EnCana™

ANNUAL INFORMATION FORM

February 17, 2006

ENCANA CORPORATION

ANNUAL INFORMATION FORM

This is the annual information form of EnCana Corporation ("EnCana" or the "Corporation") for the year ended December 31, 2005. In this annual information form, unless otherwise specified or the context otherwise requires, reference to "EnCana" or to the "Corporation" includes reference to subsidiaries of and partnership interests held by EnCana Corporation and its subsidiaries.

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

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

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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: oilsands strategy and the effect of this strategy, timing and completion of the sale of the Ecuador assets, the Chinook heavy oil discovery, the natural gas storage business and the Entrega Pipeline, plans to import diluent, capital investment levels and the allocation thereof, drilling plans and the timing and location thereof, production capacity and levels and the timing of achieving such capacity and levels, pipeline capacity, the timing of pipeline and new plant construction, the timing of completion of the environmental assessment on the Suffield Block, the timing of completion of the Foster Creek and Christina Lake expansions, the completion of waterflood implementation at Pelican Lake, government royalty rates, the results of the U.S. Bureau of Land Management decision regarding the Jonah area, the potential for natural gas resource play development on the Foix permit lands, reserves estimates, storage capacity, the level of expenditures for compliance with environmental regulations, site restoration costs including abandonment and reclamation costs, pending litigation, exploration plans, acquisition and disposition plans, including farmout plans, the timing of acquisitions, net cash flows, geographical expansion and plans for seismic surveys.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other things contemplated by the forward-looking statements will not occur. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in this annual information form include, but are not limited to: volatility of and assumptions regarding oil and natural gas prices, assumptions based upon EnCana's current guidance, fluctuations in currency and interest rates, product supply and demand, market competition, risks inherent in EnCana's North American and foreign oil and natural gas and midstream operations, risks of war, hostilities, civil insurrection and instability affecting countries in which EnCana and its subsidiaries operate and terrorist threats, risks inherent in EnCana's and its subsidiaries' marketing operations, including credit risk, imprecision of reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved reserves, EnCana's and its subsidiaries' ability to replace and expand oil and natural gas reserves, risks associated with technology, EnCana's ability to generate sufficient cash flow from operations to meet its current and future obligations, EnCana's ability to access external sources of debt and equity capital, general economic and business conditions, EnCana's ability to enter into or renew leases, the timing and costs of gas storage facility, well and pipeline construction, EnCana's ability to make capital investments and the amounts of capital investments, imprecision in estimating the timing, costs and levels of production and drilling, the results of exploration, development and drilling, imprecision in estimates of future production capacity, EnCana's and its subsidiaries' ability to secure adequate product transportation, uncertainty in the amounts and timing of royalty payments, imprecision in estimates of product sales, changes in environmental and other regulations or the interpretation of such regulations, risks associated with existing and potential future lawsuits and regulatory actions against EnCana and its subsidiaries, political and economic conditions in the countries in which EnCana and its subsidiaries operate including Ecuador, difficulty in obtaining necessary regulatory approvals and such other risks and uncertainties described from time to time in EnCana's reports and filings with the Canadian securities authorities and the United States Securities and Exchange Commission (the "SEC"). Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Readers are cautioned that the foregoing list of important factors is not exhaustive. The forward-looking statements contained in this annual information form are made as of the date hereof and EnCana undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this annual information form are expressly qualified by this cautionary statement.

NOTE REGARDING RESERVES DATA AND OTHER OIL AND GAS INFORMATION

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

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

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

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

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

CORPORATE STRUCTURE

Name and Incorporation

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

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

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

Intercorporate Relationships

The following table presents the name, the percentage of voting securities owned and the jurisdiction of incorporation, continuance or formation of EnCana's principal subsidiaries and partnerships as at December 31, 2005. 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, 2005:

Subsidiaries & Partnerships	Percentage Owned(1)	Jurisdiction of Incorporation, Continuance or Formation
EnCana Western Resources Ltd.(2)	100	Alberta
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
AECO Gas Storage Partnership	100	Alberta

Notes:

(1) Includes indirect ownership.

(2) Formerly EnCana West Ltd. (name was changed to EnCana Western Resources Ltd. on December 21, 2005). EnCana Western Resources Ltd. was wound up into EnCana Corporation on January 2, 2006.

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, 2005.

GENERAL DEVELOPMENT OF THE BUSINESS

EnCana is one of North America's leading natural gas producers, is among the largest holders of natural gas and oil resource lands onshore North America and is a technical and cost leader in the in-situ recovery of oilsands bitumen. EnCana pursues growth from its portfolio of long-life resource plays situated in Canada and the United States. Contained in unconventional reservoirs, resource plays are large contiguous accumulations of hydrocarbons, located in thick or areally extensive deposits, that typically have lower geological and commercial development risk, lower average long-term decline rates and very long producing lives compared to conventional plays. The Corporation is also engaged in select exploration and production activities internationally.

Following the Merger in 2002, the majority of EnCana's Upstream operations were located in Canada, the U.S., Ecuador and the U.K. central North Sea. From the time of the Merger through early 2004, EnCana focused on the development and expansion of its highest growth, highest return assets in these key areas. In 2004 and 2005, EnCana sharpened its strategic focus to concentrate on its inventory of North American resource play assets. In focusing its portfolio of assets, the Corporation completed a number of acquisitions and dispositions during the past three years. A portion of the disposition proceeds were used to fund EnCana's normal course issuer bid program (the "Bid"). In 2005, EnCana purchased approximately 55 million shares under the Bid for approximately $1.9 billion. For further information, refer to "Market For Securities" in this annual information form.

EnCana operates under two main divisions: (i) Upstream; and (ii) Midstream & Marketing. The following describes the significant events in the last three years that have taken place in these divisions. In this section, all disposition proceeds are provided on a before tax basis unless otherwise noted.

Upstream

The Upstream division manages EnCana's exploration for, and development and production of, natural gas, crude oil and NGLs and other related activities.

2005 Projects:

- In November 2005, EnCana announced plans to examine a number of proposals from other companies, including major multinationals, integrated producers and international oil companies, who are interested in participating in the development of EnCana's oilsands assets. The Corporation is considering creative business opportunities which may include equity investments, farm-ins, asset swaps, long-term bitumen supply agreements and the integration of upstream and downstream assets. These initiatives are expected to help EnCana enhance the value and accelerate the development of its oilsands resources.

2005 Acquisitions:

- In September 2005, a subsidiary of EnCana completed the purchase of approximately 325,000 net acres of exploration land in the Maverick Basin in southwest Texas for approximately $148 million.
- In the fourth quarter of 2005, a subsidiary of EnCana completed the purchase of approximately 24,000 total net acres (2,000 net developed acres) of development land in the Fort Worth Basin for approximately $178 million. The purchase included properties producing approximately 16 million cubic feet per day of natural gas.

2005 Dispositions:

- In May 2005, subsidiaries of EnCana completed the sale of the Corporation's Gulf of Mexico assets for approximately $2.1 billion ($1.5 billion after taxes and other adjustments). The Gulf of Mexico assets included the Corporation's interests in the Tahiti, Tonga, Sturgis, Sawtooth, Jack and St. Malo discoveries. EnCana had an average 40 percent interest in 239 exploration blocks covering approximately 1.4 million gross acres in the Gulf of Mexico.
- In June 2005, EnCana completed the sale of western Canadian conventional oil and natural gas assets producing approximately 6,400 barrels of oil equivalent per day for approximately $321 million.

In addition to the transactions completed in 2005, EnCana has a number of dispositions in progress. In October 2004, EnCana announced its intention to dispose of its Ecuador assets. The Ecuador assets include interests in five Oriente Basin blocks (Tarapoa Block, Block 14, Block 17, Shiripuno Block and EnCana's economic interest in relation to Block 15) and a 36.3 percent interest in the Oleoducto de Crudos Pesados ("OCP") pipeline. In September 2005, the Corporation reached an agreement to sell all of its interests in Ecuador for approximately $1.42 billion. The effective date of the sale is July 1, 2005. The sale is subject to approval by the Government of Ecuador, regulatory approvals and other closing conditions. EnCana expects the sale to close in the first quarter of 2006. Ecuador is reported as discontinued operations for financial reporting purposes.

In November 2005, the Corporation reached an agreement to sell its 50 percent interest in the Chinook heavy oil discovery offshore Brazil for approximately $350 million. The sale is subject to regulatory approvals and other closing conditions and is expected to close in the first quarter of 2006.

2004 Acquisitions:

- In the first quarter of 2004, a subsidiary of EnCana completed the purchase, through two separate transactions, of additional interests in the U.K. central North Sea, for net cash consideration of approximately $131 million.
- In May 2004, a subsidiary of EnCana completed the acquisition of Tom Brown, Inc. ("Tom Brown") for total consideration of approximately $2.7 billion, including debt of approximately $406 million. Tom Brown was a resource play focused, natural gas exploration and production company headquartered in Denver, Colorado. At the time of the acquisition, Tom Brown had assets in the Piceance, Green River, Wind River, Paradox, East Texas, Permian and Western Canada Sedimentary basins.
- In December 2004, a subsidiary of EnCana purchased natural gas assets in the Fort Worth Basin of north Texas for approximately $251 million.

2004 Dispositions:

- In February 2004, EnCana sold its 53.3 percent interest in Petrovera Resources ("Petrovera"), an Alberta partnership that produces heavy oil in western Canada, for net cash consideration of approximately $287 million. In order to facilitate the transaction, the Corporation purchased the 46.7 percent interest of its partner for approximately $253 million and then sold the 100 percent interest in Petrovera for a total of approximately $540 million.
- In July 2004, a subsidiary of EnCana sold assets in New Mexico for approximately $228 million.
- In August 2004, EnCana sold conventional natural gas properties in northeast Alberta for approximately $225 million.
- In September 2004, the Corporation sold conventional oil and gas assets for approximately $388 million. This transaction included properties in east central and southern Alberta producing predominantly medium and heavy oil.
- In December 2004, a subsidiary of EnCana completed the sale of all of its U.K. central North Sea assets for approximately $2.1 billion. These interests included a 43.2 percent interest in the Buzzard oil field, a 41.0 and 54.3 percent interest, respectively, in the Scott and Telford oil fields, other satellite discoveries, plus interests in exploration licences covering more than 740,000 net acres in the central North Sea.

2003 Acquisitions:

- In January 2003, EnCana acquired reserves and production in Ecuador from Vintage Petroleum, Inc. for net cash consideration of approximately $116 million.
- In September 2003, EnCana completed the acquisition of approximately 500,000 net acres of prospective natural gas development lands in Cutbank Ridge, which is located in the foothills of British Columbia and Alberta. EnCana purchased a majority interest in 39 parcels of land totalling roughly 350,000 net acres for

approximately $270 million. The Corporation had previously acquired about 150,000 net acres through purchases and land swaps with other companies and Crown land sales.

- In October 2003, a subsidiary of EnCana exchanged its non-operated interest in the Llano discovery in the Gulf of Mexico with a third party for an additional 14 percent interest in each of the Scott and Telford fields in the U.K. central North Sea, which were received by another subsidiary of EnCana.

2003 Dispositions:

- In 2003, in two separate transactions, EnCana completed the sale of its 13.75 percent working interest and a gross overriding royalty in the Syncrude Joint Venture ("Syncrude") for net cash consideration of approximately $1 billion. Syncrude operates a facility in northeast Alberta which produces crude oil from oilsands.

Over the past three years, EnCana completed a number of other acquisitions and dispositions not listed above. The majority of these transactions were individually valued at less than $100 million.

Midstream & Marketing

EnCana's Midstream & Marketing division encompasses the Corporation's market optimization activities and remaining midstream assets. The division was involved in a number of strategic projects over the past three years. In conjunction with the Corporation's resource play focus, EnCana has divested a number of its midstream assets and is currently in the process of divesting the majority of its remaining midstream assets. As a result, Midstream is reported as discontinued operations for financial reporting purposes.

2005 Projects:

- In September and October 2005, a wholly owned partnership of EnCana signed agreements with Methanex Corporation ("Methanex") and Provident Energy Ltd. ("Provident") under which Methanex will provide terminalling services to EnCana at Methanex's terminal facilities at Kitimat, British Columbia, and Provident will provide terminalling services to EnCana at Provident's terminal facilities at Redwater, Alberta. EnCana plans to import up to 25,000 barrels per day of offshore diluent to help transport its growing oilsands production in northeast Alberta to markets in the U.S.
- In December 2005, Entrega Gas Pipeline LLC ("Entrega"), an affiliate of EnCana Oil & Gas (USA) Inc., completed material portions of the construction of the first segment of its U.S. Federal Energy Regulatory Commission ("FERC") regulated pipeline project (the "Entrega Pipeline"), from Meeker Hub, Colorado to Wamsutter, Wyoming. This first segment of the pipeline is expected to be in service in February 2006, and has a capacity of up to approximately 750 million cubic feet per day.

2005 Dispositions:

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

In June 2005, EnCana announced plans to divest of its natural gas storage business. EnCana has North America's largest independent natural gas storage network, with approximately 174 billion cubic feet of working gas capacity at five facilities in Alberta, California and Oklahoma. EnCana plans to retain ownership of the Hythe facility, which has a capacity of approximately 10 billion cubic feet. The Corporation expects the sale to close in the second quarter of 2006.

In November 2005, EnCana entered into an agreement to sell Entrega to the Kinder Morgan-Sempra Pipelines & Storage project group ("KMP"). The sale is contingent upon the successful completion of certain conditions related to exit capacity from the U.S. Rockies production areas. The sale is anticipated to close in the first quarter of 2006 and will include all of the assets of the FERC-regulated company.

2004 Projects:

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

2004 Dispositions:

- In December 2004, EnCana sold its 25 percent non-operated partnership interest in the Kingston CoGen Limited Partnership ("Kingston CoGen") for net cash consideration of approximately $25 million. Kingston CoGen owns a 110 megawatt cogeneration plant in Kingston, Ontario.
- In December 2004, EnCana sold its interest in the Alberta Ethane Gathering System joint venture for approximately $108 million.

2003 Projects:

- In October 2003, the first phase of the Countess natural gas storage facility became operational, adding 10 billion cubic feet of capacity. The facility is located east of Calgary. The completion of plant facilities at Countess increased capacity to approximately 30 billion cubic feet in 2004. In 2005, EnCana received Alberta Energy and Utilities Board approval for delta pressuring, which enabled the utilization of the full design capacity of approximately 40 billion cubic feet.

2003 Dispositions:

- In January 2003, EnCana completed the sale of its indirect 70 percent interest in the Cold Lake Pipeline System for approximately $270 million. Also in January 2003, EnCana completed the sale of its indirect 100 percent interest in the Express Pipeline System for approximately $778 million, which included the assumption of approximately $385 million in debt by the purchaser. EnCana retained crude oil transportation capacity on both pipelines through its existing long-term commercial contracts.

NARRATIVE DESCRIPTION OF THE BUSINESS

The following map outlines EnCana's onshore North America landholdings and key resource plays as of December 31, 2005.

UPSTREAM

The vast majority of EnCana's Upstream operations are located in Canada, the U.S. and Ecuador. Frontier and International New Ventures is pursuing opportunities off the East Coast of Canada, in Northern Canada, Chad, Brazil, the Middle East, Greenland and France.

At December 31, 2005, EnCana had net proved reserves of approximately 11.8 trillion cubic feet of natural gas and 1.1 billion barrels of crude oil, bitumen and NGLs, as estimated by independent qualified reserves evaluators. Proved developed reserves comprise approximately 61 percent of total natural gas reserves, approximately 76 percent of crude oil and NGLs reserves excluding bitumen and approximately 16 percent of bitumen reserves. See "Reserves and Other Oil and Gas Information" in this annual information form.

Canada

EnCana has an industry-leading land position in western Canada of approximately 24 million gross acres (approximately 22 million net acres, of which approximately 13 million net acres are undeveloped). The mineral rights on approximately one third of the total net acreage is owned in fee title by EnCana, which means that production is subject to a mineral tax that is generally less than the Crown royalty imposed on production from land where the government owns the mineral rights.

EnCana's Canadian Upstream operations are divided into two regions — Canadian Plains and Canadian Foothills.

Canadian Plains Region

The Canadian Plains Region encompasses EnCana's natural gas production activities in southern Alberta and Saskatchewan as well as the Corporation's oilsands projects at Foster Creek, Christina Lake and Borealis. Three key resource plays are located in the Canadian Plains Region: (i) Shallow Gas in southern Alberta; (ii) Coalbed Methane ("CBM") developments in southern and central Alberta; and (iii) Steam-Assisted Gravity Drainage ("SAGD") operations at Foster Creek.

In 2005, in the Canadian Plains Region, EnCana had core capital expenditures of approximately $2,208 million and drilled approximately 3,411 net wells. EnCana's 2006 core capital investment in the Canadian Plains Region is projected to be approximately $1,800 to $1,900 million, which includes the drilling of approximately 3,100 to 3,200 net wells.

The following table summarizes landholdings for the Canadian Plains Region as at December 31, 2005.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Suffield	904	889	125	119	1,029	1,008	98%
Brooks	1,218	1,193	164	153	1,382	1,346	97%
Chinook	1,055	1,030	364	346	1,419	1,376	97%
Central Parkland	797	649	1,367	1,271	2,164	1,920	89%
Foster Creek	8	8	51	51	59	59	100%
Christina Lake	1	1	44	44	45	45	100%
Borealis	—	—	152	152	152	152	100%
Weyburn	86	75	604	597	690	672	97%
Other	2,712	2,391	3,869	3,601	6,581	5,992	91%
Canadian Plains Total	6,781	6,236	6,740	6,334	13,521	12,570	93%

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)	
	2005	2004	2005	2004	2005	2004
Suffield	243	241	20,756	26,706	368	401
Brooks	490	474	13,220	15,542	569	568
Chinook	276	257	2,975	4,406	294	283
Central Parkland	59	33	1,505	2,238	68	46
Foster Creek	—	—	29,019	28,774	174	173
Christina Lake	—	—	5,360	4,364	32	26
Weyburn	—	—	13,562	14,200	81	85
Other	280	269	23,183	30,690	419	454
Canadian Plains Total	1,348	1,274	109,580	126,920	2,005	2,036

Notes:

(1) The Shallow Gas key resource play, located mainly in the Suffield and Brooks areas, had 2005 average production of approximately 625 million cubic feet per day (592 million cubic feet per day in 2004).

(2) The CBM key resource play, located in the Chinook and Central Parkland areas, had 2005 average production of approximately 57 million cubic feet per day (17 million cubic feet per day in 2004).

The following table summarizes EnCana's interests in producing wells as at December 31, 2005. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2005.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Suffield	8,324	8,284	708	706	9,032	8,990
Brooks	10,034	9,599	280	276	10,314	9,875
Chinook	4,515	4,412	149	140	4,664	4,552
Central Parkland	886	643	29	12	915	655
Foster Creek	—	—	55	55	55	55
Christina Lake	—	—	5	5	5	5
Weyburn	—	—	687	430	687	430
Other	2,133	1,763	1,150	764	3,283	2,527
Canadian Plains Total	25,892	24,701	3,063	2,388	28,955	27,089

Notes:

(1) At December 31, 2005, the Shallow Gas key resource play had 17,038 gross producing gas wells (16,556 net gas wells).

(2) At December 31, 2005, the CBM key resource play had 1,651 gross producing gas wells (1,507 net gas wells).

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

Suffield

EnCana holds interests in the Upper Cretaceous shallow natural gas horizons and deeper formations in the Suffield area in southeast Alberta. Suffield is one of the core areas of the Shallow Gas key resource play. EnCana also produces conventional heavy oil in the area. The Suffield area is largely made up of the Suffield Block, where operations are carried out by EnCana in cooperation with the Canadian military according to guidelines established under agreements with the Government of Canada. In 2003, a portion of the Suffield Block was designated as a National Wildlife Area ("NWA") and since that time no further wells have been drilled in the NWA. Prior to drilling any further infill shallow gas wells in the NWA, EnCana must complete an environmental assessment under the Canadian Environmental Assessment Act. EnCana expects to complete the assessment in 2006.

Brooks

EnCana produces natural gas, crude oil and NGLs from the Cretaceous horizons in the Brooks area of southern Alberta, located east of Calgary. This area is another core area of the Shallow Gas key resource play and is largely comprised of EnCana fee title lands, covering a portion of the Palliser Block.

Chinook

The Chinook area is located immediately east of Calgary. The majority of the Corporation's lands in the area are fee title lands on the Palliser Block for which EnCana owns the mineral rights. In addition to operations in the Upper Cretaceous shallow natural gas horizons, the Chinook area is the centre of EnCana's CBM key resource play. The CBM development in the Horseshoe Canyon formation is located within the Chinook area and covers approximately 700,000 acres. In 2005, EnCana drilled approximately 656 net CBM wells on its project area on the Palliser Block, increasing production to approximately 57 million cubic feet per day at year-end.

Central Parkland

The Central Parkland area, located immediately north of the Chinook area, contains the northern extension of EnCana's Horseshoe Canyon CBM key resource play. EnCana holds a combination of fee and crown lands in the area. In 2005, EnCana drilled approximately 428 net CBM wells in the area, increasing production to approximately 27 million cubic feet per day at year-end. In December 2005, EnCana purchased approximately 218,000 net acres of land in the area for prospective CBM development in the Mannville formation, for approximately $138 million.

Oilsands

EnCana has two primary SAGD operations in the Athabasca oilsands region of northeast Alberta: (i) Foster Creek; and (ii) Christina Lake. EnCana has also identified another potential SAGD development opportunity in a third location, Borealis, located north of Fort McMurray.

In November 2005, EnCana announced plans to examine a number of proposals from other companies that would enable the Corporation to accelerate the development of its oilsands resources. EnCana is considering a number of initiatives, which may include equity investments, farm-ins, asset swaps, long-term bitumen supply agreements and the integration of upstream and downstream assets. The Corporation holds approximately 1.2 million net acres within the Athabasca oilsands area, which includes the ownership of approximately 685,000 net acres and the exclusive rights to lease an additional 557,000 net acres on the Cold Lake Air Weapons Range.

Foster Creek

EnCana has a 100 percent working interest in Foster Creek, one of the Corporation's key crude oil resource plays. EnCana holds surface access and petroleum and natural gas rights for natural gas and oilsands exploration, development and transportation from areas within the Cold Lake Air Weapons Range (Primrose Block) which were granted by the Government of Canada. EnCana has acquired, and has certain rights to acquire, oilsands leases wherever deposits of bitumen are identified within the areas for which petroleum and natural gas lease rights are held. EnCana is currently operating a thermal oil recovery project in the Foster Creek area of the Primrose Block using SAGD technology.

Crude oil production at Foster Creek in 2005 averaged approximately 29,000 barrels per day. In the fourth quarter of 2005, EnCana completed the first stage of an expansion which added an additional 10,000 barrels per day of capacity. The second stage of the expansion, which is projected to add an additional 20,000 barrels per day of capacity, is expected to be completed in late 2006. The expansion is anticipated to increase EnCana's productive capacity at Foster Creek to 60,000 barrels per day.

EnCana continues to research and develop technologies to increase recovery and decrease the costs of extracting crude oil bitumen from oilsands. One focus area is alternate methods of artificial lift where EnCana is operating alternative pump designs that are expected to enable the Corporation to optimize SAGD performance by operating at lower pressures, thereby realizing lower steam-oil ratios and decreasing facility capital costs. At

December 31, 2005, EnCana had 32 wells on electrical submersible pumps at Foster Creek, and the Corporation expects to continue to utilize this technology on new SAGD wells.

Another focus area is to reduce the reliance on steam in bitumen production. EnCana has piloted two technologies using solvents as part of the extraction process. The Vapex process, which uses solvent in place of steam, was piloted at Foster Creek from 2002 to 2005. The outcome of the pilot is currently under review. The Solvent Aided Process ("SAP") is discussed in the Christina Lake section below.

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

Christina Lake

EnCana has a 100 percent owned thermal crude oil recovery pilot project at Christina Lake which also uses SAGD technology. In 2005, EnCana added two well pairs which increased average annual production to approximately 5,400 barrels per day. The Corporation recently approved an expansion which is expected to increase production capacity to approximately 18,000 barrels per day by early 2008.

EnCana continues to pilot SAP, which commenced in 2004, at Christina Lake. This process mixes a small amount of solvent with steam to enhance recovery.

Borealis

EnCana has a 100 percent working interest in approximately 152,000 acres in the Borealis area, which is located approximately 90 kilometres north of Fort McMurray. At December 31, 2005, the Corporation had drilled approximately 135 delineation wells in the area. In 2006, EnCana plans to continue its stratigraphic well program to further delineate these lands. EnCana began acquiring land in the Borealis area in 1999.

Weyburn

EnCana has a 62 percent working interest (50 percent economic interest) in the unitized portion of the Weyburn crude oil field in southwest Saskatchewan. EnCana is the operator and expects to improve ultimate recovery in the enhanced oil recovery ("EOR") area of the field with a carbon dioxide ("CO_2") miscible flood project. In 2005, EnCana continued its infill drilling program and drilled 45 new wells in the EOR area. This program ensures optimal coverage of areas currently within the EOR area. Eight additional patterns, or well groupings, were put into operation in the CO_2 miscible flood development in 2005. As of December 31, 2005, there were 44 patterns on stream out of a planned total of 75 patterns. EnCana has secured additional volumes of CO_2 by expanding the Corporation's existing contract with the Dakota Gasification Company. This allows the Corporation to further expand its CO_2 injection program.

Canadian Foothills Region

The Canadian Foothills Region includes EnCana's natural gas and crude oil exploration, development and production activities in British Columbia and northern Alberta. Three key resource plays are located in the Canadian Foothills Region: (i) Greater Sierra; (ii) Cutbank Ridge; and (iii) Pelican Lake.

In 2005, in the Canadian Foothills Region, EnCana had core capital expenditures of approximately $1,885 million and drilled approximately 627 net wells. EnCana's 2006 core capital investment in the Canadian Foothills Region is projected to be approximately $1,700 to $1,800 million, which includes the drilling of approximately 575 to 625 net wells.

The following table summarizes landholdings for the Canadian Foothills Region as at December 31, 2005.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Greater Sierra	545	488	2,582	2,319	3,127	2,807	90%
Cutbank Ridge	153	127	858	768	1,011	895	89%
Pelican Lake	84	84	133	133	217	217	100%
Bighorn	272	156	914	584	1,186	740	62%
Sexsmith/Hythe/Saddle Hills	282	179	209	155	491	334	68%
Cold Lake Air Weapons Range	384	363	471	467	855	830	97%
Other	1,096	907	2,734	2,296	3,830	3,203	84%
Canadian Foothills Total	2,816	2,304	7,901	6,722	10,717	9,026	84%

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)	
	2005	2004	2005	2004	2005	2004
Greater Sierra	219	230	793	632	224	234
Cutbank Ridge	92	40	—	—	92	40
Pelican Lake	4	7	25,752	18,900	159	120
Bighorn	56	47	867	865	61	52
Sexsmith/Hythe/Saddle Hills	99	110	1,989	2,785	111	127
Cold Lake Air Weapons Range	129	163	—	—	129	163
Other	178	239	3,936	4,284	201	265
Canadian Foothills Total	777	836	33,337	27,466	977	1,001

The following table summarizes EnCana's interests in producing wells as at December 31, 2005. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2005.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Greater Sierra	705	664	3	3	708	667
Cutbank Ridge	213	191	—	—	213	191
Pelican Lake	13	13	507	507	520	520
Bighorn	123	73	5	2	128	75
Sexsmith/Hythe/Saddle Hills	291	228	6	3	297	231
Cold Lake Air Weapons Range	623	599	—	—	623	599
Other	1,740	1,570	264	158	2,004	1,728
Canadian Foothills Total	3,708	3,338	785	673	4,493	4,011

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

Greater Sierra

The Greater Sierra area of northeast British Columbia is one of EnCana's key natural gas resource plays. Production in the area has grown from essentially zero in 1998 to an average of approximately 219 million cubic feet per day in 2005. Sales volumes decreased in 2005 compared to 2004 due to the timing and pace of development drilling and delays in well tie-ins as a result of weather issues in the spring and summer of 2005. EnCana is selectively farming out a small portion of its Greater Sierra land position to third parties. The farmouts provide EnCana with additional capital and allow the Corporation to add production volumes at a relatively low cost.

As at December 31, 2005, EnCana held an average 99 percent interest in 13 production facilities in the area that were capable of processing approximately 486 million cubic feet per day of natural gas. EnCana also holds a 100 percent interest in the Ekwan pipeline which has a capacity of approximately 400 million cubic feet per day and transports natural gas from northeast British Columbia to Alberta. Pipeline throughput was approximately 115 million cubic feet per day in 2005.

Cutbank Ridge

Cutbank Ridge is a key natural gas resource play located in the Canadian Rocky Mountain foothills, approximately 50 kilometres southwest of Dawson Creek, British Columbia. The majority of the Corporation's lands in this area were purchased in 2003. In 2005, EnCana drilled approximately 135 net natural gas wells at Cutbank Ridge and increased production to approximately 142 million cubic feet per day of natural gas by year-end.

In April 2005, EnCana began production from the Cutbank Doig natural gas discovery, located stratigraphically below the Cutbank Ridge resource play. The initial well into this conventional discovery was drilled in 2004. In order to facilitate production from Cutbank Ridge, including the recent discovery at Cutbank Doig, EnCana is constructing the Steeprock natural gas processing plant located approximately 50 kilometres south of Dawson Creek, British Columbia. The plant is expected to have a capacity of approximately 198 million cubic feet per day. EnCana anticipates that the plant will be completed in the fourth quarter of 2006.

Pelican Lake

Pelican Lake is another of EnCana's key resource plays producing crude oil in north-central Alberta. In 2005, EnCana continued to expand its waterflood program at Pelican Lake, which has increased the recovery of crude oil in the area. The success of the waterflood program at Pelican Lake increased 2005 crude oil production by approximately 36 percent compared to 2004. In 2006, EnCana expects to complete its waterflood implementation throughout the field and expand its polymer flood pilot project to further improve performance. In 2006, EnCana expects the Pelican Lake project to reach payout status, which will result in an increase in the government royalty rate from one percent to approximately 21 percent. EnCana also holds a 38 percent non-operated interest in a 110-kilometre, 20-inch diameter crude oil pipeline which connects the Pelican Lake area to a major pipeline that transports crude oil from northern Alberta to crude oil markets.

Bighorn

The Bighorn area in west central Alberta is EnCana's newest natural gas resource play, focusing on exploitation of multi-zone stacked Cretaceous sands in the Deep Basin. EnCana has an average working interest of approximately 62 percent in approximately 1.2 million gross acres (740,000 net acres) of land in the Bighorn area. The primary producing properties in Bighorn are Berland, Wild River, Resthaven and Kakwa. In 2005, EnCana drilled approximately 51 net wells in the area and production averaged approximately 56 million cubic feet per day of sweet natural gas. Wet weather in the spring and summer of 2005 delayed drilling and well tie-ins, limiting production growth for the year. Also in 2005, EnCana expanded an existing natural gas processing plant to a capacity of 20 million cubic feet per day and commenced construction of a new 100 million cubic feet per day gas plant in the Resthaven area. At Wild River, a facility expansion to increase processing capacity to approximately 30 million cubic feet per day was initiated.

Sexsmith/Hythe/Saddle Hills

EnCana produces natural gas, crude oil and NGLs in the Sexsmith/Hythe/Saddle Hills area in northwest Alberta. EnCana also operates and has a 62 percent interest in the 210 million cubic feet per day Sexsmith sour natural gas and liquids processing plant and an 85 percent interest in the 50 million cubic feet per day Saddle Hills sweet natural gas plant. EnCana also owns 100 percent of and operates the Hythe sour natural gas plant, which has a capacity of approximately 170 million cubic feet per day. The Hythe and Sexsmith sour natural gas plants are interconnected by pipeline to provide greater operating efficiencies. EnCana also owns and operates a 275-kilometre natural gas gathering system in the area.

Cold Lake Air Weapons Range

EnCana produces natural gas from the Cold Lake Air Weapons Range (formerly referred to as the Primrose Block) located in northeast Alberta. The majority of EnCana's natural gas production in the area is processed through 100 percent owned and operated compression facilities. In 2005, production in the area was impacted by the September 2003 Alberta Energy and Utilities Board decision to shut-in natural gas production that may put at risk the recovery of bitumen resources in the area. The decision resulted in a decrease in annualized natural gas production in the area of approximately 22 million cubic feet per day (eight million cubic feet per day in 2004). No additional wells were shut-in during 2005. 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 in the area.

United States

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 and the East Texas, Fort Worth and Maverick Basins in Texas. The Corporation also has landholdings in the Columbia River basin in Washington State, as well as interests in natural gas gathering and processing assets. 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.

In 2005, EnCana had core capital expenditures in the U.S. of approximately $1,982 million and drilled approximately 617 net wells. EnCana's 2006 core capital investment in the U.S. is projected to be approximately $2,100 to $2,200 million, which includes the drilling of approximately 830 to 860 net wells.

The following table summarizes EnCana's landholdings in the United States as at December 31, 2005.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Jonah	11	9	10	10	21	19	90%
Piceance	233	220	749	704	982	924	94%
East Texas	73	46	428	294	501	340	68%
Fort Worth	37	31	206	174	243	205	84%
Maverick Basin	3	3	468	325	471	328	70%
Columbia River Basin	—	—	848	837	848	837	99%
Other	463	222	1,930	1,674	2,393	1,896	79%
United States Total	820	531	4,639	4,018	5,459	4,549	83%

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)	
	2005	2004	2005	2004	2005	2004
Jonah	435	389	3,939	3,294	459	409
Piceance	307	261	2,965	3,074	325	279
East Texas	90	50	304	167	92	51
Fort Worth	70	27	345	233	72	28
Other	193	142	6,337	6,037	230	179
United States Total	1,095	869	13,890	12,805	1,178	946

The following table summarizes EnCana's interests in producing wells as at December 31, 2005. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2005.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Jonah	511	457	—	—	511	457
Piceance	2,410	2,124	5	2	2,415	2,126
East Texas	701	356	10	4	711	360
Fort Worth	501	447	8	6	509	453
Other	2,605	1,873	26	8	2,631	1,881
United States Total	6,728	5,257	49	20	6,777	5,277

The following describes EnCana's major producing areas or activities in the United States.

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 represents EnCana's initial entry into the U.S. Rockies region. Since EnCana's initial acquisition in the area in 2000, production has approximately quadrupled — mainly through a combination of infill drilling and advanced hydraulic fracturing techniques. This approach has enabled the Corporation to access the reserves of natural gas in the Lance formation that makes up the Jonah play. These stacked sands exist at depths between 8,000 and 11,500 feet.

On January 13, 2006, the U.S. Bureau of Land Management released the Final Environmental Impact Statement covering future development in the Jonah area. A Record of Decision is expected at the conclusion of the public comment period. Approval is expected to allow the drilling of approximately 1,500 additional wells, and is expected to allow a change to vertical drilling which has the potential to reduce future drilling costs. In 2005, EnCana drilled approximately 104 net wells in the Jonah area.

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 entered the basin in 2001 with its acquisition of the Mamm Creek field. The May 2004 acquisition of Tom Brown included properties and natural gas production in the basin. In 2005, EnCana drilled approximately 266 net wells in the basin.

East Texas

EnCana produces natural gas and associated NGLs in the East Texas Basin. The East Texas properties were acquired as part of the Tom Brown acquisition in 2004, and the basin is one of EnCana's newest key resource plays. This tight gas, multi-zone play targets the Bossier and Cotton Valley zones. During 2005, EnCana drilled approximately 84 net wells in the basin.

Fort Worth

EnCana produces natural gas and associated NGLs in the Fort Worth Basin in north Texas. Fort Worth is one of EnCana's key resource plays. Since entering the area in 2003, the Corporation has assembled a significant land position in the Barnett Shale play in this basin. EnCana is applying horizontal drilling and multi-stage reservoir stimulation to improve performance in this play. The Corporation's December 2004 purchase of natural gas assets in north Texas included properties located in the Fort Worth Basin. In the fourth quarter of 2005, a subsidiary of EnCana completed the purchase of additional development land and producing properties in the basin. EnCana drilled approximately 59 net wells in the basin in 2005.

Maverick Basin

In September 2005, a subsidiary of EnCana completed the purchase of approximately 325,000 net acres of exploration land in the Maverick Basin in southwest Texas for approximately $148 million. In 2006, EnCana plans to apply its expertise in horizontal drilling and completions technology to test the multi-zone potential of gas-bearing formations in the Maverick Basin.

Columbia River Basin

EnCana holds approximately 848,000 gross acres (837,000 net acres) in the Columbia River Basin in Washington State. This sedimentary basin is covered with 5,000 to 15,000 feet of volcanic basalt and as a result it is relatively under-explored. EnCana believes that there may be potential to employ new drilling technology to cost effectively explore and develop the basin. The Corporation has entered into an agreement with an industry partner who will participate in the initial funding of the exploration program in return for a portion of EnCana's acreage in the area. EnCana is currently drilling its first two exploration wells in the basin.

Gathering & Processing Facilities

EnCana owns and operates various gas gathering and NGLs processing facilities. Near Rifle, Colorado, EnCana's gathering facilities have a capacity of approximately 360 million cubic feet per day and include over 645 kilometres of pipelines. Near Fort Lupton, Colorado, the gathering facilities include field compression and over 1,000 kilometres of pipelines. The Fort Lupton processing plant has a capacity of approximately 90 million cubic feet per day. The Corporation's gathering facilities in Rangely, Colorado include field compression and over 1,600 kilometres of pipelines. The Dragon Trail processing plant near Rangely, Colorado has a capacity of approximately 60 million cubic feet per day. The Lisbon plant in Moab, Utah was acquired as part of the Tom Brown acquisition. The Lisbon plant is a sophisticated cryogenic natural gas processing plant with a capacity of approximately 60 million cubic feet per day.

Frontier and International New Ventures

EnCana invests a small portion of its capital in high potential exploration beyond its core geographic areas, primarily offshore the East Coast of Canada, in Northern Canada, Chad, Brazil, the Middle East, Greenland and France. In 2005, EnCana's Frontier and International New Ventures division had core capital expenditures of approximately $125 million and drilled approximately three net wells. EnCana's 2006 core capital investment in the Frontier and International New Ventures region is projected to be approximately $100 million, which includes the drilling of approximately 10 net wells.

East Coast of Canada

At December 31, 2005, EnCana held an interest in approximately 3.9 million gross acres (2.4 million net acres) offshore the East Coast of Canada, which includes Nova Scotia and Newfoundland & Labrador. EnCana operates 13 of its 20 licenses in these areas and has an average working interest of approximately 57 percent.

EnCana is the operator of the Deep Panuke field, located offshore Nova Scotia, and had an approximate 85 percent working interest at December 31, 2005. EnCana continues to examine the potential economic viability of the Deep Panuke project. In late 2005 and early 2006, EnCana participated in the drilling of an exploration well, Dominion J-14, plus a sidetrack well, in the Grand Pre license in an attempt to extend the northeast boundary of the Deep Panuke field. The wells, which were abandoned in January 2006, failed to discover commercial quantities of hydrocarbons. Pursuant to a farmout agreement signed in November 2005, EnCana expects to transfer an approximate 25 percent working interest in the Grand Pre license to its partner after the final drilling costs for the Dominion J-14 well are determined.

Northern Canada

EnCana has non-operated working interests in northern Canada which include 35 Significant Discovery Licenses and three Production Licenses in Nunavut, the Northwest Territories and the Yukon Territory.

In addition, EnCana is the operator and has a working interest in one Exploration License in the Northwest Territories which encompasses approximately 133,000 gross acres (50,000 net acres). In 2005, EnCana drilled one successful well to appraise a natural gas discovery made at Umiak in the Mackenzie Delta area in 2004. A Significant Discovery License Application has been made to the relevant regulatory bodies to indefinitely continue approximately 26,000 gross acres (10,000 net acres) of the exploration license associated with the Umiak field discovery. In October 2005, EnCana relinquished approximately 79,000 gross acres in the area.

Chad

EnCana's onshore exploration operations in Chad are based out of its subsidiary's office in N'Djamena. At December 31, 2005, EnCana had a 50 percent working interest in Permit H comprising approximately 54 million gross acres (27 million net acres). In 2005, EnCana relinquished approximately 54 million gross acres of the original concession under Permit H. EnCana acquired seismic data and completed the drilling of one exploration well in 2005. In 2006, the Corporation plans to acquire seismic data and anticipates drilling approximately five to eight gross exploration and/or appraisal wells.

Brazil

In November 2005, EnCana reached an agreement to sell its 50 percent working interest in the Chinook heavy oil discovery offshore Brazil for approximately $350 million. A subsidiary of EnCana made the discovery in 2004 and two successful appraisal wells were drilled in 2005. The sale is subject to regulatory approvals and other closing conditions and is expected to close in the first quarter of 2006. The Chinook field is located in the Campos Basin (Block BM-C-7), and is approximately 75 kilometres offshore Brazil. At December 31, 2005, EnCana's working interest in the block comprised approximately 133,000 gross acres (89,000 net acres). After the transfer of a 16.7 percent earned-in share to its partner, expected to occur in early 2006, EnCana expects to have a 50 percent operated working interest in the block at the time of the sale.

In addition to Block BM-C-7, EnCana has non-operated interests in eight deep and ultra-deep water exploration blocks offshore Brazil, seven of which are operated by Petrobras, the Brazilian national oil company. EnCana's landholdings on these blocks total approximately 1.3 million gross acres (0.4 million net acres) with an average working interest of 35 percent. Seismic work was performed on several of these blocks in 2005. EnCana and its partners are planning to drill one gross exploration well in 2006 in the Campos Basin.

In October 2005, EnCana was awarded a 20 percent working interest in two deep water exploration blocks offshore Brazil in the Potiguar Basin in Agência Nacional do Petróleo ("ANP") Bid Round 7. These blocks encompass approximately 379,000 gross acres (76,000 net acres) and are also operated by Petrobras. The concession agreement for these blocks was signed in January 2006.

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

Middle East

EnCana has a 100 percent working interest in Block 2, which encompasses most of the onshore lands in the State of Qatar and covers approximately 2.2 million acres. In 2005, EnCana reached an agreement to farmout 50 percent of its working interest in the block. At December 31, 2005, the agreement was awaiting approval by Qatar Petroleum. One gross well is planned for the block in 2006.

In 2005, EnCana farmed-out a 50 percent working interest in onshore Blocks 3 and 4 in the Sultanate of Oman. The blocks cover approximately 9.6 million acres. EnCana retained a 50 percent operated interest in the blocks (approximately 4.8 million net acres) and drilled two unsuccessful wells in 2005. The Corporation plans to drill two additional gross wells in 2006.

In February 2005, EnCana exited the Kingdom of Bahrain with the expiration of the Exploration and Production Sharing Agreement, under which it held a 50 percent working interest in Block 5. In June 2005, EnCana exited the Republic of Yemen with its withdrawal from the Production Sharing Agreement, under which it held a 36.75 percent working interest in Block 47.

Greenland

EnCana has an 87.5 percent working interest in two exploration blocks in Greenland, comprising approximately 1.7 million gross acres (1.5 million net acres). In the 2004 Offshore West Greenland Bid Round, EnCana acquired one exploration license (Lady Franklin), which was signed in January 2005. EnCana also has an interest in the Atammik block, offshore west Greenland. In 2005, EnCana conducted seismic surveys on these blocks. In 2006, EnCana plans to pursue the farmout of a portion of its working interest in both blocks.

France

In October 2004, EnCana filed an application for the Foix exploration permit, which encompasses approximately 860,000 acres in the onshore Aquitaine Basin in southwest France. In February 2006, a subsidiary of EnCana was granted a 100 percent interest in this exploration permit. The Corporation has plans for a multi-well exploration drilling program in 2006 and 2007 to identify the potential for a natural gas resource play development.

Ecuador

In October 2004, EnCana announced its intention to dispose of its Ecuador assets. In September 2005, the Corporation reached an agreement to sell all of its interests in Ecuador for approximately $1.42 billion. The effective date of the sale is July 1, 2005. The sale is subject to approval by the Government of Ecuador, regulatory approvals and other closing conditions. EnCana expects the sale to close in the first quarter of 2006. As a result, Ecuador is reported as discontinued operations for financial reporting purposes.

A subsidiary of EnCana owns a concession in the Oriente Basin, known as the Tarapoa Block. The subsidiary has a 100 percent working interest in this concession, which is operated under a participation contract which has a primary term through to August 1, 2015. EnCana also has a 40 percent non-operated economic interest in relation to Block 15 in the Oriente Basin. This concession is operated under a participation contract which has primary terms through to July 2012 for base area production and July 2019 for production resulting from additional exploration. In addition, EnCana has a majority operating interest in Blocks 14, 17 and Shiripuno, also in the Oriente Basin. The production contracts for Blocks 14 and 17 expire in July 2012 and December 2018, respectively.

At December 31, 2005, EnCana held an average 64 percent working and economic interest in approximately 1.4 million gross acres (approximately 892,000 net acres, of which approximately 785,000 net acres are undeveloped) in Ecuador. At December 31, 2005, 246 gross crude oil wells (170 net wells) were producing. EnCana's contractual entitlement to net crude oil production in 2005 was 72,916 barrels per day (76,872 barrels per day in 2004). In 2005, EnCana's Ecuador operations had core capital expenditures of approximately $179 million and approximately 19 net wells were drilled. The core capital expenditures were focused mainly on the non-operated Block 15 and the south blocks (including Blocks 14, 17 and Shiripuno).

EnCana's interests in Ecuador also include an indirect 36.3 percent equity interest in the OCP pipeline. OCP is a 500-kilometre pipeline with a capacity of approximately 450,000 barrels per day that runs from the crude oil producing area of Ecuador to the Pacific Coast. In 2005, shipments on OCP totalled approximately 158,024 barrels per day (170,599 barrels per day in 2004). Pursuant to the terms of the agreement with the Government of Ecuador, OCP will be transferred to the Government of Ecuador, without cost, after a 20-year operating period. EnCana began shipping on OCP in September 2003, and has a 15-year shipping commitment of approximately 108,000 barrels per day. EnCana's shipments on OCP in 2005 averaged approximately 67,527 barrels per day (72,636 barrels per day in 2004).

MIDSTREAM & MARKETING

EnCana's marketing groups are focused on enhancing the netback price of the Corporation's proprietary production. Correspondingly, the marketing groups conduct market optimization activities that include third party purchases and sales of product to provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. In addition, EnCana's power assets are managed to optimize the Corporation's electricity costs, particularly in the Province of Alberta. The Midstream & Marketing division also holds the remainder of EnCana's midstream assets, which the Corporation plans to divest in 2006.

Natural Gas Marketing

In 2005, approximately 90 percent of EnCana's produced natural gas sales were directly marketed by EnCana to local distribution companies, industrials and energy marketing companies. The remaining 10 percent of produced natural gas sales were marketed to aggregators who supply natural gas to markets throughout North America. Prices received by EnCana are based primarily upon prevailing index prices for natural gas. Prices are impacted by competing fuels in such markets and by regional supply and demand for natural gas.

To help mitigate the market risk associated with forecasted cash flows, EnCana enters into various risk management contracts relating to produced natural gas. For 2006, after taking into account its risk management contracts, EnCana's gas sales price portfolio exposure consists of approximately 22 percent at fixed prices, approximately 71 percent with insured floor prices and approximately 7 percent at other prices. Details of these transactions are found in Note 16 to EnCana's audited consolidated financial statements for the year ended December 31, 2005.

Crude Oil Marketing

EnCana sells and manages the transportation of its western Canadian crude oil to markets in Canada and the U.S. (131,638 barrels per day in 2005 and 140,911 barrels per day in 2004). Crude oil sales are normally executed under spot and monthly evergreen contracts with delivery to major pipeline hubs, such as Edmonton and Hardisty, in Alberta, with EnCana arranging the intermediate transportation on the feeder pipeline systems. Sales are also made on a delivered basis using trunk pipeline systems, such as the Enbridge system, for sales to U.S. refinery destinations.

EnCana provides North American marketing services to certain organizations on a fee for service basis. In 2005, EnCana acted as exclusive agent for Canadian Oil Sands Limited ("COS") and marketed COS' Syncrude volumes of 81,019 barrels per day (85,157 barrels per day in 2004). The COS marketing agreement terminates in the second quarter of 2006. EnCana also provides marketing services to the Alberta Government's Department of Energy (48,425 barrels per day in 2005 and 53,026 barrels per day in 2004). This agency agreement ends in the second quarter of 2007.

In Ecuador, EnCana's crude oil volumes are sold FOB at the marine loading facility at Balao, Esmeraldas Province, Ecuador. A total of 75,488 barrels per day was marketed in 2005 (77,845 barrels per day in 2004). EnCana's production in Ecuador consists of a high viscosity crude oil with characteristics well-suited to refineries on the U.S. West and Gulf Coasts.

To help mitigate the market risk associated with forecasted cash flows, EnCana enters into various risk management contracts relating to crude oil. Details of these transactions are found in Note 16 to EnCana's audited consolidated financial statements for the year ended December 31, 2005.

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 Upstream and Midstream & Marketing divisions in Alberta's deregulated market. The physical assets include two 106 megawatt power plants in southern Alberta and the 80 megawatt Foster Creek cogeneration facility (part of EnCana's Foster Creek SAGD operation). 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 250 megawatts and its generation capacity is approximately 239 megawatts.

Midstream

In 2005, the majority of EnCana's midstream assets were deemed to be non-core to the Corporation. In December 2005, EnCana and certain affiliates completed the sale of the Corporation's NGLs processing business for approximately $625 million. EnCana is currently in the process of divesting the majority of its remaining midstream assets, including its natural gas storage business and the Entrega Pipeline. As a result of these planned dispositions, Midstream is reported as discontinued operations for financial reporting purposes.

Natural Gas Storage

In June 2005, EnCana announced plans to sell its natural gas storage business. The sale is expected to close in the second quarter of 2006. EnCana intends to retain ownership of its Hythe storage facility due to its integration with Upstream operations.

Based upon overall storage capacity, EnCana is the largest independent (non-utility) natural gas storage operator in North America with facilities in Alberta, California and Oklahoma. The AECO HUB in Alberta is Canada's largest natural gas storage and trading hub. EnCana also leases natural gas storage capacity from another storage operator located in the U.S. mid-continent region. At December 31, 2005, EnCana had owned and operated storage capacity of approximately 174 billion cubic feet, including the 10 billion cubic feet Hythe facility, as well as leased storage capacity of approximately 8.5 billion cubic feet. In July 2005, a subsidiary of EnCana received FERC approval to proceed with the development of its previously announced new Starks natural gas storage facility in southwest Louisiana.

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

The following table is a summary of EnCana's natural gas storage assets as at December 31, 2005.

Gas Storage Facility:	Location	Storage Capacity	Withdrawal Capability	Injection Capability
		(billions of cubic feet)	(billions of cubic feet per day)	
AECO HUB:				
Suffield	Southeast Alberta	85	1.80	1.60
Hythe	Northwest Alberta	10	0.20	0.15
Countess	Southeast Alberta	40	1.25	0.95
Wild Goose	Northern California	24	0.48	0.45
Salt Plains	Northern Oklahoma	15	0.20	0.15
Total Owned and Operated Capacity		174	3.93	3.30
Total Leased Capacity(1)	U.S. mid-continent	8.5	0.09	0.19

Note:

(1) Contract terms range from 16 months to 11 years.

Pipelines

In August 2005, Entrega received FERC approval to proceed with its previously announced natural gas pipeline project. The pipeline is expected to transport natural gas out of Colorado's Piceance Basin, through Wamsutter, Wyoming, to the Cheyenne natural gas trading hub in northeast Colorado. Construction of the first segment of the pipeline (from Meeker Hub, Colorado to Wamsutter, Wyoming) was completed in December 2005, and is expected to be in service in February, 2006. The first segment has a capacity of approximately 750 million cubic feet per day.

In November 2005, Entrega entered into a purchase and sale agreement with KMP. Under the terms of the agreement, it is expected that KMP will purchase Entrega and construct the second segment of the pipeline (from Wamsutter to the Cheyenne Hub), as well as a potential extension. It is anticipated that the Entrega Pipeline will become part of KMP's proposed Rockies Express Pipeline. The sale is expected to close in the first quarter of 2006.

RESERVES AND OTHER OIL AND GAS INFORMATION

EnCana retained independent qualified reserves evaluators to evaluate and prepare reports on 100 percent of EnCana's natural gas, crude oil and NGLs reserves as of December 31, 2005. EnCana's Canadian reserves were evaluated by McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd. EnCana's U.S. reserves were evaluated by Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton. EnCana's Ecuadorian reserves were evaluated by GLJ Petroleum Consultants Ltd. Since EnCana's inception in 2002, all of the Corporation's reserves have been independently evaluated on an annual basis.

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

Ecuador has been reported as discontinued operations for financial reporting purposes since December 31, 2004.

Reserve Quantities Information

EnCana's natural gas reserves increased approximately 13 percent in 2005 as a result of successful exploration and development drilling, which resulted in extensions and discoveries of 2,541 billion cubic feet. Included in the revisions and improved recovery category for changes in natural gas reserves were positive revisions in Canada and downward revisions in the U.S., resulting in total revisions of negative 58 billion cubic feet, or less than one percent of proved natural gas reserves at the beginning of 2005. CBM accounted for the majority of the 202 billion cubic feet of positive revisions in Canada. Downward revisions of 260 billion cubic feet in the U.S. occurred mainly in the southern Rockies where performance led to lower per well reserves. During 2004, the Corporation's natural gas reserves increased from exploration and development drilling and acquisitions.

EnCana's crude oil and NGLs reserves increased significantly in 2005, largely as a result of a 657 million barrel increase in bitumen reserves primarily at Foster Creek. Included in this increase is the reinstatement, due to prices at year-end 2005, of 363 million barrels that appeared as a downward revision in 2004 due to anomalously lower bitumen prices at year-end 2004. The Corporation's crude oil and NGLs reserves decreased in 2004 primarily as a result of the divestiture of non-core properties and the negative revision in Canadian bitumen reserves.

EnCana's reserves increased in 2003 primarily from exploration and development drilling, and to a lesser extent from acquisitions and upward revisions.

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 for 2005 and 2004 represent estimates derived from the reports of the independent qualified reserves evaluators referred to above. The end of year numbers for 2003 represent estimates derived from the reports of the independent qualified reserves evaluators who evaluated EnCana's reserves as of December 31, 2003.

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

	Natural Gas (billions of cubic feet)					Crude Oil and Natural Gas Liquids (millions of barrels)					
	Canada	United States	United Kingdom	Other	Total	Canada	United States	Ecuador	United Kingdom	Other	Total
2003											
Beginning of year	5,073	2,573	20	—	7,666	541.9	40.9	155.8	97.6	—	836.2
Revisions and improved recovery	73	1	3	—	77	32.3	0.5	0.4	23.5	—	56.7
Extensions and discoveries	867	706	—	90	1,663	110.9	7.4	11.9	—	0.9	131.1
Purchase of reserves in place	9	152	8	—	169	1.3	0.9	17.3	7.1	—	26.6
Sale of reserves in place	(60)	(88)	—	(90)	(238)	(0.2)	(4.7)	(5.1)	—	(0.9)	(10.9)
Production	(706)	(215)	(5)	—	(926)	(56.8)	(3.4)	(18.6)	(3.7)	—	(82.5)
End of year	5,256	3,129	26	—	8,411	629.4	41.6	161.7	124.5	—	957.2
Developed	3,984	1,833	13	—	5,830	306.1	26.3	115.0	16.7	—	464.1
Undeveloped	1,272	1,296	13	—	2,581	323.3	15.3	46.7	107.8	—	493.1
Total	5,256	3,129	26	—	8,411	629.4	41.6	161.7	124.5	—	957.2
2004											
Beginning of year	5,256	3,129	26	—	8,411	629.4	41.6	161.7	124.5	—	957.2
Revisions and improved recovery	67	(252)	—	—	(185)	31.1	0.2	(11.5)	—	—	19.8
Extensions and discoveries	1,422	1,009	—	—	2,431	93.6	47.6	21.2	—	—	162.4
Purchase of reserves in place	65	1,150	10	—	1,225	29.4	11.7	—	10.1	—	51.2
Sale of reserves in place	(215)	(82)	(25)	—	(322)	(97.3)	(5.4)	—	(128.4)	—	(231.1)
Production	(771)	(318)	(11)	—	(1,100)	(56.6)	(4.7)	(28.1)	(6.2)	—	(95.6)
End of year before bitumen revisions	5,824	4,636	—	—	10,460	629.6	91.0	143.3	—	—	863.9
Revisions due to bitumen price	—	—	—	—	—	(362.7)[3]	—	—	—	—	(362.7)
End of year	5,824	4,636	—	—	10,460	266.9	91.0	143.3	—	—	501.2
Developed	4,406	2,496	—	—	6,902	210.2	31.5	122.5	—	—	364.2
Undeveloped	1,418	2,140	—	—	3,558	56.7	59.5	20.8	—	—	137.0
Total	5,824	4,636	—	—	10,460	266.9	91.0	143.3	—	—	501.2
2005											
Beginning of year	5,824	4,636	—	—	10,460	266.9	91.0	143.3	—	—	501.2
Revisions and improved recovery	202	(260)	—	—	(58)	222.1	(3.2)	8.1	—	—	227.0
Extensions and discoveries	1,289	1,252	—	—	2,541	148.1	8.9	10.2	—	—	167.2
Purchase of reserves in place	7	76	—	—	83	—	0.4	—	—	—	0.4
Sale of reserves in place	(30)	(37)	—	—	(67)	(15.1)	(39.0)	—	—	—	(54.1)
Production	(775)	(400)	—	—	(1,175)	(52.2)	(5.0)	(26.6)	—	—	(83.8)
End of year before reinstatement of bitumen	6,517	5,267	—	—	11,784	569.8	53.1	135.0	—	—	757.9
Reinstatement of bitumen	—	—	—	—	—	362.7[4]	—	—	—	—	362.7
End of year	6,517	5,267	—	—	11,784	932.5[5]	53.1	135.0[6]	—	—	1,120.6
Developed	4,513	2,718	—	—	7,231	318.7	32.2	104.0	—	—	454.9
Undeveloped	2,004	2,549	—	—	4,553	613.8	20.9	31.0	—	—	665.7
Total	6,517	5,267	—	—	11,784	932.5	53.1	135.0	—	—	1,120.6

Notes:

(1) Definitions:

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

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

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

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

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

(3) Removal of the Corporation's Foster Creek proved bitumen reserves as a result of low bitumen prices on December 31, 2004. This included approximately 5.4 million barrels that were included under revisions and improved recovery and approximately 70.4 million barrels that were included under extensions and discoveries in 2004.

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

(5) Proved crude oil and NGLs reserves at December 31, 2005 include 657.4 million barrels of bitumen, the vast majority of which are located at Foster Creek. Changes to bitumen reserves during 2005 included revisions of 174.6 million barrels and extensions and discoveries of 134.0 million barrels.

(6) The Corporation expects to complete the disposition of its Ecuadorian operations in 2006. Accordingly, Ecuador is reported as discontinued operations for financial reporting purposes.

Other Disclosures About Oil and Gas Activities

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

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

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

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

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

	Canada			United States			Ecuador		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
				($ millions)					
Future cash inflows	71,786	37,791	35,126	40,504	27,063	17,472	5,350	3,317	3,533
Less future:									
Production costs	16,765	7,760	9,630	3,262	2,462	1,456	2,093	1,136	738
Development costs	6,164	3,157	3,024	4,174	3,213	1,336	429	198	211
Asset retirement obligation payments	2,269	1,749	1,364	264	193	97	24	22	38
Income taxes	13,170	6,279	5,874	11,041	7,021	4,960	662	342	536
Future net cash flows	33,418	18,846	15,234	21,763	14,174	9,623	2,142	1,619	2,010
Less 10% annual discount for estimated timing of cash flows	13,281	6,668	5,219	10,291	6,686	4,735	574	417	643
Discounted future net cash flows	20,137	12,178	10,015	11,472	7,488	4,888	1,568	1,202	1,367

	United Kingdom			Total		
	2005	2004	2003	2005	2004	2003
			($ millions)			
Future cash inflows	—	—	3,483	117,640	68,171	59,614
Less future:						
Production costs	—	—	961	22,120	11,358	12,785
Development costs	—	—	941	10,767	6,568	5,512
Asset retirement obligation payments	—	—	67	2,557	1,964	1,566
Income taxes	—	—	456	24,873	13,642	11,826
Future net cash flows	—	—	1,058	57,323	34,639	27,925
Less 10% annual discount for estimated timing of cash flows	—	—	493	24,146	13,771	11,090
Discounted future net cash flows	—	—	565	33,177	20,868	16,835

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

	Canada			United States			Ecuador		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
				($ millions)					
Balance, beginning of year	12,178	10,015	8,833	7,488	4,888	2,151	1,202	1,367	1,258
Changes resulting from:									
Sales of oil and gas produced during the period	(5,720)	(3,965)	(3,429)	(2,436)	(1,474)	(889)	(604)	(264)	(258)
Discoveries and extensions, net of related costs	4,278	3,562	1,272	3,582	2,436	1,381	159	236	126
Purchases of proved reserves in place	26	531	26	237	2,786	340	—	—	93
Sales of proved reserves in place	(279)	(1,579)	(95)	(486)	(271)	(108)	—	—	(54)
Net change in prices and production costs	11,624	2,264	242	4,716	143	2,751	967	(294)	(47)
Revisions to quantity estimates	1,071	546	416	(700)	(542)	4	88	(125)	4
Accretion of discount	1,629	1,349	1,636	1,103	725	304	147	176	182
Previously estimated development costs incurred net of change in future development costs	(888)	57	340	162	22	534	(148)	15	89
Other	63	32	470	(64)	(49)	157	8	(29)	(27)
Net change in income taxes	(3,845)	(634)	304	(2,130)	(1,176)	(1,737)	(251)	120	1
Balance, end of year	20,137	12,178	10,015	11,472	7,488	4,888	1,568	1,202	1,367

	United Kingdom			Total		
	2005	2004	2003	2005	2004	2003
			($ millions)			
Balance, beginning of year	—	565	411	20,868	16,835	12,653
Changes resulting from:						
Sales of oil and gas produced during the period	—	(78)	(83)	(8,760)	(5,781)	(4,659)
Discoveries and extensions, net of related costs	—	—	—	8,019	6,234	2,779
Purchases of proved reserves in place	—	77	57	263	3,394	516
Sales of proved reserves in place	—	(899)	—	(765)	(2,749)	(257)
Net change in prices and production costs	—	—	(119)	17,307	2,113	2,827
Revisions to quantity estimates	—	—	157	459	(121)	581
Accretion of discount	—	82	91	2,879	2,332	2,213
Previously estimated development costs incurred net of change in future development costs	—	—	108	(874)	94	1,071
Other	—	—	(38)	7	(46)	562
Net change in income taxes	—	253	(19)	(6,226)	(1,437)	(1,451)
Balance, end of year	—	—	565	33,177	20,868	16,835

Results of Operations, Capitalized Costs and Costs Incurred

Results of Operations

	Canada			United States			Ecuador[1]		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
					($ millions)				
Oil and gas revenues, net of royalties, transportation and selling costs	6,701	4,787	4,189	3,052	1,861	1,091	873	451	367
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	981	822	760	616	387	202	269	187	109
Depreciation, depletion and amortization	1,961	1,752	1,511	712	487	297	234	263	159
Operating income (loss)	3,759	2,213	1,918	1,724	987	592	370	1	99
Income taxes	1,274	841	218	638	375	219	134	5	17
Results of operations	2,485	1,372	1,700	1,086	612	373	236	(4)	82

	United Kingdom			Other			Total		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
					($ millions)				
Oil and gas revenues, net of royalties, transportation and selling costs	—	117	102	—	—	—	10,626	7,216	5,749
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	—	39	19	6	4	20	1,872	1,439	1,110
Depreciation, depletion and amortization	—	118	74	8	25	83	2,915	2,645	2,124
Operating income (loss)	—	(40)	9	(14)	(29)	(103)	5,839	3,132	2,515
Income taxes	—	(15)	17	—	—	(4)	2,046	1,206	467
Results of operations	—	(25)	(8)	(14)	(29)	(99)	3,793	1,926	2,048

Note:

(1) Ecuador is treated as discontinued operations for financial reporting purposes. The results of operations for 2005 includes a provision of $234 million which has been recorded against the net book value to recognize management's best estimate of the difference between the selling price and the December 31, 2005 underlying accounting value of the related investments.

Capitalized Costs

	Canada			United States			Ecuador		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
					($ millions)				
Proved oil and gas properties	27,074	22,455	18,549	7,753	7,552	3,485	1,926	1,784	1,372
Unproved oil and gas properties	1,998	1,855	1,981	870	728	501	18	45	70
Total capital cost	29,072	24,310	20,530	8,623	8,280	3,986	1,944	1,829	1,442
Accumulated DD&A	12,131	9,770	7,498	1,750	1,046	516	778	534	188
Net capitalized costs	16,941	14,540	13,032	6,873	7,234	3,470	1,166	1,295	1,254

	United Kingdom			Other			Total		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
					($ millions)				
Proved oil and gas properties	—	—	675	—	—	—	36,753	31,791	24,081
Unproved oil and gas properties	—	—	77	470	425	317	3,356	3,053	2,946
Total capital cost	—	—	752	470	425	317	40,109	34,844	27,027
Accumulated DD&A	—	—	230	222	247	206	14,881	11,597	8,638
Net capitalized costs	—	—	522	248	178	111	25,228	23,247	18,389

Costs Incurred

	Canada			United States			Ecuador		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
					($ millions)				
Acquisitions									
— Unproved reserves	—	42	47	271	954	21	—	—	80
— Proved reserves	30	204	207	141	2,051	115	—	—	59
Total acquisitions	30	246	254	412	3,005	136	—	—	139
Exploration costs	817	555	846	264	164	187	15	28	20
Development costs	3,333	2,669	2,131	1,724	1,103	651	164	213	111
Total costs incurred	4,180	3,470	3,231	2,400	4,272	974	179	241	270

	United Kingdom			Other			Total		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
					($ millions)				
Acquisitions									
— Unproved reserves	—	—	16	—	—	—	271	996	164
— Proved reserves	—	130	95	—	—	—	171	2,385	476
Total acquisitions	—	130	111	—	—	—	442	3,381	640
Exploration costs	—	22	30	70	79	78	1,166	848	1,161
Development costs	—	364	96	—	—	—	5,221	4,349	2,989
Total costs incurred	—	516	237	70	79	78	6,829	8,578	4,790

Sales Volumes, Royalty Rates and Per-Unit Results

Sales Volumes

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

	Sales Volumes — 2005				
	Year	Q4	Q3	Q2	Q1
SALES VOLUMES					
Continuing Operations:					
Produced Gas *(MMcf/d)*					
Canada					
Production	2,125	2,172	2,123	2,151	2,052
Inventory withdrawal/(injection)	7	—	—	—	27
Canada Sales	2,132	2,172	2,123	2,151	2,079
United States	1,095	1,154	1,099	1,061	1,067
Total Produced Gas	3,227	3,326	3,222	3,212	3,146
Oil and Natural Gas Liquids *(bbls/d)*					
North America					
Light and Medium Oil	47,328	45,792	43,313	50,020	50,280
Heavy Oil	83,090	88,386	81,089	82,274	80,546
Natural Gas Liquids(1)					
Canada	11,907	12,287	11,924	11,719	11,692
United States	13,675	12,824	14,131	13,095	14,666
Total Oil and Natural Gas Liquids	156,000	159,289	150,457	157,108	157,184
Total Continuing Operations *(MMcfe/d)*	4,163	4,282	4,125	4,155	4,089
Discontinued Operations:					
Ecuador					
Production(2)	72,916	70,480	71,896	73,662	75,695
(Under)/over lifting	(1,851)	(537)	(3,186)	(486)	(3,208)
Ecuador Sales *(bbls/d)*	71,065	69,943	68,710	73,176	72,487
Total Discontinued Operations *(MMcfe/d)*	426	419	412	439	435
Total *(MMcfe/d)*	4,589	4,701	4,537	4,594	4,524

Notes:

(1) Natural gas liquids include condensate volumes.

(2) Includes approximately 28,700 bbls/day related to Block 15. Information regarding the status of the participation contract for Block 15 can be found in Note 4 to EnCana's audited consolidated financial statements for the year ended December 31, 2005.

	Sales Volumes — 2004				
	Year	Q4	Q3	Q2	Q1
SALES VOLUMES					
Continuing Operations:					
Produced Gas ***(MMcf/d)***					
Canada					
Production	2,105	2,106	2,138	2,177	2,000
Inventory (injection)/withdrawal	(6)	(26)	—	—	—
Canada Sales[1]	2,099	2,080	2,138	2,177	2,000
United States	869	1,007	958	824	684
Total Produced Gas	2,968	3,087	3,096	3,001	2,684
Oil and Natural Gas Liquids ***(bbls/d)***					
North America					
Light and Medium Oil	56,215	52,725	52,824	64,448	54,940
Heavy Oil	84,164	79,336	89,682	79,899	87,729
Natural Gas Liquids[2]					
Canada	13,452	13,452	12,804	13,588	13,971
United States	12,586	13,957	14,363	12,752	9,237
Total Oil and Natural Gas Liquids[3]	166,417	159,470	169,673	170,687	165,877
Total Continuing Operations ***(MMcfe/d)***	3,966	4,044	4,114	4,025	3,679
Discontinued Operations:					
Ecuador					
Production[4]	76,872	76,235	76,567	78,376	76,320
Over/(under) lifting	1,121	1,641	(1,721)	(73)	4,662
Ecuador Sales *(bbls/d)*	77,993	77,876	74,846	78,303	80,982
United Kingdom *(BOE/d)*	20,973	13,927	20,222	26,728	22,755
Total Discontinued Operations ***(MMcfe/d)***	594	551	570	630	623
Total ***(MMcfe/d)***	4,560	4,595	4,684	4,655	4,302

Notes:

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

(2) Natural gas liquids include condensate volumes.

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

(4) Includes approximately 31,000 barrels per day related to Block 15.

	Sales Volumes — 2003				
	Year	Q4	Q3	Q2	Q1
SALES VOLUMES					
Continuing Operations:					
Produced Gas ***(MMcf/d)***					
Canada					
Production	1,935	2,008	1,914	1,899	1,922
Inventory withdrawal/(injection)	30	—	—	—	120
Canada Sales	1,965	2,008	1,914	1,899	2,042
United States	588	654	604	558	534
Total Produced Gas	2,553	2,662	2,518	2,457	2,576
Oil and Natural Gas Liquids ***(bbls/d)***					
North America					
Light and Medium Oil	54,459	56,585	54,597	52,733	53,890
Heavy Oil	87,867	95,059	94,985	82,001	79,171
Natural Gas Liquids[1]					
Canada	14,278	13,348	13,758	14,740	15,291
United States	9,291	9,479	9,530	10,194	7,943
Total Oil and Natural Gas Liquids	165,895	174,471	172,870	159,668	156,295
Total Continuing Operations ***(MMcfe/d)***	3,548	3,709	3,555	3,415	3,514
Discontinued Operations:					
Ecuador					
Production	51,089	72,731	54,582	36,754	39,893
Transferred to OCP Pipeline[2]	(3,213)	—	(4,919)	(2,039)	(5,941)
(Under)/over lifting	(1,355)	4,621	(9,856)	2,506	(2,679)
Ecuador Sales *(bbls/d)*	46,521	77,352	39,807	37,221	31,273
United Kingdom *(BOE/d)*	12,295	18,400	6,979	11,019	12,777
Syncrude *(bbls/d)*	7,629	—	3,399	7,316	20,070
Total Discontinued Operations ***(MMcfe/d)***	399	574	301	333	385
Total ***(MMcfe/d)***	3,947	4,283	3,856	3,748	3,899

Notes:

(1) Natural gas liquids include condensate volumes.

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

Average Royalty Rates

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

	2005					2004					2003				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
	(percent)					(percent)					(percent)				
Continuing Operations:															
Produced Gas															
Canada	11.7	11.9	11.8	11.0	11.9	12.5	12.0	12.2	12.7	13.3	12.9	12.2	12.9	14.2	12.4
United States	18.6	18.6	19.9	17.9	18.1	19.6	19.8	18.3	21.1	19.3	20.0	19.5	20.2	20.1	20.5
Crude Oil															
Canada and United States	8.8	8.8	8.7	9.2	8.7	9.0	8.7	8.8	11.6	9.4	10.3	9.7	9.0	10.7	11.8
Natural Gas Liquids															
Canada	14.9	14.4	15.8	15.6	13.8	15.7	16.5	18.5	13.1	14.8	17.5	14.7	16.6	18.0	20.2
United States	18.2	19.4	20.1	12.7	20.0	18.7	21.4	13.6	20.7	19.2	17.6	17.5	17.0	17.3	18.5
Total North America	13.3	13.5	13.8	12.6	13.3	13.7	13.8	13.2	14.1	13.7	13.8	13.2	13.4	14.5	13.9
Discontinued Operations:															
Crude Oil — Ecuador	27.2	29.4	26.3	26.3	26.9	27.1	27.8	26.5	26.5	27.4	25.6	25.4	25.7	24.9	26.9

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 — 2005				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Produced Gas — Canada ($/Mcf)					
Price	7.27	10.00	7.18	6.08	5.70
Production and mineral taxes	0.10	0.10	0.10	0.10	0.09
Transportation and selling	0.36	0.36	0.36	0.36	0.37
Operating	0.67	0.72	0.68	0.62	0.65
Netback	6.14	8.82	6.04	5.00	4.59
Produced Gas — United States ($/Mcf)					
Price	7.82	10.84	7.51	6.60	6.04
Production and mineral taxes	0.81	1.19	0.75	0.65	0.62
Transportation and selling	0.46	0.45	0.49	0.42	0.46
Operating	0.53	0.60	0.55	0.50	0.45
Netback	6.02	8.60	5.72	5.03	4.51
Produced Gas — Total North America ($/Mcf)					
Price	7.46	10.29	7.29	6.25	5.81
Production and mineral taxes	0.34	0.48	0.32	0.28	0.27
Transportation and selling	0.40	0.39	0.41	0.38	0.40
Operating	0.62	0.68	0.64	0.58	0.58
Netback	6.10	8.74	5.92	5.01	4.56

	Per-Unit Results — 2005				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids — Canada ($/bbl)					
Price	44.24	49.51	47.39	39.55	40.04
Production and mineral taxes	—	—	—	—	—
Transportation and selling	0.42	0.46	0.48	0.39	0.35
Netback	43.82	49.05	46.91	39.16	39.69
Natural Gas Liquids — United States ($/bbl)					
Price	48.36	54.14	53.92	44.79	40.93
Production and mineral taxes	4.86	5.42	5.46	4.37	4.20
Transportation and selling	0.01	0.01	0.01	0.01	0.01
Netback	43.49	48.71	48.45	40.41	36.72
Natural Gas Liquids — Total North America ($/bbl)					
Price	46.44	51.87	50.93	42.32	40.53
Production and mineral taxes	2.60	2.77	2.96	2.31	2.34
Transportation and selling	0.20	0.23	0.23	0.19	0.16
Netback	43.64	48.87	47.74	39.82	38.03
Crude Oil — Light and Medium — North America ($/bbl)					
Price	45.09	46.27	55.41	41.44	38.57
Production and mineral taxes	1.54	1.83	1.29	1.71	1.32
Transportation and selling	1.20	1.14	1.29	1.20	1.19
Operating	6.34	6.41	6.24	6.34	6.38
Netback	36.01	36.89	46.59	32.19	29.68
Crude Oil — Heavy — North America ($/bbl)					
Price	27.92	28.27	39.69	22.77	20.76
Production and mineral taxes	0.04	0.05	0.04	0.02	0.03
Transportation and selling	1.20	1.11	1.08	1.13	1.52
Operating	6.50	6.96	6.57	6.57	5.83
Netback	20.18	20.15	32.00	15.05	13.38
Crude Oil — Total North America ($/bbl)					
Price	34.15	34.41	45.16	29.83	27.60
Production and mineral taxes	0.58	0.66	0.48	0.66	0.53
Transportation and selling	1.20	1.12	1.15	1.15	1.39
Operating	6.44	6.77	6.45	6.48	6.04
Netback	25.93	25.86	37.08	21.54	19.64
Total Liquids — Canada ($/bbl)					
Price	34.97	35.65	45.35	30.58	28.60
Production and mineral taxes	0.53	0.60	0.43	0.61	0.48
Transportation and selling	1.14	1.07	1.09	1.09	1.31
Operating	5.89	6.19	5.83	5.96	5.55
Netback	27.41	27.79	38.00	22.92	21.26

	Per-Unit Results — 2005				
	Year	Q4	Q3	Q2	Q1
Total Liquids — Total North America ($/bbl)					
Price	36.17	37.16	46.16	31.80	29.77
Production and mineral taxes	0.91	0.99	0.91	0.92	0.83
Transportation and selling	1.04	0.98	0.99	1.00	1.18
Operating	5.38	5.70	5.33	5.46	5.03
Netback	28.84	29.49	38.93	24.42	22.73
Total North America ($/Mcfe)					
Price	7.13	9.37	7.38	6.03	5.62
Production and mineral taxes	0.30	0.41	0.29	0.25	0.24
Transportation and selling	0.35	0.34	0.35	0.33	0.36
Operating(1)	0.68	0.74	0.69	0.66	0.64
Netback	5.80	7.88	6.05	4.79	4.38
Discontinued Operations:					
Crude Oil — Ecuador ($/bbl)					
Price	39.36	37.82	47.76	36.37	35.80
Production and mineral taxes	5.04	4.63	7.66	4.53	3.42
Transportation and selling	2.25	1.86	2.45	2.48	2.21
Operating	5.32	5.82	6.05	5.18	4.26
Netback	26.75	25.51	31.60	24.18	25.91

Note:

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

	Per-Unit Results — 2004				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Produced Gas — Canada ($/Mcf)					
Price	5.34	5.86	5.10	5.20	5.21
Production and mineral taxes	0.08	0.10	0.09	0.07	0.08
Transportation and selling	0.39	0.39	0.37	0.35	0.44
Operating	0.52	0.55	0.50	0.49	0.56
Netback	4.35	4.82	4.14	4.29	4.13
Produced Gas — United States ($/Mcf)					
Price	5.79	6.53	5.36	5.72	5.39
Production and mineral taxes	0.65	0.69	0.57	0.80	0.51
Transportation and selling	0.31	0.27	0.26	0.34	0.39
Operating	0.37	0.41	0.36	0.37	0.33
Netback	4.46	5.16	4.17	4.21	4.16
Produced Gas — Total North America ($/Mcf)					
Price	5.47	6.08	5.18	5.34	5.26
Production and mineral taxes	0.25	0.29	0.24	0.27	0.19
Transportation and selling	0.36	0.35	0.33	0.35	0.43
Operating	0.48	0.50	0.46	0.46	0.50
Netback	4.38	4.94	4.15	4.26	4.14

	Per-Unit Results — 2004				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids — Canada ($/bbl)					
Price	31.43	36.73	33.46	28.48	27.27
Production and mineral taxes	—	—	—	—	—
Transportation and selling	0.41	0.47	0.45	0.35	0.35
Netback	31.02	36.26	33.01	28.13	26.92
Natural Gas Liquids — United States ($/bbl)					
Price	35.43	38.74	36.09	32.93	32.77
Production and mineral taxes	3.82	3.94	4.05	3.93	3.09
Transportation and selling	—	—	—	—	—
Netback	31.61	34.80	32.04	29.00	29.68
Natural Gas Liquids — Total North America ($/bbl)					
Price	33.36	37.75	34.85	30.63	29.46
Production and mineral taxes	1.84	2.00	2.14	1.90	1.23
Transportation and selling	0.21	0.23	0.21	0.18	0.21
Netback	31.31	35.52	32.50	28.55	28.02
Crude Oil — Light and Medium — North America ($/bbl)					
Price	34.67	39.57	37.40	32.43	29.92
Production and mineral taxes	0.96	1.38	0.85	0.79	0.86
Transportation and selling	1.01	1.04	1.08	0.76	1.19
Operating	5.85	6.41	6.49	4.84	5.87
Netback	26.85	30.74	28.98	26.04	22.00
Crude Oil — Heavy — North America ($/bbl)					
Price	23.41	21.37	28.01	22.35	21.48
Production and mineral taxes	0.04	0.04	0.05	(0.01)	0.06
Transportation and selling	1.09	(0.57)	1.63	1.50	1.69
Operating	5.32	6.27	4.79	4.82	5.44
Netback	16.96	15.63	21.54	16.04	14.29
Crude Oil — Total North America ($/bbl)					
Price	27.92	28.63	31.49	26.85	24.73
Production and mineral taxes	0.41	0.57	0.34	0.35	0.37
Transportation and selling	1.06	0.07	1.42	1.17	1.50
Operating	5.53	6.33	5.42	4.83	5.61
Netback	20.92	21.66	24.31	20.50	17.25
Total Liquids — Canada ($/bbl)					
Price	28.21	29.36	31.63	26.99	24.95
Production and mineral taxes	0.37	0.52	0.31	0.32	0.34
Transportation and selling	1.00	0.11	1.35	1.10	1.40
Operating	5.05	5.75	4.98	4.42	5.11
Netback	21.79	22.98	24.99	21.15	18.10
Total Liquids — Total North America ($/bbl)					
Price	28.77	30.20	32.03	27.43	25.39
Production and mineral taxes	0.63	0.82	0.63	0.59	0.49
Transportation and selling	0.93	0.10	1.23	1.02	1.32
Operating	4.67	5.24	4.55	4.09	4.82
Netback	22.54	24.04	25.62	21.73	18.76

	Per-Unit Results — 2004				
	Year	Q4	Q3	Q2	Q1
Total North America ($/Mcfe)					
Price	5.30	5.83	5.22	5.15	4.98
Production and mineral taxes	0.21	0.25	0.21	0.22	0.16
Transportation and selling	0.31	0.27	0.30	0.30	0.37
Operating(1)	0.55	0.59	0.53	0.52	0.58
Netback	4.23	4.72	4.18	4.11	3.87
Discontinued Operations:					
Crude Oil — Ecuador ($/bbl)					
Price	28.68	29.97	33.47	27.78	23.82
Production and mineral taxes	2.13	2.73	2.62	1.84	1.37
Transportation and selling	2.12	1.57	2.36	1.92	2.63
Operating	4.39	5.02	4.35	4.14	4.04
Netback	20.04	20.65	24.14	19.88	15.78
Crude Oil — United Kingdom ($/bbl)					
Price	36.92	46.19	40.88	34.68	31.11
Production and mineral taxes	—	—	—	—	—
Transportation and selling	2.06	2.17	2.44	1.85	1.94
Operating	6.75	5.00	9.98	7.84	3.86
Netback	28.11	39.02	28.46	24.99	25.31

Note:

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

	Per-Unit Results — 2003				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Produced Gas — Canada ($/Mcf)					
Price	4.87	4.41	4.61	4.92	5.53
Production and mineral taxes	0.07	0.10	0.08	0.08	0.02
Transportation and selling	0.38	0.44	0.40	0.35	0.33
Operating	0.48	0.45	0.50	0.47	0.48
Netback	3.94	3.42	3.63	4.02	4.70
Produced Gas — United States ($/Mcf)					
Price	4.88	4.71	4.82	4.74	5.32
Production and mineral taxes	0.47	0.42	0.46	0.46	0.57
Transportation and selling	0.40	0.51	0.39	0.36	0.32
Operating	0.28	0.29	0.33	0.31	0.20
Netback	3.73	3.49	3.64	3.61	4.23
Produced Gas — Total North America ($/Mcf)					
Price	4.87	4.49	4.66	4.88	5.49
Production and mineral taxes	0.16	0.18	0.17	0.17	0.14
Transportation and selling	0.39	0.46	0.40	0.35	0.33
Operating	0.43	0.41	0.46	0.43	0.42
Netback	3.89	3.44	3.63	3.93	4.60

	Per-Unit Results — 2003				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids — Canada ($/bbl)					
Price	24.26	25.13	23.52	21.02	27.31
Production and mineral taxes	—	—	—	—	—
Transportation and selling	0.17	0.13	0.58	—	—
Netback	24.09	25.00	22.94	21.02	27.31
Natural Gas Liquids — United States ($/bbl)					
Price	26.97	26.68	25.50	24.64	32.18
Production and mineral taxes	2.03	2.69	2.64	1.21	1.55
Transportation and selling	—	—	—	—	—
Netback	24.94	23.99	22.86	23.43	30.63
Natural Gas Liquids — Total North America ($/bbl)					
Price	25.33	25.77	24.33	22.50	28.98
Production and mineral taxes	0.80	1.12	1.08	0.50	0.53
Transportation and selling	0.10	0.08	0.35	—	—
Netback	24.43	24.57	22.90	22.00	28.45
Crude Oil — Light and Medium — North America ($/bbl)					
Price	26.61	25.53	24.31	27.43	29.34
Production and mineral taxes	0.29	0.73	(1.35)	0.71	1.08
Transportation and selling	1.42	1.33	0.71	1.73	1.95
Operating	6.00	6.28	5.93	6.07	5.68
Netback	18.90	17.19	19.02	18.92	20.63
Crude Oil — Heavy — North America ($/bbl)					
Price	19.61	18.43	17.93	20.07	22.62
Production and mineral taxes	(0.03)	0.09	(0.49)	0.34	(0.02)
Transportation and selling	1.24	1.54	0.58	1.37	1.56
Operating	5.67	4.95	5.93	6.18	5.70
Netback	12.73	11.85	11.91	12.18	15.38
Crude Oil — Total North America ($/bbl)					
Price	22.29	21.08	20.26	22.95	25.34
Production and mineral taxes	0.09	0.33	(0.80)	0.49	0.43
Transportation and selling	1.31	1.46	0.63	1.51	1.72
Operating	5.80	5.45	5.93	6.13	5.70
Netback	15.09	13.84	14.50	14.82	17.49
Total Liquids — Canada ($/bbl)					
Price	22.47	21.41	20.54	22.76	25.55
Production and mineral taxes	0.08	0.30	(0.73)	0.44	0.38
Transportation and selling	1.21	1.36	0.62	1.36	1.54
Operating	5.27	5.01	5.43	5.53	5.11
Netback	15.91	14.74	15.22	15.43	18.52
Total Liquids — Total North America ($/bbl)					
Price	22.72	21.69	20.81	22.88	25.88
Production and mineral taxes	0.19	0.43	(0.55)	0.49	0.44
Transportation and selling	1.14	1.28	0.59	1.28	1.46
Operating	4.97	4.74	5.13	5.18	4.85
Netback	16.42	15.24	15.64	15.93	19.13

	Per-Unit Results — 2003				
	Year	Q4	Q3	Q2	Q1
Total North America ($/Mcfe)					
Price	4.57	4.24	4.31	4.58	5.17
Production and mineral taxes	0.13	0.15	0.10	0.14	0.12
Transportation and selling	0.33	0.39	0.31	0.31	0.31
Operating	0.54	0.52	0.58	0.55	0.53
Netback	3.57	3.18	3.32	3.58	4.21
Discontinued Operations:					
Crude Oil — Ecuador ($/bbl)					
Price	24.21	23.57	22.13	22.31	30.86
Production and mineral taxes	1.47	1.06	0.45	1.11	4.27
Transportation and selling	2.56	2.81	2.36	2.41	2.35
Operating	4.84	4.62	4.33	5.63	5.09
Netback	15.34	15.08	14.99	13.16	19.15
Crude Oil — United Kingdom ($/bbl)					
Price	28.11	27.05	27.92	27.17	30.61
Production and mineral taxes	—	—	—	—	—
Transportation and selling	1.97	1.70	1.98	1.86	2.45
Operating	5.09	6.23	6.55	4.69	2.92
Netback	21.05	19.12	19.39	20.62	25.24

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

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

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

	2003				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Natural Gas ($/Mcf)	(0.10)	0.16	(0.06)	(0.25)	(0.25)
Liquids ($/bbl)	(3.41)	(3.29)	(2.76)	(2.08)	(5.64)
Total ($/Mcfe)	(0.23)	(0.04)	(0.18)	(0.28)	(0.44)
Discontinued Operations:					
Ecuador Oil ($/bbl)	—	—	—	—	—
United Kingdom Oil ($/bbl)	—	—	—	—	—

Note:

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

Drilling Activity

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

Exploration Wells Drilled

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
Continuing Operations:											
2005:											
Canada	605	540	8	8	7	7	620	555	99	719	555
United States	7	6	—	—	9	7	16	13	1	17	13
Other	—	—	3	1	3	2	6	3	—	6	3
Total	612	546	11	9	19	16	642	571	100	742	571
2004:											
Canada	566	534	48	47	9	6	623	587	51	674	587
United States	19	16	2	—	—	—	21	16	—	21	16
Other	—	—	3	2	5	2	8	4	—	8	4
Total	585	550	53	49	14	8	652	607	51	703	607
2003:											
Canada	532	511	51	31	35	28	618	570	153	771	570
United States	40	35	7	2	4	2	51	39	—	51	39
Other	1	—	—	—	3	1	4	1	—	4	1
Total	573	546	58	33	42	31	673	610	153	826	610
Discontinued Operations:											
Ecuador — 2005	—	—	2	1	3	2	5	3	—	5	3
Ecuador — 2004	—	—	6	3	—	—	6	3	—	6	3
Ecuador — 2003	—	—	3	2	—	—	3	2	—	3	2
United Kingdom — 2004	—	—	1	—	4	2	5	2	—	5	2
United Kingdom — 2003	—	—	2	1	5	3	7	4	—	7	4

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:											
2005:											
Canada	3,503	3,229	277	243	12	11	3,792	3,483	932	4,724	3,483
United States	699	604	—	—	—	—	699	604	9	708	604
Total	4,202	3,833	277	243	12	11	4,491	4,087	941	5,432	4,087
2004:											
Canada	3,632	3,419	386	364	16	15	4,034	3,798	1,105	5,139	3,798
United States	600	515	1	—	3	3	604	518	—	604	518
Total	4,232	3,934	387	364	19	18	4,638	4,316	1,105	5,743	4,316
2003:											
Canada	3,964	3,901	756	650	24	18	4,744	4,569	1,347	6,091	4,569
United States	426	401	—	—	1	1	427	402	—	427	402
Total	4,390	4,302	756	650	25	19	5,171	4,971	1,347	6,518	4,971
Discontinued Operations:											
Ecuador — 2005	—	—	28	15	3	1	31	16	—	31	16
Ecuador — 2004	—	—	43	25	1	1	44	26	—	44	26
Ecuador — 2003	—	—	53	39	6	6	59	45	—	59	45
United Kingdom — 2004	—	—	3	1	—	—	3	1	—	3	1
United Kingdom — 2003	—	—	3	—	—	—	3	—	—	3	—

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, 2005, EnCana was in the process of drilling 50 gross wells (45 net wells) in Canada, 95 gross wells (89 net wells) in the United States, zero wells in Ecuador and one well in another country.

Location of Wells

The following table summarizes EnCana's interest in producing wells and wells capable of producing as at December 31, 2005:

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Continuing Operations:						
Alberta	32,943	31,054	4,056	3,671	36,999	34,725
British Columbia	1,664	1,513	17	12	1,681	1,525
Saskatchewan	456	442	1,200	520	1,656	962
Manitoba	—	—	1	1	1	1
Total Canada	35,063	33,009	5,274	4,204	40,337	37,213
Colorado	4,493	3,535	6	3	4,499	3,538
Texas	1,931	1,283	40	15	1,971	1,298
Wyoming	1,372	1,093	1	1	1,373	1,094
Utah	64	60	2	1	66	61
Oklahoma	95	22	—	—	95	22
Louisiana	3	2	—	—	3	2
Total United States	7,958	5,995	49	20	8,007	6,015
Total	43,021	39,004	5,323	4,224	48,344	43,228
Discontinued Operations:						
Ecuador	—	—	286	200	286	200

Notes:

(1) EnCana has varying royalty interests in 13,847 natural gas wells and 8,779 crude oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: 31,405 gross natural gas wells (28,524 net wells) and 696 gross crude oil wells (548 net wells).

Interest in Material Properties

The following table summarizes EnCana's developed, undeveloped and total landholdings as at December 31, 2005:

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
		(thousands of acres)					
Continuing Operations:							
Canada							
Alberta	— Fee	4,424	4,424	2,706	2,706	7,130	7,130
	— Crown	3,842	3,020	5,798	4,818	9,640	7,838
	— Freehold	223	130	262	220	485	350
		8,489	7,574	8,766	7,744	17,255	15,318
British Columbia	— Crown	875	749	4,495	3,961	5,370	4,710
	— Freehold	—	—	7	7	7	7
		875	749	4,502	3,968	5,377	4,717
Saskatchewan	— Fee	58	58	457	457	515	515
	— Crown	158	146	571	557	729	703
	— Freehold	14	10	62	60	76	70
		230	214	1,090	1,074	1,320	1,288
Manitoba	— Fee	3	3	263	263	266	266
	— Freehold	—	—	7	7	7	7
		3	3	270	270	273	273
Newfoundland & Labrador	— Crown	—	—	2,549	1,707	2,549	1,707
Nova Scotia	— Crown	—	—	1,353	683	1,353	683
Northwest Territories	— Crown	—	—	178	62	178	62
Nunavut	— Crown	—	—	817	26	817	26
Beaufort	— Crown	—	—	126	4	126	4
Total Canada		9,597	8,540	19,651	15,538	29,248	24,078

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
				(thousands of acres)			
United States							
Colorado	— Federal/State Lands	188	174	841	774	1,029	948
	— Freehold	101	95	174	160	275	255
	— Fee	3	3	47	47	50	50
		292	272	1,062	981	1,354	1,253
Washington	— Federal/State Lands	—	—	668	657	668	657
	— Freehold	—	—	180	180	180	180
		—	—	848	837	848	837
Texas	— Federal/State Lands	9	3	446	446	455	449
	— Freehold	330	142	1,090	925	1,420	1,067
	— Fee	—	—	1	1	1	1
		339	145	1,537	1,372	1,876	1,517
Wyoming	— Federal/State Lands	142	82	696	501	838	583
	— Freehold	25	18	67	40	92	58
		167	100	763	541	930	641
Other	— Federal/State Lands	12	9	352	211	364	220
	— Freehold	10	5	77	76	87	81
		22	14	429	287	451	301
Total United States		820	531	4,639	4,018	5,459	4,549
Chad		—	—	54,103	27,052	54,103	27,052
Oman		—	—	9,606	4,803	9,606	4,803
Qatar		—	—	2,161	2,161	2,161	2,161
Greenland		—	—	1,701	1,488	1,701	1,488
Brazil		—	—	1,416	535	1,416	535
Australia		—	—	1,053	357	1,053	357
Azerbaijan		—	—	346	17	346	17
Total International		—	—	70,386	36,413	70,386	36,413
Total		10,417	9,071	94,676	55,969	105,093	65,040
Discontinued Operations:							
Ecuador		169	107	1,230	785	1,399	892

Notes:

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

(2) Fee lands are those lands in which EnCana has a fee simple interest in the minerals rights and has either: (i) not leased out all of the mineral zones; or (ii) retained a working interest. Prior to 2004, fee lands in which any zones were leased out were excluded as fee lands except with respect to lands in which EnCana 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.

Acquisitions, Dispositions 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 acquisition opportunities to develop and expand its business. The acquisition opportunities may include significant corporate or asset acquisitions, and EnCana may finance any such acquisitions with debt, equity, cash generated from operations, proceeds from asset dispositions or a combination of these sources.

The following table summarizes EnCana's net capital investment for 2004 and 2005.

	2005	2004
	($ millions)	
Upstream		
Canada	4,150	3,015
United States	1,982	1,249
Other Countries	70	79
	6,202	4,343
Midstream & Marketing	197	10
Corporate	78	46
Core Capital from Continuing Operations	6,477	4,399
Upstream		
Acquisitions		
Property		
Canada	30	64
United States	418	300
Corporate		
Petrovera	—	253
Tom Brown, Inc.(1)	—	2,335
Dispositions		
Property		
Canada	(447)	(877)
United States	(2,074)	(266)
Corporate		
Petrovera	—	(540)
Midstream & Marketing		
Property	—	(1)
Corporate		
Kingston CoGen	—	(25)
Corporate	(2)	—
Net Acquisition and Disposition Activity from Continuing Operations	(2,075)	1,243
Discontinued Operations		
Ecuador	179	240
United Kingdom	—	(1,656)
Midstream	(484)	(20)
Net Capital Investment	4,097	4,206

Note:

(1) Net cash consideration excluding debt acquired of $406 million.

EnCana plans to dispose of various non-core assets in 2006, including its interests in Ecuador, the Chinook discovery in Brazil, its gas storage business, the Entrega Pipeline and any other assets deemed to be non-core to the Corporation.

Delivery Commitments

As part of ordinary business operations, EnCana has a number of delivery commitments to provide crude oil and natural gas under existing contracts and agreements. The Corporation has sufficient reserves of natural gas and crude oil to meet these commitments. More detailed information relating to such commitments can be found in Note 18 to EnCana's audited consolidated financial statements for the year ended December 31, 2005.

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) reserve and property acquisitions; (iii) transportation and marketing of oil, natural gas and NGLs; (iv) access to services and equipment to carry out exploration, development or operating activities; and (v) attracting and retaining experienced industry personnel. The oil and gas industry also competes with other industries focused on providing alternative forms of energy to consumers. Competitive forces can lead to cost increases or result in an oversupply of oil and natural gas, both of which could have a negative impact on EnCana's financial results.

Environmental Protection

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

EnCana expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2005, expenditures beyond normal compliance with environmental regulations were not material. EnCana does not anticipate making material expenditures beyond normal compliance with environmental regulations in 2006. 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 $4.9 billion.

Social and Environmental Policies

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

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

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

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

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

Some of the steps that EnCana has taken to embed the corporate responsibility approach throughout the organization include: (i) a comprehensive approach to training and communicating policies and practices; (ii) an EH&S management system; (iii) a security program to regularly assess security threats to business operations and manage the associated risks; (iv) a formalized approach to stakeholder relations with a standardized Stakeholder Engagement Guide; (v) corporate responsibility performance metrics to track the Corporation's progress; (vi) contribution of a minimum of one percent of EnCana's pre-tax domestic profits to charitable and non-profit organizations in the communities in which EnCana operates; (vii) an Investigations Practice and an Investigations Committee to review and resolve potential violations of EnCana policies or practices and other regulations; (viii) an Integrity Hotline that provides an additional avenue for EnCana's stakeholders to raise their concerns; (ix) an internal corporate EH&S audit program that evaluates EnCana's compliance with the expectations and requirements of the EH&S management system; and (x) related policies and practices such as an Alcohol and Drug Policy and Business Conduct and Ethics Practice. In addition, EnCana's Board of Directors approves such policies, 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, 2005, EnCana employed 4,547 full time equivalent ("FTE") employees as set forth in the following table:

	FTE Employees
Upstream	3,618
Midstream & Marketing	273
Corporate	656
Total	4,547

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

Foreign Operations

As at December 31, 2005, approximately 96 percent of EnCana's reserves and 91 percent of its production were located in North America, which limits EnCana's exposure to risks and uncertainties in countries considered politically and economically unstable. EnCana's operations and related assets outside North America may be adversely affected by changes in governmental policy, social instability or other political or economic developments which are not within the control of EnCana, including the expropriation of property, the cancellation or modification of contract rights and restrictions on repatriation of cash. The Corporation has undertaken to mitigate these risks where practical and considered warranted.

Reorganizations

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

As a general matter, EnCana reorganizes its subsidiaries as required to maintain proper alignment of its businesses and facilitate acquisitions and dispositions. On January 1, 2005 EnCana completed a reorganization of its U.S. subsidiaries. The U.S. corporate structure had grown significantly due to corporate acquisitions, and a number of entities were merged in order to rationalize the structure and help reduce administrative burdens. In October 2005, EnCana completed a restructuring to facilitate the sale of its NGLs business and the planned sale of its gas storage business. In addition, in December 2005 the Corporation initiated a restructuring of various Canadian subsidiaries in order to eliminate corporate entities that had become unnecessary. EnCana expects to complete this restructuring in February 2006.

DIRECTORS AND OFFICERS

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

Directors

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

Name and Municipality of Residence	Director Since[12]	Principal Occupation
BARRY W. HARRISON[1,4,9] Calgary, Alberta, Canada	1996	Corporate Director and independent businessman
DALE A. LUCAS[1,5] Calgary, Alberta, Canada	1997	Corporate Director
KEN F. MCCREADY[2,5,10] Calgary, Alberta, Canada	1992	President K.F. McCready & Associates Ltd. *(Sustainable energy development consulting company)*
GWYN MORGAN Calgary, Alberta, Canada	1993	Executive Vice-Chairman EnCana Corporation
VALERIE A. A. NIELSEN[2,6] Calgary, Alberta, Canada	1990	Corporate Director
DAVID P. O'BRIEN[4,7,11] Calgary, Alberta, Canada	1990	Chairman EnCana Corporation Chairman Royal Bank of Canada
JANE L. PEVERETT[1] West Vancouver, British Columbia, Canada	2003	President & Chief Executive Officer British Columbia Transmission Corporation *(Electrical transmission)*
DENNIS A. SHARP[2,4] Calgary, Alberta, Canada & Montreal, Quebec, Canada	1998	Executive Chairman UTS Energy Corporation *(Oilsands company)*
JAMES M. STANFORD, O.C.[1,3,6] Calgary, Alberta, Canada	2001	President Stanford Resource Management Inc. *(Investment management)*

Notes:

(1) Audit Committee.

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

(3) Human Resources and Compensation Committee.

(4) Nominating and Corporate Governance Committee.

(5) Pension Committee.

(6) Reserves Committee.

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

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

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

(10) Mr. McCready was a director of Colonia Corporation when the company was placed into receivership in October 2000. The company came out of receivership in October 2001. Mr. McCready was a director, Chairman and Chief Executive Officer of Etho Power Corporation, a small private company, when it was assigned into bankruptcy on April 7, 2003.

(11) Mr. O'Brien resigned as a director of Air Canada on November 26, 2003. On April 1, 2003, Air Canada obtained an order from the Ontario Superior Court of Justice providing creditor protection under the *Companies' Creditors Arrangement Act* (Canada). Air Canada also made a concurrent petition under Section 304 of the U.S. Bankruptcy Code. On September 30, 2004, Air Canada announced that it had successfully completed its restructuring process and implemented its Plan of Arrangement.

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

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

At the date of this annual information form, there are 15 directors of the Corporation. At the next Annual Meeting of Shareholders, shareholders will be asked to elect as directors the 15 nominees listed in the above table to serve until the close of the next annual meeting of shareholders, or until their respective successors are duly elected or appointed. Subject to mandatory retirement age restrictions which have been established by the Board of Directors, all of the directors shall be eligible for re-election.

Executive Officers

Name and Municipality of Residence	Office
DAVID P. O'BRIEN Calgary, Alberta, Canada	Chairman
GWYN MORGAN(1) Calgary, Alberta, Canada	Executive Vice-Chairman
RANDALL K. ERESMAN(1) Calgary, Alberta, Canada	President & Chief Executive Officer
ROGER J. BIEMANS(2) Denver, Colorado, United States	Executive Vice-President
BRIAN C. FERGUSON(3) Calgary, Alberta, Canada	Executive Vice-President, Corporate Development
MICHAEL M. GRAHAM Calgary, Alberta, Canada	Executive Vice-President
R. WILLIAM OLIVER Calgary, Alberta, Canada	Executive Vice-President
GERARD J. PROTTI Calgary, Alberta, Canada	Executive Vice-President, Corporate Relations
HAYWARD J. WALLS(4) Calgary, Alberta, Canada	Executive Vice-President, Corporate Services & Chief Information Officer
JOHN D. WATSON(3) Calgary, Alberta, Canada	Executive Vice-President & Chief Financial Officer
JEFF E. WOJAHN(2) Calgary, Alberta, Canada	Executive Vice-President

Notes:

(1) Gwyn Morgan stepped down as President & Chief Executive Officer effective December 31, 2005. He has agreed to remain an officer of the Corporation in the role of Executive Vice-Chairman for the year 2006. Effective January 1, 2006, Randy Eresman became President & Chief Executive Officer and a Director of the Corporation.

(2) Effective March 1, 2006, Roger Biemans (currently Executive Vice-President and President, USA Region) and Jeff Wojahn (currently Executive Vice-President and President, Canadian Plains Region) will switch positions.

(3) Effective March 1, 2006, Brian Ferguson will succeed John Watson as Executive Vice-President & Chief Financial Officer. Also effective March 1, 2006, Don Swystun (currently President, Ecuador Region) will be appointed Executive Vice-President, Corporate Development.

(4) Successor of Drude Rimell who stepped down as Executive Vice-President, Corporate Services effective December 31, 2005.

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

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

Mr. Grandin served as Dean of the Haskayne School of Business, University of Calgary from April 2004 to January 2006. He was President of PanCanadian Energy Corporation from October 2001 to April 2002. He was Executive Vice-President and Chief Financial Officer of Canadian Pacific Limited from December 1997 to October 2001.

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

Ms. Peverett was Vice President, Corporate Services and Chief Financial Officer of British Columbia Transmission Corporation (BCTC) from June 2003 to April 2005 when she was appointed President and Chief Executive Officer of BCTC. She was President of Union Gas Limited from April 2002 to May 2003, President and Chief Executive Officer from April 2001 to April 2002 and Senior Vice President Sales & Marketing from June 2000 to April 2001.

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

All of the directors and executive officers of EnCana listed above beneficially owned, as of February 14, 2006, directly or indirectly, or exercised control or direction over an aggregate of 2,428,657 Common Shares representing 0.29 percent of the issued and outstanding voting shares of EnCana, and directors and executive officers held options to acquire an aggregate of 3,160,500 additional Common Shares.

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

AUDIT COMMITTEE INFORMATION

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

Composition of the Audit Committee

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

Patrick D. Daniel

Mr. Daniel holds a Bachelor of Science (University of Alberta) and a Masters of Science (University of British Columbia), both in chemical engineering. He also completed the Harvard Advanced Management Program. He is President and Chief Executive Officer and a director of Enbridge Inc. (energy delivery company). He is a director of a number of Enbridge subsidiaries and a director of the general partner of Enbridge Energy Partners, L.P. and Enbridge Energy Management, L.L.C. He is also a director and member of the Audit Committee of Enerflex Systems Ltd. (compression systems manufacturer), a director of Synenco Energy Inc. (oilsands mining), and a Trustee of Enbridge Commercial Trust, a subsidiary entity of Enbridge Income Fund.

Barry W. Harrison (Audit Committee Chair)

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

Dale A. Lucas

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

Jane L. Peverett

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

James M. Stanford, O.C.

Mr. Stanford holds a Doctor of Laws (Hon.) and a Bachelor of Science in Petroleum Engineering (University of Alberta), and a Doctor of Laws (Hon.) and a Bachelor of Science in Mining (Concordia University). He is President of Stanford Resource Management Inc. (investment management) and is a director of a number of publicly traded companies: Kinder Morgan, Inc. (North American midstream energy company), 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 President and Chief Executive Officer of Petro-Canada (oil and gas company) for seven years and was Chief Operating Officer and President for three years.

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 2005 and 2004:

($ thousands)	2005	2004
Audit Fees(1)	3,726	3,177
Audit-Related Fees(2)	894	166
Tax Fees(3)	1,021	1,097
All Other Fees(4)	26	24
Total	5,667	4,464

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 2005 and 2004, the services provided in this category included due diligence reviews in connection with acquisitions and dispositions, research of accounting and audit-related issues, review of reserves disclosure and the completion of audits required by contracts to which the Corporation is a party.

(3) Tax fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal 2005 and 2004, 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 2005 and 2004, 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 2004 or 2005.

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, 2005 there were approximately 859 million Common Shares outstanding and no Preferred Shares outstanding.

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

Common Shares

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

EnCana has stock-based compensation plans that allow employees to purchase Common Shares of the Corporation. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the plan are generally fully exercisable after three years and expire five years after the grant date. Options granted under predecessor and/or related company replacement plans expire up to 10 years from the date the options were granted.

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

Preferred Shares

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

CREDIT RATINGS

The following table outlines the ratings of the Corporation's debt as of December 31, 2005.

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

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

Moody's long-term credit ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. A rating of Baa2 by Moody's is 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 ratings are on a scale ranging from P-1 (highest quality) to NP (lowest quality). P-2 is the second highest of four categories and indicates that the issuer has a strong ability to repay short-term debt obligations.

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

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

MARKET FOR SECURITIES

All of the outstanding Common Shares of EnCana are listed and posted for trading on the Toronto Stock Exchange (“TSX”) and the New York Stock Exchange (“NYSE”) under the symbol ECA. The following table outlines the share price trading range and volume of shares traded by month in 2005.

	Toronto Stock Exchange Share Price Trading Range				New York Stock Exchange Share Price Trading Range			
	High	**Low**	**Close**	**Share Volume**	**High**	**Low**	**Close**	**Share Volume**
	(C$ per share)			(millions)	($ per share)			(millions)
2005								
January	37.43	32.55	36.68	71.9	30.27	26.45	29.55	38.3
February	42.50	36.48	40.91	63.5	34.62	29.37	33.45	41.5
March	44.28	39.68	42.72	79.8	36.45	32.72	35.21	55.7
April	45.25	39.05	40.27	69.5	37.11	31.31	31.93	54.6
May	44.74	40.00	43.50	52.2	35.50	31.53	34.67	42.2
June	51.27	43.48	48.33	61.1	41.56	34.84	39.59	47.6
July	53.65	47.72	50.47	49.3	43.96	39.26	41.35	43.8
August	58.94	49.56	58.21	75.7	49.77	40.55	49.19	66.1
September	68.70	56.75	67.85	78.0	58.49	47.78	58.31	76.0
October	69.64	51.90	54.00	116.1	59.82	44.50	45.86	149.0
November	57.70	50.04	51.77	73.3	48.80	42.00	44.32	76.4
December	59.95	51.45	52.56	66.9	52.04	43.85	45.16	71.1

Note:

(1) EnCana’s common shares began trading on a post-split basis (two-for-one) on May 10, 2005. All data from January 1, 2005 to May 10, 2005 has been adjusted to reflect the share split.

In February 2005, EnCana received approval from the TSX to amend its normal course issuer bid program. Under the amended Bid, EnCana was entitled to purchase up to 92.2 million Common Shares on a post-split basis (10 percent of the public float on October 22, 2004), over a period ending October 28, 2005. Purchases may be made through the facilities of the TSX and the NYSE, in accordance with the policies and rules of each exchange. During 2005, EnCana purchased approximately 55 million shares under the terms of the Bid for approximately $1.9 billion.

In October 2005, EnCana received approval from the TSX to renew the Bid. Under the renewed Bid, EnCana is entitled to purchase up to 85.6 million Common Shares (10 percent of the public float on October 25, 2005) over a period ending October 30, 2006. As of December 31, 2005, the Corporation had not purchased any shares under the renewed Bid. During January 2006, EnCana purchased approximately 6.8 million shares for approximately $314 million.

EnCana issued one series of debt securities in 2005 that are not listed or quoted on an exchange. On September 21, 2005, the Corporation completed the offering of C$500 million of senior unsecured medium term notes at a price of 99.967 percent. The notes have a coupon rate of 3.60% and mature on September 15, 2008.

During 2005, the Corporation completed the redemption of nine issues of Canadian medium term notes: EnCana’s 5.95% notes due October 1, 2007, 5.95% notes due June 2, 2008, 5.80% notes due June 19, 2008, 6.10% notes due June 1, 2009, 7.15% notes due December 17, 2009, 8.50% notes due March 15, 2011, 7.10% notes due October 11, 2011, 7.30% notes due September 2, 2014 and 5.50%/6.20% notes due June 23, 2028. The aggregate principal amount of the notes was C$1.15 billion. The notes were redeemed at a total cost of C$1.3 billion.

DIVIDENDS

The declaration of dividends is at the discretion of the Board of Directors and is approved quarterly. In 2003, cash dividends were paid to common shareholders at a rate of C$0.20 per share annually (C$0.05 per share quarterly). In 2004, EnCana began paying cash dividends to common shareholders in United States dollars at a rate of $0.20 per share annually ($0.05 per share quarterly). In the second quarter of 2005, EnCana increased its dividend by 50 percent to $0.30 per share annually ($0.075 per share quarterly). EnCana's Board of Directors has declared a dividend of $0.075 per share payable on March 31, 2006 to common shareholders of record on March 15, 2006. All of the figures in this section have been adjusted to reflect the May 2005 share split.

LEGAL PROCEEDINGS

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

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

RISK FACTORS

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

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

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

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

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

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

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

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

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

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

The nature of the Corporation's operations results in exposure to fluctuations in commodity prices and interest rates. The Corporation monitors its exposure to such fluctuations and, where the Corporation deems it appropriate, utilizes derivative financial instruments and physical delivery contracts to mitigate the potential impact of declines in crude oil and natural gas prices and changes in interest rates.

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

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

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

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of drilling and other equipment;
- the ability to access lands;
- weather;
- unexpected cost increases;
- accidents;
- the availability of skilled labour; and
- regulatory matters.

Oil and natural gas exploration and production is 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 and natural gas business are subject to environmental regulation pursuant to a variety of Canadian, U.S. and other federal, provincial, territorial, state and municipal laws and regulations (collectively, "environmental legislation").

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

The Kyoto protocol, ratified by the Canadian Federal Government in December 2002, came into force on February 16, 2005. The protocol commits Canada to reducing greenhouse gas emissions to six percent below 1990 levels over the period 2008 - 2012. There is currently no clear direction post-2012. The previous Federal Government released a framework outlining its Climate Change action plan on April 13, 2005, and partially addressed the uncertainty associated with ratification and implementation of Kyoto in a July 16, 2005 Canada Gazette notice. The Gazette notice outlined provisions for the oil and gas sector that limit the cost of compliance for existing facilities to C$15 per tonne and made a commitment that emissions reduction targets would not exceed 12 percent lower than business-as-usual levels of total covered emissions for a given sector. The notice also made a commitment to targets based on the "best available technology economically achievable" for new facilities. With the recent change in the Federal Government, EnCana is unable to predict the impact of the potential regulations on its business; however, it is possible that the Corporation could face increases in operating costs in order to comply with greenhouse gas emissions legislation.

EnCana, via the Climate Change Working Group of the Canadian Association of Petroleum Producers, will continue to work with the Federal and Alberta Governments to develop an approach to deal with climate change issues which protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

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 facilities. These risks include blowouts, explosions, fire, gaseous leaks, migration of harmful substances and crude oil spills, any of which could cause personal injury, result in damage to, or destruction of, crude oil and natural gas wells or formations or production facilities and other property, equipment and the environment, as well as interrupt operations. In addition, all of EnCana's operations will be subject to all of the risks normally incident to the transportation, processing, storing 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 and natural gas 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 small 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 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.

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

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

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

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

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

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

An action has been filed by E. & J. Gallo Winery ("Gallo") in the United States District Court, Eastern District of California, against EnCana Corporation and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), alleging that they engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws. The Gallo complaint claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

In addition, EnCana Corporation and WD, along with other energy companies, have been named as defendants in several other lawsuits filed in California (some of which are class actions and some of which are brought by individual parties on their own behalf). The California lawsuits relate to sales of natural gas in California from 1999 through 2002 and contain essentially similar allegations as in the Gallo complaint. Without admitting any liability in the lawsuits, WD has agreed to pay $20.5 million to settle the class action lawsuits that were consolidated in San Diego Superior Court, subject to final documentation and approval by the San Diego Superior Court. The actions against WD and EnCana Corporation brought by the individual parties and certain of the class actions filed in California that are currently before the United States District Court in Nevada are not included in this settlement.

WD is a defendant in a consolidated class action lawsuit filed in the United States District Court in New York. The consolidated New York lawsuit claims that the defendants' alleged manipulation of natural gas price indices affected natural gas futures and option contracts traded on the New York Mercantile Exchange (NYMEX) during the period from 2000 to 2002. EnCana Corporation has been dismissed from the New York lawsuit, leaving WD and several other companies unrelated to EnCana Corporation as the remaining defendants. Without admitting any liability in the lawsuit, WD has agreed to pay a maximum of $9.1 million to settle all claims that are the subject of the lawsuit, subject to final documentation and approval by the New York District Court.

As is customary, the class actions do not specify the amount of damages claimed. There is no assurance that there will not be other actions arising out of these allegations on behalf of the same or different classes.

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

EnCana is subject to indemnification obligations in connection with PanCanadian's spin-off from Canadian Pacific Limited.

In connection with PanCanadian's spin-off from Canadian Pacific Limited ("CPL") on October 1, 2001, PanCanadian entered into an arrangement agreement with certain other parties to the spin-off which contains a number of representations, warranties and covenants, including (a) an agreement by each of the parties to indemnify and hold harmless each other party on an after-tax basis against any loss suffered or incurred resulting from a breach of a representation, warranty or covenant; and (b) a covenant that each party will not take any action, omit to take any action or enter into any transaction that could adversely impact certain tax rulings received in connection with the spin-off, including government opinions and related opinions of counsel and the assumptions upon which they were made. As PanCanadian's successor, EnCana is bound by the agreement. With respect to Canadian taxation, in addition to various transactions that the respective parties were prohibited from undertaking prior to the implementation of the CPL arrangement, after the implementation of the CPL arrangement, no party generally is permitted to dispose of or exchange more than 10 percent of its assets or, among other things, undergo an acquisition of control without severe adverse consequences where such disposition or acquisition of control is for Canadian tax purposes part of a "series of transactions or events" that includes the CPL arrangement, except in limited circumstances. Should the Corporation be found to have breached its representations and warranties or should the Corporation fail to satisfy the contractual covenants, EnCana would be obligated to indemnify the other parties to the arrangement agreement for losses incurred in connection with such breach or failure. In addition, the Corporation is required to indemnify the parties to the arrangement agreement against any loss which they may incur resulting from a claim against EnCana, their respective businesses or their respective assets, whether arising prior to or after the completion of the CPL arrangement. An indemnification claim against EnCana pursuant to the provisions of the arrangement agreement could have a material adverse effect upon the Corporation.

TRANSFER AGENTS AND REGISTRARS

In Canada:
CIBC Mellon Trust Company
320 Bay Street
P.O. Box 1
Toronto, ON M5H 4A6
Tel: 1-800-387-0825
Website: www.cibcmellon.com

In the United States:
Mellon Investor Services LLC
44 Wall Street, 6th Floor
New York, New York
10005
Tel: 1-800-387-0825
Website: www.cibcmellon.com

INTERESTS OF EXPERTS

PricewaterhouseCoopers LLP, Chartered Accountants, are the Corporation's auditors and such firm has prepared an opinion with respect to the Corporation's consolidated financial statements as at and for the fiscal year ended December 31, 2005. PricewaterhouseCoopers LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta. Information relating to reserves in this annual information form dated February 17, 2006 was calculated by GLJ Petroleum Consultants Ltd., McDaniel & Associates Consultants Ltd., Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton as independent qualified reserves evaluators.

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

ADDITIONAL INFORMATION

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

Additional information, including directors' and officers' remuneration, principal holders of EnCana's securities, and options to purchase securities, is contained in the Information Circular for EnCana's most recent annual meeting of shareholders that involved the election of directors. Additional financial information is contained in EnCana's audited consolidated financial statements and Management's Discussion and Analysis for the year ended December 31, 2005.

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, 2005. The reserves data consist of the following:

   (i) estimated proved oil and gas reserve quantities as at December 31, 2005 using constant prices and costs; and

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

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

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

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

4. The following table sets forth both the estimated proved reserve quantities (after royalties) and related estimates of future net cash flows (before deduction of income taxes) assuming constant prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2005:

		Estimated Proved Reserve Quantities After Royalty		Related Estimates of Future Net Cash Flow BTax, 10% discount rate
Evaluator and Preparation Date of Report	**Reserves Location**	**Gas**	**Liquids**	
		(Bcf)	(MMbbl)	($USMM)
McDaniel & Associates Consultants Ltd. January 12, 2006	Canada	3,975	842.7	18,825
GLJ Petroleum Consultants Ltd. January 13, 2006	Canada	2,542	89.9	9,861
Netherland, Sewell & Associates, Inc. January 26, 2006	United States	4,326	48.9	14,656
DeGolyer and MacNaughton February 3, 2006	United States	941	4.1	2,619
GLJ Petroleum Consultants Ltd. January 13, 2006	Ecuador	—	135.0	2,335
Totals		11,784	1,120.6	48,296

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

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

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

Executed as to our report referred to above:

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

(signed) GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

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

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

February 13, 2006

APPENDIX B

Report of Management and Directors on Reserves Data and Other Information

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

(i) proved oil and gas reserve quantities estimated as at December 31, 2005 using constant prices and costs; and

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

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. A report from the independent qualified reserves evaluators dated February 13, 2006 (the "IQRE Report"), highlighting the standards they followed and their results, accompanies this Report.

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

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

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

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

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

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

(b) the filing of the IQRE Report; and

(c) the content and filing of this Report.

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

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

(signed) Brian C. Ferguson
Executive Vice-President, Corporate Development

(signed) David P. O'Brien
Director and Chairman of the Board

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

February 14, 2006

APPENDIX C

Audit Committee Mandate

Last Updated August 22, 2005

I. PURPOSE

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

The Committee's primary duties and responsibilities are to:

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

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

II. COMPOSITION AND MEETINGS

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

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

Composition

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

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

- An understanding of generally accepted accounting principles and financial statements;

- The ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves;
- Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the registrant's financial statements, or experience actively supervising one or more persons engaged in such activities;
- An understanding of internal controls and procedures for financial reporting; and
- An understanding of audit committee functions.

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

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

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

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

Appointment of Members

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

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

If the Chairman of the Committee is not present at any meeting of the Committee, one of the other members of the Committee present at the meeting shall be chosen to preside 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.

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

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

Quorum

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

Minutes

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

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

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

III. RESPONSIBILITIES

Review Procedures

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

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

Annual Financial Statements

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

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

   b. Management's Discussion and Analysis.

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

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

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

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

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

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

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

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

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

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

      (iv) The consistency of disclosure.

   b. Management's Discussion and Analysis.

   c. Annual Information Form as to financial information.

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

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

Quarterly Financial Statements

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

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

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

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

Other Financial Filings and Public Documents

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

Internal Control Environment

5. Ensure that management, the external auditors, and the internal auditors provide to the Committee an annual report on the Corporation's control environment as it pertains to the Corporation's financial reporting process and controls.
6. Review and discuss significant financial risks or exposures and assess the steps management has taken to monitor, control, report and mitigate such risk to the Corporation.
7. Review significant findings prepared by the external auditors and the internal auditing department together with management's responses.
8. Review in consultation with the internal auditors and the external auditors the degree of coordination in the audit plans of the internal auditors and the external auditors and enquire as to the extent the planned scope can be relied upon to detect weaknesses in internal controls, fraud, or other illegal acts. The Committee will assess the coordination of audit effort to assure completeness of coverage and the effective use of audit resources. Any significant recommendations made by the auditors for the strengthening of internal controls shall be reviewed and discussed with management.

Other Review Items

9. Review policies and procedures with respect to officers' and directors' expense accounts and perquisites, including their use of corporate assets, and consider the results of any review of these areas by the internal auditor or the external auditors.
10. Review all related party transactions between the Corporation and any officers or directors, including affiliations of any officers or directors.
11. Review with the General Counsel, the head of internal audit and the external auditors the results of their review of the Corporation's monitoring compliance with each of the Corporation's published codes of business conduct and applicable legal requirements.
12. Review legal and regulatory matters, including correspondence with regulators and governmental agencies, that may have a material impact on the interim or annual financial statements, related corporation compliance policies, and programs and reports received from regulators or governmental agencies. Members from the Legal and Tax departments should be at the meeting in person to deliver their reports.
13. Review policies and practices with respect to off-balance sheet transactions and trading and hedging activities, and consider the results of any review of these areas by the internal auditors or the external auditors.
14. Ensure that the Corporation's presentations on net proven reserves have been reviewed with the Reserves Committee of the Board.
15. Establish procedures for the receipt, retention and treatment of complaints received by the Corporation, including confidential, anonymous submissions by employees of the Corporation, regarding accounting, internal accounting controls, or auditing matters.
16. Review with the President & Chief Executive Officer, the Executive Vice-President & Chief Financial Officer of the Corporation and the external auditors: (i) all significant deficiencies and material weaknesses in the design or operation of the Corporation's internal controls and procedures for financial reporting

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

17. Meet on a periodic basis separately with management.

External Auditors

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

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

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

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

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

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

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

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

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

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

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

23. Review and evaluate:

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

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

c. External audit plans and results.

d. Any other related audit engagement matters.

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

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

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

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

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

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

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

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

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

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

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

f. The internal audit department mandate.

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

Internal Audit Department and Legal Compliance

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

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

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

Approval of Audit and Non-Audit Services

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

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

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

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

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

Other Matters

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

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

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

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

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

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

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

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

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

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