and restrictions on repatriation of cash. The Corporation has undertaken to mitigate these risks where practical and considered warranted.

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.

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[1]	Principal Occupation
RALPH S. CUNNINGHAM[3,4,7,8] Houston, Texas, United States	2003	President & Chief Executive Officer EPE Holdings, LLC *(Midstream energy services)*
PATRICK D. DANIEL[2,5,7,8] Calgary, Alberta, Canada	2001	President & Chief Executive Officer Enbridge Inc. *(Energy delivery)*
IAN W. DELANEY[4,5,7,8] Toronto, Ontario, Canada	1999	Chairman & Chief Executive Officer Sherritt International Corporation *(Nickel/cobalt mining, oil and natural gas production, electricity generation and coal mining)*
RANDALL K. ERESMAN[7,10] Calgary, Alberta, Canada	2006	President & Chief Executive Officer EnCana Corporation
CLAIRE S. FARLEY[3,6,7,9] Houston, Texas, United States	2008	Advisory Director Jefferies Randall & Dewey *(Global oil and gas energy industry advisor)*
MICHAEL A. GRANDIN[4,5,6,7,8,12] Calgary, Alberta, Canada	1998	Corporate Director
BARRY W. HARRISON[2,5,7,9,13] Calgary, Alberta, Canada	1996	Corporate Director and independent businessman
DALE A. LUCAS[2,4,7,9] Calgary, Alberta, Canada	1997	Corporate Director
VALERIE A. A. NIELSEN[3,6,7,8] Calgary, Alberta, Canada	1990	Corporate Director

Name and Municipality of Residence	Director Since[1]	Principal Occupation
DAVID P. O'BRIEN, O.C.[5,7,9,11,14] Calgary, Alberta, Canada	1990	Chairman EnCana Corporation Chairman Royal Bank of Canada
JANE L. PEVERETT[2,4,7,9] West Vancouver, British Columbia, Canada	2003	Corporate Director
ALLAN P. SAWIN[2,4,7,9] Edmonton, Alberta, Canada	2007	President Bear Investments Inc. *(Private investment company)*
JAMES M. STANFORD, O.C.[2,6,7,8] Calgary, Alberta, Canada	2001	President Stanford Resource Management Inc. *(Private investment management)*
WAYNE G. THOMSON[3,6,7,8] Calgary, Alberta, Canada	2007	President Virgin Resources Limited *(Private international oil & gas exploration company)*
CLAYTON H. WOITAS[3,6,7,9] Calgary, Alberta, Canada	2008	Chairman & Chief Executive Officer Range Royalty Management Ltd. *(Private oil & gas company)*

Notes:

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

(2) Member of Audit Committee.

(3) Member of Corporate Responsibility, Environment, Health and Safety Committee.

(4) Member of Human Resources and Compensation Committee.

(5) Member of Nominating and Corporate Governance Committee.

(6) Member of Reserves Committee.

(7) On June 4, 2008, the Board of Directors created the GasCo Committee and the Cenovus Committee charged with the oversight of strategic planning, governance and other matters related to each of the two separate public entities that would result from the proposed reorganization announced on May 11, 2008.

(8) Member of Cenovus Committee.

(9) Member of GasCo Committee.

(10) As an officer of EnCana and a non-independent director, Mr. Eresman is not a member of any Board committees, except for the GasCo and Cenovus Committees.

(11)
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.

(12)
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 (U.S.). A liquidation plan for that company received court confirmation later that year.

(13)
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.

(14)
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.

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

At the date of this annual information form, there are 15 directors of the Corporation. All of the current directors were appointed at the last annual meeting of shareholders held on April 22, 2008. At the next annual meeting, shareholders will be asked to elect as directors the 13 individuals listed in the above table, with the exception of Messrs. Lucas and Stanford who are retiring from the Board. 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 nominees shall be eligible for re-election.

Executive Officers

Name and Municipality of Residence	Corporate Office (Divisional Title)
RANDALL K. ERESMAN Calgary, Alberta, Canada	President & Chief Executive Officer
JOHN K. BRANNAN Calgary, Alberta, Canada	Executive Vice-President *(President, Integrated Oil Division)*
SHERRI A. BRILLON 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 Calgary, Alberta, Canada	Executive Vice-President, Corporate Communications
R. WILLIAM OLIVER Calgary, Alberta, Canada	Executive Vice-President, Business Development, Canadian Gas Marketing and Power
GERARD J. PROTTI Calgary, Alberta, Canada	Executive Vice-President, Corporate Relations
IVOR M. RUSTE Calgary, Alberta, Canada	Executive Vice-President & Chief Risk Officer
DONALD T. SWYSTUN 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, U.S.A.	Executive Vice-President *(President, USA Division)*

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:

Since August 1, 2007, Mr. Cunningham has been a director and President and Chief Executive Officer of EPE Holdings, LLC, the sole general partner of Enterprise GP Holdings L.P. (a publicly traded midstream energy holding company). From February 13, 2006 until July 31, 2007, he served as Group Executive Vice President and Chief Operating Officer and, from June 30, 2007 to July 31, 2007, also served as Interim President and Chief Executive Officer of Enterprise Products GP, LLC, the sole general partner of Enterprise Products Partners L.P. (a publicly traded midstream energy company). He was a director and Chairman of the Board of

Texas Eastern Products Pipeline Company, LLC from March 2005 until November 2005. Prior to March 2005, he was a Corporate Director.

Mr. Delaney, Chairman of the Board of Sherritt International Corporation, assumed the additional responsibilities of Chief Executive Officer effective January 27, 2009.

Ms. Farley became an Advisory Director of Jefferies Randall & Dewey (global oil and gas energy industry advisor) in August 2008. She was Co-President of Jefferies Randall & Dewey from February 2005 to August 2008 and Chief Executive Officer of Randall & Dewey (oil and gas asset transaction advisors) from September 2002 until February 2005 when Randall & Dewey became the Oil and Gas Investment Banking Group of Jefferies & Company, Inc. She was also a Managing Partner of Castex Energy Partners (private exploration and production limited partnership with assets in south Louisiana) from August 2008 to January 2009.

Mr. Grandin was Chairman and Chief Executive Officer of Fording Canadian Coal Trust from February 2003 to October 2008 when the company was acquired by Teck Cominco Limited. He also served as Dean of the Haskayne School of Business, University of Calgary from April 2004 to January 2006.

Ms. Peverett was President and Chief Executive Officer of BC Transmission Corporation (BCTC) from April 2005 to January 2009 and was Vice-President, Corporate Services and Chief Financial Officer of BCTC from June 2003 to April 2005. 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. Ruste joined EnCana on May 1, 2006 as Vice-President, Finance of the Corporate Finance Group. He was appointed Vice-President, Finance for the Integrated Oil Division effective January 1, 2007 and was appointed Executive Vice-President & Chief Risk Officer effective January 1, 2008. From February 2003 to April 2006, he was a partner and the Office Managing Partner for the Edmonton, Alberta office of KPMG LLP, as well as the Alberta Region Managing Partner for KPMG LLP. During this period, he was also a member of the Board of Directors of KPMG Canada and, from December 2003 to March 2006, he was Vice Chair of the Board of Directors for KPMG Canada.

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.

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.

Mr. Woitas is Chairman and Chief Executive Officer of Range Royalty Management Ltd., a private company which is focused on acquiring royalty interests in Western Canadian oil and natural gas production. He was founder, Chairman, and President and Chief Executive Officer of privately held Profico Energy Management Ltd. (January 2000 to June 2006), a company focused on natural gas exploration and production in western Canada.

All of the directors and executive officers of EnCana listed above beneficially owned, as of February 11, 2009, directly or indirectly, or exercised control or direction over an aggregate of 970,092 Common Shares representing 0.13 percent of the issued and outstanding voting shares of EnCana, and directors and executive officers held options to acquire an aggregate of 6,061,293 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 six members, all of whom are independent and financially literate in accordance with the definitions in National 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 Master 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), as well as 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) which was acquired by Total E&P Canada Ltd. in August 2008.

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. (private oil and gas company). He is also a director and Chairman (as well as past Chairman of the Audit Committees) of The Wawanesa Mutual Insurance Company (Canadian property and casualty insurer) and its related companies, The Wawanesa Life Insurance Company and its U.S. subsidiary, 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 President of D.A. Lucas Enterprises Inc., a private company owned by Mr. Lucas and through which he consulted internationally. He was Chairman and a director of Petaquilla Copper Ltd. (a public mining company) from April 2007 until September 2008 when the company was acquired by Inmet Mining Corp. During his 45-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 Master 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 President and Chief Executive Officer of BC Transmission Corporation (BCTC) from April 2005 to January 2009 and was Vice President, Corporate Services and Chief Financial Officer of BCTC (electrical transmission) from June 2003 to April 2005. 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.

Allan P. Sawin

Mr. Sawin holds a Bachelor of Commerce (University of Alberta) and a designation as a Chartered Accountant (Alberta). He is President of Bear Investments Inc. (private investment company). From 1990 until their sale to CCS Income Trust in May 2006, Mr. Sawin was President, director and part owner of Grizzly Well Servicing Inc. and related companies (private oilfield service companies operating drilling and service rigs in western Canada). From 1995 to 2003, he also served as a director and member of the Audit Committee of NQL Drilling Tools Inc. while it was a public company listed on the Toronto Stock Exchange.

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 both OPTI Canada Inc. (oilsands development and upgrading 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 2008 and 2007.

($ thousands)	2008	2007
Audit Fees[(1)]	4,060	4,038
Audit-Related Fees[(2)]	1,053	153
Tax Fees[(3)]	1,408	847
All Other Fees[(4)]	5	35
Total	6,526	5,073

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 2008 and 2007, 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 2008 and 2007, 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 2008 and 2007, 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 2007 or 2008.

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, 2008, there were approximately 751 million Common Shares outstanding and no Preferred Shares outstanding.

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 ten 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 take-over 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 acquirer, 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 2007 annual and special meeting of shareholders and must be reconfirmed at every third annual meeting thereafter until it expires on July 30, 2011.

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 and outlooks of the Corporation's debt as of December 31, 2008.

	Standard & Poor's Ratings Services ("S&P")	**Moody's Investors Service ("Moody's")**	**DBRS Limited ("DBRS")**
Senior Unsecured Long-Term Rating	A /CreditWatch Negative	Baa2/Stable	A (low)/Under Review with Developing Implications
Commercial Paper Short-Term Rating	A-1 (low)/CreditWatch Negative	P-2/Stable	R-1 (low)/Stable

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 nor do the ratings comment on 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.

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. S&P's Canadian commercial paper ratings scale ranges from A-1 (high) to D, which represents the range from highest to lowest quality. A rating of A-1 (low) is the third highest of eight categories and indicates that the obligor has satisfactory capacity to meet its financial commitments. CreditWatch highlights the potential direction of a long-term rating and the "negative" designation indicates that a rating may be lowered.

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. Moody's short-term credit ratings are on a scale that ranges from P-1 (highest quality) to NP (lowest quality). A rating of 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 substantial, but the degree of strength is less than that of higher rated entities. 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 credit ratings are on a scale ranging from R-1 (high) to D, which represents the range from highest to lowest quality. A rating of 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. A rating is placed "Under Review with Developing Implications" when there is uncertainty regarding the outcome of an event. A rating that is "Under Review" remains outstanding; however, this status indicates that the outstanding rating may no longer be appropriate. Upon a rating being placed "Under

Review", the rating trend of stable, positive or negative is removed and when the "Under Review" status is removed, a rating trend is re-established.

Following the announcement of the proposed Arrangement, S&P placed the Corporation's corporate credit and long-term debt ratings on "CreditWatch Negative", Moody's changed its outlook from "Positive" to "Stable" and DBRS placed the Corporation "Under Review with Developing Implications" and confirmed the short-term rating and stable outlook on the short-term rating.

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 2008.

	Toronto Stock Exchange				**New York Stock Exchange**			
	Share Price Trading Range				**Share Price Trading Range**			
	High	**Low**	**Close**	**Share Volume**	**High**	**Low**	**Close**	**Share Volume**
		(C$ per share)		(millions)		($ per share)		(millions)
2008								
January	70.90	59.95	66.19	49.8	71.72	58.13	66.06	64.7
February	77.29	64.39	75.03	48.4	79.38	63.69	76.21	63.0
March	79.26	70.60	78.20	61.7	79.75	68.83	75.75	67.1
April	88.06	76.41	81.25	49.8	87.69	74.16	80.81	59.8
May	97.81	78.09	89.51	60.0	99.36	76.50	90.37	74.6
June	97.64	87.34	93.36	55.6	96.60	86.22	90.93	71.3
July	95.91	72.00	73.90	74.8	94.41	70.04	72.19	95.8
August	79.97	69.02	79.81	58.4	76.42	64.68	74.90	91.1
September	77.15	63.84	67.96	90.1	74.44	61.13	65.73	134.9
October	68.04	41.36	61.23	112.2	64.19	34.53	50.91	174.0
November	62.99	43.86	60.00	70.2	54.76	34.00	46.81	101.8
December	59.87	47.52	56.96	62.7	48.71	36.58	46.48	80.4

In November 2008 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 as at November 13, 2008. Purchases may be made through the facilities of the TSX and the NYSE, in accordance with the policies and rules of each exchange.

In 2008, EnCana purchased approximately 4.8 million shares under the program for an average price of $67.13 for approximately $326 million.

On May 11, 2008 EnCana announced its plans with respect to the proposed Arrangement, and in connection with that proposed transaction, EnCana suspended the purchase of Common Shares for cancellation pending completion of the transaction. Upon completion of the Arrangement, and subject to market conditions prevailing at that time, EnCana intends to resume purchases of Common Shares.

DIVIDENDS

The declaration of dividends is at the discretion of the Board of Directors and is approved quarterly. In the second quarter of 2006, EnCana increased its dividend by 33 percent to $0.10 per share quarterly ($0.40 per share annually). In the first quarter of 2007, EnCana increased its dividend by 100 percent to $0.20 per share quarterly ($0.80 per share annually). In the first quarter of 2008, EnCana increased its dividend by 100 percent to $0.40 per share quarterly ($1.60 per share annually). EnCana's Board of Directors has declared a quarterly dividend of $0.40 per share payable on March 31, 2009 to common shareholders of record on March 16, 2009.

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 and in some cases its reputation 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 and refined products 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, refined products, 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 (including refined product and imported liquefied natural gas). 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.

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

The Corporation's ability to operate, generate sufficient cash flows, and complete projects depends upon numerous factors beyond the Corporation's control. In addition to commodity prices and continued market demand for its products, these non-controllable factors include: general business and market conditions; economic recessions and financial market turmoil; the ability to secure and maintain cost effective financing for its commitments; environmental and regulatory matters; unexpected cost increases; royalties; taxes; the availability of drilling and other equipment; the ability to access lands; weather; the availability of processing capacity; the availability and proximity of pipeline capacity; the availability of diluents to transport crude oil; technology failures; accidents; the availability of skilled labour; and reservoir quality.

Current market conditions are challenging with the global recession negatively impacting commodity prices as well as access to credit and capital markets. These conditions impact EnCana's customers and suppliers and may alter the Corporation's spending and operating plans. There may be unexpected business impacts from this market uncertainty.

EnCana's downstream operations are sensitive to margins for refined products. Margin volatility is impacted by numerous conditions including: market competitiveness, the costs of crude oil, labour, electricity, chemicals and other inputs, maintenance and turnaround costs, fluctuations in the supply and demand for refined products, especially production levels at other refineries in the regions which impact the supply of product and therefore crack spreads and prices in those regions, unplanned production disruptions due to equipment failure, power disruptions and other factors including 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 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.

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.

A number of federal, provincial and state governments have announced intentions to regulate greenhouse gases and other air pollutants. These governments are currently developing the regulatory and policy frameworks to deliver on their announcements. In most cases there are few technical details regarding the implementation and coordination of these plans to regulate emissions. Additionally, it is anticipated that other federal, provincial and state announcements and regulatory frameworks to address emissions will continue to emerge.

As these federal and regional programs are 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 emissions legislation.

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 certainty 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, including with respect to royalty payments, 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 fail to fulfill their obligations under the hedging agreements.

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, acts of vandalism and terrorism, 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 and maintain the operation of the refineries.

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 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. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission for $20 million and of a previously disclosed consolidated class action lawsuit in the U.S. District Court in New York for $8.2 million. Also, without admitting any liability whatsoever, WD concluded settlements with a group of individual plaintiffs for $23.0 million.

The remaining lawsuit was commenced by E. & J. Gallo Winery ("Gallo"). The Gallo lawsuit claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

The Corporation and WD intend to vigorously defend this outstanding claim; however, the Corporation cannot predict the outcome of these proceedings or any future proceedings against EnCana, whether these proceedings 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.

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.

TRANSFER AGENTS AND REGISTRARS

In Canada:	In the United States:
CIBC Mellon Trust Company	BNY Mellon Shareowner Services
P.O Box 7010	480 Washington Blvd
Adelaide Street Postal Station	Jersey City, NJ
Toronto, ON M5C 2W9	07310
Tel: 1-800-387-0825	Tel: 1-800-387-0825
Website: www.cibcmellon.com/investorinquiry	Website: www.cibcmellon.com/investorinquiry

INTERESTS OF EXPERTS

The Corporation's independent auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have issued an independent auditors' report dated February 19, 2009 in respect of the Corporation's consolidated financial statements as at December 31, 2008 and December 31, 2007 and for each of the years in the three year period ended December 31, 2008 and the Corporation's internal control over financial reporting as at December 31, 2008. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and the rules of the SEC.

Information relating to reserves in this annual information form dated February 20, 2009 was calculated by GLJ Petroleum Consultants Ltd., McDaniel & Associates Consultants Ltd., Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton, each of which is an independent qualified reserves evaluator.

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 1 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, 2008.

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, 2008. The reserves data consists of the following:

   (a) estimated proved oil and gas reserves quantities as at December 31, 2008 using constant prices and costs; and

   (b) 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, 2008:

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 16, 2009	Canada	3,936	847	9,164
GLJ Petroleum Consultants Ltd. January 23, 2009	Canada	3,911	107	6,863
Netherland, Sewell & Associates, Inc. January 19, 2009	United States	4,081	49	5,697
DeGolyer and MacNaughton January 20, 2009	United States	1,750	3	2,499
Totals		13,678	1,006	24,223

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. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

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 10, 2009

(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 a Decision dated September 29, 2008, and require disclosure of information contemplated by, and consistent with, US Disclosure Requirements (as defined in the Decision). Required information includes reserves data, which consist of the following:

(a) proved oil and gas reserves quantities estimated as at December 31, 2008 using constant prices and costs; and

(b) 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 10, 2009 (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.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to their probability of recovery.

(signed) Randall K. Eresman
President & Chief Executive Officer

(signed) Sherri A. Brillon
Executive Vice-President,
Strategic Planning & Portfolio Management

(signed) David P. O'Brien

(signed) James M. Stanford

Director and Chairman of the Board	Director and Chairman of the Reserves Committee

February 11, 2009

APPENDIX C

Audit Committee Mandate

Last updated February 10, 2009

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 National Instrument 52-110 *Audit Committees* (as implemented by the Canadian Securities Administrators and as amended from time to time) ("NI 52-110").

All members of the Committee shall be financially literate, as defined in NI 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 (the "*Exchange Act*"), and the rules adopted by the U.S. Securities and Exchange Commission ("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 SEC.

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 *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 therefore, 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, 2008

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, 2008, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2007. Readers should also read the Forward-Looking Statements legal advisory contained at the end of this document.

The Consolidated Financial Statements and comparative information have been prepared in United States (U.S.) dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles (GAAP). Production volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This document is dated effective February 19, 2009.

Readers can find the definition of certain terms used in this document 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 document.

EnCana s Financial Strategy in the Current Economic Environment

The current economic environment is challenging and uncertain amidst a global recession, low commodity prices, volatile financial markets and limited access to capital markets.

In this environment, EnCana is highly focused on the key business objectives of maintaining financial strength, generating significant free cash flow, further optimizing capital investments and continuing to pay a stable dividend to shareholders. This measured investment approach is underpinned by a strong balance sheet and a market risk mitigation strategy where EnCana has hedged about two thirds of its expected gas production from January through October 2009 at an average NYMEX equivalent price of about $9.13 per Mcf, along with other actions within its risk management program that are more fully described in the Risk Management section of this MD&A.

EnCana has a strong balance sheet and continues to employ a conservative capital structure. As at December 31, 2008, over 80 percent of EnCana s outstanding debt was composed of long-term, fixed rate debt with an average remaining term of more than 14 years. Long-term maturities are $250 million in 2009 and $200 million in 2010. As at December 31, 2008, EnCana had available unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for up to $5.0 billion and unused committed bank credit facilities in the amount of $2.6 billion. EnCana targets a Debt to Capitalization ratio of between 30 to 40 percent and, at December 31, 2008, the Company s Debt to Capitalization ratio was 28 percent.

In addition, EnCana will continue to monitor expenses and capital programs. In light of the current market situation, EnCana has planned a measured, flexible approach to 2009 investment and has designed a 2009 capital program with the flexibility to adjust investment up or down depending upon how economic circumstances unfold during the year. Additional detail regarding EnCana s 2009 capital investment is available in the Corporate Guidance on the Company s website at www.encana.com.

EnCana s Business

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

On May 11, 2008, EnCana announced its plans to split into two independent energy companies one a North American natural gas company and the other a fully integrated oil company with in-situ oil properties and refineries supplemented by reliable production from various natural gas and crude oil resource plays.

The proposed corporate reorganization (the Arrangement) would be implemented through a court approved Plan of Arrangement and is subject to shareholder approval. The Arrangement would result in two publicly traded entities with the names of Cenovus Energy Inc. (Cenovus) and EnCana Corporation. Each EnCana shareholder would receive one share of each entity in exchange for each EnCana Common Share held.

On October 15, 2008, EnCana announced the proposed Arrangement would be delayed until the global debt and equity markets regain stability. Meanwhile, the Company remains focused on being a leading producer of unconventional natural gas and in-situ oil as well as participating in the downstream refining and marketing of petroleum products. Additional details on the Arrangement are available in the 2008 news releases dated May 11, October 15, October 23 and December 11 on the Company s website at www.encana.com.

EnCana s operating divisions, post-Arrangement, would include Canadian Foothills and USA. Cenovus operating divisions, post-Arrangement, would include Canadian Plains and Integrated Oil.

EnCana s operating and reportable segments are as follows:

Canada includes the Company s exploration for, and development and production of natural gas, crude oil and natural gas liquids (NGLs) and other related activities within the Canadian cost centre.

USA includes the Company s exploration for, and development and production of natural gas, NGLs and other related activities within the United States cost centre.

Downstream Refining is focused on the refining of crude oil into petroleum and chemical products at two refineries located in the United States. The refineries are jointly owned with ConocoPhillips.

Market Optimization is primarily responsible for the sale of the Company s proprietary production. These results are included in the Canada and USA segments. Market optimization activities include 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 and Other mainly includes unrealized gains or losses recorded on derivative financial 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 upstream production to third-party customers. Transactions between segments are based on market values and eliminated on consolidation. Segmented financial information is presented on an after eliminations basis.

EnCana has updated its segmented reporting to present the upstream Canadian and United States cost centres and Downstream Refining as separate reportable segments. This results in EnCana presenting the Canadian portion of the Integrated Oil Division as part of the Canada segment. Previously, this was aggregated and presented in the Integrated Oil segment. Prior periods have been restated to reflect the new presentation.

EnCana has a decentralized decision making and reporting structure. Accordingly, the Company is organized into divisions as follows:

Canadian Plains Division includes natural gas production and crude oil development and production assets located in eastern Alberta and Saskatchewan.

Canadian Foothills Division includes natural gas development and production assets located in western Alberta and British Columbia as well as the Company s Canadian offshore assets.

USA Division includes the assets located in the United States and comprises the USA segment described above.

Integrated Oil Division is the combined total of Integrated Oil Canada and Downstream Refining. Integrated Oil Canada includes the Company s exploration for, and development and production of bitumen using in-situ recovery methods. Integrated Oil Canada is composed of EnCana s interests in the FCCL Oil Sands Partnership jointly owned with ConocoPhillips, the Athabasca natural gas assets and other bitumen interests.

2008 Overview

In 2008 compared to 2007, EnCana:

Increased Cash Flow by 11 percent to $9,386 million;

Increased Operating Earnings by 7 percent to $4,405 million;

Reported a 50 percent increase in Net Earnings to $5,944 million primarily due to after-tax unrealized mark-to-market hedging gains of $1,818 million in 2008 compared to losses of $811 million in 2007;

Reported Free Cash Flow of $2,306 million which is slightly lower compared to 2007;

Grew total production 6 percent to 4,639 million cubic feet equivalent (MMcfe) per day (MMcfe/d). On a per share basis, production increased 7 percent;

Increased production from natural gas key resource plays 14 percent and from oil key resource plays 2 percent;

Reported a 35 percent increase in natural gas prices, excluding financial hedges, to $7.94 per thousand cubic feet (Mcf) and a 53 percent increase in liquids prices, excluding financial hedges, to $76.58 per barrel (bbl). Realized hedging losses were $219 million after-tax in 2008 compared to gains of $1,023 million after-tax in 2007;

Reported a $1,315 million decrease in operating cash flows from downstream operations;

Acquired additional land acreage in the Haynesville Shale play in Louisiana for approximately $1,010 million;

Completed the sale of mature conventional oil and natural gas assets in North America for proceeds of $698 million and interests in Brazil for proceeds of $164 million before closing adjustments;

Purchased approximately 4.8 million of its Common Shares at an average price of $67.13 per share under the Normal Course Issuer Bid (NCIB) for a total cost of $326 million in 2008 compared to approximately 38.9 million of its Common Shares at an average price of $52.05 per share for a total cost of $2,025 million in 2007;

Added net proved natural gas reserves of 1,783 billion cubic feet (Bcf) and crude oil and NGLs reserves of 127 million barrels (MMbbls);

Increased its quarterly dividend to 40 cents per share in 2008 compared to 20 cents per share in 2007; and

Reported a Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) of 0.7x and a Debt to Capitalization ratio of 28 percent at December 31, 2008.

Business Environment

EnCana s financial results are significantly influenced by fluctuations in commodity prices, which include price differentials, crack spreads and the U.S./Canadian dollar exchange rate. The following table shows select market benchmark prices and foreign exchange rates to assist in understanding EnCana s financial results:

(Average for the year ended December 31)	2008	2008 vs 2007	2007	2007 vs 2006	2006
Natural Gas Price Benchmarks					
AECO *(C$/Mcf)*	**$ 8.13**	**23%**	$ 6.61	-5%	$ 6.98
NYMEX ($/*MMBtu)*	**9.04**	**32%**	6.86	-5%	7.22
Rockies (Opal) *($/MMBtu)*	**6.25**	**58%**	3.95	-30%	5.65
Texas (HSC) *($/MMBtu)*	**8.67**	**32%**	6.58	1%	6.53
Basis Differential *($/MMBtu)*					
AECO/NYMEX	**1.23**	**64%**	0.75	-29%	1.06
Rockies/NYMEX	**2.79**	**-4%**	2.91	85%	1.57
Texas/NYMEX	**0.37**	**32%**	0.28	-60%	0.70
Crude Oil Price Benchmarks					
West Texas Intermediate (WTI) *($/bbl)*	**99.75**	**38%**	72.41	9%	66.25
Western Canadian Select (WCS) *($/bbl)*	**79.70**	**61%**	49.50	11%	44.69
Differential - WTI/WCS *($/bbl)*	**20.05**	**-12%**	22.91	6%	21.56
Refining Margin Benchmark					
Chicago 3-2-1 Crack Spread *($/bbl)*(1)	**11.22**	**-37%**	17.67	32%	13.38
Foreign Exchange					
U.S./Canadian Dollar Exchange Rate	**0.938**	**1%**	0.930	5%	0.882

(1) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of diesel. 2006 value is calculated using Low Sulphur Diesel; 2007 and 2008 values are calculated using Ultra Low Sulphur Diesel.

The following table shows benchmark information on a quarterly basis to assist in understanding quarterly volatility in prices and foreign exchange rates that have impacted EnCana s financial results.

Quarterly Market Benchmark Prices and Foreign Exchange Rates

(Average for the period)	**2008**	**Q4**	**Q3**	**Q2**	**Q1**	2007	Q4	Q3	Q2	Q1
Natural Gas Price Benchmarks										
AECO *(C$/Mcf)*	**$ 8.13**	**$ 6.79**	**$ 9.24**	**$ 9.35**	**$ 7.13**	$ 6.61	$ 6.00	$ 5.61	$ 7.37	$ 7.46
NYMEX *($/MMBtu)*	**9.04**	**6.94**	**10.24**	**10.93**	**8.03**	6.86	6.97	6.16	7.55	6.77
Rockies (Opal) *($/MMBtu)*	**6.25**	**3.53**	**5.88**	**8.56**	**7.02**	3.95	3.46	2.94	3.85	5.54
Texas (HSC) *($/MMBtu)*	**8.67**	**6.37**	**9.98**	**10.58**	**7.73**	6.58	6.64	5.89	7.26	6.54
Basis Differential *($/MMBtu)*										
AECO/NYMEX	**1.23**	**1.10**	**1.28**	**1.71**	**0.84**	0.75	0.85	0.84	0.90	0.40
Rockies/NYMEX	**2.79**	**3.41**	**4.36**	**2.37**	**1.01**	2.91	3.50	3.22	3.70	1.23
Texas/NYMEX	**0.37**	**0.58**	**0.26**	**0.35**	**0.30**	0.28	0.33	0.27	0.29	0.23
Crude Oil Price Benchmarks										
WTI *($/bbl)*	**99.75**	**59.08**	**118.22**	**123.80**	**97.82**	72.41	90.50	75.15	65.02	58.23
WCS *($/bbl)*	**79.70**	**39.95**	**100.22**	**102.18**	**76.37**	49.50	56.85	52.71	45.84	41.77
Differential - WTI/WCS *($/bbl)*	**20.05**	**19.13**	**18.00**	**21.62**	**21.45**	22.91	33.65	22.44	19.18	16.46
Refining Margin Benchmark										
Chicago 3-2-1 Crack Spread *($/bbl)*(1)	**11.22**	**6.31**	**17.29**	**13.60**	**7.69**	17.67	9.17	18.48	30.12	12.90
Foreign Exchange										
U.S./Canadian Dollar Exchange Rate	**0.938**	**0.825**	**0.961**	**0.990**	**0.996**	0.930	1.019	0.957	0.911	0.854

(1) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of diesel. 2007 and 2008 values are calculated using Ultra Low Sulphur Diesel.

Consolidated Financial Results

($ millions, except per share amounts)	**2008**	**Q4**	**Q3**	**Q2**	**Q1**	2007	Q4	Q3	Q2	Q1	2006
Total Consolidated											
Cash Flow (1)	**$ 9,386**	**$ 1,299**	**$ 2,809**	**$ 2,889**	**$ 2,389**	$ 8,453	$ 1,934	$ 2,218	$ 2,549	$ 1,752	$ 7,161
- per share diluted	**12.48**	**1.73**	**3.74**	**3.85**	**3.17**	11.06	2.56	2.93	3.33	2.25	8.56
Net Earnings	**5,944**	**1,077**	**3,553**	**1,221**	**93**	3,959	1,082	934	1,446	497	5,652
- per share basic	**7.92**	**1.44**	**4.74**	**1.63**	**0.12**	5.23	1.44	1.24	1.91	0.65	6.89
- per share diluted	**7.91**	**1.43**	**4.73**	**1.63**	**0.12**	5.18	1.43	1.24	1.89	0.64	6.76
Operating Earnings (2)	**4,405**	**449**	**1,442**	**1,469**	**1,045**	4,100	849	1,032	1,369	850	3,271
- per share diluted	**5.86**	**0.60**	**1.92**	**1.96**	**1.39**	5.36	1.12	1.37	1.79	1.09	3.91
Total Assets	**47,247**					46,974					35,106
Total Long-Term Debt	**9,005**					9,543					6,834
Cash Dividends per share	**1.60**	**0.40**	**0.40**	**0.40**	**0.40**	0.80	0.20	0.20	0.20	0.20	0.375

Revenues, Net of Royalties	**30,064**	**6,359**	**10,849**	**7,422**	**5,434**	21,700	5,875	5,654	5,674	4,497	16,670

(1) Cash Flow is a non-GAAP measure and is defined under the Cash Flow section of this MD&A.

(2) Operating Earnings is a non-GAAP measure and is defined under the Operating Earnings section of this MD&A.

CASH FLOW

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. Cash Flow from Continuing Operations is a non-GAAP measure defined as cash flow excluding cash flow from discontinued operations. While cash flow measures are considered non-GAAP, they are commonly used in the oil and gas industry and by EnCana to assist Management and investors in measuring the Company s ability to finance capital programs and meet financial obligations.

Summary of Cash Flow

($ millions)		2008		2007		2006
Cash From Operating Activities	**$**	**8,855**	$	8,429	$	7,973
(Add back) deduct:						
Net change in other assets and liabilities		**(262)**		(16)		138
Net change in non-cash working capital		**(269)**		(8)		3,343
Net change in non-cash working capital from Discontinued Operations		**-**		-		(2,669)
Cash Flow	**$**	**9,386**	$	8,453	$	7,161

2008 versus 2007

Cash Flow in 2008 increased $933 million or 11 percent compared to 2007 as a result of:

Average total natural gas prices, excluding financial hedges, increased 35 percent to $7.94 per Mcf in 2008 compared to $5.89 per Mcf in 2007;

Average total liquids prices, excluding financial hedges, increased 53 percent to $76.58 per bbl in 2008 compared to $50.05 per bbl in 2007;

Natural gas production volumes in 2008 increased 8 percent to 3,838 million cubic feet (MMcf) per day (MMcf/d) from 3,566 MMcf/d in 2007; and

In addition to the reduction in current tax associated with realized financial hedging mentioned below, current income tax decreased primarily as a result of accelerated write-offs for certain U.S. capital expenditures and increased benefits from international financing partially offset by a one time tax recovery of $179 million in 2007 for a Canadian tax legislative change.

Cash Flow was reduced by:

Operating cash flows from downstream operations decreased $1,315 million primarily due to weaker refining margins and higher purchased product costs;

Realized financial natural gas, crude oil and other commodity hedging losses of $219 million after-tax in 2008 compared to gains of $1,023 million after-tax in 2007; and

Increases in transportation and selling, operating, production and mineral taxes, interest and administrative expenses in 2008 compared to 2007.

2007 versus 2006

EnCana s 2007 Cash Flow of $8,453 million increased $1,292 million or 18 percent compared to 2006 Cash Flow of $7,161 million.

Cash Flow from Continuing Operations in 2007 was $8,453 million (2006 $7,043 million). The decrease in Cash Flow from Discontinued Operations of $118 million was primarily due to the sales of the gas storage business and Ecuador assets in 2006 (discussed in the Discontinued Operations section of this MD&A).

The increase in Cash Flow from Continuing Operations in 2007 compared to 2006 resulted from:

Realized financial natural gas, crude oil and other commodity hedging gains were $1,023 million after-tax in 2007 compared to gains of $263 million after-tax in 2006;

Operating cash flows from downstream operations was $1,074 million in 2007 with no comparative amount in 2006;

Natural gas production volumes in 2007 increased 6 percent to 3,566 MMcf/d from 3,367 MMcf/d in 2006; and

Average North American liquids prices, excluding financial hedges, increased 15 percent to $50.05 per bbl in 2007 compared to $43.71 per bbl in 2006.

Cash Flow from Continuing Operations was reduced by:

Cash taxes were $1,554 million in 2007 compared to $942 million in 2006 primarily as a result of increased operating cash flows in the U.S. and higher realized financial hedging gains offset partially by a $179 million recovery due to a Canadian federal corporate tax legislative change;

Average North American natural gas prices, excluding financial hedges, decreased 6 percent to $5.89 per Mcf in 2007 compared to $6.25 per Mcf in 2006; and

North American liquids production volumes decreased 15 percent to 134,154 barrels per day (bbls/d) in 2007 from 157,273 bbls/d in 2006. This decrease reflects the increased production volumes at Foster Creek offset by EnCana s 50 percent contribution of the Foster Creek and Christina Lake properties to the joint venture with ConocoPhillips and natural declines in conventional properties.

Q4 2008 versus Q4 2007

Cash Flow in 2008 decreased $635 million or 33 percent compared to 2007 as a result of:

Operating cash flows from downstream operations decreased $760 million primarily due to weaker refining margins and higher purchased product costs;

Average total liquids prices, excluding financial hedges, decreased 43 percent to $33.81 per bbl in 2008 compared to $59.60 per bbl in 2007; and

Average total natural gas prices, excluding financial hedges, decreased 7 percent to $5.44 per Mcf in 2008 compared to $5.83 per Mcf in 2007.

Cash Flow was increased by:

Current income tax decreased primarily as a result of decreased cash flow in the quarter as well as accelerated write-offs for certain U.S. capital expenditures and increased benefits from international financing partially offset by the tax increase associated with realized financial hedging mentioned below;

Realized financial natural gas, crude oil and other commodity hedging gains of $439 million after-tax in 2008 compared to gains of $246 million after-tax in 2007; and

Natural gas production volumes in 2008 increased 4 percent to 3,858 MMcf/d from 3,722 MMcf/d in 2007.

NET EARNINGS

2008 versus 2007

EnCana s 2008 Net Earnings of $5,944 million were $1,985 million higher compared to 2007. Net Earnings are equal to Net Earnings from Continuing Operations in 2008. Net Earnings from Discontinued Operations of $75 million in 2007 were related to final adjustments on the December 2005 sale of the Company s Midstream NGLs processing operations.

EnCana s 2008 Net Earnings from Continuing Operations were $2,060 million higher compared to 2007. In addition to the items affecting Cash Flow from Continuing Operations as detailed previously, significant items affecting Net Earnings from Continuing Operations were:

Unrealized mark-to-market hedging gains of $1,818 million after-tax in 2008 compared to losses of $811 million after-tax in 2007;

A gain of $99 million after-tax from the sale of interests in Brazil in 2008 compared to gains of $59 million and $25 million after-tax from the sale of interests in Chad and assets in Australia, respectively, in 2007;

Depreciation, depletion and amortization (DD&A) increased $407 million in 2008 compared to 2007 primarily due to the increase in production volumes;

- Non-operating foreign exchange losses of $378 million after-tax in 2008 compared to gains of $217 million after-tax in 2007; and

- Future income tax increased primarily as a result of the unrealized mark-to-market hedging gains mentioned above, accelerated write-offs for certain U.S. capital expenditures and the effect of the reduction in Canadian federal corporate tax rates reflected in 2007 offset partially by a tax recovery on non-operating foreign exchange losses mentioned above.

2007 versus 2006

EnCana s 2007 Net Earnings were $3,959 million, a decrease of $1,693 million compared to 2006. Net Earnings from Discontinued Operations of $75 million in 2007 decreased $526 million from 2006 primarily due to sales of the gas storage business and Ecuador assets in 2006 (discussed in the Discontinued Operations section of this MD&A).

EnCana s 2007 Net Earnings from Continuing Operations were $3,884 million or $1,167 million lower than 2006. In addition to the items affecting Cash Flow from Continuing Operations as detailed previously, significant items affecting Net Earnings from Continuing Operations were:

Unrealized mark-to-market losses of $811 million after-tax in 2007 compared to gains of $1,357 million after-tax in 2006;

DD&A increased $704 million in 2007 compared to 2006 primarily due to higher future development costs, the higher U.S./Canadian dollar exchange rate and the increase in production volumes. In addition, downstream refining DD&A was $159 million in 2007 with no comparative amount in 2006;

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 in 2006;

Reductions in future income tax in addition to the impact detailed above related to the unrealized mark-to-market losses; and

Non-operating foreign exchange gains of $217 million after-tax in 2007 with no comparative amount in 2006.

Q4 2008 versus Q4 2007

EnCana s 2008 Net Earnings of $1,077 million were $5 million lower compared to 2007. In addition to the items affecting Cash Flow as detailed previously, significant items affecting Net Earnings were:

Non-operating foreign exchange losses of $119 million after-tax in 2008 compared to gains of $267 million after-tax in 2007;

Future income tax increased primarily as a result of the unrealized mark-to-market hedging gains mentioned above, accelerated write-offs for certain U.S. capital expenditures and the effect of the reduction in Canadian federal corporate tax rates reflected in the fourth quarter of 2007 offset partially by a tax recovery on non-operating foreign exchange losses mentioned below;

DD&A decreased $90 million in 2008 compared to 2007 primarily due to the lower U.S./Canadian dollar exchange rate and lower international impairments offset partially by the increase in production volumes; and

Unrealized mark-to-market hedging gains of $747 million after-tax in 2008 compared to losses of $366 million after-tax in 2007.

OPERATING EARNINGS

Operating Earnings is a non-GAAP measure that adjusts Net Earnings by non-operating items that Management believes reduces the comparability of the Company s underlying financial performance between periods. The following reconciliation of Operating Earnings has been prepared to provide investors with information that is more comparable between periods.

Summary of Operating Earnings

($ millions, except per share amounts)	2008	Per share(5)	2007	Per share(5)	2006	Per share(5)
Net Earnings, as reported	**$ 5,944**	**$ 7.91**	$ 3,959	$ 5.18	$ 5,652	$ 6.76
Add back (losses) and deduct gains:						
Unrealized mark-to-market accounting gain (loss), after-tax	**1,818**	**2.42**	(811)	(1.06)	1,370	1.64
Non-operating foreign exchange gain (loss), after-tax (1)	**(378)**	**(0.50)**	217	0.28	-	-
Gain (loss) on discontinuance, after-tax (2)	**99**	**0.13**	152	0.20	554	0.66
Future tax recovery due to tax rate reductions	**-**	**-**	301	0.40	457	0.55
Operating Earnings (3) (4)	**$ 4,405**	**$** 5.86	$ 4,100	$ 5.36	$ 3,271	$ 3.91

(1) Unrealized foreign exchange gain (loss) on translation of Canadian issued US dollar debt, the partnership contribution receivable, realized foreign exchange gain (loss) on settlement of intercompany transactions, after-tax and future income tax on foreign exchange related to US dollar intercompany debt recognized for tax purposes only. The majority of US dollar debt issued from Canada has maturity dates in excess of five years.

(2) For 2008, gain on sale of interests in Brazil. For 2007, gain on sale of Australia assets and interests in Chad as well as final adjustments on the NGL processing business sold in 2005. For 2006, gain on sale of storage facilities and interests in Ecuador.

(3) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gain/loss on discontinuance, after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of US dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains/losses on settlement of intercompany transactions, future income tax on foreign exchange related to US dollar intercompany debt recognized for tax purposes only and the effect of changes in statutory income tax rates. In 2007, EnCana changed its calculation of Operating Earnings to exclude the foreign exchange effects on settlement of significant intercompany transactions to provide information that is more comparable between periods.

(4) Unrealized gains or losses and realized foreign exchange gains or losses on settlement of intercompany transactions have no impact on Cash Flow.

(5) Per Common Share - diluted.

FOREIGN EXCHANGE

As disclosed in the Business Environment section of this MD&A, the average U.S./Canadian dollar exchange rate increased 1 percent to $0.938 in 2008 compared to $0.930 in 2007. The table below summarizes the quarterly and total year impacts of these changes on EnCana s operations when compared to the same periods in the prior years.

	2008		Q4		Q3		Q2		Q1		2007	
Average U.S./Canadian Dollar Exchange Rate	**$ 0.938**		$ 0.825		$ 0.961		$ 0.990		$ 0.996		$ 0.930	
Change from comparative period in prior year	**0.008**		(0.194)		0.004		0.079		0.142		0.048	
($ millions, except $/Mcfe amounts)	**$**	**/Mcfe**	$	/Mcfe	$	/Mcfe	$	/Mcfe	$	/Mcfe	$	/Mcfe
Increase (decrease) in:												
Capital Investment	**$ 10**		$ (212)		$ 2		$ 57		$ 163		$ 199	
Operating Expense	**11**	**0.01**	(63)	(0.15)	1	-	24	0.06	48	0.13	68	0.04
Administrative Expense	**4**	**-**	(17)	(0.04)	1	-	6	0.01	14	0.04	18	0.01
DD&A Expense	**16**		(127)		2		51		90		130	

RESULTS OF OPERATIONS

Production Volumes

	2008	**Q4**	**Q3**	**Q2**	**Q1**	2007	Q4	Q3	Q2	Q1	2006
Produced Gas *(MMcf/d)*											
Canadian Plains	**842**	**820**	**831**	**856**	**860**	875	876	858	874	891	906
Canadian Foothills	**1,300**	**1,302**	**1,351**	**1,289**	**1,256**	1,255	1,313	1,280	1,231	1,196	1,166
USA	**1,633**	**1,677**	**1,674**	**1,629**	**1,552**	1,345	1,464	1,387	1,303	1,222	1,182
Integrated Oil - Other(1)	**63**	**59**	**61**	**67**	**65**	91	69	105	98	91	113
	3,838	**3,858**	**3,917**	**3,841**	**3,733**	3,566	3,722	3,630	3,506	3,400	3,367
Crude Oil *(bbls/d)* (2)											
Canadian Plains	**66,157**	**64,990**	**64,789**	**65,097**	**69,781**	70,940	70,287	70,711	70,148	72,639	75,612
Canadian Foothills	**8,473**	**8,437**	**8,217**	**8,376**	**8,867**	8,216	8,441	7,978	7,959	8,489	9,037
Foster Creek/Christina Lake	**30,183**	**35,068**	**31,547**	**24,671**	**29,376**	26,814	27,190	28,740	27,994	23,269	42,768
Integrated Oil - Other(1)	**2,729**	**2,133**	**2,273**	**3,009**	**3,514**	2,688	3,040	2,235	2,489	2,990	5,185
	107,542	**110,628**	**106,826**	**101,153**	**111,538**	108,658	108,958	109,664	108,590	107,387	132,602
NGLs *(bbls/d)* (2)											
Canadian Plains	**1,181**	**1,126**	**1,147**	**1,189**	**1,262**	1,260	1,422	1,209	1,206	1,203	1,380
Canadian Foothills	**11,507**	**11,265**	**11,730**	**11,779**	**11,256**	10,056	10,966	9,932	9,811	9,497	10,333
USA	**13,350**	**12,831**	**13,853**	**13,482**	**13,232**	14,180	14,791	15,578	13,809	12,503	12,958
	26,038	**25,222**	**26,730**	**26,450**	**25,750**	25,496	27,179	26,719	24,826	23,203	24,671
Continuing Operations *(MMcfe/d)* (3)	**4,639**	**4,673**	**4,718**	**4,607**	**4,557**	4,371	4,539	4,448	4,306	4,184	4,311
Discontinued Operations Ecuador *(bbls/d)*(4)	**-**	**-**	**-**	**-**	**-**	-	-	-	-	-	11,996
Discontinued Operations *(MMcfe/d)* (3)	**-**	**-**	**-**	**-**	**-**	-	-	-	-	-	72
Total *(MMcfe/d)* (3)	**4,639**	**4,673**	**4,718**	**4,607**	**4,557**	4,371	4,539	4,448	4,306	4,184	4,383

(1) Volumes related to operating areas outside of Foster Creek and Christina Lake including Athabasca (gas) and Senlac (crude oil).

(2) Crude oil and NGLs production in 2007 and 2006 were restated in the second quarter of 2008 to reflect the reclassification of oil to NGLs in the USA.

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

(4) Ecuador interests sold on February 28, 2006.

Key Resource Plays

	Daily Production					Drilling Activity (net wells drilled)		
	2008	**2008 vs 2007**	2007	2007 vs 2006	2006	**2008**	2007	2006
Natural Gas *(MMcf/d)*								
Jonah	**603**	**8%**	557	20%	464	**175**	135	163
Piceance	**385**	**11%**	348	7%	326	**328**	286	220
East Texas	**334**	**134%**	143	44%	99	**78**	35	59
Fort Worth	**142**	**15%**	124	23%	101	**83**	75	97
Greater Sierra	**220**	**4%**	211	-1%	213	**106**	109	115
Cutbank Ridge(1)	**296**	**15%**	258	37%	189	**82**	93	134
Bighorn(1)	**167**	**33%**	126	30%	97	**64**	62	58
CBM	**304**	**17%**	259	34%	194	**698**	1,079	729
Shallow Gas	**700**	**-4%**	726	-2%	739	**1,195**	1,914	1,310
	3,151	**14%**	2,752	14%	2,422	**2,809**	3,788	2,885
Oil *(bbls/d)*								
Foster Creek(2)	**25,947**	**7%**	24,262	31%	18,455	**20**	23	3
Christina Lake(2)	**4,236**	**66%**	2,552	-13%	2,929	**-**	3	1
	30,183	**13%**	26,814	25%	21,384	**20**	26	4
Pelican Lake	**21,975**	**-5%**	23,253	-1%	23,562	**-**	-	-
Weyburn	**14,031**	**-5%**	14,771	-2%	15,132	**21**	37	35
	66,189	**2%**	64,838	8%	60,078	**41**	63	39
Total *(MMcfe/d)* (3)	**3,548**	**13%**	3,141	13%	2,782	**2,850**	3,851	2,924

(1) Key resource play production and wells drilled information in 2007 and 2006 for Cutbank Ridge and Bighorn were restated in the first quarter of 2008 to include the addition of new areas and zones that now qualify for key resource play inclusion based on EnCana s internal criteria.

(2) Key resource play production and wells drilled information in 2006 have been adjusted on a pro forma basis to reflect the 50 percent contribution of Foster Creek and Christina Lake to the business venture with ConocoPhillips in 2007.

(3) Total key resource play production and wells drilled information in 2007 and 2006 were restated in the first quarter of 2008 to include the designation of Weyburn as an oil key resource play.

Production volumes increased 6 percent or 268 MMcfe/d in 2008 compared to 2007 due to increased production from EnCana s natural gas key resource plays of 14 percent and oil key resource plays of 2 percent offset partially by natural declines in conventional properties and the volume impact of minor property divestitures.

CANADIAN PLAINS

PRODUCED GAS

Financial Results

($ millions, except per unit amounts in $ per thousand cubic feet)	Canadian Plains											
	2008				2007				2006			
				$/Mcf				**$/Mcf**				**$/Mcf**
Revenues, Net of Royalties / Price	**$**	**2,392**	**$**	**7.77**	$	1,946	$	6.10	$	2,021	$	6.11
Realized Financial Hedging Gain (Loss)		**(91)**				240				192		
Expenses												
Production and mineral taxes		**36**		**0.12**		34		0.11		41		0.12
Transportation and selling		**71**		**0.23**		82		0.26		77		0.23
Operating		**241**		**0.78**		221		0.69		194		0.59
Operating Cash Flow / Netback (1)	**$**	**1,953**	**$**	**6.64**	$	1,849	$	5.04	$	1,901	$	5.17
Netback including Realized Financial Hedging			**$**	**6.35**			$	5.79			$	5.75
Gas Production Volumes *(MMcf/d)*				**842**				875				906

(1) Netback excludes the impact of realized financial hedging.

Produced Gas Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price(1)	Volume	**2008 Revenues Net of Royalties**
Canadian Plains	$ 2,186	$ 199	$ (84)	**$ 2,301**

(1) Includes the impact of realized financial hedging.

2008 versus 2007

Revenues, net of royalties, increased in 2008 compared to 2007 due to:

A 27 percent increase in natural gas prices, excluding the impact of financial hedging;

offset by:

Realized financial hedging losses of $91 million or $0.29 per Mcf in 2008 compared to gains of $240 million or $0.75 per Mcf in 2007; and

A 4 percent decrease in natural gas production volumes. Production added as a result of infill drilling and recompletion programs were offset by expected natural declines for the Shallow Gas key resource play and conventional properties.

The increase in Canadian Plains natural gas price in 2008, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Realized natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas per unit operating expenses for the Canadian Plains in 2008 were 13 percent or $0.09 per Mcf higher than in 2007 primarily as a result of higher property tax and lease costs, workovers and repairs and maintenance offset by lower long-term compensation costs due to the change in the EnCana share price. In addition, with a relatively high proportion of fixed costs, lower production volumes also contributed to increased per unit costs.

2007 versus 2006

Revenues, net of royalties, decreased in 2007 compared to 2006 due to:

A 3 percent decrease in natural gas production volumes. Production added as a result of infill drilling and recompletion programs was offset by natural declines for the Shallow Gas key resource play and conventional properties;

offset by:

Realized financial hedging gains of $240 million or $0.75 per Mcf in 2007 compared to gains of $192 million or $0.58 per Mcf in 2006.

Canadian Plains natural gas price in 2007, excluding the impact of financial hedges, remained relatively unchanged from 2006 and reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials.

Natural gas per unit operating expenses for the Canadian Plains in 2007 were 17 percent or $0.10 per Mcf higher than in 2006 as a result of the higher U.S./Canadian dollar exchange rate, higher long-term compensation costs, increased property tax and lease costs and higher repairs and maintenance expenses offset partially by decreased electricity costs due to lower electricity prices.

CRUDE OIL AND NGLs

Financial Results

($ millions)	Canadian Plains		
	2008	2007	2006
Revenues, Net of Royalties	**$ 2,106**	$ 1,453	$ 1,337
Expenses			
Production and mineral taxes	**38**	29	31
Transportation and selling	**321**	263	276
Operating	**239**	215	188
Operating Cash Flow	**$ 1,508**	$ 946	$ 842

Crude Oil and NGLs Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price(1)	Volume	Other(2)	**2008 Revenues Net of Royalties**
Canadian Plains	$ 1,453	$ 702	$ (101)	$ 52	**$ 2,106**

(1) Includes the impact of realized financial hedging.

(2) Revenue dollars reported include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and selling expense.

2008 versus 2007

Revenues, net of royalties, increased in 2008 compared to 2007 due to:

A 59 percent increase in crude oil prices and 32 percent increase in NGLs prices, excluding financial hedges;

offset by:

Realized financial hedging losses on liquids of $150 million or $6.02 per bbl in 2008 compared to losses of $87 million or $3.32 per bbl in 2007.

Production from the Pelican Lake key resource play in 2008 was 21,975 bbls/d, down 5 percent compared to 2007 due primarily to plant down time and treating issues. Production from the Weyburn key resource play of 14,031 bbls/d was down 5 percent mainly due to expected natural declines offset by production additions from the infill drilling program. At Suffield, production of 12,971 bbls/d was down 17 percent mainly due to natural declines and the delay in well tie-ins. Overall, Canadian Plains crude oil production decreased 7 percent.

2007 versus 2006

Revenues, net of royalties, increased in 2007 compared to 2006 due to:

A 15 percent increase in crude oil prices and 17 percent increase in NGLs prices, excluding financial hedges; and

Realized financial hedging losses on liquids of $87 million or $3.32 per bbl in 2007 compared to losses of $100 million or $3.67 per bbl in 2006;

offset by:

A 6 percent decrease in crude oil production volumes primarily due to natural declines in production from conventional properties. Production from the key resource plays of Pelican Lake and Weyburn remained relatively unchanged year-over-year while production of 15,563 bbls/d at Suffield was down 10 percent from 2006.

Per Unit Results Crude Oil

($ per barrel)		Canadian Plains	
	2008	2007	2006
Price (1)(2)	**$ 79.09**	$ 49.62	$ 43.31
Expenses			
Production and mineral taxes	**1.57**	1.11	1.17
Transportation and selling	**1.41**	1.24	0.79
Operating	**9.74**	8.33	7.03
Netback	**$ 66.37**	$ 38.94	$ 34.32
Crude Oil Production Volumes *(bbls/d)*	**66,157**	70,940	75,612

(1) Excludes the impact of realized financial hedging.

(2) Represents blend sales price net of purchased condensate costs.

2008 versus 2007

Canadian Plains crude oil prices increased in 2008 as a result of the changes in benchmark WTI and WCS crude oil prices as well as lower average differentials. Total realized financial hedging losses on crude oil for Canadian Plains were approximately $147 million or $6.02 per bbl in 2008 compared to losses of approximately $85 million or $3.31 per bbl in 2007.

Crude oil per unit production and mineral taxes for the Canadian Plains increased 41 percent or $0.46 per bbl in 2008 compared to 2007 primarily due to higher crude oil prices.

Crude oil per unit transportation and selling costs for the Canadian Plains increased 14 percent or $0.17 per bbl in 2008 compared to 2007 due to additional clean oil trucking costs at Pelican Lake offset by lower clean oil trucking costs at Weyburn.

Crude oil per unit operating costs for the Canadian Plains in 2008 increased 17 percent or $1.41 per bbl compared to 2007 mainly due to increased workovers, property tax and lease costs, salaries and benefits and chemical costs combined with lower overall crude oil volumes offset by lower long-term compensation costs due to the change in the EnCana share price.

2007 versus 2006

Canadian Plains crude oil prices in 2007 increased 15 percent compared to 2006. This increase reflects the changes in benchmark WTI and WCS crude oil prices. Total realized financial hedging losses on crude oil were approximately $85 million or $3.31 per bbl in 2007 compared to losses of approximately $98 million or $3.68 per bbl in 2006.

Crude oil per unit transportation and selling costs for the Canadian Plains increased 57 percent or $0.45 per bbl in 2007 compared to 2006 due to increased clean oil trucking costs at Weyburn and the higher U.S./Canadian dollar exchange rate.

Crude oil per unit operating costs for the Canadian Plains in 2007 increased 18 percent or $1.30 per bbl compared to 2006 mainly due to the higher U.S./Canadian dollar exchange rate, increased workovers, higher long-term compensation costs and increased chemicals offset partially by decreased electricity costs due to lower electricity prices.

Per Unit Results   NGLs

NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas.

2008 versus 2007

NGLs production volumes were 1,181 bbls/d in 2008 compared to 1,260 bbls/d in 2007, which is consistent with declining gas production. NGLs prices increased 32 percent to $78.91 per bbl in 2008 from $59.98 per bbl in 2007, which is consistent with the higher WTI benchmark price.

2007 versus 2006

NGLs production volumes were 1,260 bbls/d in 2007 compared to 1,380 bbls/d in 2006, which is consistent with declining gas production. NGLs prices increased 17 percent to $59.98 per bbl in 2007 compared to $51.10 per bbl in 2006, which is consistent with the higher WTI benchmark price.

CANADIAN FOOTHILLS

PRODUCED GAS

Financial Results

($ millions, except per unit amounts in $ per thousand cubic feet)	Canadian Foothills					
	2008		2007		2006	
		$/Mcf		**$/Mcf**		**$/Mcf**
Revenues, Net of Royalties / Price	**$ 3,862**	**$ 8.12**	$ 2,885	$ 6.30	$ 2,681	$ 6.30
Realized Financial Hedging Gain (Loss)	**(142)**		347		255	
Expenses						
Production and mineral taxes	**28**	**0.06**	36	0.08	39	0.09
Transportation and selling	**201**	**0.42**	192	0.42	186	0.44
Operating	**549**	**1.15**	482	1.05	394	0.92
Operating Cash Flow / Netback (1)	**$ 2,942**	**$ 6.49**	$ 2,522	$ 4.75	$ 2,317	$ 4.85
Netback including Realized Financial Hedging		**$ 6.19**		$ 5.51		$ 5.45
Gas Production Volumes *(MMcf/d)*		**1,300**		1,255		1,166

(1) Netback excludes the impact of realized financial hedging.

Produced Gas Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price(1)	Volume	**2008 Revenues Net of Royalties**
Canadian Foothills	$ 3,232	$ 349	$ 139	**$ 3,720**

(1) Includes the impact of realized financial hedging.

2008 versus 2007

Revenues, net of royalties, increased in 2008 compared to 2007 due to:

A 29 percent increase in natural gas prices, excluding the impact of financial hedging; and

A 4 percent increase in natural gas production volumes;

offset by:

Realized financial hedging losses of $142 million or $0.30 per Mcf in 2008 compared to gains of $347 million or $0.76 per Mcf in 2007.

Produced gas volumes in the Canadian Foothills increased in 2008 due to drilling success as well as increased tie-in and completion activity in the key resource plays of CBM, Bighorn and Cutbank Ridge offset partially by natural declines for conventional properties.

The increase in Canadian Foothills natural gas price in 2008, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Realized natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas per unit operating expenses for the Canadian Foothills in 2008 were 10 percent or $0.10 per Mcf higher than in 2007 primarily as a result of higher repairs and maintenance due to scheduled plant turnarounds, increased gathering and processing, salaries and benefits, workovers, property tax and lease costs offset by lower long-term compensation costs due to the change in the EnCana share price.

2007 versus 2006

Revenues, net of royalties, increased in 2007 compared to 2006 due to:

Realized financial hedging gains of $347 million or $0.76 per Mcf in 2007 compared to gains of $255 million or $0.60 per Mcf in 2006; and

An 8 percent increase in Canadian Foothills natural gas production volumes.

Produced gas volumes in the Canadian Foothills increased in 2007 as a result of drilling success and new facilities in the key resource plays of CBM, Cutbank Ridge and Bighorn offset partially by natural declines for conventional properties.

The change in Canadian Foothills natural gas prices in 2007, excluding the impact of financial hedges, reflects the changes in AECO and NYMEX benchmark prices and changes in the basis differentials. Realized natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas per unit operating expenses for the Canadian Foothills in 2007 were 14 percent or $0.13 per Mcf higher than in 2006 as a result of the higher U.S./Canadian dollar exchange rate, higher repairs and maintenance expenses and increased property tax and lease costs offset partially by decreased electricity costs. Operating costs were also impacted by higher long-term compensation costs in 2007 compared to 2006 due to the change in the EnCana share price.

CRUDE OIL AND NGLs

Financial Results

($ millions)	Canadian Foothills		
	2008	2007	2006
Revenues, Net of Royalties	**$ 578**	$ 390	$ 360
Expenses			
Production and mineral taxes	**5**	3	4
Transportation and selling	**12**	9	8
Operating	**39**	33	34
Operating Cash Flow	**$ 522**	$ 345	$ 314

Crude Oil and NGLs Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price(1)	Volume	**2008 Revenues Net of Royalties**
Canadian Foothills	$ 390	$ 138	$ 50	**$ 578**

(1) Includes the impact of realized financial hedging.

2008 versus 2007

Revenues, net of royalties, increased in 2008 compared to 2007 due to:

A 42 percent increase in crude oil prices and 35 percent increase in NGLs prices, excluding financial hedges;

offset by:

Realized financial hedging losses on liquids of $44 million or $6.08 per bbl in 2008 compared to losses of $23 million or $3.37 per bbl in 2007.

2007 versus 2006

Revenues, net of royalties, increased in 2007 compared to 2006 due to:

A 12 percent increase in crude oil prices and 16 percent increase in NGLs prices, excluding financial hedges; and

Realized financial hedging losses on liquids of $23 million or $3.37 per bbl in 2007 compared to losses of $25 million or $3.57 per bbl in 2006.

Per Unit Results Crude Oil

($ per barrel)	Canadian Foothills		
	2008	2007	2006
Price (1)	**$ 91.78**	$ 64.63	$ 57.74
Expenses			
Production and mineral taxes	**1.48**	1.05	1.27
Transportation and selling	**2.07**	1.77	1.41
Operating	**12.75**	10.84	10.21
Netback	**$ 75.48**	$ 50.97	$ 44.85
Crude Oil Production Volumes *(bbls/d)*	**8,473**	8,216	9,037

(1) Excludes the impact of realized financial hedging.

2008 versus 2007

Canadian Foothills crude oil prices increased in 2008 as a result of the changes in benchmark WTI and WCS crude oil prices as well as lower average differentials. Total realized financial hedging losses on crude oil for Canadian Foothills were approximately $18 million or $5.93 per bbl in 2008 compared to losses of approximately $10 million or $3.32 per bbl in 2007.

Canadian Foothills crude oil per unit production and mineral taxes increased 41 percent or $0.43 per bbl in 2008 compared to 2007 primarily due to higher crude oil prices.

Canadian Foothills crude oil per unit transportation and selling increased 17 percent or $0.30 per bbl in 2008 compared to 2007 primarily due to higher transportation rates.

Canadian Foothills crude oil per unit operating costs in 2008 increased 18 percent or $1.91 per bbl compared to 2007 mainly due to higher electricity, repairs and maintenance and chemicals costs offset by lower purchased fuel costs.

2007 versus 2006

Canadian Foothills crude oil prices increased in 2007 as a result of the changes in benchmark WTI and WCS crude oil prices offset partially by higher average differentials. Total realized financial hedging losses on crude oil for Canadian Foothills were approximately $10 million or $3.32 per bbl in 2007 compared to losses of approximately $12 million or $3.58 per bbl in 2006.

Canadian Foothills crude oil per unit production and mineral taxes decreased 17 percent or $0.22 per bbl in 2007 compared to 2006 primarily due to lower royalty income volumes in 2007 compared to 2006.

Canadian Foothills crude oil per unit transportation and selling costs increased 26 percent or $0.36 per bbl in 2007 compared to 2006 due to the higher U.S./Canadian dollar exchange rate and additional marketing costs.

Canadian Foothills crude oil per unit operating costs in 2007 increased 6 percent or $0.63 per bbl compared to 2006 mainly due to the higher U.S./Canadian dollar exchange rate, increased workovers, property tax and lease costs offset partially by lower gathering and processing and electricity costs.

Per Unit Results NGLs

NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas.

2008 versus 2007

NGLs production volumes were 11,507 bbls/d in 2008 compared to 10,056 bbls/d in 2007. Average NGLs prices increased 35 percent to $80.22 per bbl in 2008 from $59.26 per bbl in 2007, which is consistent with the higher WTI benchmark price.

2007 versus 2006

NGLs production volumes were 10,056 bbls/d in 2007 compared to 10,333 bbls/d in 2006. Average NGLs prices increased 16 percent to $59.26 per bbl in 2007 from $51.12 per bbl in 2006, which is consistent with the higher WTI benchmark price.

USA

PRODUCED GAS

Financial Results

($ millions, except per unit amounts in $ per thousand cubic feet)	USA					
	2008		2007		2006	
		$/Mcf		**$/Mcf**		**$/Mcf**
Revenues, Net of Royalties / Price	**$ 4,718**	**$ 7.89**	$ 2,641	$ 5.38	$ 2,742	$ 6.35
Realized Financial Hedging Gain (Loss)	**216**		1,124		112	
Expenses						
Production and mineral taxes	**334**	**0.56**	167	0.34	213	0.49
Transportation and selling	**502**	**0.84**	307	0.62	248	0.54
Operating	**352**	**0.59**	323	0.65	283	0.65
Operating Cash Flow / Netback (1)	**$ 3,746**	**$ 5.90**	$ 2,968	$ 3.77	$ 2,110	$ 4.67
Netback including Realized Financial Hedging		**$ 6.26**		$ 6.06		$ 4.93
Gas Production Volumes *(MMcf/d)*		**1,633**		1,345		1,182

(1) Netback excludes the impact of realized financial hedging.

Produced Gas Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price(1)	Volume	**2008 Revenues Net of Royalties**
USA	$ 3,765	$ 288	$ 881	**$ 4,934**

(1) Includes the impact of realized financial hedging.

2008 versus 2007

Revenues, net of royalties, increased in 2008 compared to 2007 due to:

A 47 percent increase in natural gas prices, excluding the impact of financial hedging; and

A 21 percent increase in natural gas production volumes;

offset by:

Realized financial hedging gains of $216 million or $0.36 per Mcf in 2008 compared to gains of $1,124 million or $2.29 per Mcf in 2007.

Produced gas volumes in the USA increased in 2008 as a result of drilling and operational success at East Texas, Jonah, Piceance and Fort Worth as well as incremental volumes from the Deep Bossier acquisition and upgrades to the compression and gathering facilities at Jonah. These increases were slightly offset by the impact of shut-in production (approximately 100 MMcf/d) at Piceance and Jonah during the fourth quarter of 2008 due to the low price environment.

The increase in USA natural gas prices in 2008, excluding the impact of financial hedges, reflects the changes in NYMEX and Rockies (Opal) benchmark prices and changes in the basis differentials. Realized natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas per unit production and mineral taxes in the USA increased 65 percent or $0.22 per Mcf in 2008 compared to 2007 primarily as a result of higher natural gas prices.

Natural gas per unit transportation and selling costs for the USA increased 35 percent or $0.22 per Mcf in 2008 compared to 2007 as a result of higher unutilized transportation commitments as well as transporting gas greater distances on the Rockies Express Pipeline to improve price realizations.

Natural gas per unit operating expenses for the USA in 2008 were 9 percent lower or $0.06 per Mcf lower than in 2007 due to a high proportion of fixed costs spread over increased production volumes and lower long-term compensation costs offset slightly by increased salaries and benefits, water disposal, repairs and maintenance and workover costs.

2007 versus 2006

Revenues, net of royalties, increased in 2007 compared to 2006 due to:

- Realized financial hedging gains of $1,124 million or $2.29 per Mcf in 2007 compared to gains of $112 million or $0.26 per Mcf in 2006; and

- A 14 percent increase in natural gas production volumes;

offset by:

- A 15 percent decrease in natural gas prices, excluding the impact of financial hedging.

Produced gas volumes in the USA increased in 2007 as a result of drilling and operational success as well as new facilities at Jonah, East Texas, Fort Worth and Piceance. Fourth quarter 2007 produced gas volumes in the USA also benefited slightly from incremental volumes from the Deep Bossier acquisition (approximately 34 MMcf/d).

The change in USA natural gas prices in 2007, excluding the impact of financial hedges, reflects the changes in NYMEX and Rockies (Opal) benchmark prices and changes in the basis differentials. Realized natural gas prices also reflect the variability caused by relative prices and volume weightings at given sales points.

Natural gas per unit production and mineral taxes in the USA decreased 31 percent or $0.15 per Mcf in 2007 compared to 2006 mainly as a result of lower natural gas prices in the U.S. Rockies and a reduction in the severance and ad valorem effective tax rate for Colorado properties.

Natural gas per unit transportation and selling costs for the USA increased 15 percent or $0.08 per Mcf in 2007 compared to 2006 primarily as a result of higher transportation rates in the Piceance area.

CRUDE OIL AND NGLs

All of EnCana s liquids production in the USA relates to NGLs.

Financial Results

($ millions)		USA	
	2008	2007	2006
Revenues, Net of Royalties	**$ 407**	$ 309	$ 267
Expenses			
Production and mineral taxes	**36**	22	20
Operating Cash Flow	**$ 371**	$ 287	$ 247

Crude Oil and NGLs Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price(1)	Volume	**2008 Revenues Net of Royalties**
USA	$ 309	$ 122	$ (24)	**$ 407**

(1) Includes the impact of realized financial hedging.

Per Unit Results NGLs

NGLs are a byproduct obtained through the production of natural gas. As a result, operating costs associated with the production of NGLs are included with produced gas.

2008 versus 2007

NGLs production volumes were 13,350 bbls/d in 2008 compared to 14,180 bbls/d in 2007. Average NGLs prices increased 39 percent to $83.18 per bbl in 2008 from $59.83 per bbl in 2007, which is consistent with the higher WTI benchmark price.

2007 versus 2006

NGLs production volumes were 14,180 bbls/d in 2007 compared to 12,958 bbls/d in 2006. Average NGLs prices increased 6 percent to $59.83 per bbl in 2007 from $56.33 per bbl in 2006, which is consistent with the higher WTI benchmark price.

INTEGRATED OIL

FOSTER CREEK/CHRISTINA LAKE OPERATIONS

On January 2, 2007, EnCana became a 50 percent partner in an integrated North American oil business with ConocoPhillips that consists of an upstream and a downstream entity. The upstream entity includes contributed assets from EnCana, primarily the Foster Creek and Christina Lake oil properties while the downstream entity includes ConocoPhillips Wood River and Borger refineries located in Illinois and Texas, respectively.

The current plan of the upstream business is to increase production capacity at Foster Creek/Christina Lake to approximately 218,000 bbls/d of bitumen with the completion of current expansion phases.

Financial Results

($ millions)	Foster Creek/Christina Lake		
	2008	2007	2006
Revenues, Net of Royalties	**$ 1,117**	$ 738	$ 941
Expenses			
Transportation and selling	**526**	366	476
Operating	**170**	159	194
Operating Cash Flow	**$ 421**	$ 213	$ 271

Crude Oil Revenue Variances

($ millions)	2007 Revenues Net of Royalties	Revenue Variances in: Price(1)	Volume	Other(2)	**2008 Revenues Net of Royalties**
Foster Creek/ Christina Lake	$ 738	$ 217	$ (4)	$ 166	**$ 1,117**

(1) Includes the impact of realized financial hedging.

(2) Revenue dollars reported include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and selling expense.

2008 versus 2007

Revenues, net of royalties, increased in 2008 compared to 2007 due to:

- An increase in crude oil prices, excluding financial hedges;
- An increase in average condensate prices; and

Relatively unchanged crude oil sales volumes attributable to a 13 percent increase in production volumes offset by changes in inventory levels;

offset by:

Realized financial hedging losses of $67 million or $6.11 per bbl in 2008 compared to losses of $43 million or $3.88 per bbl in 2007.

2007 versus 2006

Revenues, net of royalties, decreased in 2007 compared to 2006 due to:

A 37 percent decrease in Foster Creek/Christina Lake crude oil production volumes as a result of the joint venture with ConocoPhillips partially offset by a 10 percent increase in crude oil prices, excluding financial hedges. Production volumes on a pro forma basis, after reflecting 100 percent of Foster Creek and Christina Lake production, grew 25 percent to 53,628 bbls/d in 2007 compared to 2006; and

Lower condensate purchased for bitumen blending at Foster Creek/Christina Lake as a result of the joint venture with ConocoPhillips;

offset by:

Realized financial hedging losses of $43 million or $3.88 per bbl in 2007 compared to losses of $62 million or $3.98 per bbl in 2006.

Per Unit Results Crude Oil

($ per barrel)	Foster Creek/Christina Lake		
	2008	2007	2006
Price (1)(2)(3)	**$ 62.44**	$ 40.14	$ 36.49
Expenses			
Transportation and selling	**2.36**	2.88	2.64
Operating	**15.53**	14.46	12.38
Netback	**$ 44.55**	$ 22.80	$ 21.47
Crude Oil Production Volumes *(bbls/d)*	**30,183**	26,814	42,768
Pro forma Production Volumes *(bbls/d)* (4)	**30,183**	26,814	21,384

(1) Excludes the impact of realized financial hedging.

(2) Represents blend sales price net of purchased condensate costs.

(3) 2008 price includes a reduction of $4.26 per barrel related to the impact of a write-down to net realizable value of condensate inventories (2007 nil; 2006 nil).

(4) 2006 production volumes adjusted on a pro forma basis to reflect the 50 percent contribution of Foster Creek and Christina Lake to the business venture with ConocoPhillips in 2007.

2008 versus 2007

Foster Creek/Christina Lake crude oil prices increased in 2008 as a result of the changes in benchmark WTI and WCS crude oil prices as well as lower average differentials. WCS as a percentage of WTI was 80 percent in 2008 compared to 68 percent in 2007.

Foster Creek/Christina Lake crude oil per unit transportation and selling costs in 2008 decreased 18 percent or $0.52 per bbl compared to 2007 due to variability in sales destinations and pipelines utilized to transport the product.

Foster Creek/Christina Lake crude oil per unit operating costs increased 7 percent or $1.07 per bbl in 2008 compared to 2007. The increase is mainly due to increased workovers and staff levels offset by lower long-term compensation costs due to the change in the EnCana share price.

2007 versus 2006

Foster Creek/Christina Lake crude oil prices in 2007 increased 10 percent compared to 2006. This increase reflects the changes in benchmark WTI and WCS crude oil prices compared to 2006.

Foster Creek/Christina Lake crude oil per unit transportation and selling costs in 2007 increased 9 percent or $0.24 per bbl compared to 2006 due to a higher percentage of volumes being delivered to the U.S. Gulf Coast in 2007 compared to 2006 and the higher U.S./Canadian dollar exchange rate.

Foster Creek/Christina Lake crude oil per unit operating costs increased 17 percent or $2.08 per bbl in 2007 compared to 2006. This reflected increased purchased fuel costs at Foster Creek to steam new well pairs prior to commencing production, increased repairs and maintenance, salaries and benefits and chemicals. In addition, operating costs for 2007 compared to 2006 were impacted by the higher U.S./Canadian dollar exchange rate and higher long-term compensation costs due to the change in the EnCana share price.

DOWNSTREAM OPERATIONS

Financial Results

($ millions)	2008	2007
Revenues	**$ 9,011**	$ 7,315
Expenses		
Operating	**492**	428
Purchased product	**8,760**	5,813
Operating Cash Flow	**$ (241)**	$ 1,074

The downstream business commenced on January 2, 2007 when EnCana became a 50 percent partner in the entity that owns the Wood River and Borger refineries operated by ConocoPhillips.

The Wood River refinery, located in Roxana, Illinois, has a current capacity of approximately 306,000 bbls/d of crude oil (on a 100 percent basis). In the third quarter of 2008, the Wood River refinery received regulatory approvals to start construction on the Coker and Refinery Expansion (CORE) project. EnCana s 50 percent share of the CORE project is expected to cost approximately $1.8 billion and is anticipated to be completed and in full operation in 2011. The expansion is expected to increase crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d (on a 100 percent basis) and more than double heavy crude oil refining capacity to 240,000 bbls/d.

The Borger refinery, located in Borger, Texas, has a current capacity of approximately 146,000 bbls/d of crude oil and approximately 45,000 bbls/d of NGLs (on a 100 percent basis). The coker installed in 2007 is enabling the refinery to upgrade approximately 35,000 bbls/d of WCS heavy crude.

The current plan of the downstream business is to refine approximately 135,000 bbls/d of bitumen equivalent (on a 100 percent basis) to primarily motor fuels with the completion of the CORE project in 2011. As at December 31, 2008, the Wood River and Borger refineries have processing capability to refine up to approximately 70,000 bbls/d of bitumen equivalent (on a 100 percent basis).

The two refineries have a combined crude oil refining capacity of 452,000 bbls/d (on a 100 percent basis) and operated at an average 93 percent of that capacity during 2008 compared to 96 percent in 2007. Refinery crude utilization was lower in 2008 primarily due to unplanned refinery outages and maintenance activities at Wood River as well as crude oil supply disruptions resulting from hurricane activity in the Gulf Coast. Refined products averaged 448,000 bbls/d (224,000 bbls/d net to EnCana) in 2008 compared to 457,000 bbls/d (228,500 bbls/d net to EnCana) in 2007.

Revenues reflect EnCana s 50 percent share of the sale of refined petroleum products in the United States. Operating Cash Flow from downstream operations in 2008 decreased $1,315 million compared to 2007. Weaker refining margins as evidenced by the 37 percent decrease in Chicago 3-2-1 crack spreads combined with a 3 percent decline in capacity utilization accounted for approximately $825 million of the decrease in Operating Cash Flow.

Pursuant to Canadian GAAP, the Company uses the First In, First Out (FIFO) method of inventory valuation. The 50 percent drop in WTI prices during the fourth quarter of 2008 compared to the third quarter of 2008 resulted in much lower inventory values at year-end and therefore much higher purchased product costs. This decreased Operating Cash Flow by $192 million compared to an increase of $159 million in 2007. In addition, as a result of low crude oil and refined product prices at year-end, a $95 million write-down of inventory values to net realizable value was recorded.

Purchased products, consisting mainly of crude oil, represented 95 percent of total expenses in 2008 compared to 93 percent in 2007. Operating costs for labour, utilities and supplies comprised the balance of expenses. Revenues and purchased product have increased 23 percent and 51 percent in 2008, respectively, in line with the significant increase in crude oil prices and reduced refining margins.

OTHER INTEGRATED OIL OPERATIONS

In addition to the 50 percent owned Foster Creek/Christina Lake operations, Integrated Oil also manages the 100 percent owned natural gas operations in Athabasca and crude oil operations in Senlac.

2008 versus 2007

Production volumes from Athabasca were 63 MMcf/d in 2008 compared to 91 MMcf/d in 2007 and from Senlac were 2,729 bbls/d in 2008 compared to 2,688 bbls/d in 2007. The decrease at Athabasca is due to increased internal usage to supply a portion of the fuel gas requirements at Foster Creek and expected natural declines.

2007 versus 2006

Production volumes from Athabasca were 91 MMcf/d in 2007 compared to 113 MMcf/d in 2006 and from Senlac were 2,688 bbls/d in 2007 compared to 5,185 bbls/d in 2006. These decreases are due to expected natural declines.

DEPRECIATION, DEPLETION AND AMORTIZATION

UPSTREAM DD&A

EnCana uses full cost accounting and calculates DD&A on a country-by-country cost centre basis.

2008 versus 2007

Upstream DD&A expenses of $3,889 million in 2008 increased $410 million or 12 percent compared to 2007 due to:

- Production volumes increased 6 percent; and

- DD&A rates in 2008 for the USA were higher than 2007 primarily due to higher capitalized costs, mainly attributable to the Deep Bossier acquisition. DD&A rates in Canada for 2008 were lower than 2007 primarily as a result of the higher proved reserves.

2007 versus 2006

Upstream DD&A expenses of $3,479 million in 2007 increased $464 million or 15 percent compared to 2006 due to:

- North American production volumes increased 1 percent; and

DD&A rates in 2007 were higher than 2006 primarily as a result of increased future development costs and the higher U.S./Canadian dollar exchange rate.

DOWNSTREAM DD&A

EnCana calculates DD&A on a straight-line basis over estimated service lives of approximately 25 years.

Downstream refining DD&A was $188 million in 2008 compared to $159 million in 2007 as a result of a full year of depreciation on prior year capital additions, as well as accelerated depreciation on certain assets expected to be retired sooner than originally anticipated.

MARKET OPTIMIZATION

Financial Results

($ millions)		2008		2007		2006
Revenues	**$**	**2,655**	$	2,944	$	3,007
Expenses						
Transportation and selling		**-**		10		16
Operating		**45**		37		62
Purchased product		**2,577**		2,858		2,862
Operating Cash Flow		**33**		39		67
Depreciation, depletion and amortization		**15**		17		12
Segment Income	**$**	**18**	$	22	$	55

Market Optimization revenues and purchased product expenses relate to activities that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification that enhance the sale of EnCana s production.

2008 versus 2007

Revenues and purchased product expenses decreased in 2008 compared to 2007 mainly due to overall volume decreases required for Market Optimization offset partially by increased pricing.

2007 versus 2006

Revenues and purchased product expenses were basically flat in 2007 compared to 2006, with slight decreases in prices being offset by increases in volumes required for optimization activities.

CORPORATE AND OTHER

Financial Results

($ millions)	2008	2007	2006
Revenues	**$ 2,719**	$ (1,239)	$ 2,052
Expenses			
Operating	**(13)**	14	(1)
Depreciation, depletion and amortization	**131**	161	85
Segment Income (Loss)	**$ 2,601**	$ (1,414)	$ 1,968

Revenues represent unrealized mark-to-market gains or losses related to financial natural gas and liquids hedge contracts.

DD&A includes provisions for corporate assets, such as computer equipment, office furniture and leasehold improvements, as well as for international assets. DD&A in 2008 included impairments of $38 million related to exploration prospects in Qatar and France as a result of exiting these countries and in 2007 included impairments of $68 million related to exploration prospects in France and Oman. DD&A in 2006 included impairments of $6 million related to exploration prospects in the Middle East.

Consolidated Corporate and Other Expenses

($ millions)	2008	2007	2006
Administrative	**$ 473**	$ 384	$ 271
Interest, net	**586**	428	396
Accretion of asset retirement obligation	**79**	64	50
Foreign exchange (gain) loss, net	**423**	(164)	14
(Gain) loss on divestitures	**(140)**	(65)	(323)

2008 versus 2007

Administrative expenses increased $89 million in 2008 compared to 2007 primarily due to higher staff levels and other related costs as a result of growth, one time charges for settlements of a lawsuit and an arbitration ruling offset by lower long-term compensation costs of $93 million as a result of the change in the EnCana share price. The proposed corporate reorganization also added $67 million of costs related to work needed to prepare for the transaction. Excluding these corporate reorganization costs, EnCana s administrative expenses were $0.24 per Mcfe in 2008, which is unchanged from 2007. Fourth quarter administrative expenses decreased $47 million in 2008 compared to 2007 primarily due to lower long-term compensation costs of $83 million and lower costs of $17 million due to the lower U.S./Canadian dollar exchange rate offset partially by $24 million for the proposed corporate reorganization and other related costs due to growth.

Net interest expense in 2008 increased $158 million compared to 2007 primarily as a result of higher weighted average outstanding debt in 2008. Weighted average debt for 2008 was impacted for the entire year as a result of the Deep Bossier acquisition, which occurred in November 2007, compared to weighted average debt for 2007, which was impacted by this acquisition for a relatively short period of time. EnCana s total long-term debt, including current portion, decreased $538 million to $9,005 million at December 31, 2008 compared to $9,543 million at December 31, 2007 primarily as a result of the decrease in the period end U.S./Canadian dollar exchange rate. EnCana s 2008 weighted average interest rate on outstanding debt was 5.5 percent compared to 5.6 percent in 2007.

Foreign exchange losses of $253 million and $423 million in the fourth quarter and full year of 2008, respectively, are primarily due to the effects of the U.S./Canadian dollar exchange rate on U.S. dollar denominated debt issued from Canada offset by revaluation of the partnership contribution receivable.

The gain on divestitures in 2008 relates primarily to the divestiture of interests in Brazil. The gain on divestitures in 2007 relates primarily to the divestiture of interests in Chad and Australia.

2007 versus 2006

Administrative expenses increased $113 million in 2007 compared to 2006 primarily due to higher long-term compensation costs of $56 million as a result of the change in the EnCana share price. The higher U.S./Canadian dollar exchange rate added an additional $18 million and the remaining increase was due to increased staff levels, higher salaries, and other related expenses. Administrative expenses in 2007 were $0.24 per Mcfe compared to $0.17 per Mcfe in 2006. Fourth quarter administrative expenses increased $37 million in 2007 compared to 2006 primarily due to higher long-term compensation costs of $23 million and increased costs of $13 million due to the higher U.S./Canadian dollar exchange rate.

Net interest expense in 2007 increased $32 million from 2006 primarily as a result of higher average outstanding debt. EnCana s total long-term debt, including current portion, increased $2,709 million to $9,543 million at December 31, 2007 compared to $6,834 million at December 31, 2006. EnCana s 2007 weighted average interest rate on outstanding debt was 5.6 percent compared to 5.7 percent in 2006.

The foreign exchange gain of $164 million in 2007 is primarily due to the effects of the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada and settlement of foreign denominated intercompany transactions offset by revaluation of the partnership contribution receivable. Fourth quarter 2007 foreign exchange gain of $233 million is primarily due to the effects of the U.S./Canadian dollar exchange rate on settlement of foreign currency denominated intercompany transactions.

The gain on divestitures in 2007 relates primarily to the divestiture of interests in Chad and assets in Australia. The gain on divestitures in 2006 relates to the divestitures of the Chinook heavy oil discovery offshore Brazil and the Entrega Pipeline.

Summary of Unrealized Mark-to-Market Gains (Losses) from Continuing Operations

($ millions)	2008	2007	2006
Revenues			
Natural Gas	**$ 2,475**	$ (1,049)	$ 1,910
Crude Oil	**242**	(190)	140
	2,717	(1,239)	2,050
Expenses	**(12)**	(4)	(10)
	2,729	(1,235)	2,060
Income Tax Expense (Recovery)	**911**	(424)	703
Unrealized Mark-to-Market Gains (Losses), after-tax	**$ 1,818**	$ (811)	$ 1,357

Commodity price volatility impacts net earnings. As a means of managing this commodity price volatility, EnCana enters into various financial instrument agreements. The financial instrument agreements were recorded at the date of the financial statements based on mark-to-market accounting. Changes in the mark-to-market gains or losses reflected in corporate revenues are the result of volatility between periods in the forward curve commodity price market and changes in the balance of unsettled contracts. Further information regarding financial instrument agreements can be found in Note 20 to the Consolidated Financial Statements.

INCOME TAX

2008 versus 2007

The effective tax rate for 2008 was 30.7 percent compared to 19.4 percent in 2007. The 2007 effective tax rate was lower primarily due to a one time Canadian federal corporate legislative change and a reduction in the Canadian federal corporate tax rates.

Current income tax expense was $987 million in 2008 compared to $1,554 million in 2007. The decrease is primarily due to the increased benefits from international financing and a U.S. tax legislative change in 2008 that allows an accelerated write-off of certain capital expenditures, offset by a one time tax recovery of $179 million in 2007 for a Canadian tax legislative change.

Future income tax expense was $1,646 million in 2008 compared to a recovery of $617 million in 2007. The increase is primarily due to the provision for tax on unrealized mark-to-market hedging gains and the accelerated write-offs for certain U.S. capital expenditures as well as the reduction of the Canadian federal corporate tax rates in 2007 as noted below.

2007 versus 2006

The effective tax rate for 2007 was 19.4 percent compared to 27.3 percent in 2006. The 2007 rate reflects the effect of a Canadian federal corporate tax legislative change ($179 million) and a reduction in the Canadian federal corporate tax rate ($301 million). The legislative change relates to phase in of the deductibility of Crown royalties, which is now complete and will not recur in the future. The Canadian federal tax rate is to be reduced from 19.5 percent to 15 percent between 2008 and 2012. The 2006 effective rate also reflects the effect of reductions in the Canadian federal and Alberta corporate tax rates ($457 million).

Cash taxes were $1,554 million in 2007 compared to $942 million in 2006. The largest component of the increase of $612 million is $519 million of higher U.S. taxes in 2007 offset by the cash tax benefit of the legislative change ($179 million) referred to above. The increase in U.S. tax is due to the cash flows from U.S. downstream refining operations and increased income from U.S. upstream operations.

Further information regarding EnCana s effective tax rate can be found in Note 10 to the Consolidated Financial Statements. EnCana s effective rate in any year is a function of the relationship between total tax (current and future) and the amount of net earnings before income taxes for the year. The effective tax rate differs from the statutory tax rate as it takes into consideration permanent differences , adjustment for changes to tax rates and other tax legislation, variation in the estimation of reserves and the estimate to actual differences. Permanent differences are a variety of items, including:

The non-taxable portion of Canadian capital gains or losses;

Non-taxable downstream partnership income;

International financing; and

Foreign exchange (gains) losses not included in net earnings.

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.

NET CAPITAL INVESTMENT

Capital Summary

($ millions)		2008		2007		2006
Canada						
Canadian Plains	**$**	**847**	$	846	$	770
Canadian Foothills		**2,299**		2,439		2,500
Integrated Oil Canada		**656**		451		745
USA		**2,615**		1,919		2,061
Downstream Refining		**478**		220		-
Market Optimization		**17**		6		44
Corporate & Other		**168**		154		149
Capital Investment		**7,080**		6,035		6,269
Acquisitions		**1,174**		2,702		331
Divestitures		**(904)**		(481)		(689)
Discontinued Operations		**-**		-		(2,647)
Net Capital Investment	**$**	**7,350**	$	8,256	$	3,264

EnCana s Capital Investment for the year ended December 31, 2008 was funded by Cash Flow and debt.

Capital investment during 2008 was primarily focused on continued development of EnCana s North American key resource plays and expansion of the Company s downstream heavy oil processing capacity through its joint venture with ConocoPhillips. Reported capital investment was also influenced by changes in the average U.S./Canadian dollar exchange rate and in the EnCana share price. The net impact of these factors on Capital Investment was a decrease of $149 million in 2008 compared to 2007.

CANADIAN PLAINS DIVISION CAPITAL INVESTMENT

2008 versus 2007

Canadian Plains capital investment of $847 million in 2008 was relatively unchanged primarily due to increased land purchases and facility work offset by lower drilling and completion costs due to fewer wells drilled and lower capitalized costs for long-term incentives. Canadian Plains drilled 1,476 net wells in 2008 compared to 2,264 net wells in 2007, focusing more on deeper integrated wells in 2008.

2007 versus 2006

Canadian Plains capital investment of $846 million in 2007 increased $76 million primarily due to the rise in the average U.S./Canadian dollar exchange rate that increased capital by $47 million. In addition, the Company drilled a larger number of lower cost wells in the Shallow Gas key resource play. Canadian Plains drilled 2,264 net wells in 2007 compared to 1,634 net wells in 2006.

CANADIAN FOOTHILLS DIVISION CAPITAL INVESTMENT

Canadian Foothills Division includes the Company s Canadian offshore assets.

2008 versus 2007

Canadian Foothills capital investment of $2,299 million in 2008 decreased $140 million primarily due to lower drilling costs as a result of increased focus on well tie-ins, more efficient completion techniques and lower capitalized costs for long-term incentives. Canadian Foothills drilled 1,064 net wells in 2008 compared to 1,539 net wells in 2007.

2007 versus 2006

Canadian Foothills capital investment of $2,439 million in 2007 decreased $61 million primarily due to:

Drilling and completion costs decreased due to increased efficiencies through the use of fit-for-purpose rigs. In addition, the Company drilled a larger number of lower cost wells in the CBM key resource play. Canadian Foothills drilled 1,539 net wells in 2007 compared to 1,275 net wells in 2006;

Facility costs decreased mainly due to higher costs in 2006 resulting from the construction of the Steeprock and Kakwa gas plants at Cutbank Ridge and Bighorn, respectively; and

Offsetting the decreases in capital investment was the rise in the average U.S./Canadian dollar exchange rate, which increased Canadian Foothills capital by $120 million.

USA DIVISION CAPITAL INVESTMENT

2008 versus 2007

USA capital investment of $2,615 million in 2008 increased $696 million primarily due to increased drilling and completion activity in the East Texas, Piceance and Jonah key resource plays, including incremental costs from the Deep Bossier acquisition offset slightly by lower capitalized costs for long-term incentives. The number of net wells drilled in the USA increased to 750 from 644 in 2007.

2007 versus 2006

USA capital investment decreased $142 million to $1,919 million primarily due to lower drilling and completion costs resulting from increased efficiencies through the use of additional fit-for-purpose rigs. EnCana employed an average of 22 fit-for-purpose rigs during 2007 compared to 5 during 2006. The number of net wells drilled in the USA increased slightly to 644 from 639 in 2006.

INTEGRATED OIL DIVISION CAPITAL INVESTMENT

Integrated Oil Division is the combined total of Integrated Oil Canada and Downstream Refining.

2008 versus 2007

Integrated Oil Division capital investment of $1,134 million during 2008 was primarily focused on continued development of the Foster Creek and Christina Lake resource plays and on the CORE project at the Wood River refinery. The $463 million increase in capital investment in 2008 compared to 2007 was primarily due to:

Higher facility costs at Foster Creek and Christina Lake and spending related to the Wood River CORE project. Facility expenditures at Foster Creek are expected to increase plant capacity to 120,000 bbls/d (on a 100 percent basis) to accommodate Phases D and E expansions. Christina Lake facility costs are expected to increase plant capacity to 58,000 bbls/d (on a 100 percent basis) to accommodate Phases B and C expansion. In addition, drilling costs were higher mainly due to drilling of 139 stratigraphic test wells in 2008 (2007 75 wells) at Foster Creek, Christina Lake, Borealis and Senlac related to the next phases of development. The Wood River CORE project received regulatory approvals in the third quarter of 2008 and is expected to cost about $1.8 billion, net to EnCana, over the next three years. The expansion is expected to increase crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d (on a 100 percent basis) and heavy crude oil refining capacity is expected to more than double to 240,000 bbls/d (on a 100 percent basis);

offset partially by:

Lower capitalized costs for long-term incentives.

2007 versus 2006

Integrated Oil capital investment during 2007 was primarily focused on continued development of the Foster Creek and Christina Lake resource plays and on capacity maintenance and heavy oil expansion projects at the Wood River and Borger refineries.

MARKET OPTIMIZATION CAPITAL INVESTMENT

Market Optimization capital investment in 2008 and 2007 was focused on developing infrastructure for optimization activities and maintaining power generation facilities. Expenditures in 2006 were mostly focused on the completion of construction for the Entrega Pipeline prior to the sale in February 2006.

CORPORATE AND OTHER CAPITAL INVESTMENT

Corporate and Other capital investment in 2008 and 2007 was primarily directed to business information systems, leasehold improvements and office furniture as well as to the Company s International exploration prospects. 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 entered into a 25 year lease agreement with a third-party developer. Cost-of-design changes to the building requested by EnCana and leasehold improvements are the responsibility of the Company.

ACQUISITIONS AND DIVESTITURES

Acquisitions in 2008 included land purchases of approximately $1,010 million in the Haynesville Shale play in Louisiana. Acquisitions in 2007 included the purchase of all of the Deep Bossier natural gas and land interests of privately owned Leor Energy group in East Texas for approximately $2.55 billion before closing adjustments, increasing EnCana s interest to 100 percent in these lands.

In September 2008, EnCana completed the sale of its interests in Brazil for net proceeds of $164 million, before closing adjustments, resulting in a gain on sale of $124 million before-tax ($99 million after-tax). In addition, during 2008, EnCana also completed the divestiture of mature conventional oil and natural gas assets for proceeds of $698 million.

EnCana completed the following divestitures in 2007:

The sale of assets in Australia for $31 million resulting in a gain on sale of $30 million before-tax ($25 million after-tax);

The sale of certain assets in the Mackenzie Delta and Beaufort Sea for proceeds of $159 million;

The sale of its interests in Chad for $208 million resulting in a gain on sale of $59 million;

The sale of The Bow office project assets for approximately $57 million, largely representing its investment at the date of sale; and

The sale of other minor properties.

Proceeds from the 2007 divestitures were directed primarily to the purchase of shares under EnCana s NCIB.

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	**2008**	2007	2006	**2008**	2007	2006
Canada(2)	**7,847**	7,292	7,028	**954.0**	868.9	1,079.4
United States	**5,831**	6,008	5,390	**51.6**	58.3	54.0
Total	**13,678**	13,300	12,418	**1,005.6**	927.2	1,133.4

(1) Crude Oil and NGLs include condensate.

(2) Includes Foster Creek/Christina Lake.

Each year, EnCana engages independent qualified reserves evaluators to prepare reports on 100 percent of the Company s oil and natural gas reserves. The Company has a Reserves Committee of independent Board of Directors members, which reviews the qualifications and appointment of the independent qualified reserves evaluators. The Committee also reviews the procedures for providing information to the evaluators. EnCana s disclosure of reserves data is covered by National Instrument 51-101 (NI 51-101) of the Canadian Securities Administrators as amended by a Decision dated September 29, 2008 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 U.S. Financial Accounting Standards Board (FASB) reserves 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, 2008.

As of December 31, 2009, the SEC will permit companies to disclose their probable and possible reserves in their SEC filings and determine their oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices. Further information regarding these new disclosure requirements can be found under the Accounting Policies and Estimates section of this MD&A.

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, 2008	**Canada**	**United States**	**Total**	**Canada(2)**	**United States**	**Total**
Beginning of year	7,292	6,008	13,300	868.9	58.3	927.2
Revisions and improved recovery	148	(166)	(18)	112.8	(3.6)	109.2
Extensions and discoveries	1,311	655	1,966	17.0	3.8	20.8
Acquisitions	32	7	39	0.2	-	0.2
Divestitures	(129)	(75)	(204)	(0.9)	(2.0)	(2.9)
Production	(807)	(598)	(1,405)	(44.0)	(4.9)	(48.9)
End of year	7,847	5,831	13,678	954.0	51.6	1,005.6

(1) Crude Oil and NGLs include condensate.

(2) Includes Foster Creek/Christina Lake.

NATURAL GAS

EnCana s proved natural gas reserves at December 31, 2008 totaled 13,678 Bcf. Approximately 125 percent of production was replaced by reserves additions during 2008. Extensions and discoveries resulting from successful exploration and development capital programs amounted to 1,966 Bcf. Negative revisions of 18 Bcf were less than 1 percent of natural gas reserves at the beginning of 2008. In Canada, positive revisions of 148 Bcf (or 2 percent of the opening balance) were largely associated with the Bighorn, Shallow Gas and Integrated CBM key resource plays. Downward revisions in the U.S. amounted to 166 Bcf (or 3 percent of the opening balance), mainly due to lower prices in the U.S. Rockies. In total, EnCana s key resource plays accounted for over 70 percent of extensions and discoveries. Deep Panuke accounts for over 15 percent of extensions and discoveries. Divestitures net of acquisitions account for approximately 1 percent of the opening natural gas reserves balance.

CRUDE OIL AND NGLs

EnCana s proved crude oil and NGLs reserves at December 31, 2008 totaled 1,005.6 MMbbls. Approximately 260 percent of production was replaced by reserves additions during 2008. Extensions and discoveries amounted to 20.8 MMbbls, while revisions were positive 109.2 MMbbls (or 12 percent of the opening balance). Foster Creek and Christina Lake on a combined basis accounted for approximately 82 MMbbls or 75 percent of revisions and improved recovery. This was primarily due to lower royalties as a result of lower field prices at December 31, 2008. Over 80 percent of extensions and discoveries were in Canada. Reserves changes due to acquisitions and divestitures during 2008 were not significant.

Discontinued Operations

In keeping with EnCana s North American resource play and refining operations strategy, the Company has made a number of divestitures over the years that are accounted for as discontinued operations. EnCana s 2008 Net Earnings from Discontinued Operations were nil (2007 $75 million; 2006 $601 million).

MIDSTREAM

The $75 million gain on discontinuance in 2007 was the result of an expired obligation included in the December 2005 sale of the Company s Midstream NGLs processing operations. The obligation provided potential market price support and was accrued for in 2005.

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.

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.

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.

Amounts recorded as DD&A in 2006 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 GAAP.

Liquidity and Capital Resources

($ millions)	2008	2007	2006
Net cash from (used in)			
Operating activities	**$ 8,855**	$ 8,429	$ 7,973
Investing activities	**(7,553)**	(8,175)	(3,382)
Financing activities	**(1,439)**	(119)	(4,294)
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**(33)**	16	-
Increase (decrease) in cash and cash equivalents	**$ (170)**	$ 151	$ 297

OPERATING ACTIVITIES

Net cash from operating activities in 2008 increased $426 million compared to 2007. Cash Flow was $9,386 million in 2008 compared to $8,453 million in 2007. Reasons for this change are discussed under the Cash Flow section of this MD&A. Cash from operating activities was also impacted by net changes in non-cash working capital and net changes in other assets and liabilities, including decreases in accounts payable and accrued liabilities and income tax payable offset by decreases in accounts receivable and accrued revenues and inventories. Excluding the impact of current risk management assets and liabilities, the Company had a working capital deficit of $1,067 million at December 31, 2008 compared to $2,064 million at December 31, 2007. As is typical in the oil and gas industry, there is a timing difference between cash receipts from sales transactions and payments of trade payables, which often results in a working capital deficit. EnCana anticipates that it will continue to meet the payment terms of its suppliers.

INVESTING ACTIVITIES

Net cash used for investing activities in 2008 decreased $622 million compared to 2007. Capital expenditures, including property acquisitions, in 2008 decreased $483 million compared to 2007 and proceeds from divestitures increased $423 million compared to 2007. Reasons for this change are discussed under the Net Capital Investment section of this MD&A. Decreases in cash used for investing activities were partially offset by net changes in investments and other.

FINANCING ACTIVITIES

Net issuance of long-term debt in 2008 was $6 million compared to net issuance of $2,333 million in 2007. EnCana s total long-term debt, including current portion, was $9,005 million at December 31, 2008 compared to $9,543 million at December 31, 2007. The reduction in debt was primarily attributable to the lower period end U.S./Canadian dollar exchange rate.

EnCana maintains a Canadian and a U.S. dollar shelf prospectus and two committed bank credit facilities.

As at December 31, 2008, EnCana had available unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for up to $5.0 billion.

On March 11, 2008, EnCana filed a shelf prospectus whereby it may issue from time to time up to $4.0 billion, or the equivalent in foreign currencies, of debt securities in the United States. At December 31, 2008, $4.0 billion of the shelf prospectus remains unutilized, the availability of which is dependent upon market conditions. The shelf prospectus replaces EnCana s $2.0 billion shelf prospectus, which was fully utilized, and EnCana Holdings Finance Corp. s $2.0 billion shelf prospectus, which expired on July 9, 2008.

EnCana has in place a shelf prospectus whereby it may issue from time to time up to C$2.0 billion, or the equivalent in foreign currencies, of debt securities in Canada. The shelf prospectus was renewed in 2007 and expires in June 2009. The Company plans to renew the shelf prospectus upon expiry.

On January 18, 2008, EnCana completed a public offering in Canada of senior unsecured medium term notes in the aggregate principal amount of C$750 million. The notes have a coupon rate of 5.80 percent and mature on January 18, 2018. The net proceeds of the offering were used to repay a portion of EnCana s existing bank and commercial paper indebtedness.

As at December 31, 2008, EnCana had available unused committed bank credit facilities in the amount of $2.6 billion. EnCana has in place a revolving bank credit facility for C$4.5 billion that remains committed through October 28, 2012. One of EnCana s U.S. subsidiaries has in place a revolving bank credit facility for $600 million, of which $565 million is accessible, that remains committed through February 28, 2013. One of the lenders under the $600 million revolving credit facility, Lehman Brothers Bank, FSB, ceased funding its $35 million commitment as a result of the bankruptcy filing made by its affiliate, Lehman Brothers Holdings Inc., on September 15, 2008.

EnCana is currently in compliance with and anticipates that it will continue to be in compliance with all financial covenants under its credit facility agreements.

EnCana maintains investment grade credit ratings on its senior unsecured debt. On May 12, 2008, following the announcement of the proposed Arrangement, Standard & Poor s Ratings Service assigned a rating of A- and placed the Company on CreditWatch Negative , DBRS Limited assigned a rating of A(low) and placed the Company Under Review with Developing Implications and Moody s Investors Services assigned a rating of Baa2 and changed the outlook to Stable from Positive .

EnCana has obtained regulatory approval under Canadian securities laws to purchase Common Shares under a NCIB. During 2008, EnCana purchased 4.8 million of its Common Shares for total consideration of approximately $326 million compared with 38.9 million Common Shares for total consideration of approximately $2,025 million in 2007. As of December 31, 2008, the number of Common Shares that EnCana will be permitted to purchase in 2009 under the current NCIB is approximately 75.0 million. As a result of the proposed Arrangement, EnCana has suspended the purchase of Common Shares. Shareholders may obtain a copy of the Company s Notice of Intention to make a Normal Course Issuer Bid by contacting investor.relations@encana.com or at www.sedar.com.

EnCana pays quarterly dividends to shareholders at the discretion of the Board of Directors. EnCana doubled its quarterly dividend to 40 cents per share in 2008 and payments for 2008 totaled $1,199 million compared to $603 million in 2007. These dividends were funded by Cash Flow.

Financial Metrics

	2008	2007	2006
Debt to Capitalization (1)	**28%**	32%	28%
Debt to Adjusted EBITDA (2)	**0.7x**	1.1x	0.7x

(1) Capitalization is a non-GAAP measure defined as Long-Term Debt including current portion plus Shareholders Equity.

(2) Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as Net Earnings from Continuing Operations before gains or losses on divestitures, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation, depletion and amortization.

Debt to Capitalization and 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.

To provide a more conservative measure of liquidity, the Company has changed its calculation of these metrics as follows: Net Debt to Capitalization has been changed to Debt to Capitalization and Net Debt to Adjusted EBITDA has been changed to Debt to Adjusted EBITDA. Debt is defined as the current and long-term portions of Long-Term Debt. Previously, Net Debt was defined as Long-Term Debt plus Current Liabilities less Current Assets. The Company believes this presentation is more comparable between periods by excluding the impact of unrealized mark-to-market accounting gains and losses on working capital.

At December 31, 2008, EnCana s Debt to Capitalization ratio was 28 percent (December 31, 2007 32 percent). Without giving effect to the change in calculation as described above, EnCana s Net Debt to Capitalization ratio would have been 23 percent at December 31, 2008 (December 31, 2007 34 percent). EnCana targets a Debt to Capitalization ratio of between 30 to 40 percent and a Debt to Adjusted EBITDA of 1.0 to 2.0 times to steward the Company s overall debt position.

FREE CASH FLOW

EnCana s 2008 Free Cash Flow of $2,306 million was slightly lower compared to 2007. Reasons for the increase in total Cash Flow and capital investment are discussed under the Cash Flow and Net Capital Investment sections of this MD&A.

($ millions)	2008	2007	2006
Cash Flow (1)	**$ 9,386**	$ 8,453	$ 7,161
Capital Investment	**7,080**	6,035	6,269
Free Cash Flow (2)	**$ 2,306**	$ 2,418	$ 892

(1) Cash Flow is a non-GAAP measure and is defined under the Cash Flow section of this MD&A.

(2) Free Cash Flow is a non-GAAP measure that EnCana defines as Cash Flow in excess of Capital Investment, excluding net acquisitions and divestitures, and is used by Management to determine the funds available for other investing and/or financing activities.

As part of ongoing efforts to maintain financial resilience and flexibility, EnCana has taken steps to reduce pricing risk through a commodity price hedging program. Further information regarding this program can be found under the Risk Management section of this MD&A.

Outstanding Share Data

(millions)	2008	2007	2006
Common Shares outstanding, beginning of year	**750.2**	777.9	854.9
Common Shares issued under option plans	**3.0**	8.3	8.6
Common Shares purchased	**(2.8)**	(36.0)	(85.6)
Common Shares outstanding, end of year	**750.4**	750.2	777.9
Weighted average Common Shares outstanding diluted	**751.8**	764.6	836.5

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, 2008, 2007 and 2006.

Employees have been granted options to purchase Common Shares under various plans. At December 31, 2008, approximately 0.5 million options without Tandem Share Appreciation Rights (TSARs) attached were outstanding, all of which are exercisable.

Stock options granted after December 31, 2003 have an associated TSAR attached, which gives employees the right to elect to receive a cash payment equal to the excess of the market price of EnCana s Common Shares over the exercise price of their stock option in exchange for surrendering their stock option. The exercise of a TSAR, for a cash payment, does not result in the issuance of any additional EnCana Common Shares, so has no dilutive effect. Historically, virtually all employees holding options with TSARs attached deciding to realize the value of their options have exercised their TSARs to receive a cash payment. At December 31, 2008, approximately 19.4 million options with TSARs attached were outstanding, of which 8.5 million are exercisable.

In 2007 and 2008, EnCana also granted Performance TSARs, which vest and expire under the same terms and service conditions as TSARs and are also subject to EnCana attaining prescribed performance relative to pre-determined key measures. Performance TSARs that do not vest when eligible are forfeited. At December 31, 2008, approximately 13.0 million Performance TSARs were outstanding, of which 1.5 million are exercisable.

During the first quarter of 2008, vesting provisions for the Performance Share Units (PSUs) granted in 2005 were met and 2.0 million shares were distributed from the EnCana Employee Benefit Plan Trust. Additional information on these incentives is contained in Note 19 of the Consolidated Financial Statements.

In 2008, EnCana granted Share Appreciation Rights (SARs) and Performance SARs to certain employees, 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 grant price. SARs are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years and expire five years after the grant date. Performance SARs vest and expire under the same terms and service conditions as SARs and are also subject to EnCana attaining prescribed performance relative to pre-determined key measures. Performance

SARs that do not vest when eligible are forfeited. At December 31, 2008, approximately 2.9 million SARs and Performance SARs were outstanding, of which none are exercisable.

Contractual Obligations, Commitments and Contingencies

Contractual Obligations and Commitments (1)

		Expected Payment Date			
($ millions)	2009	2010 to 2011	2012 to 2013	2014+	Total
Long-Term Debt (2)	$ 250	$ 700	$ 2,565	$ 5,512	$ 9,027
Partnership Contribution Payable(3)	306	670	754	1,433	3,163
Asset Retirement Obligation	87	64	68	6,350	6,569
Pipeline Transportation	469	970	977	2,533	4,949
Purchase of Goods and Services	1,061	756	393	534	2,744
Product Purchases	23	43	36	43	145
Operating Leases (4)	70	191	334	2,678	3,273
Capital Commitments	5	106	-	38	149
Other Long-Term Commitments	15	16	1	-	32
Total	$ 2,286	$ 3,516	$ 5,128	$ 19,121	$ 30,051
Product Sales	$ 38	$ 80	$ 89	$ 149	$ 356
Partnership Contribution Receivable(3)	313	677	752	1,405	3,147

(1) In addition, the Company has made commitments related to its risk management program. See Note 20 to the Consolidated Financial Statements. The Company has an obligation to fund its defined benefit pension and Other Post-Employment Benefit plans as disclosed in Note 19 to the Consolidated Financial Statements.

(2) Principal component only. See Note 15 to the Consolidated Financial Statements.

(3) Principal component only. See Note 11 to the Consolidated Financial Statements.

(4) 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 obligations of $9,027 million at December 31, 2008 are $1,657 million in obligations related to Bankers Acceptances, Commercial Paper and LIBOR loans. 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. The revolving credit and term loan facilities are fully revolving for the periods disclosed in the Liquidity and Capital Resources section of this MD&A. Based on the current maturity dates of the credit facilities, these amounts are included in cash outflows for the period disclosed as 4 to 5 years as described in Note 20 to the Consolidated Financial Statements. Further details regarding EnCana s long-term debt are described in Note 15 to the Consolidated Financial Statements.

The Company expects its 2009 commitments to be funded from Cash Flow.

As at December 31, 2008, EnCana remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 33 MMcf/d, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 97 Bcf at a weighted average price of $3.66 per Mcf.

LEASES

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

DEEP PANUKE

In October 2007, EnCana received regulatory approval from the Canada-Nova Scotia Offshore Petroleum Board to develop the Deep Panuke natural gas project located about 175 kilometres offshore Nova Scotia. Expected to start production in 2010, the approximately $760 million project is expected to deliver between 200 MMcf/d and 300 MMcf/d.

On January 4, 2008, EnCana signed the contract for the design and construction of the Production Field Centre (PFC) for the Deep Panuke project. The agreement is for Single Buoy Moorings to construct a production facility that EnCana will lease upon delivery, expected in late 2010. EnCana also has the option to purchase the facility. EnCana has determined that it has substantially all the construction period risk and consequently is reporting the PFC as an asset under construction during the construction period.

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 has entered into a 25 year lease agreement with a third-party developer. Cost of design changes to the building requested by EnCana and leasehold improvements will be the responsibility of the Company. As such, The Bow is reported as an asset under construction during the construction period.

VARIABLE INTEREST ENTITIES (VIEs)

On September 25, 2008, EnCana acquired certain land and property in Louisiana for approximately $101 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Haynesville Leasehold LLC (Brown Haynesville), which holds the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes.

On July 23, 2008, EnCana acquired certain land and mineral interests in Louisiana for approximately $457 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Southwest Minerals LLC (Brown Southwest), which holds the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. On November 12, 2008, an unrelated party exercised an option to purchase certain interests as part of the above acquisition for $157 million, reducing the qualifying like kind exchange to approximately $300 million.

Pursuant to the agreements with Brown Haynesville and Brown Southwest, EnCana operates the properties, receives all the revenue and pays all of the expenses associated with the properties. The arrangements with Brown Haynesville and Brown Southwest will be completed on March 24, 2009 and January 19, 2009, respectively, and the assets will be transferred to EnCana at that time. EnCana has determined that each relationship with Brown Haynesville and Brown Southwest represents an interest in a VIE and that EnCana is the primary beneficiary of the VIE. EnCana has consolidated Brown Haynesville and Brown Southwest from the dates of acquisition.

On November 20, 2007, EnCana acquired certain natural gas and land interests in Texas for approximately $2.55 billion before closing adjustments. The purchase was facilitated by an unrelated party, Brown Kilgore Properties LLC (Brown Kilgore), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. The relationship with Brown Kilgore represented an interest in a VIE from November 20, 2007 to May 18, 2008. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Kilgore. On May 18, 2008, when the arrangement with Brown Kilgore was completed, the assets were transferred to EnCana.

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 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. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission (CFTC) for $20 million and of a previously disclosed consolidated class action lawsuit in the United States District Court in New York for $8.2 million. Also, without admitting any liability whatsoever, WD concluded settlements with a group of individual plaintiffs for $23 million.

The remaining lawsuit was commenced by E. & J. Gallo Winery (Gallo). The Gallo lawsuit claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

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

Accounting Policies and Estimates

NEW ACCOUNTING STANDARDS ADOPTED

The Company adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3031 Inventories , Section 3863 Financial Instruments Presentation , Section 3862 Financial Instruments Disclosures and Section 1535 Capital Disclosures on January 1, 2008. The adoption of these standards has had no material impact on the Company s Net Earnings or Cash Flows. Additional information on the effects of the implementation of the new standards can be found in Note 2 to the Consolidated Financial Statements.

RECENT ACCOUNTING PRONOUNCEMENTS

As of January 1, 2009, EnCana will be required to adopt the CICA Handbook Section 3064, Goodwill and Intangible Assets , which will replace the existing Goodwill and Intangible Assets standard. The new standard revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard should not have a material impact on EnCana s Consolidated Financial Statements.

Oil and Gas Reserves

As previously described, EnCana currently follows the U.S. reporting standards for disclosure of reserves data. As of December 31, 2009, EnCana will be required to prospectively adopt the new reserves disclosure requirements announced by the U.S. SEC on December 29, 2008. The new rules include provisions that permit the use of new technologies to establish proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The new rules permit companies to disclose probable and possible reserves in addition to proved reserves. In addition, the new rules require companies to report the independence and qualifications of a reserves preparer or auditor and report oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices.

The new rules will affect the determination of proved reserves and therefore will impact the Company s oil and gas information disclosed in accordance with Statement of Financial Accounting Standard (SFAS) 69, including the net proved reserves and the standardized measure of discounted future net cash flows. As well, the new rules will affect the reserves estimate used in the calculation of DD&A and the ceiling test for U.S. GAAP purposes. The Company is assessing the impact these new rules will have on its Consolidated Financial Statements and oil and gas disclosures.

International Financial Reporting Standards (IFRS)

In February 2008, the CICA s Accounting Standards Board confirmed that IFRS will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. EnCana will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information.

The key elements of EnCana s changeover plan include:

- determine appropriate changes to accounting policies and required amendments to financial disclosures;

- identify and implement changes in associated processes and information systems;
- comply with internal control requirements;
- communicate collateral impacts to internal business groups; and
- educate and train internal and external stakeholders.

The Company is currently analyzing accounting policy alternatives and identifying implementation options for the corresponding process changes. EnCana will update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board. As IFRS is expected to change prior to 2011, the impact of IFRS on the Company s Consolidated Financial Statements is not reasonably determinable at this time.

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 the development of natural gas and crude oil reserves, are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs, including estimated future development costs, are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserves estimates can have a significant impact on earnings, as they are a key component in the calculation of DD&A. A downward revision in reserves 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 reserves 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 and resources are evaluated and reported on by independent qualified reserves 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. Reserves 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. Contingent resources are not classified as reserves due to the absence of a commercial development plan that includes a firm intent to develop within a reasonable time frame and, in some cases, due to higher uncertainty as a result of lower core-hole drilling density. Estimated recovery for leases assigned contingent resources considers detailed reservoir and pilot studies, demonstrated commercial success of analogous commercial projects and drilling density.

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.

An impairment loss is recognized on refining property, plant and equipment when the carrying amount is not recoverable and exceeds its fair value. The carrying amount is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from expected use and eventual disposition. If the carrying amount is not recoverable, an impairment loss is measured as the amount by which the refinery asset exceeds the discounted future cash flows from the refinery asset. EnCana has assessed its property, plant and equipment for impairment as at December 31, 2008 and has determined that no write-down is required under Canadian GAAP.

Asset Retirement Obligations

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when incurred and a reasonable estimate of fair value can be made. Asset retirement obligations are legal obligations associated with the requirement to retire tangible long-lived assets such as producing well sites, offshore production platforms, natural gas processing plants and refining facilities. 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. 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 expenditures incurred are charged against the accumulated obligation.

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 and all other assets and liabilities have been allocated to the country cost centre level, 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. EnCana has assessed its goodwill for impairment as at December 31, 2008 and has determined that no write-down is required.

Income Taxes

EnCana follows the liability method of accounting for income taxes. Under this method, future income taxes are estimated and 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.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

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 financial derivatives related to natural gas and crude oil prices 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 indications and forecasts. The estimated fair value of financial assets and liabilities, by their very nature, is subject to measurement uncertainty.

In 2006, 2007, and 2008, the Company elected not to designate any of its price risk management activities as accounting hedges and, accordingly, accounted 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 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 accrued benefit obligation is discounted using the market interest rate on high quality corporate debt instruments as at the measurement date.

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. The amortization period covers the expected average remaining service lives of employees covered by the plans. EnCana s defined benefit pension plan was $30 million under funded at December 31, 2008. Funding requirements will be determined after completion of the December 31, 2008 actuarial evaluation in the first quarter of 2009 and are not expected to be material.

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

Further details are disclosed in Note 19 to the Consolidated Financial Statements.

Performance TSARs, Performance SARs and PSUs

These plans provide for a range of payouts, based on key predetermined performance measures or EnCana s performance relative to certain peers. EnCana expenses the cost of these plans based on expected payouts. However, the amounts to be paid, if any, may vary from the current estimate. Further details on these plans are disclosed in Note 19 to the Consolidated Financial Statements.

Risk Management

EnCana s business, prospects, financial condition, results of operation and cash flows, and in some cases its reputation, are impacted by risks that are categorized as follows:

financial risks including market risks (such as commodity price, foreign exchange and interest rates), credit and liquidity;

operational risks including capital, operating and reserves replacement risks; and

safety, environmental and regulatory risks.

EnCana is committed to identifying and managing these risks in the near-term as well as on a strategic and longer term basis at all levels in the organization in accordance with the Company s Board of Directors approved Corporate Risk Management policy and EnCana s risk management programs.

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

FINANCIAL RISKS

EnCana defines financial risks as the risk of loss or lost opportunity resulting from financial management and market conditions that could have a positive or negative impact on EnCana s business.

The current global credit crisis and recession is impacting EnCana s business. EnCana has a strong financial position and continues to implement its business model, which focuses on developing low-risk and low-cost long-life resource plays, which allows the Company to respond well to the current market uncertainty. Management has been adjusting operational and financial risk strategies to proactively respond to the difficult economic conditions and to mitigate or reduce risk. The prudent and conservative capital budget for 2009 continues to be monitored and it contains the flexibility to allow spending to be reduced or increased as commodity prices and forecasts are revised, including the impact of changes on EnCana s longer term plans. Cost containment and reduction strategies are in place to ensure all aspects of the Company s controllable costs are efficiently managed. Counterparty and credit risks are closely monitored as are the programs to ensure EnCana s ability to access cost effective credit is maintained and that sufficient cash resources are in place to fund capital expenditures and fund dividend payments. Further insight into these risks and strategies is summarized below.

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.

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.

Further information, including the details of EnCana s positions for these financial instruments as of December 31, 2008, is disclosed in Note 20 to the Consolidated Financial Statements.

Commodity Price

EnCana defines commodity price risk as the uncertainties and fluctuations of future market prices for commodities. To partially mitigate the natural gas commodity price risk, the Company enters into swaps and puts, which establish NYMEX floor prices. To December 31, 2008, EnCana has hedged about two thirds of its expected gas production from January through October 2009 at an average NYMEX equivalent price of about $9.13 per Mcf. To help protect against widening natural gas price differentials in various production areas, EnCana has entered into swaps to manage the price differentials between these production areas and various sales points. 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. As at December 31, 2008, the Company has not hedged any of its exposure to the WTI NYMEX price or crack spreads for its expected 2009 oil production or refining margins. To manage its electricity consumption costs, EnCana has entered into two derivative contracts for a term of 11 years, commencing January 1, 2007.

Credit

EnCana defines credit risk as the potential for loss if a counterparty in a transaction fails to meet its obligations in accordance with agreed terms. A substantial portion of EnCana s accounts receivable is with customers in the oil and gas industry. 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. All financial derivative agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

Liquidity

EnCana defines liquidity risk as the risk the Company cannot meet a demand for cash or fund obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company manages liquidity risk through cash and debt management programs, including maintaining a strong balance sheet and significant unused credit facilities. The Company also has access to a wide range of funding alternatives at competitive rates, including commercial paper, capital market debt and bank loans. EnCana maintains investment grade credit ratings on its senior unsecured debt. The details of these facilities as of December 31, 2008 are disclosed in Note 15 to the Consolidated Financial Statements.

Foreign Exchange

EnCana defines foreign exchange risk as the risk of gains or losses that could result from changes in foreign currency exchange rates. As EnCana operates primarily in North America, fluctuations in the exchange rate between the U.S. and Canadian dollar can have a significant effect on the Company s reported results. As a means of mitigating the exposure to fluctuations in the U.S./Canadian dollar exchange rate, EnCana may enter 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. All foreign exchange agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings. By maintaining U.S. and Canadian operations, EnCana has a natural hedge to some foreign exchange exposure.

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 may enter into cross currency swaps on a portion of its debt as a means of managing the U.S./Canadian dollar debt mix.

Interest Rates

EnCana defines interest rate risk as the impact of changing interest rates on earnings, cash flows, and valuations. The Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt. EnCana may enter into interest rate swap transactions from time to time as an additional means of managing the fixed/floating rate debt portfolio mix.

OPERATIONAL RISKS

Operational risks are defined as the risk of loss or lost opportunity resulting from operating and capital activities that, by their nature, could have an impact on EnCana s ability to achieve its objectives.

The Company s ability to operate, generate cash flows, complete projects, and value reserves is dependent on financial risks, including commodity prices mentioned above, continued market demand for its products and other risk factors outside of its control, which include: general business and market conditions; economic recessions and financial market turmoil; the ability to secure and maintain cost effective financing for its commitments; environmental and regulatory matters; unexpected cost increases; royalties; taxes; the availability of drilling and other equipment; the ability to access lands; weather; the availability of processing capacity; the availability and proximity of pipeline capacity; the availability of diluents to transport crude oil; technology failures; accidents; the availability of skilled labour; and reservoir quality.

If EnCana fails to acquire or find additional crude oil and natural gas reserves its reserves and production will decline materially from their current levels and, therefore, its cash flows are highly dependent upon successfully exploiting current reserves and acquiring, discovering or developing additional reserves.

To mitigate these risks, 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 its 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.

When making operating and investing decisions, EnCana s business model allows flexibility in capital allocation to optimize investments focused on project returns, long-term value creation, and risk mitigation. EnCana also mitigates operational risks through a number of other policies, systems and processes as well as by maintaining a comprehensive insurance program.

SAFETY, ENVIRONMENTAL AND REGULATORY

EnCana is engaged in relatively higher risk activities of natural gas exploration and production and integrated in-situ oil development. The Company is committed to safety in its operations and with high regard for the environment and stakeholders, including regulators. 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, security 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 provides recommended environmental policies for approval by EnCana s Board of Directors 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. In addition, security risks are managed through a Security Program designed to protect EnCana s personnel and assets.

EnCana has 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.

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 Company s existing and planned projects as well as impose a cost of compliance.

Regulatory and legal risks are identified by the operating divisions and corporate groups and EnCana s compliance with the required laws and regulations is monitored by EnCana s legal group, which stays abreast of new developments and changes in laws and regulations to ensure that EnCana continues to comply with prescribed laws and regulations. Of note in this regard currently is EnCana s approach to changes in regulations relating to climate change and royalty frameworks as discussed below. To partially mitigate resource access risks, keep abreast of regulatory developments and be a responsible operator, EnCana maintains relationships with key stakeholders and conducts other mitigation initiatives mentioned herein.

Climate Change

A number of federal, provincial and state governments have announced intentions to regulate greenhouse gases (GHG) and other air pollutants while some jurisdictions have provided details on these regulations. It is anticipated that other jurisdictions will announce emissions reduction plans in the future. As these federal and regional programs are under development, EnCana is unable to predict the total impact of the potential regulations upon its business. Therefore, it is possible that the Company could face increases in operating costs in order to comply with GHG emissions legislation. However, EnCana will continue to work with governments 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.

The Alberta Government has set targets for GHG emissions reductions. In March 2007, regulations were amended to require facilities that emit more than 100,000 tonnes of GHG emissions per year to reduce their emissions intensity by 12 percent from a regulated baseline starting July 1, 2007. To comply, companies can make operating improvements, purchase carbon offsets or make a C$15 per tonne contribution to an Alberta Climate Change and Emissions Management Fund. In Alberta, EnCana has four facilities covered under the emissions regulations. The forecast cost of carbon associated with the Alberta regulations is not material to EnCana at this time and is being actively managed.

In British Columbia, effective July 1, 2008, a revenue neutral carbon tax will be applied to virtually all fossil fuels, including diesel, natural gas, coal, propane, and home heating fuel. The tax applies to combustion emissions and to the purchase or use of fossil fuels within the province. The rate starts at C$10 per tonne of carbon equivalent emissions, rising by C$5 per tonne a year for the next four years. The forecast cost of carbon associated with the British Columbia regulations is not material to EnCana at this time and is being actively managed.

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 the following key elements:

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

EnCana s strategy for addressing the implications of emerging carbon regulations is proactive and is composed of three principal elements:

1. Manage Existing Costs

When regulations are implemented, a cost is placed on EnCana s emissions (or a portion thereof) and while these are not material at this stage, they are being actively managed to ensure compliance. Factors such as effective emissions tracking, attention to fuel consumption, and a focus on minimizing the Company s steam to oil ratio help to support and drive its focus on cost reduction.

2. Respond to Price Signals

As regulatory regimes for GHGs develop in the jurisdictions where EnCana works, inevitably price signals begin to emerge. The Company has initiated an Energy Efficiency Initiative in an effort to improve the energy efficiency of its operations. The price of potential carbon reductions plays a role in the economics of the projects that are implemented. In response to the anticipated price of carbon, EnCana is also attempting, where appropriate, to realize the associated value of its reduction projects.

3. Anticipate Future Carbon Constrained Scenarios

EnCana continues to work with governments, academics and industry leaders to develop and respond to emerging GHG regulations. By continuing to stay engaged in the debate on the most appropriate means to regulate these emissions, the Company gains useful knowledge that allows it to explore different strategies for managing its emissions and costs. These scenarios inform EnCana s long range planning and its analyses on the implications of regulatory trends.

EnCana incorporates the potential costs of carbon into future planning. Management and the Board review the impact of a variety of carbon constrained scenarios on its strategy, with a current price range from $15 to $65 per tonne of emissions applied to a range of emissions coverage levels. A major benefit of applying a range of carbon prices at the strategic level is that it provides direct guidance to the capital allocation process. EnCana also examines the impact of carbon regulation on its major projects. Although uncertainty remains regarding potential future emissions regulation, EnCana s plan is to continue to assess and evaluate the cost of carbon relative to its investments across a range of scenarios.

EnCana recognizes that there is a cost associated with carbon emissions. EnCana is confident that greenhouse gas regulations and the cost of carbon at various price levels have been adequately accounted for as part of its business planning and scenarios analysis. EnCana believes that the resource play strategy is an effective way to develop the resource, generate shareholder returns and coordinate overall environmental objectives with respect to carbon, air emissions, water and land. 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 the Company s website at www.encana.com.

Alberta s New Royalty Framework (NRF)

On October 25, 2007, the Alberta Government announced the New Royalty Framework. The NRF established new royalties for conventional oil, natural gas and bitumen that are linked to commodity prices, well production volumes and well depths for gas wells and oil quality for oil wells. These new rates apply to both new and existing conventional oil and gas activities and oil sands projects in Alberta. The changes introduced by the NRF became effective as of January 1, 2009.

The NRF established new price-sensitive and volume-sensitive rates for conventional oil that range from 0 percent to 50 percent with the price sensitivity topping out between C$68 and C$116 per barrel dependent on the well productivity, and for natural gas that range from 5 percent to 50 percent with the price sensitivity topping out between C$9.92 and C$17.75 per gigajoule. On November 19, 2008, the Alberta Government introduced the Transitional Royalty Program (TRP), which allows for a one time option of selecting between transitional rates and the NRF rates on new natural gas or conventional oil wells drilled between 1,000 metres to 3,500 metres in depth. These would apply until January 1, 2014, at which time all wells would be moved to the NRF. In addition, the NRF introduces royalty rates for bitumen that range from 1 percent to 9 percent (before payout) and from 25 percent to 40 percent (after payout) with rate caps at C$120 WTI per barrel.

The NRF has changed the economics of operating in Alberta and the impact of these changes has been reflected in EnCana s 2009 capital program.

Outlook

During the current challenging economic environment, EnCana is highly focused on the key business objectives of maintaining financial strength, generating significant free cash flow, further optimizing capital investments and continuing to pay a stable dividend to shareholders.

EnCana monitors the risks under its control and has policies in place to mitigate those risks. EnCana is managing commodity price risk through its financial risk management program designed to help ensure financial resilience and flexibility and is closely monitoring interest, credit and counterparty risk. In addition, the Company will continue to monitor expenses and capital programs and maintain flexibility to adjust to changing economic circumstances. EnCana has planned a conservative, prudent and flexible capital program in 2009 that targets total natural gas and oil production at approximately 2008 levels and advances the Company s multi-year projects. EnCana expects to continue to fund the Foster Creek and Christina Lake expansion projects, Wood River CORE project and other capital projects at the present time. EnCana targets a Debt to Capitalization ratio of between 30 to 40 percent and at December 31, 2008, the Company s Debt to Capitalization ratio was 28 percent.

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 and that unconventional resource plays can offset conventional gas production declines over the next few years. Past this period, the industry s ability to continue to grow gas supply is expected to be challenged in North America by land access and regulatory issues.

Volatility in crude oil prices is expected to continue throughout 2009 as a result of market uncertainties over supply and refining, changes in demand due to the overall state of the world economies, OPEC actions and the worldwide credit and liquidity crisis. Canadian crude prices will face added uncertainty due to the risk of refinery disruptions in an already tight United States Midwest market and growing domestic production could result in pipeline constraints out of Western Canada.

The Company expects its 2009 capital investment program to be funded from Cash Flow and debt.

As discussed in EnCana s Business section of this MD&A, the Company announced its plans to split into two highly focused energy companies. Given the uncertainty and volatility in the global financial markets, EnCana is choosing to delay the timing of a shareholder vote until clear signs of stabilization return to the financial markets. EnCana is continuing to prepare documentation and maintain support systems in anticipation of the proposed Arrangement.

EnCana, post-Arrangement, plans to focus on growing natural gas production from its diversified portfolio of existing and emerging unconventional resource plays in North America. Cenovus, post-Arrangement, plans to focus on developing its high quality in-situ oil resources, expanding its downstream heavy oil processing capacity through its joint venture with ConocoPhillips and developing its natural gas, crude oil and NGLs resources in Western Canada.

EnCana s results are affected by external market and risk factors, such as fluctuations in the prices of crude oil and natural gas, movements in foreign currency exchange rates and inflationary pressures on service costs. Additional detail regarding the impact of these factors on EnCana s 2009 results is discussed in the Risk Management section of this MD&A and is also available in the Corporate Guidance on the Company s website at www.encana.com. EnCana updated its Corporate Guidance to reflect the impact on operations of expected conditions for 2009.

EnCana s news release dated February 12, 2009 and financial statements are available on www.sedar.com.

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 document 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 document include, but are not limited to, statements with respect to: projections relating to the adequacy of the Company s provision for taxes; the potential impact of the Alberta Royalty Framework; projections with respect to growth of natural gas production from unconventional resource plays and in-situ oil resources including with respect to the Foster Creek and Christina Lake projects, the CORE project and planned expansions of the Company s downstream heavy oil processing capacity and the capital costs and expected timing of the same; the projected impact of land access and regulatory issues; projections relating to the volatility of crude oil prices in 2009 and beyond and the reasons therefor; the Company s projected capital investment levels for 2009, the flexibility of capital spending plans and the source of funding therefor; the effect of the Company s risk management program, including the impact of derivative financial instruments; the Company s defence of lawsuits; the impact of the changes and proposed changes in laws and regulations, including greenhouse gas, carbon and climate change initiatives on the Company s operations and operating costs; the impact of Western Canada pipeline constraints and potential refinery disruptions 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; projections relating to the Deep Panuke project, including projected costs, production levels and the timing thereof and the timing for completion of project facilities; expected completion dates of the arrangements with Brown Southwest and Brown Haynesville; projections with respect to the proposed Arrangement, including the potential timing for the Arrangement and the conditions which are or may be required prior to proceeding, the expected future attributes of each of EnCana and Cenovus following any such Arrangement, and the anticipated benefits of the Arrangement; projections relating to the Company s natural gas, crude oil and natural gas liquids reserves; the Company s plans to renew its Canadian debt shelf prospectus; the expected results of the Company s cost containment and reduction strategies; the Company s assessment of counterparty credit risk and the potential impact thereof; the Company s ability to fund its 2009 capital program and pay dividends to shareholders; the impact of the current business market conditions, including the economic recession and financial market turmoil on the Company s operations and expected results; the effect of the Company s risk mitigation policies, systems, processes and insurance program; the Company s expectations for future Debt to Capitalization ratios; the expected impact and timing of various accounting pronouncements, rule changes and standards on the Company and its Consolidated Financial Statements; projections with respect to expected funding requirements of the Company s defined benefit pension plan and the materiality thereof; projected costs of payouts under the Company s Performance Tandem Share Appreciation Rights, Performance Share Appreciation Rights and Performance Share Units programs; and projections relating to North American conventional natural gas supplies and the ability of unconventional resource plays to offset future conventional gas production declines over the next few years. 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: the ability to obtain any necessary approvals, waivers, consents, court orders and other requirements, including stabilization of financial and other markets necessary or desirable to permit or facilitate the Arrangement; the risk that any applicable conditions to complete the Arrangement may not occur or be satisfied; 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 reserves 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; the ability of the Company and ConocoPhillips to successfully manage and operate the North American integrated 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 and the application thereof to the business of the Company and Cenovus; 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 royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations or the interpretations of such laws or 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 document are made as of the date of this document, 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 document are expressly qualified by this cautionary statement.

The Company previously disclosed and updated guidance relating to anticipated results for 2008. There were no material differences between (a) the Company s actual cash flow, capital investment and operating costs in 2008 and (b) the amounts forecast in the Company s most recently disclosed guidance (dated December 11, 2008). Explanations for any changes contained in any updated guidance, from guidance previously disclosed, were provided in the news release issued by the Company at the time the guidance was updated.

Forward-looking information respecting anticipated 2009 cash flow, operating cash flow and pre-tax cash flow for EnCana is based upon achieving average production of oil and gas for 2009 of approximately 4.6 Bcfe/d, average commodity prices for 2009 of a WTI price of $55/bbl to $75/bbl for oil, a NYMEX price of $5.50/Mcf to $7.50/Mcf for natural gas, an average U.S./Canadian dollar foreign exchange rate of $0.75 to $0.85, an average Chicago 3-2-1 crack spread for 2009 of $5.00/bbl to $10.00/bbl for refining margins, and an average number of outstanding shares for EnCana of approximately 750 million. Forward-looking information respecting the proposed Arrangement is based upon the assumption that financial and other markets will stabilize. Assumptions relating to forward-looking statements generally include EnCana s current expectations and projections made by the Company in light of, and generally consistent with, its historical experience and its perception of historical trends, as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this document.

EnCana is required to disclose events and circumstances that occurred during the period to which this MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking statements for a period that is not yet complete that EnCana has previously disclosed to the public and the expected differences thereto. Such disclosure can be found in EnCana s news release dated February 12, 2009, which is available on EnCana s website at www.encana.com and on SEDAR at www.sedar.com.

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 that 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 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, NGLs and Natural Gas Conversions

In this document, certain crude oil and 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

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.

CURRENCY, NON-GAAP MEASURES AND REFERENCES TO ENCANA

All information included in this document and the Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after royalties basis unless otherwise noted.

Non-GAAP Measures

Certain measures in this document do not have any standardized meaning as prescribed by Canadian GAAP such as Cash Flow, Cash Flow from Continuing Operations, Cash Flow per share diluted, Free Cash Flow, Operating Earnings, Operating Earnings from Continuing Operations, Operating Earnings per share diluted, Adjusted EBITDA, Debt, Net Debt and Capitalization 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 document 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 document as these measures are discussed and presented.

References to EnCana

For convenience, references in this document to EnCana , the Company , we , us , our and its may, where applicable, refer only to or include relevant direct and indirect subsidiary corporations and partnerships (Subsidiaries) of EnCana Corporation, and the assets, activities and initiatives of such Subsidiaries.

ADDITIONAL INFORMATION

Further information regarding EnCana Corporation can be accessed under the Company s public filings found at www.sedar.com and on the Company s website at www.encana.com.

CONSOLIDATED FINANCIAL STATEMENTS

Prepared in US$

For the Year Ended December 31, 2008

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, 2008. 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 the Company s internal control over financial reporting as at December 31, 2008, as stated in their Auditors Report. PricewaterhouseCoopers LLP has provided such opinions.

(signed)
Randall K. Eresman
President &

(signed)
Brian C. Ferguson
Executive Vice-President &

Chief Executive Officer | Chief Financial Officer

February 19, 2009

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Auditors Report

To the Shareholders of EnCana Corporation

We have completed integrated audits of EnCana Corporation s 2008, 2007 and 2006 consolidated financial statements and of its internal control over financial reporting as of December 31, 2008. Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of EnCana Corporation as at December 31, 2008 and December 31, 2007, and the related consolidated statements of earnings, retained earnings, comprehensive income, accumulated other comprehensive income, and cash flows for each of the years in the three year period ended December 31, 2008. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits of the Company s financial statements as at December 31, 2008 and December 31, 2007 and for each of the years in the three year period ended December 31, 2008 in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the 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. We believe that our audits provide a reasonable basis for our opinion.

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, 2008 and December 31, 2007 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2008 in accordance with Canadian generally accepted accounting principles.

Internal Control over Financial Reporting

We have also audited EnCana Corporation s internal control over financial reporting as of December 31, 2008, 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, included in the accompanying Management s Assessment of Internal Control over Financial Reporting. Our responsibility is to express an opinion 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 dispositions 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 disposition 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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008 based on criteria established in Internal Control Integrated Framework issued by the COSO.

(signed)

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

Canada

February 19, 2009

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EnCana Corporation

Consolidated Statement of Earnings

For the years ended December 31 (US$ millions, except per share amounts)			2008		2007		2006
Revenues, Net of Royalties	*(Note 5)*	**$**	**30,064**	$	21,700	$	16,670
Expenses	*(Note 5)*						
Production and mineral taxes			**478**		291		349
Transportation and selling			**1,704**		1,264		1,341
Operating			**2,475**		2,278		1,655
Purchased product			**11,186**		8,583		2,862
Depreciation, depletion and amortization			**4,223**		3,816		3,112
Administrative			**473**		384		271
Interest, net	*(Note 8)*		**586**		428		396
Accretion of asset retirement obligation	*(Note 16)*		**79**		64		50
Foreign exchange (gain) loss, net	*(Note 9)*		**423**		(164)		14
(Gain) loss on divestitures	*(Note 7)*		**(140)**		(65)		(323)
			21,487		16,879		9,727
Net Earnings Before Income Tax			**8,577**		4,821		6,943
Income tax expense	*(Note 10)*		**2,633**		937		1,892
Net Earnings From Continuing Operations			**5,944**		3,884		5,051
Net Earnings From Discontinued Operations	*(Note 6)*		**-**		75		601
Net Earnings		**$**	**5,944**	$	3,959	$	5,652
Net Earnings From Continuing Operations per Common Share	*(Note 21)*						
Basic		**$**	**7.92**	$	5.13	$	6.16
Diluted		**$**	**7.91**	$	5.08	$	6.04
Net Earnings per Common Share	*(Note 21)*						
Basic		**$**	**7.92**	$	5.23	$	6.89
Diluted		**$**	**7.91**	$	5.18	$	6.76

See accompanying Notes to Consolidated Financial Statements

EnCana Corporation

Consolidated Statement of Retained Earnings

For the years ended December 31 (US$ millions)		**2008**	2007	2006
Retained Earnings, Beginning of Year		**$ 13,082**	$ 11,344	$ 9,481
Net Earnings		**5,944**	3,959	5,652
Dividends on Common Shares		**(1,199)**	(603)	(304)
Charges for Normal Course Issuer Bid	*(Note 17)*	**(243)**	(1,618)	(3,485)
Retained Earnings, End of Year		**$ 17,584**	$ 13,082	$ 11,344

Consolidated Statement of Comprehensive Income

For the years ended December 31 (US$ millions)	**2008**	2007	2006
Net Earnings	**$ 5,944**	$ 3,959	$ 5,652
Other Comprehensive Income, Net of Tax			
Foreign Currency Translation Adjustment	**(2,230)**	1,688	113
Comprehensive Income	**$ 3,714**	$ 5,647	$ 5,765

Consolidated Statement of Accumulated Other Comprehensive Income

For the years ended December 31 (US$ millions)	**2008**	2007	2006
Accumulated Other Comprehensive Income, Beginning of Year	**$ 3,063**	$ 1,375	$ 1,262
Foreign Currency Translation Adjustment	**(2,230)**	1,688	113
Accumulated Other Comprehensive Income, End of Year	**$ 833**	$ 3,063	$ 1,375

See accompanying Notes to Consolidated Financial Statements

EnCana Corporation

Consolidated Balance Sheet

As at December 31 (US$ millions)			**2008**		2007
Assets					
Current Assets					
Cash and cash equivalents		**$**	**383**	$	553
Accounts receivable and accrued revenues			**1,568**		2,381
Current portion of partnership contribution receivable	*(Notes 4, 11)*		**313**		297
Risk management	*(Note 20)*		**2,818**		385
Inventories	*(Note 12)*		**520**		828
			5,602		4,444
Property, Plant and Equipment, net	*(Notes 5, 13)*		**35,424**		35,865
Investments and Other Assets	*(Note 14)*		**727**		607
Partnership Contribution Receivable	*(Notes 4, 11)*		**2,834**		3,147
Risk Management	*(Note 20)*		**234**		18
Goodwill	*(Note 5)*		**2,426**		2,893
	(Note 5)	**$**	**47,247**	$	46,974
Liabilities and Shareholders Equity					
Current Liabilities					
Accounts payable and accrued liabilities		**$**	**2,871**	$	3,982
Income tax payable			**424**		1,150
Current portion of partnership contribution payable	*(Notes 4, 11)*		**306**		288
Risk management	*(Note 20)*		**43**		207
Current portion of long-term debt	*(Note 15)*		**250**		703
			3,894		6,330
Long-Term Debt	*(Note 15)*		**8,755**		8,840
Other Liabilities			**576**		242
Partnership Contribution Payable	*(Notes 4, 11)*		**2,857**		3,163
Risk Management	*(Note 20)*		**7**		29
Asset Retirement Obligation	*(Note 16)*		**1,265**		1,458
Future Income Taxes	*(Note 10)*		**6,919**		6,208
			24,273		26,270
Commitments and Contingencies	*(Note 22)*				
Shareholders Equity					
Share capital	*(Note 17)*		**4,557**		4,479
Paid in surplus	*(Note 17)*		**-**		80
Retained earnings			**17,584**		13,082
Accumulated other comprehensive income			**833**		3,063
Total Shareholders Equity			**22,974**		20,704
		$	**47,247**	$	46,974

See accompanying Notes to Consolidated Financial Statements

Approved by the Board

(signed)
David P. O Brien
Director

(signed)
Barry W. Harrison
Director

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EnCana Corporation

Consolidated Statement of Cash Flows

For the years ended December 31 (US$ millions)		**2008**	2007	2006
Operating Activities				
Net earnings from continuing operations		**$ 5,944**	$ 3,884	$ 5,051
Depreciation, depletion and amortization		**4,223**	3,816	3,112
Future income taxes	*(Note 10)*	**1,646**	(617)	950
Cash tax on sale of assets	*(Note 10)*	**25**	-	49
Unrealized (gain) loss on risk management	*(Note 20)*	**(2,729)**	1,235	(2,060)
Unrealized foreign exchange (gain) loss		**417**	41	-
Accretion of asset retirement obligation	*(Note 16)*	**79**	64	50
(Gain) loss on divestitures	*(Note 7)*	**(140)**	(65)	(323)
Other		**(79)**	95	214
Cash flow from discontinued operations		**-**	-	118
Net change in other assets and liabilities		**(262)**	(16)	138
Net change in non-cash working capital from continuing operations	*(Note 21)*	**(269)**	(8)	3,343
Net change in non-cash working capital from discontinued operations		**-**	-	(2,669)
Cash From Operating Activities		**8,855**	8,429	7,973
Investing Activities				
Capital expenditures	*(Note 5)*	**(8,254)**	(8,737)	(6,600)
Proceeds from divestitures	*(Note 7)*	**904**	481	689
Cash tax on sale of assets	*(Note 10)*	**(25)**	-	(49)
Net change in investments and other		**(267)**	(5)	2
Net change in non-cash working capital from continuing operations	*(Note 21)*	**89**	86	19
Discontinued operations		**-**	-	2,557
Cash (Used in) Investing Activities		**(7,553)**	(8,175)	(3,382)
Financing Activities				
Net issuance (repayment) of revolving long-term debt		**(53)**	181	134
Issuance of long-term debt	*(Note 15)*	**723**	2,409	-
Repayment of long-term debt	*(Note 15)*	**(664)**	(257)	(73)
Issuance of common shares	*(Note 17)*	**80**	176	179
Purchase of common shares	*(Note 17)*	**(326)**	(2,025)	(4,219)
Dividends on common shares		**(1,199)**	(603)	(304)
Other		**-**	-	(11)
Cash (Used in) Financing Activities		**(1,439)**	(119)	(4,294)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(33)**	16	-
Increase (Decrease) in Cash and Cash Equivalents		**(170)**	151	297
Cash and Cash Equivalents, Beginning of Year		**553**	402	105
Cash and Cash Equivalents, End of Year		**$ 383**	$ 553	$ 402

Supplemental Cash Flow Information *(Note 21)*

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

For the year ended December 31, 2008

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 s functional currency is Canadian 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 oil and gas 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 the exploration for, the development of, and the production and marketing of natural gas, crude oil and natural gas liquids (NGLs), refining operations 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 (GAAP). Information prepared in accordance with GAAP in the United States is included in Note 23.

Investments in jointly controlled partnerships and unincorporated joint ventures carry on EnCana s exploration, development, production and crude oil refining businesses 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 in Accumulated Other Comprehensive Income (AOCI) as a separate component of Shareholders Equity. As at December 31, 2008, AOCI is comprised solely of foreign currency translation adjustments.

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 GAAP requires that Management make estimates and assumptions and use judgment 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, costs and the related future cash flows, are subject to measurement uncertainty. Accordingly, the impact in the Consolidated Financial Statements of future periods could be material.

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

The amount of compensation expense accrued for long-term performance-based compensation arrangements is subject to Management s best estimate of whether or not the performance criteria will be met and what the ultimate payout will be.

The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

D) Revenue Recognition

Revenues associated with the sales of EnCana s natural gas, crude oil, NGLs and petroleum and chemical products 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 products that are entered into in contemplation of each other with the same counterparty are recorded on a net basis. Revenues associated with the services provided where EnCana acts as agent are recorded as 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 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 accrued benefit obligation is discounted using the market interest rate on high quality corporate debt instruments as at the measurement date.

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.

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, including petroleum and chemical products, are valued at the lower of cost and net realizable value on a first-in, first-out or weighted average cost basis.

L) Property, Plant and Equipment

Upstream

EnCana accounts for natural gas and crude oil properties in accordance with the Canadian Institute of Chartered Accountants (CICA) 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, the exploration for, and the development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis.

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves 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.

Downstream Refining

The initial acquisition costs of refinery property, plant and equipment are capitalized when incurred. Costs include the cost of constructing or otherwise acquiring the equipment or facilities, the cost of installing the asset and making it ready for its intended use and the associated asset retirement costs. Capitalized costs are not subject to depreciation until the asset is put into use, after which they are depreciated on a straight-line basis over their estimated service lives of approximately 25 years.

An impairment loss is recognized on refinery property, plant and equipment when the carrying amount is not recoverable and exceeds its fair value. The carrying amount is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from expected use and eventual disposition. If the carrying amount is not recoverable, an impairment loss is measured as the amount by which the refinery asset exceeds the fair value.

Market Optimization

Midstream facilities, including 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 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 three to 25 years. Assets under construction are not subject to depreciation until put into use. 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

Items included in Investments and Other Assets are amortized, where applicable, on a straight-line basis over the estimated useful lives of the assets.

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 the country cost centre levels, 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 incurred 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, natural gas processing plants, and refining facilities. 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.

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

Obligations for payments, cash or common shares, under the Company s share appreciation rights, stock options with tandem share appreciation rights attached, deferred share 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.

R) Financial Instruments

Financial instruments are measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as held-for-trading , available-for-sale , held-to-maturity , loans and receivables , or other financial liabilities as defined by the accounting standard.

Financial assets and financial liabilities held-for-trading are measured at fair value with changes in those fair values recognized in net earnings. Financial assets available-for-sale are measured at fair value, with changes in those fair values recognized in Other Comprehensive Income (OCI). Financial assets held-to-maturity , loans and receivables and other financial liabilities are measured at amortized cost using the effective interest method of amortization.

Cash and cash equivalents are designated as held-for-trading and are measured at fair value. Accounts receivable and accrued revenues and the partnership contribution receivable are designated as loans and receivables . Accounts payable and accrued liabilities, the partnership contribution payable and long-term debt are designated as other financial liabilities . EnCana capitalizes long-term debt transaction costs, premiums and discounts. These costs are capitalized within long-term debt and amortized using the effective interest method.

Derivative Financial Instruments

Risk management assets and liabilities are derivative financial instruments classified as held-for-trading unless designated for hedge accounting. 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 an impact on the Company:

- As of January 1, 2009, EnCana will be required to adopt the CICA Handbook Section 3064, Goodwill and Intangible Assets , which will replace the existing Goodwill and Intangible Assets standard. The new standard revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard should not have a material impact on EnCana s Consolidated Financial Statements.

- In February 2008, the CICA s Accounting Standards Board confirmed that International Financial Reporting Standards (IFRS) will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. EnCana will be required to report its results in accordance with IFRS beginning in 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information.

The key elements of EnCana s changeover plan include:

- determine appropriate changes to accounting policies and required amendments to financial disclosures;
- identify and implement changes in associated processes and information systems;
- comply with internal control requirements;
- communicate collateral impacts to internal business groups; and
- educate and train internal and external stakeholders.

The Company is currently analyzing accounting policy alternatives and identifying implementation options for the corresponding process changes. EnCana will update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board. As IFRS is expected to change prior to 2011, the impact of IFRS on the Company s Consolidated Financial Statements is not reasonably determinable at this time.

T) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2008.

NOTE 2. Changes in Accounting Policies and Practices

On January 1, 2008, the Company adopted the following CICA Handbook Sections:

- Inventories , Section 3031. The new standard replaces the previous inventories standard and requires inventory to be valued on a first-in, first-out or weighted average cost basis, which is consistent with EnCana s former accounting policy. The new standard allows the reversal of previous write-downs to net realizable value when there is a subsequent increase in the value of inventories. The adoption of this standard has had no material impact on EnCana s Consolidated Financial Statements.

- Financial Instruments Presentation , Section 3863 and Financial Instruments Disclosures , Section 3862. The new disclosure standard increases EnCana s disclosure regarding the nature and extent of the risks associated with financial instruments and how those risks are managed (See Note 20). The new presentation standard carries forward the former presentation requirements.

- Capital Disclosures , Section 1535. The new standard requires EnCana to disclose its objectives, policies and processes for managing its capital structure (See Note 18).

NOTE 3. Proposed Corporate Reorganization

On May 11, 2008, EnCana announced its plans to split into two independent energy companies one a North American natural gas company and the other a fully integrated oil company with in-situ oil properties and refineries supplemented by reliable production from various natural gas and crude oil resource plays.

The proposed corporate reorganization (the Arrangement) would be implemented through a court approved Plan of Arrangement and is subject to shareholder approval. The Arrangement would result in two publicly traded entities with the names of Cenovus Energy Inc. (Cenovus) and EnCana Corporation. Each EnCana shareholder would receive one share of each entity in exchange for each EnCana Common Share held. On October 15, 2008, EnCana announced the proposed Arrangement would be delayed until the global debt and equity markets regain stability.

NOTE 4. Joint Venture with ConocoPhillips

On January 2, 2007, EnCana became a 50 percent partner in an integrated, North American oil business with ConocoPhillips which consists of an upstream and a downstream entity. The upstream entity contribution included assets from EnCana, primarily the

Foster Creek and Christina Lake properties, with a fair value of $7.5 billion and a note receivable contributed from ConocoPhillips of an equal amount. For the downstream entity, ConocoPhillips contributed its Wood River and Borger refineries, located in Illinois and Texas, respectively, for a fair value of $7.5 billion and EnCana contributed a note payable of $7.5 billion. Further information about these notes is included in Note 11.

In accordance with Canadian GAAP, these entities have been accounted for using the proportionate consolidation method with the results of operations included in the Integrated Oil Division (See Note 5).

NOTE 5. Segmented Information

The Company s operating and reportable segments are as follows:

- **Canada** includes the Company s exploration for, and development and production of natural gas, crude oil and NGLs and other related activities within the Canadian cost centre.

- **USA** includes the Company s exploration for, and development and production of natural gas, NGLs and other related activities within the United States cost centre.

- **Downstream Refining** is focused on the refining of crude oil into petroleum and chemical products at two refineries located in the United States. The refineries are jointly owned with ConocoPhillips.

- **Market Optimization** is primarily responsible for the sale of the Company s proprietary production. These results are included in the Canada and USA segments. Market optimization activities include 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 and Other** mainly includes unrealized gains or losses recorded on derivative financial 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 upstream production to third-party customers. Transactions between segments are based on market values and eliminated on consolidation. The tables in this note present financial information on an after eliminations basis.

EnCana has updated its segmented reporting to present the upstream Canadian and United States cost centres and Downstream Refining as separate reportable segments. This results in EnCana presenting the Canadian portion of the Integrated Oil Division as part of the Canada segment. Previously, this was aggregated and presented in the Integrated Oil segment. Prior periods have been restated to reflect the new presentation.

EnCana has a decentralized decision making and reporting structure. Accordingly, the Company is organized into Divisions as follows:

- **Canadian Plains** Division includes natural gas production and crude oil development and production assets located in eastern Alberta and Saskatchewan.

- **Canadian Foothills** Division includes natural gas development and production assets located in western Alberta and British Columbia as well as the Company s Canadian offshore assets.

- **USA** Division includes the assets located in the United States and comprises the USA segment described above.

- **Integrated Oil** Division is the combined total of Integrated Oil Canada and Downstream Refining. Integrated Oil Canada includes the Company s exploration for, and development and production of bitumen using in-situ recovery methods. Integrated Oil Canada is composed of EnCana s interests in the FCCL Oil Sands Partnership jointly owned with ConocoPhillips, the Athabasca natural gas assets and other bitumen interests.

Operations that have been discontinued are disclosed in Note 6.

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Results of Continuing Operations

Segment and Geographic Information

	Canada			USA			Downstream Refining		
For the years ended December 31	**2008**	2007	2006	**2008**	2007	2006	**2008**	2007	2006
Revenues, Net of Royalties	**$10,050**	$8,308	$8,266	**$ 5,629**	$ 4,372	$ 3,345	**$ 9,011**	$ 7,315	$ -
Expenses									
Production and mineral taxes	**108**	102	116	**370**	189	233	**-**	-	-
Transportation and selling	**1,202**	947	1,077	**502**	307	248	**-**	-	-

Operating	**1,333**	1,204	1,104	**618**	595	490	**492**	428	-
Purchased product	**(151)**	(88)	-	**-**	-	-	**8,760**	5,813	-
	7,558	6,143	5,969	**4,139**	3,281	2,374	**(241)**	1,074	-
Depreciation, depletion and amortization	**2,198**	2,298	2,146	**1,691**	1,181	869	**188**	159	-
Segment Income (Loss)	**$ 5,360**	$3,845	$3,823	**$ 2,448**	$ 2,100	$ 1,505	**$ (429)**	$ 915	$ -

	Market Optimization			Corporate & Other			Consolidated		
	2008	2007	2006	**2008**	2007	2006	**2008**	2007	2006
Revenues, Net of Royalties	**$ 2,655**	$2,944	$3,007	**$2,719**	$(1,239)	$ 2,052	**$30,064**	$21,700	$16,670
Expenses									
Production and mineral taxes	**-**	-	-	**-**	-	-	**478**	291	349
Transportation and selling	**-**	10	16	**-**	-	-	**1,704**	1,264	1,341
Operating	**45**	37	62	**(13)**	14	(1)	**2,475**	2,278	1,655
Purchased product	**2,577**	2,858	2,862	**-**	-	-	**11,186**	8,583	2,862
	33	39	67	**2,732**	(1,253)	2,053	**14,221**	9,284	10,463
Depreciation, depletion and amortization	**15**	17	12	**131**	161	85	**4,223**	3,816	3,112
Segment Income (Loss)	**$ 18**	$ 22	$ 55	**$2,601**	$(1,414)	$ 1,968	**9,998**	5,468	7,351
Administrative							**473**	384	271
Interest, net							**586**	428	396
Accretion of asset retirement obligation							**79**	64	50
Foreign exchange (gain) loss, net							**423**	(164)	14
(Gain) loss on divestitures							**(140)**	(65)	(323)
							1,421	647	408
Net Earnings Before Income Tax							**8,577**	4,821	6,943
Income tax expense							**2,633**	937	1,892
Net Earnings From Continuing Operations							**$ 5,944**	$ 3,884	$ 5,051

Results of Continuing Operations

Product and Divisional Information

	Canada Segment								
	Canadian Plains			Canadian Foothills			Integrated Oil - Canada		
For the years ended December 31	**2008**	2007	2006	**2008**	2007	2006	**2008**	2007	2006
Revenues, Net of Royalties	**$ 4,418**	$ 3,652	$ 3,559	**$ 4,355**	$ 3,679	$ 3,338	**$ 1,277**	$ 977	$ 1,369
Expenses									
Production and mineral taxes	**74**	63	72	**33**	39	43	**1**	-	1
Transportation and selling	**392**	345	353	**239**	201	194	**571**	401	530
Operating	**484**	440	387	**609**	535	439	**240**	229	278
Purchased product	**-**	-	-	**-**	-	-	**(151)**	(88)	-
Operating Cash Flow	**$ 3,468**	$ 2,804	$ 2,747	**$ 3,474**	$2,904	$2,662	**$ 616**	$ 435	$ 560

	Total		
	2008	2007	2006
Revenues, Net of Royalties	**$ 10,050**	$ 8,308	$ 8,266
Expenses			
Production and mineral taxes	**108**	102	116
Transportation and selling	**1,202**	947	1,077
Operating	**1,333**	1,204	1,104
Purchased product	**(151)**	(88)	-
Operating Cash Flow	**$ 7,558**	$ 6,143	$ 5,969

Results of Continuing Operations

Product and Divisional Information

Canadian Plains Division

For the years ended December 31	Gas 2008	Gas 2007	Gas 2006	Oil & NGLs 2008	Oil & NGLs 2007	Oil & NGLs 2006	Other 2008	Other 2007	Other 2006
Revenues, Net of Royalties	**$2,301**	$2,186	$2,213	**$2,106**	$1,453	$1,337	**$ 11**	$ 13	$ 9
Expenses									
Production and mineral taxes	**36**	34	41	**38**	29	31	**-**	-	-
Transportation and selling	**71**	82	77	**321**	263	276	**-**	-	-
Operating	**241**	221	194	**239**	215	188	**4**	4	5
Operating Cash Flow	**$1,953**	$1,849	$1,901	**$1,508**	$ 946	$ 842	**$ 7**	$ 9	$ 4

	Total 2008	Total 2007	Total 2006
Revenues, Net of Royalties	**$4,418**	$3,652	$3,559
Expenses			
Production and mineral taxes	**74**	63	72
Transportation and selling	**392**	345	353
Operating	**484**	440	387
Operating Cash Flow	**$3,468**	$2,804	$2,747

Canadian Foothills Division

For the years ended December 31	Gas 2008	Gas 2007	Gas 2006	Oil & NGLs 2008	Oil & NGLs 2007	Oil & NGLs 2006	Other 2008	Other 2007	Other 2006
Revenues, Net of Royalties	**$3,720**	$3,232	$2,936	**$ 578**	$ 390	$ 360	**$ 57**	$ 57	$ 42
Expenses									
Production and mineral taxes	**28**	36	39	**5**	3	4	**-**	-	-
Transportation and selling	**201**	192	186	**12**	9	8	**26**	-	-
Operating	**549**	482	394	**39**	33	34	**21**	20	11
Operating Cash Flow	**$2,942**	$2,522	$2,317	**$ 522**	$ 345	$ 314	**$ 10**	$ 37	$ 31

	Total 2008	Total 2007	Total 2006
Revenues, Net of Royalties	**$4,355**	$3,679	$3,338
Expenses			
Production and mineral taxes	**33**	39	43
Transportation and selling	**239**	201	194
Operating	**609**	535	439
Operating Cash Flow	**$3,474**	$2,904	$2,662

Results of Continuing Operations

Product and Divisional Information

	USA Division								
	Gas			Oil & NGLs			Other		
For the years ended December 31	**2008**	2007	2006	**2008**	2007	2006	**2008**	2007	2006
Revenues, Net of Royalties	**$4,934**	$3,765	$2,854	**$ 407**	$ 309	$ 267	**$ 288**	$ 298	$ 224
Expenses									
Production and mineral taxes	**334**	167	213	**36**	22	20	**-**	-	-
Transportation and selling	**502**	307	248	**-**	-	-	**-**	-	-
Operating	**352**	323	283	**-**	-	-	**266**	272	207
Operating Cash Flow	**$3,746**	$2,968	$2,110	**$ 371**	$ 287	$ 247	**$ 22**	$ 26	$ 17

	Total		
	2008	2007	2006
Revenues, Net of Royalties	**$ 5,629**	$4,372	$3,345
Expenses			
Production and mineral taxes	**370**	189	233
Transportation and selling	**502**	307	248
Operating	**618**	595	490
Operating Cash Flow	**$ 4,139**	$3,281	$2,374

	Integrated Oil Division								
	Oil *			Downstream Refining			Other *		
For the years ended December 31	**2008**	2007	2006	**2008**	2007	2006	**2008**	2007	2006
Revenues, Net of Royalties	**$1,117**	$ 738	$ 941	**$9,011**	$7,315	$ -	**$ 160**	$ 239	$ 428
Expenses									
Production and mineral taxes	**-**	-	-	**-**	-	-	**1**	-	1
Transportation and selling	**526**	366	476	**-**	-	-	**45**	35	54
Operating	**170**	159	194	**492**	428	-	**70**	70	84
Purchased product	**-**	-	-	**8,760**	5,813	-	**(151)**	(88)	-
Operating Cash Flow	**$ 421**	$ 213	$ 271	**$ (241)**	$1,074	$ -	**$ 195**	$ 222	$ 289

	Total		
	2008	2007	2006
Revenues, Net of Royalties	**$10,288**	$8,292	$1,369
Expenses			
Production and mineral taxes	**1**	-	1
Transportation and selling	**571**	401	530
Operating	**732**	657	278
Purchased product	**8,609**	5,725	-
Operating Cash Flow	**$ 375**	$1,509	$ 560

* Oil and Other comprise Integrated Oil Canada. Other includes production of natural gas and bitumen from the Athabasca and Senlac properties.

Capital Expenditures (Continuing Operations)

For the years ended December 31	**2008**	2007	2006
Capital			
Canadian Plains	**$ 847**	$ 846	$ 770
Canadian Foothills	**2,299**	2,439	2,500
Integrated Oil Canada	**656**	451	745
Canada	**3,802**	3,736	4,015
USA	**2,615**	1,919	2,061
Downstream Refining	**478**	220	-
Market Optimization	**17**	6	44
Corporate & Other	**168**	154	149
	7,080	6,035	6,269
Acquisition Capital			
Canadian Foothills	**151**	75	26
Integrated Oil Canada	**-**	14	21
Canada	**151**	89	47
USA	**1,023**	2,613	284
	1,174	2,702	331
Total	**$ 8,254**	$ 8,737	$ 6,600

On September 25, 2008, EnCana acquired certain land and property in Louisiana for approximately $101 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Haynesville Leasehold LLC (Brown Haynesville), which holds the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes.

On July 23, 2008, EnCana acquired certain land and mineral interests in Louisiana for approximately $457 million before closing adjustments. The purchase was facilitated by an unrelated party, Brown Southwest Minerals LLC (Brown Southwest), which holds the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. On November 12, 2008, an unrelated party exercised an option to purchase certain interests as part of the above acquisition for approximately $157 million, reducing the qualifying like kind exchange to approximately $300 million.

Pursuant to the agreements with Brown Haynesville and Brown Southwest, EnCana operates the properties, receives all the revenue and pays all of the expenses associated with the properties. The arrangements with Brown Haynesville and Brown Southwest will be completed on March 24, 2009 and January 19, 2009, respectively, and the assets will be transferred to EnCana at that time. EnCana has determined that each relationship with Brown Haynesville and Brown Southwest represents an interest in a Variable Interest Entity (VIE) and that EnCana is the primary beneficiary of the VIE. EnCana has consolidated Brown Haynesville and Brown Southwest from the dates of acquisition.

On November 20, 2007, EnCana acquired certain natural gas and land interests in Texas for approximately $2.55 billion before closing adjustments. The purchase was facilitated by an unrelated party, Brown Kilgore Properties LLC (Brown Kilgore), which held the majority of the assets in trust for the Company in anticipation of a qualifying like kind exchange for U.S. tax purposes. The relationship with Brown Kilgore represented an interest in a VIE from November 20, 2007 to May 18, 2008. During this period, EnCana was the primary beneficiary of the VIE and consolidated Brown Kilgore. On May 18, 2008, when the arrangement with Brown Kilgore was completed, the assets were transferred to EnCana.

Additions to Goodwill

There were no additions to goodwill during 2008 or 2007.

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Property, Plant and Equipment and Total Assets by Segment

	Property, Plant and Equipment		Total Assets	
As at December 31	**2008**	2007	**2008**	2007
Canada	**$ 17,105**	$ 19,519	**$ 23,441**	$ 27,014
USA	**13,541**	11,879	**14,635**	12,948
Downstream Refining	**4,032**	3,706	**4,637**	4,887
Market Optimization	**140**	171	**429**	478
Corporate & Other	**606**	590	**4,105**	1,647
Total	**$ 35,424**	$ 35,865	**$ 47,247**	$ 46,974

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 has entered into a 25 year lease agreement with a third-party developer. As at December 31, 2008, Corporate and Other Property, Plant and Equipment and Total Assets include EnCana s accrual to date of $252 million (2007 $147 million) related to this office project as an asset under construction.

On January 4, 2008, EnCana signed the contract for the design and construction of the Production Field Centre (PFC) for the Deep Panuke project. As at December 31, 2008, Canada Property, Plant and Equipment and Total Assets include EnCana s accrual to date of $199 million related to this offshore facility as an asset under construction.

Corresponding liabilities for these projects are included in Other Liabilities in the Consolidated Balance Sheet. There is no effect on the Company s net earnings or cash flows related to the capitalization of The Bow office project or the Deep Panuke PFC.

Property, Plant and Equipment, Goodwill and Total Assets by Geographic Region

As at December 31	Goodwill 2008	2007	Property, Plant and Equipment 2008	2007	Total Assets 2008	2007
Canada	**$ 1,953**	$ 2,420	**$ 17,790**	$ 20,126	**$ 27,726**	$ 28,402
United States	**473**	473	**17,624**	15,602	**19,414**	18,317
Other Countries	**-**	-	**10**	137	**107**	255
Total	**$ 2,426**	$ 2,893	**$ 35,424**	$ 35,865	**$ 47,247**	$ 46,974

Export Sales

Sales of natural gas, crude oil and NGLs produced or purchased in Canada delivered to customers outside of Canada were $1,874 million (2007 $1,362 million; 2006 $1,814 million).

Major Customers

In connection with the marketing and sale of EnCana s own and purchased natural gas, crude oil and refined products for the year ended December 31, 2008, the Company had two customers (2007 two; 2006 one) which individually accounted for more than 10 percent of its consolidated revenues, net of royalties. Sales to these customers, major international integrated energy companies with a high quality investment grade credit rating, were approximately $10,190 million (2007 $7,652 million; 2006 $1,951 million).

NOTE 6. Discontinued Operations

As EnCana has focused its continuing operations on North American Upstream and Downstream Refining operations, a number of divestitures have been made which are accounted for as discontinued operations.

Midstream

The $75 million gain on discontinuance in 2007 is the result of an expired clause included in the December 2005 sale of the Company s Midstream natural gas liquids processing operations. The clause provided potential market price support for the facilities and was accrued for in 2005.

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.

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 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 GAAP.

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 table presents the effect of the discontinued operations in the Consolidated Statement of Earnings:

	Midstream		Ecuador	United Kingdom	Consolidated Total		
For the years ended December 31	2007	2006	2006	2006	**2008**	2007	2006
Revenues, Net of Royalties*	$ -	$ 482	$ 200	$ -	**$ -**	$ -	$ 682
Expenses							
Production and mineral taxes	-	-	23	-	**-**	-	23
Transportation and selling	-	-	10	-	**-**	-	10
Operating	-	37	25	-	**-**	-	62
Purchased product	-	356	-	-	**-**	-	356
Depreciation, depletion and amortization	-	-	84	-	**-**	-	84
Administrative	-	-	-	-	**-**	-	-

Interest, net	-	-	(2)	-	**-**	-	(2)
Accretion of asset retirement obligation	-	-	-	-	**-**	-	-
Foreign exchange (gain) loss, net	-	4	1	(1)	**-**	-	4
(Gain) loss on discontinuance	(75)	(807)	279	-	**-**	(75)	(528)
	(75)	(410)	420	(1)	-	(75)	9
Net Earnings (Loss) Before Income Tax	75	892	(220)	1	**-**	75	673
Income tax expense (recovery)	-	17	59	(4)	**-**	-	72
Net Earnings (Loss) From Discontinued Operations	$ 75	$ 875	$ (279)	$ 5	**$ -**	$ 75	$ 601
Net Earnings (Loss) From Discontinued Operations per Common Share							
Basic					**$ -**	$ 0.10	$ 0.73
Diluted					**$ -**	$ 0.10	$ 0.72

* Revenues, net of royalties in Ecuador for 2006 include realized losses of $1 million related to derivative financial instruments.

There were no assets and liabilities related to discontinued operations as at December 31, 2008.

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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 7. Divestitures

For the years ended December 31		**2008**		2007		2006
Canadian Plains	**$**	**39**	$	-	$	3
Canadian Foothills		**400**		213		56
Integrated Oil Canada		**8**		-		-
Canada		**447**		213		59
USA		**251**		10		19
Market Optimization		**-**		-		244
Corporate & Other		**206**		258		367
	$	**904**	$	481	$	689

Proceeds received on the sale of assets and investments in 2008 were $904 million (2007 $481 million; 2006 $689 million). The significant items are described below.

Canada

In 2008, the Company completed the divestiture of mature conventional oil and natural gas assets for proceeds of $39 million (2007 nil; 2006 $3 million) in Canadian Plains and $400 million (2007 $213 million; 2006 $56 million) in Canadian Foothills.

In May 2007, the Company completed the sale of its assets in the Mackenzie Delta and Beaufort Sea for proceeds of $159 million, which were credited to property, plant and equipment in the Canadian cost centre and reported in Canadian Foothills.

USA

In 2008, the Company completed the divestiture of mature conventional natural gas assets for proceeds of $251 million (2007 $10 million; 2006 $19 million).

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.

Corporate and Other

In September 2008, the Company completed the sale of its interests in Brazil for net proceeds of $164 million, before closing adjustments, resulting in a gain on sale of $124 million. After recording income tax of $25 million, EnCana recorded an after-tax gain of $99 million.

In August 2007, the Company closed the sale of Australia assets for proceeds of $31 million resulting in a gain on sale of $30 million. After recording income tax of $5 million, EnCana recorded an after-tax gain of $25 million.

In February 2007, the Company sold The Bow office project assets for proceeds of approximately $57 million, largely representing its investment at the date of sale. Refer to Note 5 for further discussion of The Bow office project assets.

In January 2007, the Company completed the sale of its interests in Chad, properties that were in the pre-production stage, for proceeds of $208 million which resulted in a gain on sale of $59 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.

NOTE 8. Interest, Net

For the years ended December 31		**2008**		2007		2006
Interest Expense Long-Term Debt	**$**	**556**	$	460	$	366
Interest Expense Other*		**246**		244		76
Interest Income*		**(216)**		(276)		(46)
	$	**586**	$	428	$	396

* In 2008 and 2007, Interest Expense Other and Interest Income are primarily due to the Partnership Contribution Payable and Receivable, respectively. See Note 11.

NOTE 9. Foreign Exchange (Gain) Loss, Net

For the years ended December 31		**2008**		2007		2006
Unrealized Foreign Exchange (Gain) Loss on:						
Translation of U.S. dollar debt issued from Canada	**$**	**1,033**	$	(683)	$	-
Translation of U.S. dollar partnership contribution receivable issued from Canada		**(608)**		617		-
Other Foreign Exchange (Gain) Loss		**(2)**		(98)		14
	$	**423**	$	(164)	$	14

NOTE 10. Income Taxes

The provision for income taxes is as follows:

For the years ended December 31		**2008**		2007		2006
Current						
Canada	**$**	**548**	$	900	$	764
United States		**396**		647		128
Other Countries		**43**		7		50
Total Current Tax		**987**		1,554		942
Future		**1,646**		(316)		1,407
Future Tax Rate Reductions		**-**		(301)		(457)
Total Future Tax		**1,646**		(617)		950
	$	**2,633**	$	937	$	1,892

Included in current tax for 2008 is $25 million related to the sale of assets in Brazil (2007 nil; 2006 $49 million).

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

For the years ended December 31		**2008**		2007		2006
Net Earnings Before Income Tax	**$**	**8,577**	$	4,821	$	6,943
Canadian Statutory Rate		**29.7%**		32.3%		34.7%
Expected Income Tax		**2,544**		1,557		2,407
Effect on Taxes Resulting from:						
Non-deductible Canadian Crown payments		**-**		-		97
Canadian resource allowance		**-**		-		(16)
Statutory and other rate differences		**167**		76		(98)
Effect of tax rate changes		**-**		(301)		(457)
Effect of legislative changes		**-**		(179)		-
Non-taxable downstream partnership (income) loss		**6**		(70)		-
International financing		**(309)**		(62)		(59)
Foreign exchange (gains) losses not included in net earnings		**49**		-		-
Non-taxable capital (gains) losses		**84**		(124)		(1)
Other		**92**		40		19
	$	**2,633**	$	937	$	1,892
Effective Tax Rate		**30.7%**		19.4%		27.3%

The net future income tax liability is comprised of:

As at December 31		**2008**		2007
Future Tax Liabilities				
Property, plant and equipment in excess of tax values	**$**	**5,372**	$	5,400
Timing of partnership items		**924**		961
Risk management		**958**		89
Future Tax Assets				
Non-capital and net operating losses carried forward		**(66)**		(44)
Other		**(269)**		(198)
Net Future Income Tax Liability	**$**	**6,919**	$	6,208

The approximate amounts of tax pools available are as follows:

As at December 31		**2008**		2007
Canada	**$**	**9,105**	$	11,014
United States		**8,516**		7,101
	$	**17,621**	$	18,115

Included in the above tax pools are $261 million (2007 $23 million) related to non-capital and net operating losses available for carry forward to reduce taxable income in future years. These losses expire between 2009 and 2027.

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 11. Partnership Contribution Receivable / Payable

Partnership Contribution Receivable

On January 2, 2007, upon the creation of the Integrated Oil joint venture, ConocoPhillips entered into a subscription agreement for a 50 percent interest in the upstream entity in exchange for a promissory note of $7.5 billion. The note bears interest at a rate of 5.3 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term partnership contribution receivable shown in the Consolidated Balance Sheet represent EnCana s 50 percent share of this promissory note, net of payments to date.

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Mandatory Receipts

	2009	2010	2011	2012	2013	Thereafter	**Total**
Partnership Contribution Receivable	$ 313	$ 330	$ 347	$ 366	$ 386	$ 1,405	**$ 3,147**

Partnership Contribution Payable

On January 2, 2007, upon the creation of the Integrated Oil joint venture, EnCana issued a promissory note to the downstream entity in the amount of $7.5 billion in exchange for a 50 percent interest. The note bears interest at a rate of 6.0 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term partnership contribution payable amounts shown in the Consolidated Balance Sheet represent EnCana s 50 percent share of this promissory note, net of payments to date.

Mandatory Payments

	2009	2010	2011	2012	2013	Thereafter	**Total**
Partnership Contribution Payable	$ 306	$ 325	$ 345	$ 366	$ 388	$ 1,433	**$ 3,163**

NOTE 12. Inventories

As at December 31	**2008**	2007
Product		
Canada	**$ 46**	$ 65
USA	**8**	2
Downstream Refining	**323**	570
Market Optimization	**127**	180
Parts and Supplies	**16**	11
	$ 520	$ 828

As a result of a significant decline in commodity prices in the latter half of 2008, EnCana has written down its product inventory by $152 million from cost to net realizable value.

The total amount of inventories recognized as an expense during the year, including the write-down, was $8,749 million (2007 $5,752 million).

NOTE 13. Property, Plant and Equipment, Net

As at December 31	**2008**			2007		
	Cost	**Accumulated DD&A***	**Net**	Cost	Accumulated DD&A*	Net
Canada	**$ 34,660**	**$ (17,555)**	**$ 17,105**	$ 38,825	$ (19,306)	$ 19,519
USA	**19,052**	**(5,511)**	**13,541**	15,681	(3,802)	11,879
Downstream Refining	**4,347**	**(315)**	**4,032**	3,855	(149)	3,706
Market Optimization	**220**	**(80)**	**140**	253	(82)	171
Corporate & Other	**1,074**	**(468)**	**606**	1,207	(617)	590
	$ 59,353	**$ (23,929)**	**$ 35,424**	$ 59,821	$ (23,956)	$ 35,865

* Depreciation, depletion and amortization.

Canada and USA property, plant and equipment include internal costs directly related to exploration, development and construction activities of $378 million (2007 $469 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 are excluded from the country cost centre s depletable base. Downstream Refining assets not put into use are excluded from depreciable costs. At the end of the year these costs were:

As at December 31		2008		2007		2006
Canada	**$**	**870**	$	1,381	$	1,449
United States		**3,399**		1,852		956
Other Countries		**10**		137		263
Downstream Refining		**488**		139		-
	$	**4,767**	$	3,509	$	2,668

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, 2008, the Company completed its impairment review of pre-production cost centres and determined that $38 million of costs should be charged to depreciation, depletion and amortization in the Consolidated Statement of Earnings (2007 $68 million; 2006 $6 million).

Downstream Refining expenditures capitalized during the construction phase are not subject to depreciation until put in use and total $488 million at December 31, 2008 (2007 $139 million).

The prices used in the ceiling test evaluation of the Company s natural gas and crude oil reserves at December 31, 2008 were:

	2009	2010	2011	2012	2013	Cumulative % Change to 2020
Natural Gas ($/Mcf)						
Canada	6.60	6.57	6.37	6.28	6.32	4%
United States	6.54	6.74	6.81	6.72	6.73	-
Crude Oil ($/barrel)						
Canada	49.51	48.46	47.50	47.02	46.70	(5)%
Natural Gas Liquids ($/barrel)						
Canada	68.51	69.20	69.73	70.18	70.17	-
United States	61.65	61.37	61.46	61.14	60.93	(1)%

NOTE 14. Investments and Other Assets

As at December 31	2008	2007

Prepaid Capital	**$**	**520**	$	383
Deferred Asset Downstream Refining		**134**		159
Deferred Pension Plan and Savings Plan		**59**		50
Other		**14**		15
	$	**727**	$	607

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NOTE 15. Long-Term Debt

As at December 31	Note		2008		2007
Canadian Dollar Denominated Debt					
Revolving credit and term loan borrowings	*B*	**$**	**1,410**	$	1,506
Unsecured notes	*C*		**1,020**		1,138
			2,430		2,644
U.S. Dollar Denominated Debt					
Revolving credit and term loan borrowings	*D*		**247**		495
Unsecured notes	*E*		**6,350**		6,421
			6,597		6,916
Increase in Value of Debt Acquired	*F*		**49**		66
Debt Discounts and Financing Costs	*G*		**(71)**		(83)
Current Portion of Long-Term Debt	*H*		**(250)**		(703)
		$	**8,755**	$	8,840

A) Overview

Revolving Credit and Term Loan Borrowings

At December 31, 2008, EnCana Corporation had in place a revolving credit facility for C$4.5 billion or its equivalent amount in U.S. dollars ($3.7 billion). The facility, which matures in October 2012, is fully revolving for a period of up to 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 90 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, 2008, one of EnCana s subsidiaries had in place a credit facility totaling $600 million, of which $565 million was accessible. One of the lenders under the facility, Lehman Brothers Bank, FSB, has ceased funding its $35 million commitment as a result of the bankruptcy filing made by its affiliate, Lehman Brothers Holding Inc., on September 15, 2008. The facility, which matures in February 2013, is guaranteed by EnCana Corporation and is fully revolving for up to 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 90 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, Commercial Paper and LIBOR loans of $1,657 million (2007 $2,001 million) maturing at various dates with a weighted average interest rate of 1.92 percent (2007 5.00 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 2008 relating to revolving credit and term loan agreements were approximately $4 million (2007 $4 million; 2006 $5 million).

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$2.0 billion which expires in June 2009. 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, 2008, C$1.25 billion ($1.0 billion) of the shelf prospectus remained 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 $4.0 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 maturity dates, are determined by reference to market conditions at the date of issue. The shelf prospectus was filed in March 2008, expires in April 2010, and replaces the $2.0 billion shelf prospectus which was fully utilized. At December 31, 2008, $4.0 billion of the shelf prospectus remained unutilized, the availability of which is dependent upon market conditions.

EnCana has an indirect wholly owned subsidiary, EnCana Holdings Finance Corp., which, at December 31, 2007, had in place a debt shelf prospectus for U.S. unsecured notes in the amount of $2.0 billion under the MJDS. The outstanding 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 allowed 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, expired in July 2008 and was not renewed.

B) Canadian Revolving Credit and Term Loan Borrowings

	C$ Principal Amount	2008	2007
Bankers Acceptances	**$ 1,105**	**$ 902**	$ 425
Commercial Paper	**622**	**508**	1,081
	$ 1,727	**$ 1,410**	$ 1,506

C) Canadian Unsecured Notes

	C$ Principal Amount	2008	2007
5.80% due June 2, 2008	**$ -**	**$ -**	$ 126
3.60% due September 15, 2008	**-**	**-**	506
4.30% due March 12, 2012	**500**	**408**	506
5.80% due January 18, 2018	**750**	**612**	-
	$ 1,250	**$ 1,020**	$ 1,138

D) U.S. Revolving Credit and Term Loan Borrowings

	2008	2007
LIBOR	**$ 184**	$ 20
Commercial Paper	**63**	475
	$ 247	$ 495

E) U.S. Unsecured Notes

	2008	2007
5.80% due June 2, 2008	**$ -**	$ 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
5.90% due December 1, 2017	**700**	700
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
6.625% due August 15, 2037	**500**	500
6.50% due February 1, 2038	**800**	800
	$ 6,350	$ 6,421

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 dates of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 20 years.

G) Debt Discounts and Financing Costs

On January 1, 2007, upon adoption of the financial instruments standard, $52 million of long-term debt transaction costs, premiums and discounts were reclassified from other assets to long-term debt. The costs capitalized within long-term debt are being amortized using the effective interest method. Previously, the Company deferred these costs within other assets and amortized them straight-line over the life of the related long-term debt. During 2008, $5 million (2007 $25 million) in transaction costs and discounts have been capitalized within long-term debt relating to the issuance of Canadian and U.S. unsecured notes.

H) Current Portion of Long-Term Debt

	C$ Principal Amount	2008	2007
5.80% due June 2, 2008	**$ -**	**$ -**	$ 126
5.80% due June 2, 2008	**-**	**-**	71
3.60% due September 15, 2008	**-**	**-**	506
4.60% due August 15, 2009	**-**	**250**	-
	$ -	**$ 250**	$ 703

I) Mandatory Debt Payments

	C$ Principal Amount	US$ Principal Amount	Total US$ Equivalent
2009	**$ -**	**$ 250**	**$ 250**
2010	**-**	**200**	**200**
2011	**-**	**500**	**500**
2012	**2,227**	**-**	**1,818**
2013	**-**	**747**	**747**
Thereafter	**750**	**4,900**	**5,512**
Total	**$ 2,977**	**$ 6,597**	**$ 9,027**

The amount due in 2009 excludes Bankers Acceptances, Commercial Paper and LIBOR loans, which are fully supported by revolving credit and term loan facilities that have no repayment requirements within the next year. The revolving credit and term loan facilities are fully revolving for a period of up to five years. Based on the current maturity dates of the credit facilities, the payments are included in 2012 and 2013.

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NOTE 16. 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 assets and refining facilities:

As at December 31		**2008**		2007
Asset Retirement Obligation, Beginning of Year	**$**	**1,458**	$	1,051
Liabilities Incurred		**54**		89
Liabilities Settled		**(115)**		(100)
Liabilities Divested		**(38)**		-
Change in Estimated Future Cash Flows		**54**		184
Accretion Expense		**79**		64
Foreign Currency Translation		**(227)**		163
Other		**-**		7
Asset Retirement Obligation, End of Year	**$**	**1,265**	$	1,458

The total undiscounted amount of estimated cash flows required to settle the obligation is $6,569 million (2007 $7,395 million), which has been discounted using a weighted average credit-adjusted risk free rate of 6.04 percent (2007 5.85 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 17. 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	**2008**			2007		
	Number (millions)		**Amount**	Number (millions)		Amount
Common Shares Outstanding, Beginning of Year	**750.2**	**$**	**4,479**	777.9	$	4,587
Common Shares Issued under Option Plans	**3.0**		**80**	8.3		176
Stock-Based Compensation	**-**		**11**	-		17
Common Shares Purchased	**(2.8)**		**(13)**	(36.0)		(301)
Common Shares Outstanding, End of Year	**750.4**	**$**	**4,557**	750.2	$	4,479

Normal Course Issuer Bid

EnCana has received regulatory approval each year under Canadian securities laws to purchase Common Shares under seven consecutive Normal Course Issuer Bids (Bids). EnCana is entitled to purchase, for cancellation, up to approximately 75.0 million Common Shares under the renewed Bid which commenced on November 13, 2008 and terminates on November 12, 2009.

In 2008, the Company purchased 4.8 million Common Shares for total consideration of approximately $326 million. Of the amount paid, $29 million was charged to Share capital and $297 million was charged to Retained earnings. Included in the Common Shares Purchased in 2008 are 2.0 million Common Shares distributed, valued at $16 million, from the EnCana Employee Benefit Plan Trust that vested under EnCana s Performance Share Unit Plan (See Note 19). For these Common Shares distributed, there was a $54 million adjustment to Retained earnings with a reduction to Paid in surplus of $70 million.

In 2007, the Company purchased 38.9 million Common Shares for total consideration of approximately $2,025 million. Of the amount paid, $325 million was charged to Share capital and $1,700 million was charged to Retained earnings. Included in the Common Shares Purchased in 2007 are 2.9 million Common Shares distributed, valued at $24 million, from the EnCana Employee Benefit Plan Trust that vested under EnCana s Performance Share Unit Plan (See Note 19). For these Common Shares distributed, there was an $82 million adjustment to Retained earnings with a reduction to Paid in surplus of $106 million.

Stock Options

EnCana has stock-based compensation plans that allow employees to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were granted. 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 19).

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 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. In addition, certain stock options granted since 2007 are performance based. The performance based stock options vest and expire under the same terms and service conditions as the underlying option, and vesting is subject to EnCana attaining prescribed performance relative to pre-determined key measures (See Note 19).

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.

The following tables summarize the information related to options to purchase Common Shares that do not have a TSAR attached to them:

As at December 31	**2008**		2007		2006	
	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	**3.4**	**21.82**	11.8	23.17	20.7	23.36

Exercised	**(2.9)**	**23.68**	(8.3)	23.73	(8.6)	23.60
Forfeited	**-**	**-**	(0.1)	22.53	(0.3)	23.80
Outstanding, End of Year	**0.5**	**11.62**	3.4	21.82	11.8	23.17
Exercisable, End of Year	**0.5**	**11.62**	3.4	21.82	11.8	23.17

As at December 31, 2008	**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 14.50	**0.5**	**0.9**	**11.62**	**0.5**	**11.62**

At December 31, 2008, there were 16.5 million Common Shares reserved for issuance under stock option plans (2007 12.2 million; 2006 20.7 million).

At December 31, 2007, the balance in Paid in surplus relates to stock-based compensation programs.

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NOTE 18. Capital Structure

The Company s capital structure is comprised of Shareholders Equity plus Long-Term Debt. The Company s objectives when managing its capital structure are to:

i) maintain financial flexibility to preserve EnCana s access to capital markets and its ability to meet its financial obligations; and
ii) finance internally generated growth as well as potential acquisitions.

The Company monitors its capital structure and short-term financing requirements using non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA). These metrics are used to steward the Company s overall debt position as measures of the Company s overall financial strength.

To provide a more conservative measure of liquidity, the Company has changed its calculation of these metrics as follows: Net Debt to Capitalization has been changed to Debt to Capitalization and Net Debt to Adjusted EBITDA has been changed to Debt to Adjusted EBITDA. Debt is defined as the current and long-term portions of Long-Term Debt. Previously, Net Debt was defined as Long-Term Debt plus Current Liabilities less Current Assets. The Company believes this presentation is more comparable between periods by excluding the impact of unrealized mark-to-market accounting gains and losses on working capital.

EnCana targets a Debt to Capitalization ratio of between 30 and 40 percent. At December 31, 2008, EnCana s Debt to Capitalization ratio was 28 percent (December 31, 2007 32 percent) calculated as follows:

As at December 31		**2008**		2007
Debt	**$**	**9,005**	$	9,543
Total Shareholders Equity		**22,974**		20,704
Total Capitalization	**$**	**31,979**	$	30,247
Debt to Capitalization ratio		**28%**		32%

Without giving effect to the change in calculation as described above, EnCana s Net Debt to Capitalization ratio would have been 23 percent at December 31, 2008 (December 31, 2007 34 percent).

EnCana targets a Debt to Adjusted EBITDA of 1.0 to 2.0 times. At December 31, 2008, Debt to Adjusted EBITDA was 0.7x (December 31, 2007 1.1x; December 31, 2006 0.7x) calculated on a trailing twelve-month basis as follows:

As at December 31		**2008**		2007		2006
Debt	**$**	**9,005**	$	9,543	$	6,834
Net Earnings from Continuing Operations		**5,944**		3,884		5,051

Add (deduct):			
Interest, net	**586**	428	396
Income tax expense	**2,633**	937	1,892
Depreciation, depletion and amortization	**4,223**	3,816	3,112
Accretion of asset retirement obligation	**79**	64	50
Foreign exchange (gain) loss, net	**423**	(164)	14
(Gain) loss on divestitures	**(140)**	(65)	(323)
Adjusted EBITDA	**$ 13,748**	$ 8,900	$ 10,192
Debt to Adjusted EBITDA	**0.7x**	1.1x	0.7x

Without giving effect to the change in calculation as described above, EnCana s Net Debt to Adjusted EBITDA would have been 0.5x at December 31, 2008 (December 31, 2007 1.2x; December 31, 2006 0.6x).

EnCana has a long-standing practice of maintaining capital discipline, managing its capital structure and adjusting its capital structure according to market conditions to maintain flexibility while achieving the objectives stated above. To manage the capital structure, the Company may adjust

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capital spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt or repay existing debt.

The Company s capital management objectives, evaluation measures, definitions and targets have remained unchanged over the periods presented, except as noted above. EnCana is subject to certain financial covenants in its credit facility agreements and is in compliance with all financial covenants.

NOTE 19. Compensation Plans

A) Pensions and Other Post-Employment Benefits

The Company sponsors defined benefit and defined contribution plans, providing pension and other post-employment benefits (OPEB) to its employees.

The Company is required to file an actuarial valuation of its pension plans with the provincial regulator at least every three years. The most recent filing was dated December 31, 2005, and the Company is required, by June 30, 2009, to file an actuarial valuation as at December 31, 2008.

Information related to defined benefit pension and other post-employment benefit plans, based on actuarial estimations as at December 31, 2008 is as follows:

Accrued Benefit Obligation

	Pension Benefits		OPEB	
As at December 31	**2008**	2007	**2008**	2007
Accrued Benefit Obligation, Beginning of Year	**$ 357**	$ 308	**$ 53**	$ 45
Current service cost	**7**	8	**8**	8
Interest cost	**18**	16	**3**	3
Benefits paid	**(17)**	(17)	**(1)**	(1)
Actuarial (gain) loss	**(36)**	(14)	**(3)**	(5)
Contributions	**1**	1	**-**	-
Foreign exchange (gain) loss	**(67)**	55	**(5)**	3
Accrued Benefit Obligation, End of Year	**$ 263**	$ 357	**$ 55**	$ 53

Plan Assets

	Pension Benefits		OPEB	
As at December 31	**2008**	2007	**2008**	2007

	Pension Benefits 2008	Pension Benefits 2007	OPEB 2008	OPEB 2007
Fair Value of Plan Assets, Beginning of Year	**$ 355**	$ 304	**$ -**	$ -
Actual gain (loss) on return of plan assets	**(53)**	5	**-**	-
Employer contributions	**8**	8	**-**	-
Employees contributions	**1**	1	**-**	-
Benefits paid	**(17)**	(17)	**-**	-
Foreign exchange gain (loss)	**(61)**	54	**-**	-
Fair Value of Plan Assets, End of Year	**$ 233**	$ 355	**$ -**	$ -

Accrued Benefit Asset (Liability)

	Pension Benefits		OPEB	
As at December 31	**2008**	2007	**2008**	2007
Funded Status Plan Assets (less) than Benefit Obligation	**$ (30)**	$ (2)	**$ (55)**	$ (53)
Amounts Not Recognized:				
Unamortized net actuarial (gain) loss	**74**	59	**(5)**	(3)
Unamortized past service cost	**4**	6	**1**	1
Net transitional asset (liability)	**-**	(3)	**10**	12
Accrued Benefit Asset (Liability)	**$ 48**	$ 60	**$ (49)**	$ (43)

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As at December 31	Pension Benefits 2008	2007	OPEB 2008	2007
Prepaid Benefit Cost	**$ 48**	$ 60	**$ -**	$ -
Accrued Benefit Cost	**-**	-	**(49)**	(43)
Net Amount Recognized	**$ 48**	$ 60	**$ (49)**	$ (43)

The Company s OPEB plans are funded on an as required basis.

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

As at December 31	Pension Benefits 2008	2007	OPEB 2008	2007
Discount Rate	**6.25%**	5.25%	**6.25%**	5.50%
Rate of Compensation Increase	**4.16%**	4.28%	**6.00%**	5.77%

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

For the years ended December 31	Pension Benefits 2008	2007	OPEB 2008	2007
Discount Rate	**5.25%**	5.00%	**5.50%**	5.38%
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	**4.28%**	4.34%	**6.00%**	5.77%

The periodic expense for benefits is as follows:

For the years ended December 31	Pension Benefits 2008	2007	2006	OPEB 2008	2007	2006
Current Service Cost	**$ 7**	$ 8	$ 9	**$ 8**	$ 8	$ 7
Interest Cost	**18**	16	15	**3**	3	2
Actual (Gain) Loss on Return of Plan Assets	**53**	(5)	(27)	**-**	-	-
Actuarial (Gain) Loss on Accrued Benefit Obligation	**(36)**	(14)	6	**(3)**	(5)	(2)
Difference Between Actual and:						
Expected return on plan assets	**(72)**	(14)	11	**-**	-	-
Recognized actuarial gain (loss)	**40**	18	-	**3**	5	2
Difference Between Amortization of Past Service Costs and Actual Plan Amendments	**2**	2	2	**-**	-	-
Amortization of Transitional Assets (Obligation)	**(3)**	(3)	(3)	**1**	1	2
Defined Benefit Plans Expense	**$ 9**	$ 8	$ 13	**$ 12**	$ 12	$ 11
Defined Contribution Plans Expense	**$ 44**	$ 34	$ 28	**$ -**	$ -	$ -
Total Benefit Plans Expense	**$ 53**	$ 42	$ 41	**$ 12**	$ 12	$ 11

The average remaining service period of the active employees covered by the defined benefit pension plan is five years. The average remaining service period of the active employees covered by the OPEB plan is 11 years.

Assumed health care cost trend rates are as follows:

As at December 31	**2008**	2007
Health Care Cost Trend Rate for Next Year	**9.50%**	10.50%
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	**2017**	2016

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	$ 5	$ (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	**2008**	2007	
Domestic Equity	35	25-45	**34**	39	
Foreign Equity	30	20-40	**25**	27	
Bonds	30	20-40	**33**	27	
Real Estate and Other	5	0-20	**8**	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 the results of the actuarial valuation and direction by the Human Resources and Compensation Committee. Contributions by the participants to the pension and other benefits plans were $1 million for the year ended December 31, 2008 (2007 $1 million; 2006 $1 million).

Estimated future payment of pension and other benefits are as follows:

	Pension Benefits	OPEB
2009	$ 17	$ 2
2010	18	2
2011	19	3
2012	20	3

2013		21		4
2014 2018		120		28
Total	$	215	$	42

B) Tandem Share Appreciation Rights

Subsequent to December 31, 2003, all options to purchase Common Shares issued under the share option plans described in Note 17 have an associated 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 TSARs vest and expire under the same terms and conditions as the underlying option.

The following tables summarize information related to the TSARs:

As at December 31	**2008**		2007	
	Outstanding TSARs	**Weighted Average Exercise Price**	Outstanding TSARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**18,854,141**	**48.44**	17,276,191	44.99
Granted	**4,420,272**	**70.11**	4,814,338	57.70
Exercised SARs	**(3,173,443)**	**43.68**	(2,020,357)	41.20
Exercised Options	**(82,936)**	**42.00**	(12,235)	35.04
Forfeited	**(606,095)**	**55.27**	(1,203,796)	50.02
Outstanding, End of Year	**19,411,939**	**53.97**	18,854,141	48.44
Exercisable, End of Year	**8,452,111**	**46.45**	5,267,550	43.18

As at December 31, 2008	**Outstanding TSARs**			**Exercisable TSARs**	
Range of Exercise Price (C$)	**Number of TSARs**	**Weighted Average Remaining Contractual Life (years)**	**Weighted Average Exercise Price**	**Number of TSARs**	**Weighted Average Exercise Price**
20.00 to 29.99	**156,873**	**0.37**	**27.66**	**156,873**	**27.66**
30.00 to 39.99	**2,790,012**	**1.12**	**38.22**	**2,789,912**	**38.22**
40.00 to 49.99	**6,904,479**	**2.12**	**48.17**	**3,652,139**	**48.10**
50.00 to 59.99	**4,442,058**	**2.90**	**55.92**	**1,536,897**	**55.73**
60.00 to 69.99	**4,548,147**	**3.94**	**68.24**	**302,205**	**63.99**
70.00 to 79.99	**355,420**	**4.37**	**74.13**	**14,085**	**70.14**
80.00 to 89.99	**128,650**	**4.41**	**85.50**	**-**	**-**
90.00 to 99.99	**86,300**	**4.45**	**92.94**	**-**	**-**
	19,411,939	**2.63**	**53.97**	**8,452,111**	**46.45**

During the year, the Company recorded a reduction of compensation costs of $47 million related to the outstanding TSARs (2007 compensation costs of $225 million; 2006 compensation costs of $52 million).

C) Performance Tandem Share Appreciation Rights

Beginning in 2007, under the terms of the existing Employee Stock Option Plan, EnCana granted Performance Tandem Share Appreciation Rights (Performance TSARs) under which the employee has the right to receive a cash payment equal to the excess of the market price of EnCana Common Shares at the time of exercise over the grant price. Performance TSARs vest and expire under the same terms and service conditions as the underlying option, and vesting is subject to EnCana attaining prescribed performance relative to key pre-determined measures. Performance TSARs that do not vest when eligible are forfeited.

The following tables summarize information related to the Performance TSARs:

As at December 31	**2008**		2007	
	Outstanding Performance TSARs	**Weighted Average Exercise Price**	Outstanding Performance TSARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**6,930,925**	**56.09**	-	-
Granted	**7,058,538**	**69.40**	7,275,575	56.09
Exercised SARs	**(287,299)**	**56.09**	-	-
Exercised Options	**(5,123)**	**56.09**	-	-
Forfeited	**(717,316)**	**59.65**	(344,650)	56.09
Outstanding, End of Year	**12,979,725**	**63.13**	6,930,925	56.09
Exercisable, End of Year	**1,461,276**	**56.09**	-	-

As at December 31, 2008	Outstanding Performance TSARs			Exercisable Performance TSARs	
Range of Exercise Price (C$)	Number of TSARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of TSARs	Weighted Average Exercise Price
50.00 to 59.99	**6,113,087**	**3.08**	**56.09**	**1,461,276**	**56.09**
60.00 to 69.99	**6,866,638**	**4.08**	**69.40**	**-**	**-**
	12,979,725	**3.55**	**63.13**	**1,461,276**	**56.09**

During the year, EnCana recorded a reduction of compensation costs of $6 million related to the outstanding Performance TSARs (2007 compensation costs of $21 million).

D) Share Appreciation Rights

EnCana has a program whereby employees may be granted Share Appreciation Rights (SARs) 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. SARs granted during 2008 are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years and expire five years after the grant date.

The following tables summarize information related to the SARs:

	2008		2007	
As at December 31	**Outstanding SARs**	**Weighted Average Exercise Price**	Outstanding SARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**-**	**-**	-	-
Granted	**1,314,115**	**72.07**	-	-
Forfeited	**(29,050)**	**69.42**	-	-
Outstanding, End of Year	**1,285,065**	**72.13**	-	-
Exercisable, End of Year	**-**	**-**	-	-
U.S. Dollar Denominated (US$)				
Outstanding, Beginning of Year	**-**	**-**	2,088	14.21
Exercised	**-**	**-**	(2,088)	14.21
Outstanding, End of Year	**-**	**-**	-	-
Exercisable, End of Year	**-**	**-**	-	-

As at December 31, 2008	Outstanding SARs	Exercisable SARs

Range of Exercise Price (C$)	Number of SARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of SARs	Weighted Average Exercise Price
40.00 to 49.99	**20,400**	**4.79**	**45.74**	**-**	**-**
50.00 to 59.99	**28,800**	**4.81**	**57.79**	**-**	**-**
60.00 to 69.99	**815,065**	**4.09**	**69.37**	**-**	**-**
70.00 to 79.99	**260,550**	**4.65**	**73.40**	**-**	**-**
80.00 to 89.99	**87,150**	**4.44**	**87.05**	**-**	**-**
90.00 to 99.99	**73,100**	**4.42**	**93.65**	**-**	**-**
	1,285,065	**4.16**	**72.13**	**-**	**-**

During the year, the Company has not recorded any compensation costs related to the outstanding SARs (2007 nil; 2006 reduction of compensation costs of $1 million).

E) Performance Share Appreciation Rights

In 2008, EnCana granted Performance Share Appreciation Rights (Performance SARs) to certain employees which entitles 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 grant price. Performance SARs vest and expire under the same terms and service conditions as SARs and are also subject to EnCana attaining prescribed performance relative to pre-determined key measures. Performance SARs that do not vest when eligible are forfeited.

The following tables summarize information related to the Performance SARS:

	2008		2007	
As at December 31	**Outstanding Performance SARs**	**Weighted Average Exercise Price**	Outstanding Performance SARs	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**-**	**-**	-	-
Granted	**1,677,030**	**69.40**	-	-
Forfeited	**(56,100)**	**69.40**	-	-
Outstanding, End of Year	**1,620,930**	**69.40**	-	-
Exercisable, End of Year	**-**	**-**	-	-

As at December 31, 2008	**Outstanding Performance SARs**			**Exercisable Performance SARs**	
Range of Exercise Price (C$)	**Number of SARs**	**Weighted Average Remaining Contractual Life (years)**	**Weighted Average Exercise Price**	**Number of SARs**	**Weighted Average Exercise Price**
60.00 to 69.99	**1,620,930**	**4.08**	**69.40**	**-**	**-**

During the year, the Company has not recorded any compensation costs related to the outstanding Performance SARS (2007 nil).

F) Deferred Share Units

The Company has in place a program whereby Directors and certain key employees are issued Deferred Share Units (DSUs), which are equivalent in value to a Common Share of the Company. DSUs granted to Directors vest immediately. DSUs expire on December 15th of the year following the Director s resignation or employee s termination.

The following table summarizes information related to the DSUs:

As at December 31	**2008 Outstanding DSUs**	2007 Outstanding DSUs
Canadian Dollar Denominated		
Outstanding, Beginning of Year	**589,174**	866,577
Granted	**85,792**	79,168
Units, in Lieu of Dividends	**15,883**	9,314
Redeemed	**(34,008)**	(365,885)
Outstanding, End of Year	**656,841**	589,174

During the year, the Company recorded compensation costs of $2 million related to the outstanding DSUs (2007 $14 million; 2006 $5 million).

G) Performance Share Units

Performance Share Units (PSUs) were granted in 2003, 2004 and 2005 and entitled employees 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 PSUs granted. PSUs vested over a three year period from the date granted. If EnCana s performance was at or above a specified level compared to a pre-determined peer group, payments ranged from one half to two times the PSU. At December 31, 2008, there are no PSUs outstanding.

PSUs granted in 2003 were paid out in cash at 75 percent of the number granted. PSUs granted in 2004 were paid out in Common Shares at 100 percent of the number granted. PSUs granted in 2005 were paid out in Common Shares at 125 percent of the number granted.

The following table summarizes information related to the PSUs:

As at December 31	**2008**		2007	
	Outstanding PSUs	**Average Share Price**	Outstanding PSUs	Average Share Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**1,685,036**	**38.79**	4,766,329	31.24
Granted	**408,686**	**70.77**	23,097	62.84
Distributed	**(2,042,541)**	**45.34**	(2,937,491)	26.98
Forfeited	**(51,181)**	**38.32**	(166,899)	34.38
Outstanding, End of Year	**-**	**-**	1,685,036	38.79

During the year, the Company recorded compensation costs of $1 million related to the outstanding PSUs (2007 $43 million; 2006 $27 million).

NOTE 20. Financial Instruments and Risk Management

EnCana's financial assets and liabilities are comprised of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, the partnership contribution receivable and payable, risk management assets and liabilities, and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments. Fair values of financial assets and liabilities, summarized information related to risk management positions, and discussion of risks associated with financial assets and liabilities are presented as follows.

A) Fair Value of Financial Assets and Liabilities

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, and accounts payable and accrued liabilities approximate their carrying amount due to the short-term maturity of those instruments.

The fair values of the partnership contribution receivable and partnership contribution payable approximate their carrying amount due to the specific nature of these instruments in relation to the creation of the integrated oil joint venture. Further information about these notes is disclosed in Note 11.

Risk management assets and liabilities are recorded at their estimated fair value based on the mark-to-market method of accounting, using quoted market prices or, in their absence, third-party market indications and forecasts.

Long-term debt is carried at amortized cost using the effective interest method of amortization. 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 expected to be available to the Company at period end.

The fair value of financial assets and liabilities were as follows:

As at December 31	2008 Carrying Amount	2008 Fair Value	2007 Carrying Amount	2007 Fair Value
Financial Assets				
Held-for-trading:				
Cash and cash equivalents	**$ 383**	**$ 383**	$ 553	$ 553
Risk management assets *	**3,052**	**3,052**	403	403
Loans and Receivables:				
Accounts receivable and accrued revenues	**1,568**	**1,568**	2,381	2,381
Partnership contribution receivable *	**3,147**	**3,147**	3,444	3,444
Financial Liabilities				
Held-for-trading:				
Risk management liabilities *	**$ 50**	**$ 50**	$ 236	$ 236
Other Financial Liabilities:				
Accounts payable and accrued liabilities	**2,871**	**2,871**	3,982	3,982
Long-term debt *	**9,005**	**8,242**	9,543	9,763
Partnership contribution payable *	**3,163**	**3,163**	3,451	3,451

* Including current portion.

B) Risk Management Assets and Liabilities

Net Risk Management Position

As at December 31	2008	2007
Risk Management		
Current asset	**$ 2,818**	$ 385
Long-term asset	**234**	18
	3,052	403
Risk Management		
Current liability	**43**	207
Long-term liability	**7**	29
	50	236
Net Risk Management Asset (Liability)	**$ 3,002**	$ 167

Summary of Unrealized Risk Management Positions

As at December 31	2008 Risk Management Asset	2008 Risk Management Liability	2008 Net	2007 Risk Management Asset	2007 Risk Management Liability	2007 Net
Commodity Prices						
Natural Gas	**$ 2,941**	**$ 10**	**$ 2,931**	$ 375	$ 29	$ 346
Crude Oil	**92**	**40**	**52**	6	205	(199)
Power	**19**	**-**	**19**	19	-	19
Interest Rates	**-**	**-**	**-**	2	-	2
Credit	**-**	**-**	**-**	1	2	(1)

Total Fair Value	**$ 3,052**	**$ 50**	**$ 3,002**	$ 403	$ 236	$ 167

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

As at December 31	**2008**	2007
Prices actively quoted	**$ 2,055**	$ 105
Prices sourced from observable data or market corroboration	**947**	62
Total Fair Value	**$ 3,002**	$ 167

Prices actively quoted refers to the fair value of contracts valued using quoted prices in an active market. Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data.

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Net Fair Value of Commodity Price Positions at December 31, 2008

	Notional Volumes	Term	Average Price	Fair Value
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	1,648 MMcf/d	2009	9.28 US$/Mcf	$ 1,981
NYMEX Fixed Price	35 MMcf/d	2010	9.21 US$/Mcf	23
Purchased Options				
NYMEX Call Options	(150) MMcf/d	2009	11.67 US$/Mcf	(22)
NYMEX Put Options	516 MMcf/d	2009	9.10 US$/Mcf	536
Basis Contracts				
Canada	71 MMcf/d	2009		-
United States	917 MMcf/d	2009		111
Canada and United States*		2010-2013		193
				2,822
Other Financial Positions**				(1)
Total Unrealized Gain on Financial Contracts				2,821
Premiums Paid on Unexpired Options				110
Natural Gas Fair Value Position				$ 2,931
Crude Oil Contracts* **				
Crude Oil Fair Value Position				$ 52
Power Purchase Contracts				
Power Fair Value Position				$ 19

* EnCana has entered into swaps to protect against widening natural gas price differentials between production areas, including Canada, the U.S. Rockies and Texas, and various sales points. These basis swaps are priced using both fixed prices and basis prices determined as a percentage of NYMEX.

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

*** The Crude Oil financial positions are part of the ongoing operations of the Company s proprietary production and condensate management and its share of downstream refining positions.

Net Earnings Impact of Realized and Unrealized Gains (Losses) on Risk Management Positions

			Realized Gain (Loss)	
For the years ended December 31		**2008**	2007	2006
Revenues, Net of Royalties		**$ (309)**	$ 1,601	$ 393
Operating Expenses and Other		**28**	3	5
Gain (Loss) on Risk Management	Continuing Operations	**(281)**	1,604	398
Gain (Loss) on Risk Management	Discontinued Operations	**-**	-	12
		$ (281)	$ 1,604	$ 410

			Unrealized Gain (Loss)	
For the years ended December 31		**2008**	2007	2006
Revenues, Net of Royalties		**$ 2,717**	$ (1,239)	$ 2,050
Operating Expenses and Other		**12**	4	10
Gain (Loss) on Risk Management	Continuing Operations	**2,729**	(1,235)	2,060
Gain (Loss) on Risk Management	Discontinued Operations	**-**	-	20
		$ 2,729	$ (1,235)	$ 2,080

Reconciliation of Unrealized Risk Management Positions from January 1 to December 31, 2008

	2008		2007	2006
	Fair Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**$ 167**			
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Year	**2,448**	**$ 2,448**	$ 353	$ 2,466
Fair Value of Contracts in Place at Transition that Expired During the Year	**-**	**-**	16	24
Foreign Exchange Gain (Loss) on Canadian Dollar Contracts	**(4)**	**-**	-	-
Fair Value of Contracts Realized During the Year	**281**	**281**	(1,604)	(410)
Fair Value of Contracts Outstanding	**$ 2,892**	**$ 2,729**	$ (1,235)	$ 2,080
Premiums Paid on Unexpired Options	**110**			
Fair Value of Contracts and Premiums Paid, End of Year	**$ 3,002**			

Commodity Price Sensitivities

The following table summarizes the sensitivity of the fair value of the Company s risk management positions to fluctuations in commodity prices, with all other variables held constant. When assessing the potential impact of these commodity price changes, the Company believes 10 percent volatility is a reasonable measure. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting net earnings as at December 31, 2008 as follows:

	Favourable 10% Change	Unfavourable 10% Change
Natural gas price	$ 424	$ (418)
Crude oil price	7	(7)
Power price	9	(9)

C) Risks Associated with Financial Assets and Liabilities

The Company is exposed to financial risks arising from its financial assets and liabilities. Financial risks include market risks (such as commodity prices, foreign exchange and interest rates), credit risk and liquidity risk. The fair value or future cash flows of financial assets or liabilities may fluctuate due to movement in market prices and the exposure to credit and liquidity risks.

Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company s policy is to not use derivative financial instruments for speculative purposes.

Natural Gas - To partially mitigate the natural gas commodity price risk, the Company has entered into option contracts and swaps, which fix the NYMEX prices. To help protect against widening natural gas price differentials in various production areas, EnCana has entered into swaps to manage the price differentials between these production areas and various sales points.

Crude Oil - The Company has partially mitigated its exposure to the commodity price risk on its condensate supply with fixed price swaps.

Power - The Company has in place two Canadian dollar denominated derivative contracts, which commenced January 1, 2007 for a period of 11 years, to manage its electricity consumption costs.

Credit Risk

Credit risk arises from the potential the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk 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. All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings. 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. As at December 31, 2008, over 95% of EnCana s accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At December 31, 2008, EnCana had two 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. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets and the partnership contribution receivable is the total carrying value.

Liquidity Risk

Liquidity risk is the risk the Company will encounter difficulties in meeting a demand to fund its financial liabilities as they come due. The Company manages its liquidity risk through cash and debt management. As disclosed in Note 18, EnCana targets a Debt to Capitalization ratio between 30 and 40 percent and a Debt to Adjusted EBITDA of 1.0 to 2.0 times to steward the Company s overall debt position.

In managing liquidity risk, the Company has access to a wide range of funding at competitive rates through commercial paper, capital markets and banks. As at December 31, 2008, EnCana had available unused committed bank credit facilities in the amount of $2.6 billion and unused capacity under shelf prospectuses, the availability of which is dependent on market conditions, for $5.0 billion. The Company believes it has sufficient funding through the use of these facilities to meet foreseeable borrowing requirements.

EnCana maintains investment grade credit ratings on its senior unsecured debt. On May 12, 2008, following the announcement of the proposed Arrangement (See Note 3), Standard & Poor s Ratings Service assigned a rating of A- and placed the Company on CreditWatch Negative , DBRS Limited assigned a rating of A(low) and placed the Company Under Review with Developing Implications , and Moody s Investors Service assigned a rating of Baa2 and changed the outlook to Stable from Positive .

The timing of cash outflows relating to financial liabilities are outlined in the table below:

	Less than 1 Year	1 3 Years	4 5 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	$ 2,871	$ -	$ -	$ -	$2,871
Risk Management Liabilities	43	7	-	-	50
Long-Term Debt *	727	1,589	3,344	10,392	16,052
Partnership Contribution Payable *	489	978	978	1,588	4,033

* Principal and interest, including current portion.

Included in EnCana s total long-term debt obligations of $16,052 million at December 31, 2008 are $1,657 million in principal obligations related to Bankers Acceptances, Commercial Paper and LIBOR loans. 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. The revolving credit and term loan facilities are fully revolving for a period of up to five years. Based on the current maturity dates of the credit facilities, these amounts are included in cash outflows for the period disclosed as 4 5 Years. Further information on Long-term Debt is contained in Note 15.

Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of the Company s financial assets or liabilities. As EnCana operates primarily in North America, fluctuations in the exchange rate between the U.S./Canadian dollar can have a significant effect on the Company s reported results. EnCana s functional currency is Canadian dollars, however, the Company reports its results in U.S. dollars as most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American oil and gas companies. As the effects of foreign exchange fluctuations are embedded in the Company s results, the total effect of foreign exchange fluctuations are not separately identifiable.

To mitigate the exposure to the fluctuating U.S./Canadian exchange rate, EnCana maintains a mix of both U.S. dollar and Canadian dollar debt.

As disclosed in Note 9, EnCana s foreign exchange (gain) loss is primarily comprised of unrealized foreign exchange gains and losses on the translation of U.S. dollar debt issued from Canada and the translation of the U.S. dollar partnership contribution receivable issued from Canada. At December 31, 2008, EnCana had $5,350 million in U.S. dollar debt issued from Canada ($5,421 million at December 31, 2007) and $3,147 million related to the U.S. dollar partnership contribution receivable ($3,444 million at December 31, 2007). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in an $18 million change in foreign exchange (gain) loss at December 31, 2008.

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect the fair value or future cash flows from the Company s financial assets or liabilities. The Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt.

At December 31, 2008, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $12 million (2007 $14 million; 2006 $11 million).

NOTE 21. 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	**2008**	2007	2006
Weighted Average Common Shares Outstanding Basic	**750.1**	756.8	819.9
Effect of Stock Options and Other Dilutive Securities	**1.7**	7.8	16.6
Weighted Average Common Shares Outstanding Diluted	**751.8**	764.6	836.5

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

For the years ended December 31		2008		2007		2006
Operating Activities						
Accounts receivable and accrued revenues	**$**	**452**	$	33	$	3,128
Inventories		**222**		42		(75)
Accounts payable and accrued liabilities		**(354)**		(78)		(260)
Income tax payable		**(589)**		(5)		550
	$	**(269)**	$	(8)	$	3,343
Investing Activities						
Accounts payable and accrued liabilities	**$**	**89**	$	86	$	19

C) Supplementary Cash Flow Information   Continuing Operations

For the years ended December 31		2008		2007		2006
Interest Paid	**$**	**771**	$	698	$	387
Income Taxes Paid	**$**	**1,641**	$	1,423	$	450

NOTE 22.   Commitments and Contingencies

Commitments

As at December 31, 2008		2009		2010		2011		2012		2013		Thereafter		Total
Pipeline Transportation	$	469	$	492	$	478	$	500	$	477	$	2,533	**$**	**4,949**
Purchases of Goods and Services		1,061		466		290		227		166		534		**2,744**
Product Purchases		23		23		20		18		18		43		**145**
Operating Leases*		70		71		120		176		158		2,678		**3,273**
Capital Commitments		5		2		104		-		-		38		**149**
Other Long-Term Commitments		15		11		5		1		-		-		**32**
Total	$	1,643	$	1,065	$	1,017	$	922	$	819	$	5,826	**$**	**11,292**
Product Sales	$	38	$	39	$	41	$	44	$	45	$	149	**$**	**356**

*Operating leases consist of building leases, including The Bow (See Note 5).

In addition to the above, the Company has made commitments related to its risk management program (See Note 20).

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. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission (CFTC) for $20 million and of a previously disclosed consolidated class action lawsuit in the United States District Court in New York for $8.2 million. Also, without admitting any liability whatsoever, WD concluded settlements with a group of individual plaintiffs for $23 million.

The remaining lawsuit was commenced by E. & J. Gallo Winery (Gallo). The Gallo lawsuit claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

The Company and WD intend to vigorously defend against this outstanding claim; 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, refining facilities and Midstream facilities at the end of their useful lives. The Company has recognized a liability of $1,265 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.

NOTE 23. 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*	**2008**	2007	2006
Net Earnings Canadian GAAP		**$ 5,944**	$ 3,959	$ 5,652
Less:				
Net Earnings From Discontinued Operations Canadian GAAP		**-**	75	601
Net Earnings From Continuing Operations Canadian GAAP		**5,944**	3,884	5,051
Increase (Decrease) in Net Earnings From Continuing Operations Under U.S. GAAP:				
Revenues, net of royalties	*A*	**-**	(15)	179
Operating	*A, D ii*)	**(46)**	3	(15)
Depreciation, depletion and amortization	*B, D ii*)	**(1,755)**	86	95
Administrative	*D ii*)	**(27)**	1	(8)
Interest, net	*A*	**(3)**	(2)	(15)
Stock-based compensation options	*C*	**2**	(5)	-
Income tax expense	*E*	**695**	(204)	(80)
Net Earnings From Continuing Operations U.S. GAAP		**4,810**	3,748	5,207
Net Earnings From Discontinued Operations U.S. GAAP		**-**	75	644
Net Earnings Before Change in Accounting Policy U.S. GAAP		**4,810**	3,823	5,851
Cumulative Effect of Change in Accounting Policy, net of tax	*D ii*)	**-**	-	(15)
Net Earnings U.S. GAAP		**$ 4,810**	$ 3,823	$ 5,836
Net Earnings per Common Share Before Change in Accounting Policy U.S. GAAP				
Basic		**$ 6.41**	$ 5.05	$ 7.14
Diluted		**$ 6.40**	$ 5.00	$ 6.99
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy U.S. GAAP				
Basic		**$ 6.41**	$ 5.05	$ 7.12
Diluted		**$ 6.40**	$ 5.00	$ 6.98

Consolidated Statement of Earnings U.S. GAAP

For the years ended December 31	Note	**2008**	2007	2006
Revenues, Net of Royalties	*A*	**$ 30,064**	$ 21,431	$ 16,578
Expenses				
Production and mineral taxes		**478**	291	349
Transportation and selling		**1,704**	1,010	1,070
Operating	*A, D ii)*	**2,521**	2,275	1,670
Purchased product		**11,186**	8,583	2,862
Depreciation, depletion and amortization	*B, D ii)*	**5,978**	3,730	3,017
Administrative	*D ii)*	**500**	383	279
Interest, net	*A*	**589**	430	411
Accretion of asset retirement obligation		**79**	64	50
Foreign exchange (gain) loss, net		**423**	(164)	14
Stock-based compensation options	*C*	**(2)**	5	-
(Gain) loss on divestitures		**(140)**	(65)	(323)
Net Earnings Before Income Tax		**6,748**	4,889	7,179
Income tax expense	*E*	**1,938**	1,141	1,972
Net Earnings From Continuing Operations U.S. GAAP		**4,810**	3,748	5,207
Net Earnings From Discontinued Operations U.S. GAAP		**-**	75	644
Net Earnings Before Change in Accounting Policy U.S. GAAP		**4,810**	3,823	5,851
Cumulative Effect of Change in Accounting Policy, net of tax	*D ii)*	**-**	-	(15)
Net Earnings U.S. GAAP		**$ 4,810**	$ 3,823	$ 5,836
Net Earnings From Continuing Operations per Common Share U.S. GAAP				
Basic		**$ 6.41**	$ 4.95	$ 6.35
Diluted		**$ 6.40**	$ 4.90	$ 6.22
Net Earnings From Discontinued Operations per Common Share U.S. GAAP				
Basic		**$ -**	$ 0.10	$ 0.79
Diluted		**$ -**	$ 0.10	$ 0.77
Net Earnings per Common Share Before Change in Accounting Policy U.S. GAAP				
Basic		**$ 6.41**	$ 5.05	$ 7.14
Diluted		**$ 6.40**	$ 5.00	$ 6.99
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy U.S. GAAP				
Basic		**$ 6.41**	$ 5.05	$ 7.12
Diluted		**$ 6.40**	$ 5.00	$ 6.98

Consolidated Statement of Comprehensive Income U.S. GAAP

For the years ended December 31	Note	**2008**	2007	2006
Net Earnings U.S. GAAP		**$ 4,810**	$ 3,823	$ 5,836
Change in Fair Value of Financial Instruments	*A*	**2**	-	4
Foreign Currency Translation Adjustment	*B, D ii), F*	**(2,217)**	1,707	(224)
Compensation Plans	*F*	**(12)**	1	-
Comprehensive Income		**$ 2,583**	$ 5,531	$ 5,616

Consolidated Statement of Accumulated Other Comprehensive Income U.S. GAAP

For the years ended December 31	*Note*	**2008**	2007	2006
Balance, Beginning of Year		**$ 3,038**	$ 1,330	$ 1,598
Change in Fair Value of Financial Instruments	*A*	**2**	-	4
Foreign Currency Translation Adjustment	*B, F*	**(2,217)**	1,707	(224)
Compensation Plans	*D i), F*	**(12)**	1	(48)
Balance, End of Year		**$ 811**	$ 3,038	$ 1,330

Consolidated Statement of Retained Earnings   U.S. GAAP

For the years ended December 31	**2008**	2007	2006
Retained Earnings, Beginning of Year	**$ 12,976**	$ 11,374	$ 9,327
Net Earnings	**4,810**	3,823	5,836
Dividends on Common Shares	**(1,199)**	(603)	(304)
Charges for Normal Course Issuer Bid	**(243)**	(1,618)	(3,485)
Retained Earnings, End of Year	**$ 16,344**	$ 12,976	$ 11,374

Condensed Consolidated Balance Sheet   U.S. GAAP

As at December 31	*Note*	**2008 As Reported**	**U.S. GAAP**	2007 As Reported	U.S. GAAP
Assets					
Current Assets	*D i)*	**$ 5,602**	**$ 5,604**	$ 4,444	$ 4,446
Property, Plant and Equipment (includes unproved properties and major development projects of $4,767 and $3,509 as of December 31, 2008 and 2007, respectively)	*B, D ii)*	**59,354**	**59,313**	59,821	59,729
Accumulated Depreciation, Depletion and Amortization		**(23,930)**	**(25,451)**	(23,956)	(23,669)
Property, Plant and Equipment, net (Full Cost Method for Oil and Gas Activities)		**35,424**	**33,862**	35,865	36,060
Investments and Other Assets	*D i)*	**727**	**681**	607	557
Partnership Contribution Receivable		**2,834**	**2,834**	3,147	3,147
Risk Management		**234**	**234**	18	18
Goodwill		**2,426**	**2,426**	2,893	2,893
		$ 47,247	**$ 45,641**	$ 46,974	$ 47,121
Liabilities and Shareholders Equity					
Current Liabilities	*A, Di), ii)*	**$ 3,894**	**$ 4,201**	$ 6,330	$ 6,574
Long-Term Debt		**8,755**	**8,755**	8,840	8,840
Other Liabilities	*A, Di) ii)*	**576**	**613**	242	277
Partnership Contribution Payable		**2,857**	**2,857**	3,163	3,163
Risk Management		**7**	**7**	29	29
Asset Retirement Obligation		**1,265**	**1,265**	1,458	1,458
Future Income Taxes	*E*	**6,919**	**6,198**	6,208	6,172
		24,273	**23,896**	26,270	26,513
Share Capital	*C*				
Common shares, no par value		**4,557**	**4,590**	4,479	4,514
Outstanding: 2008 750.4 million shares; 2007 750.2 million shares					
Paid in Surplus		**-**	**-**	80	80
Retained Earnings		**17,584**	**16,344**	13,082	12,976
Accumulated Other Comprehensive Income	*A,B, Di), F*	**833**	**811**	3,063	3,038
		22,974	**21,745**	20,704	20,608
		$ 47,247	**$ 45,641**	$ 46,974	$ 47,121

Condensed Consolidated Statement of Cash Flows U.S. GAAP

For the years ended December 31		**2008**		2007		2006
Operating Activities						
Net earnings from continuing operations	**$**	**4,810**	$	3,748	$	5,207
Depreciation, depletion and amortization		**5,978**		3,730		3,017
Future income taxes		**951**		(592)		1,030
Unrealized (gain) loss on risk management		**(2,729)**		1,251		(2,229)
Unrealized foreign exchange (gain) loss		**417**		41		-
Accretion of asset retirement obligation		**79**		64		50
(Gain) loss on divestitures		**(140)**		(65)		(323)
Other		**(8)**		97		242
Cash flow from discontinued operations		**-**		-		118
Net change in other assets and liabilities		**(259)**		(16)		138
Net change in non-cash working capital from continuing operations		**(269)**		171		3,343
Net change in non-cash working capital from discontinued operations		**-**		-		(2,669)
Cash From Operating Activities	**$**	**8,830**	$	8,429	$	7,924
Cash (Used in) Investing Activities	**$**	**(7,528)**	$	(8,175)	$	(3,333)
Cash (Used in) From Financing Activities	**$**	**(1,439)**	$	(119)	$	(4,294)

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 derivatives 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 was recognized into earnings when realized. As at December 31, 2007, under Canadian GAAP, the remaining transition amount had been fully recognized into net earnings.

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 derivatives 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. Any gain or loss on implementation of SFAS 133 was recorded in Other Comprehensive Income. These transitional amounts are recognized into net earnings as the positions are realized.

Unrealized gain (loss) on derivatives relate to:

For the years ended December 31	**2008**	2007	2006
Commodity Prices (Revenues, net of royalties)	**$ 2,729**	$ (1,249)	$ 2,327
Interest and Currency Swaps (Interest, net)	**(3)**	(2)	(11)
Total Unrealized Gain (Loss)	**$ 2,726**	$ (1,251)	$ 2,316
Amounts Allocated to Continuing Operations	**$ 2,726**	$ (1,251)	$ 2,229
Amounts Allocated to Discontinued Operations	**-**	-	87
	$ 2,726	$ (1,251)	$ 2,316

In 2008, the remaining balance related to the transitional amounts in Accumulated Other Comprehensive Income was recognized in net earnings for U.S. GAAP.

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B) Full Cost Accounting

Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum, net of applicable income taxes, of the present value, discounted at 10 percent, of the estimated future net revenues calculated on the basis of estimated value of future production from proved reserves using oil and gas prices at the balance sheet date, less related unescalated estimated future development and production costs, plus unimpaired unproved property costs. Depletion charges under U.S. GAAP are also calculated by reference to proved reserves estimated using oil and gas prices at the balance sheet date.

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 and future development and production costs to determine whether impairment exists. The impairment amount is measured using the fair value of proved and probable reserves. Depletion charges under Canadian GAAP are also calculated by reference to proved reserves estimated using estimated future prices and costs.

At December 31, 2008, the Company s capitalized costs of oil and gas properties in the United States exceeded the full cost ceiling resulting in a non-cash U.S. GAAP write-down of $1.8 billion charged to depreciation, depletion and amortization ($1.1 billion after-tax). Additional depletion was also recorded in 2001, and certain prior years, as a result of the ceiling test difference between Canadian GAAP and U.S. GAAP. As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes.

The U.S. GAAP adjustment for the difference in depletion calculations results in an impact to DD&A charges and foreign currency translation adjustment of $13.3 million decrease and $0.8 million increase respectively (2007 $85.4 million decrease and $2.9 million increase; 2006 $97 million decrease and $1.2 million decrease).

C) Stock-Based Compensation CPL Reorganization

Under Financial Accounting Standards Board (FASB) Interpretation No. 44, *Accounting for Certain Transactions Involving Stock Compensation* , compensation expense must be recorded if the intrinsic value of the stock options is not exactly the same immediately before and after an equity restructuring. As part of the corporate reorganization of CPL, an equity restructuring occurred which resulted in CPL stock options being replaced with stock options granted by EnCana, as described in Note 17. 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

i) 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 does not require the Company to recognize the funded status of these plans on its balance sheet.

ii) Liability-Based Stock Compensation Plans

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-value method of accounting for liability-based stock compensation plans is no longer an alternative. Liability-based stock compensation plans, including tandem share appreciation rights, performance tandem share appreciation rights, share appreciation rights, performance share appreciation rights and deferred share units, are 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. The current period adjustments have the following impact:

- Net capital assets increased by $37.7 million (2007 $8.4 million decrease)
- Current liabilities increased by $111.4 million (2007 $10.8 million decrease)
- Other liabilities decreased by $0.5 million (2007 $2.8 million decrease)
- Other comprehensive income increased by $5.9 million (2007 $0.5 million increase)
- Operating expenses increased by $46.1 million (2007 $3.3 million decrease)
- Administrative expenses increased by $26.7 million (2007 $0.5 million decrease)
- Depreciation, depletion and amortization expenses increased by $9.9 million (2007 $0.9 million decrease)

As the Company adopted SFAS 123(R) using the modified prospective approach, prior periods have not been restated.

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) Income Taxes

Under U.S. GAAP, enacted tax rates and legislative changes are used to calculate current and future income taxes; whereas Canadian GAAP uses substantively enacted tax rates and legislative changes. In 2007, a Canadian tax legislative change was substantively enacted for Canadian GAAP; however, this tax legislative change was not considered enacted for U.S. GAAP by December 31, 2007. This tax legislative change was still not considered enacted for U.S. GAAP by December 31, 2008. Accordingly, there was no difference in 2008 (2007 increase to income tax expense of $179 million; 2006 nil) for U.S. GAAP.

The remaining differences resulted from 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		2008		2007		2006
Net Earnings Before Income Tax U.S. GAAP	**$**	**6,748**	$	4,889	$	7,179
Canadian Statutory Rate		**29.7%**		32.3%		34.7%
Expected Income Tax		**2,001**		1,579		2,491
Effect on Taxes Resulting from:						
Non-deductible Canadian Crown payments		**-**		-		97
Canadian resource allowance		**-**		-		(16)
Statutory and other rate differences		**12**		76		(98)
Effect of tax rate changes		**-**		(301)		(457)
Non-taxable downstream partnership income		**6**		(70)		-
International financing		**(309)**		(62)		-
Foreign exchange (gains) losses not included in net earnings		**49**		-		-
Non-taxable capital (gains) losses		**84**		(124)		(1)
Other		**95**		43		(44)
Income Tax U.S. GAAP	**$**	**1,938**	$	1,141	$	1,972
Effective Tax Rate		**28.7%**		23.3%		27.5%

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The net future income tax liability is comprised of:

As at December 31	2008	2007
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	**$ 4,641**	$ 5,340
Timing of partnership items	**924**	961
Risk management	**958**	89
Future Tax Assets		
Non-capital and net operating losses carried forward	**(66)**	(44)
Other	**(259)**	(174)
Net Future Income Tax Liability	**$ 6,198**	$ 6,172

F) Other Comprehensive Income

SFAS 158 requires the change in the funded status of defined benefit and post-employment plans on the balance sheet and changes in the funded status through comprehensive income. In 2008, a loss of $12.0 million, net of tax was recognized in other comprehensive income (2007 $1.2 million gain net of tax) as noted in D i). On adoption of SFAS 158, as required, the transitional amount of $48 million, net of tax was booked directly to Accumulated Other Comprehensive Income.

The foreign currency translation adjustment includes the effect of the accumulated U.S. GAAP differences.

G) Joint Venture with ConocoPhillips

Under Canadian GAAP, the Integrated Oil operations that are jointly controlled are proportionately consolidated. U.S. GAAP requires the Downstream Refining operations included in the Integrated Oil Division be accounted for using the equity method. However, under an accommodation of the U.S. Securities and Exchange Commission (SEC), accounting for jointly controlled investments does not require reconciliation from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity. This is the case for the Downstream Refining operations. Equity accounting for the Downstream Refining operations would have no impact on EnCana s net earnings or retained earnings. As required, the following disclosures are provided for the Downstream Refining operations of the joint venture.

Income Statement For the year ended December 31	2008	2007
Operating Cash Flow (See Note 5)	**$ (241)**	$ 1,074
Depreciation, depletion and amortization	**(188)**	(159)
Other	**19**	(5)
Net Income	**$ (410)**	$ 910

Balance Sheet As at December 31	2008	2007

Current Assets	**$**	**321**	$	1,172
Long-term Assets		**4,157**		3,851
Current Liabilities		**422**		644
Long-term Liabilities		**35**		21

Statement of Cash Flows				
For the year ended December 31		**2008**		2007
Cash From Operating Activities	**$**	**118**	$	885
Cash (Used in) Investing Activities		**(519)**		(322)
Cash (Used in) From Financing Activities		**-**		-

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. Cash tax on sale of assets presented as investing activities under Canadian GAAP is presented as operating activities under U.S. GAAP.

I) Dividends Declared on Common Stock

For the years ended December 31		**2008**		2007		2006
Dividends per share	**$**	**1.60**	$	0.80	$	0.375

J) Recent Accounting Pronouncements

As of January 1, 2008, EnCana adopted, 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 standard applies when other accounting pronouncements require fair value measurements and does not require new fair value measurements. The adoption of this standard did not have a material impact on EnCana s Consolidated Financial Statements.

As of January 1, 2008, EnCana adopted, for U.S. GAAP purposes, measurement requirements under SFAS 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)* . This standard also requires EnCana to measure the funded status of a plan as of the balance sheet date. The adoption of the change in measurement date did not have a material impact on EnCana s Consolidated Financial Statements.

In May 2008, the FASB issued Statement of Financial Accounting Standards No. 162, *The Hierarchy of Generally Accepted Accounting Principles* . This standard became effective November 15, 2008 following the SEC s approval of the Public Company Accounting Oversight Board Auditing amendments to AU Section, 411 *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles* . The statement is intended to improve financial reporting by identifying a consistent hierarchy for selecting accounting principles to be used in preparing financial statements that are presented in conformity with U.S. GAAP. The adoption of this standard did not have a material impact on EnCana s Consolidated Financial Statements.

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, 2009, EnCana will be required to adopt, for U.S. GAAP purposes, SFAS 141(R), *Business Combinations* , which replaces SFAS 141. This revised standard requires assets and liabilities acquired in a business combination, contingent consideration, and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination. The adoption of this standard will impact EnCana s U.S. GAAP accounting treatment of business combinations entered into after January 1, 2009.

- As of January 1, 2009, EnCana will be required to adopt, for U.S. GAAP purposes, SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB No. 51* . This standard requires a noncontrolling interest in a subsidiary to be classified as a separate component of equity. The standard also changes the way the U.S. GAAP Consolidated Statement of Earnings is presented by requiring net earnings to include the amounts attributable to both the parent and the noncontrolling interest and to disclose these respective amounts. The adoption of this standard should not have a material impact on EnCana s Consolidated Financial Statements.

- As of December 31, 2009, EnCana will be required to prospectively adopt the new reserves requirements that arise from the completion of the SEC s project, *Modernization of Oil and Gas Reporting.* The new rules include provisions that permit the use of new technologies to establish proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. Additionally, oil and gas reserves will be reported using an average price based upon the prior 12-month period rather than year-end prices. The new rules will affect the reserve estimate used in the calculation of DD&A and the ceiling test for U.S. GAAP purposes. The Company is assessing the impact these new rules will have on its Consolidated Financial Statements.

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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, 2008, 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 (the "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, 2008, 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, 2008, 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, 2008, 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.

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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" (as amended to the date of this Form 40-F, 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). In addition, the Code of Ethics has been filed as Exhibit 99.10 to this Form 40-F.

Since the adoption of the Code of Ethics, there have not been any waivers, including implicit waivers, granted from any provision of the Code of Ethics. The Code of Ethics was amended, effective December 12, 2008, to address certain housekeeping matters and recently adopted Canadian legislation with respect to restrictions on lobbying.

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, 2008, 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, 2008, 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, 2008, 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, Allan P. Sawin, James M. Stanford and David P. O'Brien (ex officio).

New York Stock Exchange Disclosure.

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 2008 Annual and Special 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 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 registrant.

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 20, 2009.

EnCana Corporation

By: /s/ GERALD T. INCE

Name: Gerald T. Ince
Title: Treasurer

By: /s/ WILLIAM A. STEVENSON

Name: William A. Stevenson
Title: Comptroller

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.
99.10	Business Conduct & Ethics Practice, as amended effective December 12, 2008