ANNUAL INFORMATION FORM

February 25, 2005

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INTRODUCTORY INFORMATION

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

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

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

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

Unless otherwise specified, all dollar amounts are expressed in United States dollars and all references to ''dollars'' or ''$'' are to United States dollars and all references to ''C$'' are to Canadian dollars.

NOTE REGARDING FORWARD-LOOKING STATEMENTS

This annual information form contains certain forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements are typically identified by words such as ''anticipate'', ''believe'', ''expect'', ''plan'', ''intend'' 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: 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 construction, reserve estimates, the use of facilities related to the Hythe Gas Storage Facility and the timing thereof, storage capacity, the level of expenditures for compliance with environmental regulations, site restoration costs including abandonment and reclamation costs, plans for examining the Deep Panuke project, pending litigation, exploration plans, acquisition and disposition plans, including farmout plans, research and development plans, the timing and results of the environmental impact study in the Jonah area, the timing of acquisitions, the timing, completion and capacity of the Starks Storage facility, net cash flows, geographical expansion and plans for seismic acquisitions and 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 oil and natural gas prices, fluctuations in currency and interest rates, product supply and demand, market competition, risks inherent in EnCana's North American and foreign oil and natural gas and midstream operations, risks of war, hostilities, civil insurrection and instability affecting countries in which EnCana and its subsidiaries operate and terrorist threats, risks inherent in EnCana's and its subsidiaries' marketing operations, including credit risk, imprecision of reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved reserves, EnCana's and its subsidiaries' ability to replace and expand oil and natural gas reserves, EnCana's ability to generate sufficient cash flow from operations to meet its current and future obligations, EnCana's ability to access external sources of debt and equity capital, general economic and business conditions, EnCana's ability to enter into or renew leases, the timing and costs of gas storage facility, well and pipeline construction, EnCana's ability to make capital investments and the amounts of capital investments, imprecision in estimating the timing, costs and levels of production and drilling, the results of exploration, development and drilling, imprecision in estimates of future production capacity, EnCana's and its subsidiaries' ability to secure adequate product transportation, uncertainty in the amounts and timing of royalty payments, imprecision in estimates of product sales, changes in environmental and other regulations 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 United States (''U.S.'') capital markets, to permit the substitution of the standards required by the SEC in order to provide for comparability of oil and gas disclosure with that provided by U.S. and other international issuers. EnCana has obtained an exemption from Canadian securities regulatory authorities to permit it to provide disclosure in accordance with the relevant legal requirements of the SEC. Accordingly, the reserves data and other oil and gas information included or incorporated by reference in this annual information form is disclosed in accordance with U.S. disclosure requirements and practices. Such information, as well as the information that EnCana discloses in the future in reliance on the exemption, may differ from the corresponding information prepared in accordance with NI 51-101 standards.

The primary differences between the U.S. requirements and the NI 51-101 requirements are that (i) the U.S. standards require disclosure only of proved reserves, whereas NI 51-101 requires disclosure of proved and probable reserves, and (ii) the U.S. standards require that the reserves and related future net revenue be estimated under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made, whereas NI 51-101 requires disclosure of proved reserves and the related future net revenue estimated using constant prices and costs as at the 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. There are also differences in accepted practices for determining constant prices for purposes of evaluating bitumen reserves, as outlined under ''Narrative Description of the Business — Reserves and Other Oil and Gas Information — Reserve Quantities Information'' in this annual information form.

EnCana has disclosed proved reserve quantities, using the standards contained in U.S. 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'' (''FAS 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 equivalency at the well head.

CORPORATE STRUCTURE

Name and Incorporation

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

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

Intercorporate Relationships

The following table presents the name, the percentage of voting securities owned and the jurisdiction of incorporation, continuance or formation of EnCana's principal subsidiaries and partnerships with total assets that exceed 10 percent of the total consolidated assets of EnCana or revenues that exceed 10 percent of the total consolidated revenues of EnCana as at and for the year ended December 31, 2004:

Subsidiaries & Partnerships	Percentage Owned(1)	Jurisdiction of Incorporation, Continuance or Formation
EnCana West Ltd.	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
McMurry Oil Company(2)	100	Wyoming
Plaza Acquisition I Corp.(2)	100	Delaware
Tom Brown, Inc.(2)	100	Delaware
EnCana Midstream & Marketing (Holdings) Inc.	100	Canada
EnCana Midstream & Marketing	100	Alberta

Notes:

(1) Includes indirect ownership.

(2) Merged with EnCana Oil & Gas (USA) Inc. on January 1, 2005. EnCana Oil & Gas (USA) Inc. is the continuing entity.

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, 2004.

GENERAL DEVELOPMENT OF THE BUSINESS

EnCana is one of North America's leading independent crude oil and natural gas exploration and production companies, based on landholdings and production at December 31, 2004. EnCana pursues growth from its portfolio of unconventional long-life resource plays situated in Canada and the United States. EnCana defines resource plays as large contiguous accumulations of hydrocarbons, located in thick or areally extensive deposits, that typically have low geological and commercial development risk and low average decline rates. EnCana's disciplined pursuit of these unconventional assets enabled it to become North America's largest natural gas producer, based on production in the second half of 2004, and a leading developer of oilsands through in-situ recovery. The Corporation is also engaged in exploration and production activities internationally and has interests in midstream operations and assets, including natural gas storage facilities, NGLs processing facilities, power plants and pipelines.

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.

Upstream

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

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, EnCana sharpened its strategic focus to concentrate on its inventory of North American resource play assets. In focusing its portfolio of assets, EnCana completed a number of significant acquisitions and dispositions during the past three years.

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. The Tom Brown assets are located 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 north Texas for approximately $251 million, subject to post-closing adjustments.

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 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, subject to post-closing adjustments.
- In September 2004, the Corporation sold conventional oil and gas assets for approximately $388 million, subject to post-closing adjustments. This transaction included properties in east central and southern Alberta producing predominantly medium and heavy oil.
- In December 2004, a subsidiary of EnCana closed 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 North Sea. As a result of this disposition, the U.K. Region is now treated as a discontinued operation for financial reporting purposes.

Concurrent with the announcement of the U.K. sale, EnCana designated its Ecuador and Gulf of Mexico assets as non-core (for planned future disposition) because these assets no longer fit with EnCana's North American resource play focus. The Ecuador assets include interests in five Oriente Basin blocks and a 36.3 percent interest in the

Oleoducto de Crudos Pesados (''OCP'') pipeline. The Ecuador Region is now treated as a discontinued operation for financial reporting purposes. The Gulf of Mexico assets include EnCana's interests in the Tahiti, Tonga, Sturgis, Sawtooth, Jack and St. Malo discoveries. EnCana has an average 40 percent interest in 239 exploration blocks covering approximately 1.4 million gross acres in the Gulf of Mexico.

In December 2004, EnCana announced its intention to sell additional mature western Canadian conventional oil and natural gas properties representing production of approximately 22,000 barrels of oil equivalent per day. EnCana expects these transactions to close in the second quarter of 2005.

In February 2005, EnCana Oil and Gas (USA) Inc. announced plans to sell three natural gas gathering and processing facilities in the U.S. — Fort Lupton and Dragon Trail in Colorado, and Lisbon in Utah. The three plants have a total processing capacity of approximately 210 million cubic feet per day.

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, EnCana Oil & Gas (USA) Inc. acquired natural gas and associated NGLs production, reserves and acreage from Mesa Hydrocarbons LLC for net cash consideration of approximately $100 million. The principal producing properties acquired are in the Piceance Basin of northwest Colorado.
- In October 2003, a subsidiary of EnCana exchanged its non-operated interest in the Llano discovery in the Gulf of Mexico 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 February 2003, EnCana sold a 10 percent interest in the Syncrude Joint Venture (''Syncrude'') for net cash consideration of approximately $690 million. In July 2003, EnCana sold its remaining 3.75 percent interest in Syncrude and an overriding royalty for net cash consideration of approximately $309 million. Both of these transactions are subject to post-closing adjustments. Syncrude operates a facility in northeast Alberta which produces crude oil from oilsands.

2002 Acquisitions:

- In May 2002, wholly owned subsidiaries of EnCana Oil & Gas (USA) Inc. acquired natural gas and associated NGLs production, reserves and acreage located in the Piceance Basin of northwest Colorado from subsidiaries of El Paso Corporation for approximately $275 million.
- In July 2002, EnCana Oil & Gas (USA) Inc. acquired natural gas and associated NGLs production, reserves and acreage located in the Jonah natural gas field in southwest Wyoming from a subsidiary of The Williams Companies for approximately $350 million.

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 midstream operations and market optimization activities. EnCana's midstream activities are comprised of natural gas storage operations, NGLs processing and storage, power generation operations and pipelines. EnCana's marketing groups are focused on enhancing the sale of Upstream's proprietary production. Correspondingly, the marketing groups undertake market optimization activities, including third party purchases and sales of product, which provides operational flexibility for transportation commitments, product type, delivery points and customer diversification.

In focusing its portfolio of assets, the Midstream & Marketing division completed a number of project expansions as well as asset dispositions over the past three years.

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.
- In June 2004, following successful completion of its open season, Entrega Gas Pipeline Inc. (''Entrega''), an affiliate of EnCana Oil & Gas (USA) Inc., announced that it is proceeding with its proposed natural gas pipeline project. Entrega filed its certificate application with the U.S. Federal Energy Regulatory Commission (''FERC'') in September 2004 for construction of the pipeline from Colorado's Piceance Basin, through Wamsutter, Wyoming, to the Cheyenne natural gas trading hub in northeast Colorado. The pace of construction will be dependent upon FERC certification. If approved, the first segment of the pipeline to Wamsutter, Wyoming is expected to be on stream in late 2005, with an initial capacity of approximately 700 million cubic feet per day.
- In November 2004, EnCana Midstream & Marketing, a wholly owned partnership of EnCana, signed a memorandum of understanding with The Premcor Refining Group Inc., an indirect wholly owned subsidiary of U.S. independent oil refiner Premcor Inc., to conduct a preliminary design and engineering study of the modifications necessary to upgrade Premcor's existing refinery at Lima, Ohio to process an estimated 200,000 barrels per day of blended EnCana heavy oil supplied under a proposed long-term sales contract. The memorandum contemplates the establishment of a 50-50 joint venture which would own and operate the upgraded refinery.

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, subject to post-closing adjustments. Kingston CoGen owns a 110 megawatt cogeneration plant in Kingston, Ontario.
- In December 2004, EnCana disposed of its interest in the Alberta Ethane Gathering System joint venture for approximately $108 million, subject to post-closing adjustments.

2003 Projects:

- In October 2003, the first phase of the Countess natural gas storage facility came online, 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. Utilization of the full design capacity of 40 billion cubic feet is expected in 2005, upon approval to operate at increased pressures in the reservoir.
- In October 2003, plans to develop a new natural gas storage facility at Starks, in southwest Louisiana, were announced by a subsidiary of EnCana. An open season for capacity was held in early 2004. In October 2004, an application was filed with the FERC requesting regulatory approval. Subject to regulatory approvals and a satisfactory second open season in February 2005, the facility is expected to be in service during the third quarter of 2006 with approximately 9 billion cubic feet of initial storage capacity. Full future capacity of the Starks facility is expected to be approximately 19 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 (''Express'') 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.

2002 Dispositions:

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

NARRATIVE DESCRIPTION OF THE BUSINESS

The following map outlines EnCana's onshore North America landholdings and key resource plays as of December 31, 2004.

UPSTREAM

The majority of EnCana's Upstream operations are located in Canada, the U.S. and Ecuador. International New Ventures Exploration is mainly focused on opportunities in Africa, Brazil, the Middle East and Greenland.

As at December 31, 2004, EnCana had net proved reserves of approximately 10.5 trillion cubic feet of natural gas and 501 million barrels of crude oil and NGLs, as estimated by independent qualified reserves evaluators. Proved developed reserves comprise approximately 67 percent of total net proved 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 25 million gross acres (approximately 22 million net acres, of which approximately 14 million net acres are undeveloped). The mineral rights on approximately one third of this land is acreage owned in fee title by EnCana, which means that production is subject to a mineral tax that is generally less than the Crown royalty imposed on production from land where the government owns the mineral rights.

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

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 primary crude oil thermal recovery projects at Foster Creek and Christina Lake. The three key resource plays in the Canadian Plains Region are: (i) Shallow Gas in southern Alberta (2004 production of approximately 592 million cubic feet per day and 2003 production of approximately 507 million cubic feet per day); (ii) Coalbed Methane (''CBM'') developments in southern and central Alberta (2004 production of approximately 17 million cubic feet per day and 2003 production of approximately four million cubic feet per day); and (iii) Steam-Assisted Gravity Drainage (''SAGD'') operations at Foster Creek (2004 production of approximately 28,774 barrels per day and 2003 production of approximately 21,823 barrels per day).

EnCana's 2005 capital investment in core programs for natural gas projects in the Canadian Plains Region is budgeted to be approximately $1,085 million, with approximately $65 million directed to exploration and approximately $1,020 million to development. EnCana anticipates drilling approximately 4,098 gross natural gas wells (3,925 net wells) in this region in 2005. Capital investment in 2005 for crude oil projects is budgeted to be approximately $423 million, primarily directed towards development projects, including approximately $290 million for SAGD projects, and the drilling of approximately 358 gross oil wells (349 net wells).

The following table summarizes landholdings for the Canadian Plains Region as at December 31, 2004.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Suffield	942	930	275	271	1,217	1,201	99%
Brooks	1,232	1,206	183	170	1,415	1,376	97%
Chinook	1,344	1,317	300	279	1,644	1,596	97%
Foster Creek	6	6	52	52	58	58	100%
Christina Lake	4	4	68	62	72	66	92%
Weyburn	73	64	460	449	533	513	96%
Other	2,873	2,452	5,890	5,502	8,763	7,954	91%
Canadian Plains Total	6,474	5,979	7,228	6,785	13,702	12,764	93%

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

Production (annual average)	Natural Gas (MMcf/d) 2004	2003	Crude Oil and NGLs (bbls/d) 2004	2003	Total Production (MMcfe/d) 2004	2003	Total Production (BOE/d) 2004	2003
Suffield	241	230	26,706	26,945	401	391	66,873	65,279
Brooks	474	434	15,542	15,295	568	526	94,542	87,628
Chinook	356	329	7,150	7,342	399	373	66,483	62,175
Foster Creek	—	—	28,774	21,823	173	131	28,774	21,823
Christina Lake	—	—	4,364	3,806	26	23	4,364	3,806
Weyburn	—	—	14,200	10,846	85	65	14,200	10,846
Other	203	188	30,184	44,171	384	453	64,017	75,504
Canadian Plains Total	1,274	1,181	126,920	130,228	2,036	1,962	339,253	327,061

The following table summarizes EnCana's interests in producing wells as at December 31, 2004. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2004.

Producing Wells (number of wells)	Producing Gas Wells Gross	Net	Producing Oil Wells Gross	Net	Total Producing Wells Gross	Net
Suffield	7,603	7,510	641	639	8,244	8,149
Brooks	9,622	9,006	699	573	10,321	9,579
Chinook	3,134	3,041	139	133	3,273	3,174
Foster Creek	—	—	36	36	36	36
Christina Lake	—	—	3	3	3	3
Weyburn	—	—	685	422	685	422
Other	1,888	1,499	1,322	937	3,210	2,436
Canadian Plains Total	22,247	21,056	3,525	2,743	25,772	23,799

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 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.

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 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 resource play. The 1,100 section Horseshoe Canyon CBM development is located within the Chinook area. In 2004, EnCana drilled approximately 577 CBM wells on its project area on the Palliser Block, increasing production to approximately 30 million cubic feet per day at year-end. In 2005, EnCana plans to drill approximately 1,000 CBM wells, which is expected to increase CBM production to approximately 60 million cubic feet per day by year-end.

Foster Creek

EnCana has a 100 percent working interest in Foster Creek, one of the Corporation's two 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 100 percent owned thermal oil recovery project in the Foster Creek area of the Primrose Block using SAGD technology.

Pilot operations at Foster Creek commenced in 1998, and a 20,000 barrel per day commercial facility was started up in 2001. The first expansion, which increased commercial capacity to approximately 30,000 barrels per day, was completed in the third quarter of 2003. Net crude oil production in 2004 averaged approximately 28,800 barrels per day. An additional expansion has been approved and the engineering is underway. A total of 30,000 barrels per day of incremental production capacity is expected to be added in two stages with this development: 10,000 barrels per day of capacity is expected to be on stream in the fourth quarter of 2005, with an additional 20,000 barrels per day expected in the fourth quarter of 2006. EnCana anticipates reaching this expected output of 60,000 barrels per day in early 2007.

EnCana continues to operate its 80 megawatt, natural gas-fired cogeneration facility in conjunction with its SAGD operation at Foster Creek. The facility reached its full capacity in the fourth quarter of 2003. 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 2004, EnCana added two well pairs and had total productive capacity of approximately 6,000 barrels per day at year-end.

Thermal Recovery Research and Development

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

One focus area is to reduce the reliance on steam in bitumen production. To this end, EnCana is piloting two technologies using solvents as part of the extraction process. The Solvent Aided Process (''SAP'') mixes a small amount of solvent with steam to enhance recovery. A second technology, the Vapex process, uses solvent in place of steam. After piloting SAP at Senlac, Saskatchewan in 2002, EnCana completed construction and commenced operation of a pilot operation at Christina Lake in 2004. The Vapex pilot at Foster Creek has been in operation since 2002. The first phase of the pilot is nearing completion, and there is additional research planned in the area for 2005.

Another focus area is artificial lift where EnCana is pursuing pump designs that are expected to enable the Corporation to optimize SAGD by operating at lower pressures, thereby realizing lower steam oil ratios and decreasing facility capital costs. EnCana now has more than 10 wells on electrical submersible pumps at Foster Creek, and the Corporation expects to utilize this technology on new SAGD wells. Low pressure SAGD technology is being utilized in one well pair at Foster Creek, and EnCana plans to utilize this technology in up to 10 wells in 2005.

Weyburn

EnCana has a 62 percent working interest (50 percent economic interest) in the Weyburn crude oil field in southwest Saskatchewan. EnCana is the operator and expects to improve ultimate recovery in the enhanced oil recovery area with a carbon dioxide (''CO_2'') miscible flood project. In 2004, EnCana continued with its infill drilling program which began in 2003. This program ensures optimal coverage of areas currently within the enhanced oil recovery area. Four additional patterns, or well groupings, were completed in the CO_2 miscible flood development in 2004. As of December 31, 2004, there were 36 patterns on stream out of a planned total of 75 patterns.

Canadian Foothills & Frontier Region

The Canadian Foothills & Frontier Region includes EnCana's natural gas and crude oil exploration, development and production activities in northern Alberta and British Columbia. It also includes EnCana's exploration and development activities offshore the East Coast of Canada and in the Mackenzie Delta area of the Northwest Territories. There are three key resource plays in the Canadian Foothills & Frontier Region: (i) Greater Sierra; (ii) Cutbank Ridge; and (iii) Pelican Lake.

EnCana's 2005 capital investment in core programs for natural gas projects in the Canadian Foothills & Frontier Region is budgeted to be approximately $1,432 million, with approximately $150 million directed to exploration and approximately $1,282 million to development. EnCana plans to drill approximately 740 gross natural gas wells (688 net wells) and approximately 77 gross crude oil wells (77 net wells) in this region in 2005. Capital investment for crude oil projects is budgeted to be approximately $95 million, primarily directed towards development projects.

The following table summarizes landholdings for the Canadian Foothills & Frontier Region as at December 31, 2004.

Landholdings (thousands of acres)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Greater Sierra	464	397	2,780	2,424	3,244	2,821	87%
Cutbank Ridge	73	61	815	735	888	796	90%
Pelican Lake	83	83	135	135	218	218	100%
Sexsmith/Hythe/Saddle Hills	288	194	242	178	530	372	70%
Cold Lake Air Weapons Range	386	365	473	469	859	834	97%
East Coast of Canada	—	—	5,861	3,558	5,861	3,558	61%
Mackenzie Delta	—	—	529	198	529	198	37%
Other	1,330	1,074	5,195	3,447	6,525	4,521	69%
Canadian Foothills & Frontier Total	2,624	2,174	16,030	11,144	18,654	13,318	71%

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)		Total Production (BOE/d)	
	2004	2003	2004	2003	2004	2003	2004	2003
Greater Sierra	230	143	632	607	234	147	38,965	24,440
Cutbank Ridge	40	3	—	—	40	3	6,667	500
Pelican Lake	7	9	18,900	15,944	120	105	20,067	17,444
Sexsmith/Hythe/Saddle Hills	110	114	2,785	2,990	127	132	21,118	21,990
Cold Lake Air Weapons Range	163	174	—	—	163	174	27,167	29,000
Other	286	323	5,149	6,665	317	362	52,815	60,499
Canadian Foothills & Frontier Total	836	766	27,466	26,206	1,001	923	166,799	153,873

The following table summarizes EnCana's interests in producing wells as at December 31, 2004. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2004.

Producing Wells (number of wells)	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Greater Sierra	559	516	2	2	561	518
Cutbank Ridge	69	63	—	—	69	63
Pelican Lake	15	15	514	514	529	529
Sexsmith/Hythe/Saddle Hills	317	253	61	47	378	300
Cold Lake Air Weapons Range	608	583	—	—	608	583
Other	1,731	1,539	235	130	1,966	1,669
Canadian Foothills & Frontier Total	3,299	2,969	812	693	4,111	3,662

The following describes EnCana's major producing areas or activities in the Canadian Foothills & Frontier 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 230 million cubic feet per day in 2004. As at December 31, 2004, EnCana held an average 98 percent interest in 13 production facilities in the area that were capable of processing approximately 450 million cubic feet per day of natural gas. In 2004, EnCana completed the construction of the Ekwan pipeline which went into operation on April 1, 2004. The Ekwan pipeline transports natural gas from northeast British Columbia to Alberta. The pipeline extends approximately 80 kilometres and has a capacity of approximately 400 million cubic feet per day. December 2004 throughput for the pipeline was approximately 95 million cubic feet per day.

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 2004, EnCana drilled approximately 50 net natural gas wells at Cutbank Ridge and increased production to approximately 47 million cubic feet per day of natural gas by year-end. In 2005, EnCana plans to drill approximately 100 net natural gas wells at Cutbank Ridge.

Pelican Lake

Pelican Lake is another of EnCana's key resource plays producing crude oil in north-central Alberta. In 2004, EnCana continued to expand the waterflood program at Pelican Lake, which has increased the recovery of crude oil in the area. 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.

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 240-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 controlled and operated compression facilities. In 2004, 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 eight million cubic feet per day. In January 2005, the Government of Alberta reached an agreement with natural gas producers which partially compensates the producers for this shut-in production.

East Coast of Canada

Offshore Nova Scotia on the East Coast of Canada, EnCana has a 100 percent working interest in the Deep Panuke natural gas discovery. EnCana is in the process of examining the potential economic viability of the Deep Panuke project, and this is expected to continue in 2005.

In 2004, EnCana participated in the drilling of the Weymouth and Crimson deep water exploration wells offshore Nova Scotia. Both wells were unsuccessful.

EnCana also has other interests in exploration lands located offshore Nova Scotia and Newfoundland and Labrador.

Mackenzie Delta

EnCana drilled one exploration well in the Mackenzie Delta region of Canada's Northwest Territories in 2004. EnCana plans to drill one additional well in the area in 2005, as well as conduct further testing of the well drilled in 2004.

United States

EnCana's operations in the U.S. Rockies area are focused on exploiting deep, tight, long-life, unconventional natural gas formations primarily in the Jonah sweet natural gas field located in the Green River Basin of southwest Wyoming, and in the Piceance Basin of northwest Colorado (which includes the Mamm Creek natural gas field). The acquisition of Tom Brown in May 2004 expanded EnCana's operations within the Green River and Piceance Basins. EnCana's U.S. operations also include interests in the East Texas and Fort Worth Basins in Texas, the Gulf of Mexico and Alaska, as well as natural gas gathering and processing assets. The majority of the production in the U.S. is from resource plays. The key resource plays are: (i) Jonah; (ii) Piceance; (iii) East Texas; and (iv) Fort Worth.

EnCana's 2005 capital investment in core programs for natural gas projects in the U.S. is budgeted to be approximately $1,482 million, with approximately $77 million directed to exploration and approximately $1,405 million to development, and includes the drilling of approximately 923 gross natural gas wells (789 net wells). There are no budgeted amounts for capital investment in crude oil projects.

The following table summarizes EnCana's landholdings in the United States as at December 31, 2004.

Landholdings	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net	Interest
Jonah	12	10	48	47	60	57	95%
Piceance	241	216	860	796	1,101	1,012	92%
East Texas	68	40	167	142	235	182	77%
Fort Worth	36	33	127	127	163	160	98%
Gulf of Mexico	—	—	1,371	557	1,371	557	41%
Alaska	—	—	1,337	531	1,337	531	40%
Other	351	208	2,615	2,140	2,966	2,348	79%
United States Total	708	507	6,525	4,340	7,233	4,847	67%

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

Production	Natural Gas (MMcf/d)		Crude Oil and NGLs (bbls/d)		Total Production (MMcfe/d)		Total Production (BOE/d)	
(annual average)	2004	2003	2004	2003	2004	2003	2004	2003
Jonah	389	374	3,294	3,348	409	394	68,127	65,681
Piceance	261	151	3,074	2,473	279	166	46,574	27,640
East Texas	50	—	167	—	51	—	8,500	—
Fort Worth	27	7	233	136	28	8	4,733	1,303
Other	142	56	6,037	3,504	179	77	29,704	12,837
United States Total	869	588	12,805	9,461	946	645	157,638	107,461

The following table summarizes EnCana's interests in producing wells as at December 31, 2004. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2004.

Producing Wells	Producing Gas Wells		Producing Oil Wells		Total Producing Wells	
(number of wells)	Gross	Net	Gross	Net	Gross	Net
Jonah	386	343	—	—	386	343
Piceance	2,486	2,065	—	—	2,486	2,065
East Texas	458	263	—	—	458	263
Fort Worth	399	366	—	—	399	366
Other	2,062	1,224	30	12	2,092	1,236
United States Total	5,791	4,261	30	12	5,821	4,273

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 southwest Wyoming. The Jonah key resource play represents EnCana's initial entry into the U.S. Rockies region. Since arriving in 2000, EnCana has approximately tripled both reserves and production — 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. The U.S. Bureau of Land Management is working on an Environmental Impact Statement covering future development in the area. The study is expected to be complete by mid-2005. EnCana expects that the results of the study will be positive for the Corporation, and will allow for increased production growth at Jonah.

Piceance

The Piceance Basin in northwest Colorado is one of EnCana's key natural gas resource plays. This 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. As of December 31, 2004, EnCana had accumulated over one million net acres in the basin and had production of approximately 285 million cubic feet per day.

East Texas

EnCana produces natural gas 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 2004, EnCana drilled approximately 50 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, and the Corporation has assembled a significant land position in the Barnett Shale play in this basin. The Corporation entered the area in 2003 with the acquisition of Savannah Energy Inc. (''Savannah''). 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.

Gulf of Mexico

In the summer of 2004, an EnCana subsidiary, EnCana Gulf of Mexico LLC, participated in two exploration and appraisal activities in the Gulf of Mexico. A production test was completed on the two primary zones in the Tahiti well, in which EnCana holds a 25 percent non-operated interest. The well produced at a restricted rate of 15,000 barrels per day. Rate and pressure analysis indicate that the well may be capable of sustained flow of as much as 30,000 barrels of oil per day. In addition, EnCana participated in the deep water Jack exploration well which encountered approximately 350 feet of net pay. EnCana has a 25 percent non-operated interest in the well. In total, EnCana subsidiaries have participated in six discoveries in the Gulf of Mexico since 2002.

In late 2004, the Gulf of Mexico assets were deemed to be non-core to EnCana. The Corporation plans to dispose of these assets in 2005.

Alaska

In late 2004, EnCana's assets in Alaska were deemed to be non-core by the Corporation. EnCana plans to dispose of these assets in 2005.

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 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.

In February 2005, the Corporation announced its intention to sell the Fort Lupton, Dragon Trail and Lisbon plants and the associated gas gathering facilities.

International New Ventures Exploration

EnCana invests a small portion (approximately two percent) of its capital in high potential exploration beyond its core geographic areas, primarily in Africa, Brazil, the Middle East and Greenland.

Central and West Africa

EnCana's onshore exploration operations in Chad are based out of the Corporation's office in N'Djamena. EnCana has a 50 percent working interest in Permit H comprising approximately 108 million gross acres (approximately 54 million net acres). EnCana acquired seismic data and completed the drilling of four exploration wells in 2004. In 2005, the Corporation expects to acquire seismic data and anticipates drilling three to five exploration and/or appraisal wells.

In July 2004, EnCana assigned its entire interest in the offshore Keta Block in Ghana to its partner. The assignment has been submitted to the Government of Ghana and EnCana is awaiting final approval of its exit from Ghana.

Brazil

In 2004, EnCana entered into a Technology Cooperation Agreement for heavy oil activities with Petrobras, the Brazilian national oil company. This agreement is part of a larger cooperation including joint participation with Petrobras in Agência Nacional do Petróleo (''ANP'') Bid Round 6, in which EnCana acquired an average working interest ranging from 30 to 40 percent in seven Petrobras-operated blocks. This acquisition increased the Corporation's landholdings by approximately 1.1 million gross acres (approximately 402,000 net acres). In 2005, activity on these offshore blocks is expected to be limited to seismic acquisition.

In ANP Bid Round 6, EnCana also acquired a 25 percent non-operated interest in offshore Block 101, increasing its land position by approximately 177,000 gross acres (approximately 44,000 net acres). In addition to these newly acquired blocks, EnCana has a 67 percent working interest in Block BM-C-7 comprising approximately 161,000 gross acres (approximately 108,000 net acres) offshore Brazil. In 2004, the Corporation drilled one exploration well and one appraisal well on this block. Evaluation of the results is expected to continue in 2005.

Middle East

In October 2004, EnCana reached an agreement with the Government of Qatar to enter the second phase of its exploration production sharing agreement on Block 2. This block encompasses most of the onshore lands in the State of Qatar. EnCana's 100 percent working interest in the landholdings on the block total approximately 2.2 million acres. Plans for 2005 include expected seismic activity and pursuing the planned farmout of a portion of EnCana's working interest.

In 2004, the Corporation farmed out a portion of its working interest in Block 47 in the Republic of Yemen. The Corporation has a 36.75 percent working interest in Block 47 (approximately 1.9 million gross acres and approximately 691,000 net acres). EnCana drilled one unsuccessful exploration well on the block in 2004.

EnCana has a 100 percent working interest in onshore Blocks 3 and 4 in the Sultanate of Oman, which cover approximately 9.6 million acres. EnCana conducted seismic surveys in 2004 and expects to drill one well in 2005. In 2005, EnCana also plans to pursue the farmout of a portion of its interest in Oman.

EnCana has a 50 percent non-operated working interest in Block 5 in the Kingdom of Bahrain. Block 5 is comprised of approximately 97,000 gross acres (approximately 48,000 net acres). During 2004, seismic data was acquired and one exploration well was drilled and abandoned. EnCana exited the block in early 2005.

Greenland

EnCana acquired one exploration licence (Lady Franklin) in the 2004 Offshore West Greenland Bid Round. This licence was signed in January 2005. EnCana also has an 87.5 percent working interest in the Atammik block, offshore west Greenland, consisting of approximately 985,000 gross acres (approximately 862,000 net acres). EnCana conducted seismic activities in 2004. In 2005, EnCana expects to conduct additional seismic activity and pursue the farmout of a portion of its working interest in Greenland.

Ecuador

In late 2004, the Ecuador Region was deemed to be non-core to EnCana. The Corporation plans to dispose of its Ecuadorian operations in 2005. As a result, the Ecuador Region is now treated as a discontinued operation for financial reporting purposes.

An indirect, wholly owned subsidiary of EnCana owns a concession in the Oriente Basin, known as the Tarapoa Block. The Corporation has a 100 percent working interest in this concession, which is operated under a participation contract which has a primary term through to August 1, 2015. EnCana also has a 40 percent non-operated economic interest in 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, 2004, EnCana held an average 64 percent working and economic interest in approximately 1.4 million gross acres (approximately 894,000 net acres, of which approximately 795,000 net acres are undeveloped) in Ecuador. At December 31, 2004, 211 gross crude oil wells (151 net wells) were producing. EnCana's contractual entitlement to net crude oil production in 2004 was 76,872 barrels per day (51,089 barrels per day in 2003).

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 2004, shipments on OCP totalled approximately 170,599 barrels per day. 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 has a 15-year shipping commitment on OCP of approximately 108,000 barrels per day. EnCana's shipments on OCP in 2004 averaged approximately 72,636 barrels per day.

MIDSTREAM & MARKETING

Midstream

EnCana's midstream activities are primarily comprised of natural gas storage operations, NGLs processing and storage, power generation operations and pipelines. EnCana's 2005 capital investment in core programs in its midstream operations is budgeted to be approximately $342 million.

Natural Gas Storage

Based upon overall storage capacity, EnCana is the largest independent (non-utility) natural gas storage operator in North America with facilities in Alberta, California and Oklahoma. EnCana also leases natural gas storage capacity from other storage operators located in the U.S. Gulf Coast and mid-continent regions. At December 31, 2004, EnCana had owned and operated storage capacity of approximately 163 billion cubic feet, as well as leased storage capacity of approximately 15 billion cubic feet.

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) and is available to manage EnCana's produced gas sales.

AECO HUB™

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

Suffield Gas Storage Facility

Located on the Suffield Block in southeast Alberta, this facility was the first and is the most significant in the AECO HUB™ portfolio. It has storage capacity of approximately 85 billion cubic feet, a maximum withdrawal capability of approximately 1.8 billion cubic feet per day and a maximum injection capability of approximately 1.6 billion cubic feet per day.

Hythe Gas Storage Facility

The Hythe Gas Storage Facility in northwest Alberta has approximately 10 billion cubic feet of working natural gas capacity, approximately 200 million cubic feet per day of withdrawal capability, and approximately 150 million cubic feet per day of injection capability. The facility is connected to both the Alberta pipeline system of TransCanada Corporation and the Alliance Pipeline system. Commencing April 1, 2004, the compression and pipeline facilities related to the Hythe Gas Storage Facility were temporarily removed from gas storage service and utilized by the Upstream division to facilitate additional production from Cutbank Ridge. This facility is expected to return to gas storage service effective April 1, 2005.

Countess Gas Storage Facility

In October 2002, EnCana announced plans to develop a new natural gas storage facility in southeast Alberta that is expected to store up to 40 billion cubic feet of natural gas. The Countess Gas Storage Facility consists of two depleted underground reservoirs located about 85 kilometres east of Calgary. The first 10 billion cubic feet of new storage capacity came online in 2003, with free-flow injection through the summer and plant facilities completion in October. The completed facilities increased 2004 storage capacity to approximately 30 billion cubic feet, maximum withdrawal capability to approximately 850 million cubic feet per day and maximum injection capability to approximately 800 million cubic feet per day. The full 40 billion cubic feet of storage capacity and additional withdrawal capability are expected to be utilized in 2005, upon approval to operate at increased pressures in the reservoir.

Wild Goose Gas Storage Facility

The Wild Goose Gas Storage Facility, located north of Sacramento, California was California's first independent natural gas storage facility. In July 2002, Wild Goose was granted permission by the California Public Utilities Commission to approximately double the storage size and approximately triple the withdrawal capacity of the facility. Completion of the initial phase expansion was completed in March 2004, bringing the total working gas capacity to approximately 24 billion cubic feet. The expansion also increased maximum withdrawal capability to approximately 480 million cubic feet per day and expanded maximum injection capability to approximately 450 million cubic feet per day.

Salt Plains Gas Storage Facility

The Salt Plains Gas Storage Facility, located in northern Oklahoma, has a capacity of 15 billion cubic feet, a maximum withdrawal capability of approximately 200 million cubic feet per day and a maximum injection capability of approximately 150 million cubic feet per day.

Starks Project

In October 2003, Starks Gas Storage L.L.C., an indirect wholly owned subsidiary of EnCana, announced plans to develop a high-deliverability storage facility in southwest Louisiana. Subject to regulatory approvals and a satisfactory second open season, the facility is expected to be in-service during the third quarter of 2006 with approximately 9 billion cubic feet of initial storage capacity, 350 million cubic feet of injection capacity and 400 million cubic feet of withdrawal capacity. Full future capacity of the Starks facility is expected to be approximately 19 billion cubic feet.

Leased Storage Capacity

EnCana Gas Storage Inc., an indirect wholly owned subsidiary of EnCana, has entered into contracts to lease storage capacity in the U.S. Gulf Coast and mid-continent regions. Total leased capacity at December 31, 2004 was approximately 15 billion cubic feet. Contracts for approximately 7 billion cubic feet of this capacity expire at the end of March 2005, with the remaining contract terms ranging from 15 months to 12 years.

Natural Gas Liquids

EnCana holds interests in four NGLs extraction plants that straddle two major natural gas pipelines at Empress, Alberta plus storage and fractionation assets in Saskatchewan, eastern Canada and the U.S.

At Empress, the rights to extract NGLs from natural gas transported through transmission pipelines are acquired from the shippers of the natural gas. As at December 31, 2004, EnCana's share of the combined processing capacity was approximately 2.1 billion cubic feet per day.

Ethane recovered at Empress is sold as a specification product to petrochemical companies for consumption within the Province of Alberta. The remaining liquids components are transported as a mixed stream by pipeline to a plant at Sarnia, Ontario in which EnCana holds an approximate 10.4 percent interest. The mixed stream is fractionated at Sarnia into marketable products: propane, butane and pentanes plus. These are sold to distributors, refiners and petrochemical manufacturers in Canada and the U.S. under contracts, the terms of which are typically one year or less.

Other significant NGLs midstream assets include: (i) a 50 percent interest in a pipeline that delivers NGLs from Empress to storage facilities and the Enbridge pipeline at Kerrobert, Saskatchewan; (ii) interests in a NGLs storage facility and depropanizer at Superior, Wisconsin; and (iii) a 49 percent interest in a propane and butane storage facility at Marysville, Michigan.

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 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 300 megawatts and its generation capacity is approximately 239 megawatts. The Corporation disposed of its 25 percent non-operated partnership interest in the 110 megawatt Kingston CoGen plant in December 2004.

Pipelines

In 2004, Entrega, an affiliate of EnCana Oil & Gas (USA) Inc., announced that it is proceeding with its proposed natural gas pipeline project. Once complete, 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. Upon receipt of FERC certification, the first segment of the pipeline through Wamsutter is expected to be on stream in late 2005, with an initial capacity of approximately 700 million cubic feet per day.

EnCana holds a 36 percent equity investment in the Trasandino Pipeline system which carries crude oil from Argentina's Neuquen Basin to refineries in Chile. The pipeline is 420 kilometres in length and has a design capacity of approximately 113,000 barrels per day. Shipments on the Trasandino system in 2004 averaged approximately 57,000 barrels per day (approximately 104,000 barrels per day in 2003). In 2004, as a result of ongoing volume reductions, EnCana reduced the carrying value of its investment in Trasandino by approximately $35 million.

Marketing

EnCana's marketing groups are focused on enhancing the sales 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.

Natural Gas Marketing

In 2004, approximately 89 percent of EnCana's produced natural gas sales were directly marketed by EnCana to local distribution companies, industrials and energy marketing companies. The remaining 11 percent of produced natural gas sales were marketed to aggregators who supply natural gas to markets throughout North America. Prices received by EnCana are based primarily upon prevailing index prices for natural gas. Prices are impacted by competing fuels in such markets and by regional supply and demand for natural gas.

To mitigate the market risk associated with forecasted cash flows, EnCana enters into various risk management contracts relating to produced natural gas. Details of these transactions are found in Note 17 to EnCana's audited consolidated financial statements for the year ended December 31, 2004.

In 2004, EnCana sold approximately 51 percent of its produced natural gas (after royalties and mineral taxes) at fixed prices, approximately 4 percent at AECO Index based pricing, approximately 36 percent at NYMEX based pricing and approximately 9 percent at other prices. As of December 31, 2004, for 2005 EnCana has arranged for the sale of approximately 26 percent of its natural gas at fixed prices, approximately 26 percent of its natural gas at insured floor prices, approximately 12 percent exposed to AECO Index based prices, approximately 29 percent exposed to NYMEX based prices and approximately 7 percent at other prices.

In addition to sales of its proprietary production, EnCana purchases and sells natural gas for the purpose of optimizing the profitability of its midstream assets and the netback price of the Corporation's proprietary production. In 2004, EnCana's sales of purchased natural gas amounted to approximately 895 million cubic feet per day (approximately 903 million cubic feet per day in 2003).

Crude Oil Marketing

EnCana sells and manages the transportation of its western Canadian crude oil to markets in Canada and the U.S. (140,911 barrels per day in 2004 and 138,784 barrels per day in 2003). 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 Enbridge, for sales to U.S. refinery destinations.

EnCana provides North American marketing services to certain organizations on a fee for service basis. In 2004, EnCana acted as exclusive agent for Canadian Oil Sands Limited (''COS'') and marketed COS' Syncrude volumes of 85,157 barrels per day (64,863 barrels per day in 2003). The COS marketing agreement terminates in the second quarter of 2006. EnCana also provides marketing services to the Alberta Government's Department of Energy (73,852 barrels per day in 2004 and 69,264 barrels per day in 2003). 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 77,845 barrels per day was marketed in 2004 (45,561 barrels per day in 2003). Until

September 2003, Ecuador production was transported from the Ecuador Oriente region to Balao via the SOTE Pipeline. EnCana began shipping on the OCP Pipeline in September 2003, and the pipeline was fully commissioned in November 2003. EnCana's production in Ecuador consists of a high viscosity crude oil with characteristics well-suited to refineries on the U.S. West and Gulf Coasts.

To 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 17 to EnCana's audited consolidated financial statements for the year ended December 31, 2004.

NGLs Marketing

EnCana's production of NGLs in western Canada is marketed through Kinetic Resources (LPG), an Alberta partnership in which EnCana has an indirect 75 percent interest, and Kinetic Resources (U.S.A.), a Michigan partnership in which EnCana has an indirect 75 percent interest (collectively, ''Kinetic''). In 2004, Kinetic continued to market a portion of EnCana's western Canada NGLs primarily to eastern Canada and the U.S. Kinetic also markets NGLs on behalf of other parties. An indirect 100 percent owned affiliate of EnCana also directly markets certain U.S.-produced NGLs volumes to U.S.-based customers.

RESERVES AND OTHER OIL AND GAS INFORMATION

EnCana retained independent qualified reserves evaluators to evaluate and prepare reports on 100 percent of EnCana's crude oil and natural gas reserves as of December 31, 2004. EnCana's Canadian reserves were evaluated by McDaniel & Associates Consultants Ltd. and Gilbert Laustsen Jung Associates Ltd. EnCana's U.S. reserves were evaluated by Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton. EnCana's Ecuadorian reserves were evaluated by Gilbert Laustsen Jung Associates Ltd. 2004 was the third consecutive year in which all of EnCana's reserves were independently evaluated.

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

Any references to NGLs in this section include condensate.

As at December 31, 2004, both the U.K. and Ecuador Regions are classified as discontinued operations for financial reporting purposes.

Reserve Quantities Information

EnCana's natural gas reserves increased in 2004 from exploration and development drilling and acquisitions. The Corporation's crude oil and NGLs reserves decreased in 2004 primarily as a result of the divestiture of non-core properties and a negative revision in Canadian bitumen reserves as a result of anomalously lower year-end bitumen prices, as further discussed below. EnCana's reserves increased in 2003 primarily from exploration and development drilling, and to a lesser extent from acquisitions and upward revisions. Reserve acquisitions were approximately equal to reserve dispositions in 2003. The Corporation's reserves increased in 2002 predominantly from the Merger with AEC, and also partly due to extensions and discoveries. The 2002 increase was partially offset by downward revisions of reserve quantities.

On December 31, 2004, being the effective date for the Corporation's reserves evaluations, field prices for bitumen were much lower than the average for 2004 due to market conditions. The application of U.S. standards for the determination of constant prices as at that date resulted in the removal of the Corporation's Foster Creek bitumen reserves from the proved category, encompassing a negative revision of approximately 363 million barrels. Canadian securities regulators, in recognition that the bitumen market is not yet mature and that there are no published reference prices for bitumen, have accepted an approach in determining the constant price for bitumen based on using the published price for WTI and historical averages for the adjustments that create the difference in price between WTI and bitumen. Under the accepted Canadian methodology, there would not have been any negative revisions of the Corporation's proved bitumen reserves.

The following table sets forth reserves continuity information prepared by EnCana in accordance with U.S. disclosure standards, including FAS 69. The end of year numbers for 2004 represent estimates derived from the reports of the independent qualified reserves evaluators referred to above. The end of year numbers for 2003 and 2002 represent estimates derived from the reports of the independent qualified reserves evaluators who evaluated EnCana's reserves as of December 31, 2003 and December 31, 2002.

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
2002											
Beginning of year	3,504	236	7	—	3,747	286.6	19.6	—	21.6	—	327.8
Purchase of AEC reserves in place	2,686	944	—	—	3,630	233.7	6.5	168.4	—	—	408.6
Revisions and improved recovery	(1,140)	731	7	—	(402)	(15.5)	4.6	(33.5)	(9.1)	—	(53.5)
Extensions and discoveries	726	319	10	—	1,055	96.9	3.3	31.1	89.2	—	220.5
Purchase of reserves in place	30	530	—	—	560	4.9	9.9	—	—	—	14.8
Sale of reserves in place	(129)	(73)	—	—	(202)	(18.2)	(0.7)	—	—	—	(18.9)
Production	(604)	(114)	(4)	—	(722)	(46.5)	(2.3)	(10.2)	(4.1)	—	(63.1)
End of year	5,073	2,573	20	—	7,666	541.9	40.9	155.8	97.6	—	836.2
Developed	4,139	1,446	9	—	5,594	299.2	21.9	104.6	8.3	—	434.0
Undeveloped	934	1,127	11	—	2,072	242.7	19.0	51.2	89.3	—	402.2
Total	5,073	2,573	20	—	7,666	541.9	40.9	155.8	97.6	—	836.2
2003											
Beginning of year	5,073	2,573	20	—	7,666	541.9	40.9	155.8	97.6	—	836.2
Revisions and improved recovery	73	1	3	—	77	32.3	0.5	0.4	23.5	—	56.7
Extensions and discoveries	867	706	—	90	1,663	110.9	7.4	11.9	—	0.9	131.1
Purchase of reserves in place	9	152	8	—	169	1.3	0.9	17.3	7.1	—	26.6
Sale of reserves in place	(60)	(88)	—	(90)	(238)	(0.2)	(4.7)	(5.1)	—	(0.9)	(10.9)
Production	(706)	(215)	(5)	—	(926)	(56.8)	(3.4)	(18.6)	(3.7)	—	(82.5)
End of year	5,256	3,129	26	—	8,411	629.4	41.6	161.7	124.5	—	957.2
Developed	3,984	1,833	13	—	5,830	306.1	26.3	115.0	16.7	—	464.1
Undeveloped	1,272	1,296	13	—	2,581	323.3	15.3	46.7	107.8	—	493.1
Total	5,256	3,129	26	—	8,411	629.4	41.6	161.7	124.5	—	957.2
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[3]	0.2	(11.5)	—	—	19.8
Extensions and discoveries	1,422	1,009	—	—	2,431	93.6[3]	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)[4]	—	—	—	—	(362.7)
End of year	5,824	4,636[5]	—	—	10,460	266.9	91.0[5]	143.3[6]	—	—	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

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) An aggregate of approximately of 75.8 million barrels of proved reserves in the Foster Creek area are subject to the revisions due to bitumen price, including approximately 5.4 million barrels under revisions and improved recovery and approximately 70.4 million barrels under extensions and discoveries.

(4) Removal of the Corporation's Foster Creek proved bitumen reserves as described under ''Reserve Quantities Information''.

(5) Includes approximately 14 billion cubic feet of natural gas and approximately 38.8 million barrels of crude oil and NGLs reserves attributable to the Corporation's Gulf of Mexico assets, which EnCana plans to dispose of in 2005.

(6) The Corporation plans to dispose of its Ecuadorian operations in 2005. Accordingly, Ecuador is treated as a discontinued operation 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 FAS 69.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

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

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

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

	Canada			United States			Ecuador		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
	($ millions)								
Future cash inflows	37,791	35,126	29,890	27,063	17,472	9,398	3,317	3,533	3,368
Future production costs	7,760	9,630	5,873	2,462	1,456	2,090	1,136	738	635
Future development costs	4,906	4,388	2,813	3,406	1,433	1,270	220	249	273
Undiscounted pre-tax cash flows	25,125	21,108	21,204	21,195	14,583	6,038	1,961	2,546	2,460
Future income taxes	6,279	5,874	6,353	7,021	4,960	1,504	342	536	585
Future net cash flows	18,846	15,234	14,851	14,174	9,623	4,534	1,619	2,010	1,875
Less discount of net cash flows using a 10% rate	6,668	5,219	6,018	6,686	4,735	2,383	417	643	617
Discounted future net cash flows	12,178	10,015	8,833	7,488	4,888	2,151	1,202	1,367	1,258

	United Kingdom			Total		
	2004	2003	2002	2004	2003	2002
	($ millions)					
Future cash inflows	—	3,483	2,565	68,171	59,614	45,221
Future production costs	—	961	397	11,358	12,785	8,995
Future development costs	—	1,008	836	8,532	7,078	5,192
Undiscounted pre-tax cash flows	—	1,514	1,332	48,281	39,751	31,034
Future income taxes	—	456	483	13,642	11,826	8,925
Future net cash flows	—	1,058	849	34,639	27,925	22,109
Less discount of net cash flows using a 10% rate	—	493	438	13,771	11,090	9,456
Discounted future net cash flows	—	565	411	20,868	16,835	12,653

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

	Canada			United States			Ecuador		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
	($ millions)								
Balance, beginning of year	10,015	8,833	3,060	4,888	2,151	300	1,367	1,258	—
Changes resulting from:									
Sales of oil and gas produced during the period	(3,965)	(3,429)	(2,092)	(1,474)	(889)	(329)	(264)	(258)	(157)
Discoveries and extensions, net of related costs	3,562	1,272	1,293	2,436	1,381	293	236	126	330
Purchases of proved AEC reserves in place	—	—	6,810	—	—	1,044	—	—	1,830
Purchases of proved reserves in place	531	26	93	2,786	340	613	—	93	—
Sales of proved reserves in place	(1,579)	(95)	(371)	(271)	(108)	(72)	—	(54)	—
Net change in prices and production costs	2,264	242	3,358	143	2,751	194	(294)	(47)	—
Revisions to quantity estimates	546	416	(1,345)	(542)	4	667	(125)	4	(354)
Accretion of discount	1,349	1,636	455	725	304	56	176	182	—
Previously estimated development costs incurred net of change in future development costs	57	340	101	22	534	54	15	89	—
Other	32	470	(67)	(49)	157	(51)	(29)	(27)	—
Net change in income taxes	(634)	304	(2,462)	(1,176)	(1,737)	(618)	120	1	(391)
Balance, end of year	12,178	10,015	8,833	7,488	4,888	2,151	1,202	1,367	1,258

	United Kingdom			Total		
	2004	2003	2002	2004	2003	2002
	($ millions)					
Balance, beginning of year	565	411	140	16,835	12,653	3,500
Changes resulting from:						
Sales of oil and gas produced during the period	(78)	(83)	(81)	(5,781)	(4,659)	(2,659)
Discoveries and extensions, net of related costs	—	—	594	6,234	2,779	2,510
Purchases of proved AEC reserves in place	—	—	—	—	—	9,684
Purchases of proved reserves in place	77	57	—	3,394	516	706
Sales of proved reserves in place	(899)	—	—	(2,749)	(257)	(443)
Net change in prices and production costs	—	(119)	(1)	2,113	2,827	3,551
Revisions to quantity estimates	—	157	(53)	(121)	581	(1,085)
Accretion of discount	82	91	14	2,332	2,213	525
Previously estimated development costs incurred net of change in future development costs	—	108	3	94	1,071	158
Other	—	(38)	(8)	(46)	562	(126)
Net change in income taxes	253	(19)	(197)	(1,437)	(1,451)	(3,668)
Balance, end of year	—	565	411	20,868	16,835	12,653

Results of Operations, Capitalized Costs and Costs Incurred

Results of Operations

	Canada			United States			Ecuador		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
	($ millions)								
Oil and gas revenues, net of royalties, transportation and selling costs	4,787	4,189	2,630	1,861	1,091	406	451	367	224
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	822	760	538	387	202	77	187	109	67
Depreciation, depletion and amortization	1,752	1,511	871	487	297	206	263	159	79
Operating income (loss)	2,213	1,918	1,221	987	592	123	1	99	78
Income taxes	841	218	456	375	219	47	5	17	28
Results of operations	1,372	1,700	765	612	373	76	(4)	82	50

	United Kingdom			Other			Total		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
	($ millions)								
Oil and gas revenues, net of royalties, transportation and selling costs	117	102	92	—	—	—	7,216	5,749	3,352
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	39	19	11	4	20	29	1,439	1,110	722
Depreciation, depletion and amortization	118	74	39	25	83	35	2,645	2,124	1,230
Operating income (loss)	(40)	9	42	(29)	(103)	(64)	3,132	2,515	1,400
Income taxes	(15)	17	17	—	(4)	—	1,206	467	548
Results of operations	(25)	(8)	25	(29)	(99)	(64)	1,926	2,048	852

Capitalized Costs

	Canada			United States			Ecuador		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
	($ millions)								
Proved oil and gas properties	22,455	18,549	12,504	7,552	3,485	2,769	1,784	1,372	1,000
Unproved oil and gas properties	1,855	1,981	1,573	728	501	415	45	70	60
Total capital cost	24,310	20,530	14,077	8,280	3,986	3,184	1,829	1,442	1,060
Accumulated DD&A	9,770	7,498	4,770	1,046	516	262	534	188	73
Net capitalized costs	14,540	13,032	9,307	7,234	3,470	2,922	1,295	1,254	987

	United Kingdom			Other			Total		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
	($ millions)								
Proved oil and gas properties	—	675	445	—	—	—	31,791	24,081	16,718
Unproved oil and gas properties	—	77	3	425	317	226	3,053	2,946	2,277
Total capital cost	—	752	448	425	317	226	34,844	27,027	18,995
Accumulated DD&A	—	230	136	247	206	98	11,597	8,638	5,339
Net capitalized costs	—	522	312	178	111	128	23,247	18,389	13,656

Costs Incurred

	Canada			United States			Ecuador		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
					($ millions)				
Acquisitions									
— AEC unproved reserves	—	—	1,496	—	—	444	—	—	221
— other unproved reserves	42	47	12	954	21	202	—	80	—
— AEC proved reserves	—	—	3,540	—	—	1,024	—	—	686
— other proved reserves	204	207	78	2,051	115	457	—	59	—
Total acquisitions	246	254	5,126	3,005	136	2,127	—	139	907
Exploration	555	846	403	164	187	226	28	20	35
Development	2,669	2,131	902	1,103	651	282	213	111	133
Total costs incurred	3,470	3,231	6,431	4,272	974	2,635	241	270	1,075

	United Kingdom			Other			Total		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
					($ millions)				
Acquisitions									
— AEC unproved reserves	—	—	—	—	—	—	—	—	2,161
— other unproved reserves	—	16	—	—	—	—	996	164	214
— AEC proved reserves	—	—	—	—	—	—	—	—	5,250
— other proved reserves	130	95	—	—	—	—	2,385	476	535
Total acquisitions	130	111	—	—	—	—	3,381	640	8,160
Exploration	22	30	16	79	78	118	848	1,161	798
Development	364	96	66	—	—	—	4,349	2,989	1,383
Total costs incurred	516	237	82	79	78	118	8,578	4,790	10,341

Daily Sales Volumes, Royalty Rates and Per-Unit Results

Daily Sales Volumes

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

	Daily Sales Volumes — 2004				
	Year	Q4	Q3	Q2	Q1
SALES					
Continuing Operations:					
Produced Gas ***(MMcf/d)***					
Canada					
Production	2,105	2,106	2,138	2,177	2,000
Inventory withdrawal/(injection)	(6)	(26)	—	—	—
Canada Sales[(1)]	2,099	2,080	2,138	2,177	2,000
United States	869	1,007	958	824	684
Total Produced Gas	2,968	3,087	3,096	3,001	2,684
Oil and Natural Gas Liquids ***(bbls/d)***					
North America					
Light and medium oil	56,215	52,725	52,824	64,448	54,940
Heavy oil	84,164	79,336	89,682	79,899	87,729
Natural gas liquids					
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[(2)]	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
Total Continuing Operations ***(BOE/d)***	661,084	673,970	685,673	670,854	613,210
Discontinued Operations:					
Ecuador					
Production[(3)]	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 Discontinued Operations ***(BOE/d)***	98,966	91,803	95,068	105,031	103,737
Total ***(MMcfe/d)***	4,560	4,595	4,684	4,655	4,302
Total ***(BOE/d)***	760,050	765,773	780,741	775,885	716,947

Notes:

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

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

(3) 2004 includes approximately 31,000 bbls/day related to Block 15.

	Daily Sales Volumes — 2003				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
SALES					
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					
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
Total Continuing Operations ***(BOE/d)***	591,395	618,138	592,537	569,168	585,628
Discontinued Operations:					
Ecuador					
Production	51,089	72,731	54,582	36,754	39,893
Transferred to OCP Pipeline(1)	(3,213)	—	(4,919)	(2,039)	(5,941)
Over/(under) lifting	(1,355)	4,621	(9,856)	2,506	(2,679)
Ecuador Sales *(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 Discontinued Operations ***(BOE/d)***	66,445	95,752	50,185	55,556	64,120
Total ***(MMcfe/d)***	3,947	4,283	3,856	3,748	3,899
Total ***(BOE/d)***	657,840	713,890	642,722	624,724	649,748

Note:

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

	Daily Sales Volumes — 2002				
	Year	Q4	Q3	Q2	Q1
SALES					
Continuing Operations:					
Produced Gas ***(MMcf/d)***					
Canada					
Production	1,717	1,943	1,959	1,980	975
Inventory withdrawal/(injection)	(6)	117	(51)	(90)	—
Canada Sales	1,711	2,060	1,908	1,890	975
United States	337	516	423	345	58
Total Produced Gas	2,048	2,576	2,331	2,235	1,033
Oil and Natural Gas Liquids ***(bbls/d)***					
North America					
Light and medium oil	58,328	55,265	58,321	58,885	60,903
Heavy oil	58,890	77,090	70,795	67,558	19,350
Natural gas liquids					
Canada	13,852	15,987	13,985	14,168	11,212
United States	6,407	10,016	5,901	6,368	3,274
Total Oil and Natural Gas Liquids	137,477	158,358	149,002	146,979	94,739
Total Continuing Operations ***(MMcfe/d)***	2,873	3,526	3,225	3,117	1,601
Total Continuing Operations ***(BOE/d)***	478,810	587,691	537,502	519,479	266,906
Discontinued Operations:					
Ecuador					
Production	27,625	34,856	37,447	37,702	—
Over/(under) lifting	2,115	1,044	2,316	5,088	—
Ecuador Sales *(bbls/d)*	29,740	35,900	39,763	42,790	—
United Kingdom *(BOE/d)*	12,195	9,120	11,038	13,299	14,722
Syncrude *(bbls/d)*	23,540	33,918	35,585	24,152	—
Total Discontinued Operations ***(MMcfe/d)***	393	474	518	481	88
Total Discontinued Operations ***(BOE/d)***	65,475	78,938	86,386	80,241	14,722
Total ***(MMcfe/d)***	3,266	4,000	3,743	3,598	1,689
Total ***(BOE/d)***	544,285	666,629	623,888	599,720	281,628

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.

	2004					2003					2002				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
	(percent)					(percent)					(percent)				
Continuing Operations:															
Produced Gas															
Canada	12.5	12.0	12.2	12.7	13.3	12.9	12.2	12.9	14.2	12.4	10.7	13.3	10.4	11.8	2.7
United States	19.6	19.8	18.3	21.1	19.3	20.0	19.5	20.2	20.1	20.5	21.1	21.1	23.1	19.4	19.4
Crude Oil															
Canada and United States	9.0	8.7	8.8	11.6	9.4	10.3	9.7	9.0	10.7	11.8	11.0	10.8	11.7	11.6	9.5
Natural Gas Liquids															
Canada	15.7	16.5	18.5	13.1	14.8	17.5	14.7	16.6	18.0	20.2	13.8	16.4	13.8	15.6	6.9
United States	18.7	21.4	13.6	20.7	19.2	17.6	17.5	17.0	17.3	18.5	10.8	13.3	12.0	10.5	—
Total Upstream	13.7	13.8	13.2	14.1	13.7	13.8	13.2	13.4	14.5	13.9	12.3	14.1	12.7	12.8	5.7
Discontinued Operations:															
Crude Oil — Ecuador	27.1	27.8	26.5	26.5	27.4	25.6	25.4	25.7	24.9	26.9	28.4	28.1	28.5	28.5	—

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 — 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 ($/Mcf)					
Price	5.47	6.08	5.18	5.34	5.26
Production and mineral taxes	0.25	0.29	0.24	0.27	0.19
Transportation and selling	0.36	0.35	0.33	0.35	0.43
Operating	0.48	0.50	0.46	0.46	0.50
Netback	4.38	4.94	4.15	4.26	4.14
Natural Gas Liquids — Canada ($/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

	Per-Unit Results — 2004				
	Year	Q4	Q3	Q2	Q1
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 — 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 ($/Mcfe)					
Price	5.30	5.83	5.22	5.15	4.98
Production and mineral taxes	0.21	0.25	0.21	0.22	0.16
Transportation and selling	0.31	0.27	0.30	0.30	0.37
Operating	0.55	0.59	0.53	0.52	0.58
Netback	4.23	4.72	4.18	4.11	3.87
Discontinued Operations:					
Crude Oil — Ecuador ($/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

	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 ($/Mcf)					
Price	4.87	4.49	4.66	4.88	5.49
Production and mineral taxes	0.16	0.18	0.17	0.17	0.14
Transportation and selling	0.39	0.46	0.40	0.35	0.33
Operating	0.43	0.41	0.46	0.43	0.42
Netback	3.89	3.44	3.63	3.93	4.60
Natural Gas Liquids — Canada ($/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

	Per-Unit Results — 2003				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
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 — North America ($/bbl)					
Price	22.72	21.69	20.81	22.88	25.88
Production and mineral taxes	0.19	0.43	(0.55)	0.49	0.44
Transportation and selling	1.14	1.28	0.59	1.28	1.46
Operating	4.97	4.74	5.13	5.18	4.85
Netback	16.42	15.24	15.64	15.93	19.13
Total North America ($/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

	Per-Unit Results — 2002				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Produced Gas — Canada ($/Mcf)					
Price[(1)]	2.86	3.60	2.29	2.93	2.25
Production and mineral taxes	0.08	0.07	0.04	0.10	0.14
Transportation and selling	0.24	0.30	0.21	0.21	0.22
Operating	0.41	0.44	0.42	0.40	0.31
Netback	2.13	2.79	1.62	2.22	1.58
Produced Gas — United States ($/Mcf)					
Price[(1)]	2.96	3.48	2.78	2.51	2.36
Production and mineral taxes	0.27	0.34	0.22	0.23	0.29
Transportation and selling	0.47	0.46	0.76	0.23	—
Operating	0.28	0.23	0.28	0.31	0.60
Netback	1.94	2.45	1.52	1.74	1.47
Produced Gas — Total North America ($/Mcf)					
Price[(1)]	2.87	3.58	2.37	2.86	2.26
Production and mineral taxes	0.11	0.12	0.08	0.12	0.15
Transportation and selling	0.28	0.33	0.31	0.22	0.21
Operating	0.39	0.40	0.39	0.39	0.32
Netback	2.09	2.73	1.59	2.13	1.58
Natural Gas Liquids — Canada ($/bbl)					
Price	17.55	21.75	17.61	17.41	11.56
Production and mineral taxes	—	—	—	—	—
Transportation and selling	—	—	—	—	—
Netback	17.55	21.75	17.61	17.41	11.56
Natural Gas Liquids — United States ($/bbl)					
Price	23.75	25.14	25.64	23.57	16.31
Production and mineral taxes	1.02	0.94	1.32	1.37	—
Transportation and selling	—	—	—	—	—
Netback	22.73	24.20	24.32	22.20	16.31
Natural Gas Liquids — Total North America ($/bbl)					
Price	19.52	23.06	19.99	19.32	12.64
Production and mineral taxes	0.32	0.36	0.39	0.42	—
Transportation and selling	—	—	—	—	—
Netback	19.20	22.70	19.60	18.90	12.64
Crude Oil — Light and Medium — North America ($/bbl)					
Price	22.31	24.39	24.09	23.37	17.60
Production and mineral taxes	0.65	0.48	0.51	0.14	1.44
Transportation and selling	0.94	1.22	1.04	0.62	0.87
Operating	4.80	5.15	4.72	5.29	4.08
Netback	15.92	17.54	17.82	17.32	11.21

Note:

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

	Per-Unit Results — 2002				
	Year	Q4	Q3	Q2	Q1
Crude Oil — Heavy — North America ($/bbl)					
Price	17.88	17.38	19.67	17.76	13.62
Production and mineral taxes	0.22	0.54	0.03	0.04	0.32
Transportation and selling	0.71	0.93	0.81	0.48	0.21
Operating	4.58	4.12	4.96	4.39	5.73
Netback	12.37	11.79	13.87	12.85	7.36
Crude Oil — Total North America ($/bbl)					
Price	20.08	20.31	21.67	20.37	16.64
Production and mineral taxes	0.43	0.51	0.25	0.08	1.17
Transportation and selling	0.82	1.05	0.92	0.55	0.71
Operating	4.69	4.55	4.85	4.81	4.48
Netback	14.14	14.20	15.65	14.93	10.28
Total Liquids — Canada ($/bbl)					
Price	19.82	20.46	21.27	20.07	16.01
Production and mineral taxes	0.39	0.46	0.22	0.08	1.03
Transportation and selling	0.73	0.94	0.83	0.49	0.63
Operating	4.19	4.06	4.38	4.32	3.93
Netback	14.51	15.00	15.84	15.18	10.42
Total Liquids — North America ($/bbl)					
Price	20.00	20.76	21.44	20.22	16.03
Production and mineral taxes	0.42	0.49	0.27	0.13	0.99
Transportation and selling	0.70	0.88	0.79	0.47	0.60
Operating	4.00	3.80	4.20	4.14	3.79
Netback	14.88	15.59	16.18	15.48	10.65
Total North America ($/Mcfe)					
Price	3.01	3.55	2.71	3.01	2.41
Production and mineral taxes	0.10	0.11	0.07	0.10	0.15
Transportation and selling	0.23	0.28	0.26	0.18	0.17
Operating	0.47	0.46	0.48	0.47	0.43
Netback	2.21	2.70	1.90	2.26	1.66
Discontinued Operations:					
Crude Oil — Ecuador ($/bbl)					
Price	22.57	24.02	22.82	21.11	—
Production and mineral taxes	1.24	1.57	1.49	0.72	—
Transportation and selling	2.00	1.99	2.47	1.56	—
Operating	4.86	5.35	4.12	5.13	—
Netback	14.47	15.11	14.74	13.70	—
Crude Oil — United Kingdom ($/bbl)					
Price	24.76	25.73	27.07	25.92	21.18
Production and mineral taxes	—	—	—	—	—
Transportation and selling	1.69	1.53	1.92	1.62	1.65
Operating	3.28	7.07	3.65	2.01	1.78
Netback	19.79	17.13	21.50	22.29	17.75

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

	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)	—	—	—	—	—

	2002				
	Year	Q4	Q3	Q2	Q1
Continuing Operations:					
Natural Gas ($/Mcf)	0.09	0.02	0.26	(0.06)	0.20
Liquids ($/bbl)	(0.64)	(0.73)	(0.56)	(0.72)	(0.53)
Total ($/Mcfe)	0.03	(0.02)	0.16	(0.08)	0.10
Discontinued Operations:					
Ecuador Oil ($/bbl)	(0.01)	—	—	(0.03)	—
United Kingdom Oil ($/bbl)	(0.06)	—	—	—	(0.19)

Note:

(1) Excludes hedges unwound as a result of the U.K. 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:											
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
2002:											
Canada	423	382	84	72	44	37	551	491	190	741	491
United States	12	12	2	1	3	1	17	14	—	17	14
Other	—	—	—	—	4	2	4	2	—	4	2
Total	435	394	86	73	51	40	572	507	190	762	507
Discontinued Operations:											
Ecuador – 2004	—	—	6	3	—	—	6	3	—	6	3
Ecuador – 2003	—	—	3	2	—	—	3	2	—	3	2
Ecuador – 2002	—	—	7	5	—	—	7	5	—	7	5
United Kingdom – 2004	—	—	1	—	4	2	5	2	—	5	2
United Kingdom – 2003	—	—	2	1	5	3	7	4	—	7	4
United Kingdom – 2002	—	—	7	3	2	1	9	4	—	9	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:											
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
2002:											
Canada	1,397	1,340	433	349	30	23	1,860	1,712	690	2,550	1,712
United States	287	250	3	3	1	1	291	254	—	291	254
Total	1,684	1,590	436	352	31	24	2,151	1,966	690	2,841	1,966
Discontinued Operations:											
Ecuador – 2004	—	—	43	25	1	1	44	26	—	44	26
Ecuador – 2003	—	—	53	39	6	6	59	45	—	59	45
Ecuador – 2002	—	—	44	37	5	4	49	41	—	49	41
United Kingdom – 2004	—	—	3	1	—	—	3	1	—	3	1
United Kingdom – 2003	—	—	3	—	—	—	3	—	—	3	—
United Kingdom – 2002	—	—	2	—	—	—	2	—	—	2	—

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, 2004, EnCana was in the process of drilling 33 gross wells (32 net wells) in Canada, 50 gross wells (45 net wells) in the United States, 4 gross wells (2 net wells) in Ecuador and no wells in other countries.

Location of Wells

The following table summarizes EnCana's interest in producing wells and wells capable of producing as at December 31, 2004:

	Gas		Oil		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Continuing Operations:						
Alberta	29,790	27,943	4,700	4,151	34,490	32,094
British Columbia	1,329	1,196	16	10	1,345	1,206
Saskatchewan	336	332	1,177	515	1,513	847
Manitoba	—	—	3	3	3	3
Total Canada	31,455	29,471	5,896	4,679	37,351	34,150
Colorado	3,902	3,155	—	—	3,902	3,155
Texas	1,179	762	30	12	1,209	774
Wyoming	1,493	874	—	—	1,493	874
Montana	42	37	—	—	42	37
Utah	33	32	—	—	33	32
Oklahoma	47	12	—	—	47	12
Louisiana	4	2	—	—	4	2
Gulf of Mexico	—	—	6	1	6	1
Total United States	6,700	4,874	36	13	6,736	4,887
Total	38,155	34,345	5,932	4,692	44,087	39,037
Discontinued Operations:						
Ecuador	—	—	289	227	289	227

Notes:

(1) EnCana has varying royalty interests in 8,396 crude oil wells and 12,970 natural gas wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows: 26,879 gross natural gas wells (24,441 net wells) and 1,681 gross crude oil wells (1,393 net wells).

Interest in Material Properties

The following table summarizes EnCana's developed, undeveloped and total landholdings as at December 31, 2004:

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
				(thousands of acres)			
Continuing Operations:							
Canada							
Alberta	— Fee	4,319	4,319	2,835	2,835	7,154	7,154
	— Crown	3,709	2,989	6,643	5,578	10,352	8,567
	— Freehold	185	101	245	192	430	293
		8,213	7,409	9,723	8,605	17,936	16,014
British Columbia	— Crown	697	579	4,174	3,601	4,871	4,180
	— Freehold	—	—	7	7	7	7
		697	579	4,181	3,608	4,878	4,187
Saskatchewan	— Fee	57	57	461	461	518	518
	— Crown	115	96	1,064	1,049	1,179	1,145
	— Freehold	13	9	104	97	117	106
		185	162	1,629	1,607	1,814	1,769
Manitoba	— Fee	3	3	265	265	268	268
	— Freehold	—	—	23	23	23	23
		3	3	288	288	291	291
Newfoundland & Labrador	— Crown	—	—	4,027	2,514	4,027	2,514
Nova Scotia	— Crown	—	—	1,834	1,043	1,834	1,043
Northwest Territories	— Crown	—	—	633	234	633	234
Nunavut	— Crown	—	—	817	26	817	26
Beaufort	— Crown	—	—	126	4	126	4
Total Canada		9,098	8,153	23,258	17,929	32,356	26,082

		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
				(thousands of acres)			
United States							
Colorado	— Federal/State Lands	208	180	821	745	1,029	925
	— Freehold	112	102	212	191	324	293
	— Fee	3	3	60	60	63	63
		323	285	1,093	996	1,416	1,281
Washington	— Federal/State Lands	—	—	459	456	459	456
	— Freehold	—	—	199	199	199	199
	— Federal Acquired Lease	—	—	219	213	219	213
		—	—	877	868	877	868
Texas	— Federal/State Lands	8	3	205	204	213	207
	— Freehold	161	97	431	395	592	492
		169	100	636	599	805	699
Wyoming	— Federal/State Lands	148	73	729	490	877	563
	— Freehold	26	18	81	46	107	64
	— Bureau of Indian Affairs	11	10	5	4	16	14
		185	101	815	540	1,000	641
Gulf of Mexico	— Federal/State Lands	—	—	1,371	557	1,371	557
Alaska	— Federal/State Lands	—	—	1,337	531	1,337	531
Other	— Federal Lands	11	10	374	236	385	246
	— Freehold	19	10	22	13	41	23
	— Fee	1	1	—	—	1	1
		31	21	396	249	427	270
Total United States		708	507	6,525	4,340	7,233	4,847
Chad		—	—	108,536	54,268	108,536	54,268
Oman		—	—	9,606	9,606	9,606	9,606
Qatar		—	—	2,161	2,161	2,161	2,161
Greenland		—	—	985	862	985	862
Yemen		—	—	1,879	691	1,879	691
Brazil		—	—	1,444	554	1,444	554
Australia		—	—	960	320	960	320
Bahrain		—	—	97	48	97	48
Azerbaijan		—	—	346	17	346	17
Total International		—	—	126,014	68,527	126,014	68,527
Total		9,806	8,660	155,797	90,796	165,603	99,456
Discontinued Operations:							
Ecuador		160	99	1,243	795	1,403	894

Notes:

(1) This table excludes approximately 4.3 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. In prior years, 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 or equity or a combination of both.

The following table summarizes EnCana's net capital investment for 2003 and 2004.

	2004	**2003**
	($ millions)	
Upstream		
Canada	3,015	2,937
United States	1,249	830
International New Ventures Exploration	79	78
	4,343	3,845
Midstream & Marketing	64	223
Corporate	46	57
Core Capital from Continuing Operations	4,453	4,125
Acquisitions		
Upstream		
Property		
Canada	64	261
United States	300	138
Corporate		
Savannah	—	91
Petrovera	253	—
Tom Brown, Inc. (1)	2,335	—
Midstream & Marketing		
Other	34	53
Corporate	—	50
Dispositions		
Upstream		
Property		
Canada	(877)	(108)
United States	(266)	(178)
Other Countries	—	(15)
Corporate		
Petrovera	(540)	—
Midstream & Marketing		
Property	(1)	—
Corporate		
Alberta Ethane Gathering System Joint Venture	(108)	—
Kingston CoGen Partnership	(25)	—
Net Acquisition and Disposition Activity from Continuing Operations	1,169	292
Proceeds of Disposition of United Kingdom	(2,144)	—
Discontinued Operations	728	(995)
Total Discontinued Operations	(1,416)	(995)

Note:

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

EnCana plans to dispose of various non-core assets in 2005, including its interests in Ecuador, the Gulf of Mexico, select western Canadian conventional properties, U.S. gathering and processing assets 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. These commitments comprise a small portion of EnCana's total revenues and 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 19 to EnCana's audited consolidated financial statements for the year ended December 31, 2004.

GENERAL

Competitive Conditions

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

Environmental Protection

EnCana's worldwide operations are subject to government laws and regulations concerning pollution, protection of the environment and the handling and transport of hazardous materials. These laws and regulations generally require EnCana to remove or remedy the effect of its activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by the use or release of specified substances. The Corporate Responsibility, Environment, Health and Safety Committee of EnCana's Board of Directors 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 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 2004, expenditures beyond normal compliance with environmental regulations were not material. EnCana does not anticipate making material expenditures beyond normal compliance with environmental regulations in 2005.

Based on EnCana's current estimate, the total anticipated undiscounted future cost of abandonment and reclamation costs to be incurred over the life of the reserves is estimated at $3.7 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) implementation of a comprehensive on-line approach to training and communicating policies and practices, as well as face-to-face sessions; (ii) development and implementation of an environment, health and safety management system; (iii) development of a security program to regularly assess security threats to business operations and manage the associated risks; (iv) the introduction, in the first quarter of 2005, of a formalized approach to stakeholder relations with a standardized Stakeholder Engagement Guide; (v) development of corporate responsibility performance metrics to track the Corporation's progress; (vi) contribution of a minimum of one percent of EnCana's pre-tax profits to charitable and non-profit organizations in the communities in which the company operates; and (vii) the adoption of 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, 2004, EnCana employed 4,090 full time equivalent (''FTE'') employees as set forth in the following table:

	Number of FTE Employees As at December 31, 2004
Upstream	3,176
Midstream & Marketing	306
Corporate	608
Total	4,090

Foreign Operations

As at December 31, 2004, approximately 94 percent of EnCana's reserves and 89 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 ''Introductory Information'' 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. 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 reduce administrative burdens.

DIRECTORS AND OFFICERS

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

Directors

Name and Municipality of Residence	Director Since[13]	Principal Occupation
MICHAEL N. CHERNOFF[2,6] West Vancouver, British Columbia, Canada	1999	Corporate Director
RALPH S. CUNNINGHAM[2,3] Houston, Texas, United States	2003	Corporate Director
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)*
WILLIAM R. FATT[1,8] Toronto, Ontario, Canada	1995	Chief Executive Officer Fairmont Hotels & Resorts Inc. *(Hotels)*
MICHAEL A. GRANDIN[3,5,6,9] Calgary, Alberta, Canada	1998	Dean of the Haskayne School of Business University of Calgary *(Education)*
BARRY W. HARRISON[1,4,10] Calgary, Alberta, Canada	1996	Corporate Director and independent businessman
RICHARD F. HASKAYNE, O.C., F.C.A.[3,4] Calgary, Alberta, Canada	1992	Chairman of the Board TransCanada Corporation *(Pipelines and energy services)*
DALE A. LUCAS[1,5] Calgary, Alberta, Canada	1997	Corporate Director
KEN F. MCCREADY[2,5,11] Calgary, Alberta, Canada	1992	President K.F. McCready & Associates Ltd. *(Sustainable energy development consulting company)*
GWYN MORGAN Calgary, Alberta, Canada	1993	President & Chief Executive Officer EnCana Corporation
VALERIE A. A. NIELSEN[2,6] Calgary, Alberta, Canada	1990	Corporate Director
DAVID P. O'BRIEN[4,7,12] Calgary, Alberta, Canada	1990	Chairman EnCana Corporation Chairman Royal Bank of Canada
JANE L. PEVERETT[1] West Vancouver, British Columbia, Canada	2003	Chief Financial Officer British Columbia Transmission Corporation *(Electricity transmission)*
DENNIS A. SHARP[2,4] Calgary, Alberta, Canada/ Montreal, Quebec, Canada	1998	Executive Chairman UTS Energy Corporation *(Oil and natural gas 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. Fatt was a director of Unitel Communications Inc. (''Unitel'') in 1995 when it made a filing pursuant to the *Companies' Creditors Arrangement Act* (Canada). Unitel instituted a compromise with creditors on December 8, 1995 and Mr. Fatt resigned as a director in January 1996.

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

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

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

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

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

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

At the date of this annual information form, there are 16 directors of the Corporation. At the next Annual Meeting of Shareholders, shareholders will be asked to elect as directors the 15 nominees listed in the above table (all but Mr. Haskayne who will be retiring from the Board) to serve until the close of the next annual meeting of shareholders, or until their respective successors are duly elected or appointed. Subject to mandatory retirement age restrictions which have been established by the Board of Directors, all of the directors shall be eligible for re-election.

Executive Officers

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

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

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

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

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

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

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

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

All of the directors and executive officers of EnCana listed above beneficially owned, as of February 22, 2005, directly or indirectly, or exercised control or direction over an aggregate of 1,234,169 Common Shares representing 0.28 percent of the issued and outstanding voting shares of EnCana, and directors and executive officers held options to acquire an aggregate of 2,049,484 additional Common Shares.

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

AUDIT COMMITTEE INFORMATION

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

Composition of the Audit Committee

The audit committee consists of six members, all of which are independent and financially literate. The Corporation has adopted the definition of ''independence'' as set out in Section 1.4 of the proposed amendments to Multilateral Instrument 52-110 *Audit Committees*, as published on October 29, 2004. 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 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) and a Trustee of Enbridge Commercial Trust, a subsidiary entity of Enbridge Income Fund.

William R. Fatt

Mr. Fatt holds a Bachelor of Arts in Economics (York University). He is the Chief Executive Officer and a director of Fairmont Hotels & Resorts Inc. (hotel management). He is also a director and member of the Audit Committee of Enbridge Inc. (energy delivery company), a director of Sun Life Financial Inc. (life insurers) and The Jim Pattison Group (private company), and Vice Chairman and Trustee of Legacy Hotels Real Estate Investment Trust.

Mr. Fatt is the former Chairman and Chief Executive Officer of FHR Holdings Inc. (formerly known as Canadian Pacific Hotels and Resorts, Inc.). He has served in a number of finance-related positions in his 30-year career, including Executive Vice President and Chief Financial Officer of Canadian Pacific Limited, Treasurer of CP Limited, Vice-President of Morgan Bank of Canada and Vice President and Treasurer of Hiram Walker Resources Ltd., among others.

Barry W. Harrison (Audit Committee Chair)

Mr. Harrison holds a Bachelor of Business Administration and Banking (Colorado College) and a Bachelor of Law (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 Co. and its U.S. subsidiary, the Wawanesa General Insurance Co. 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 consults 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 the Chief Financial Officer of British Columbia Transmission Corporation (electrical transmission). 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: Inco Limited (mining company), OPTI Canada Inc. (oilsands development and upgrading company), NOVA Chemicals Corporation (commodity chemical company) and Terasen Inc. (energy distribution and energy transportation company). He is Chairman of the Audit Committee of Inco Limited. 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 2004 and 2003:

($ thousands)	2004	2003
Audit Fees(1)	3,177	1,977
Audit-Related Fees(2)	166	127
Tax Fees(3)	1,097	1,408
All Other Fees(4)	24	26
Total	4,464	3,538

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 2004 and 2003, 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 2004 and 2003, 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 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. During fiscal 2003, the services provided in this category included the review of EnCana's Corporate Responsibility Report and the payment of maintenance fees associated with a working paper documentation package used by the Corporation's internal audit group.

In 2003, $35,300 of the fees listed above billed by PricewaterhouseCoopers LLP in respect of tax services were approved by the audit committee pursuant to the *de minimus* exception provided by Section (c)(7)(i)(C) of Rule 2-01 of SEC Regulation S-X. EnCana did not rely on the *de minimus* exemption in 2004.

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, 2004 there were approximately 450.3 million Common Shares issued and outstanding and no Preferred Shares outstanding.

Common Shares

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

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

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, 2004.

	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 eleven 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. On September 8, 2004, S&P affirmed EnCana's long-term A– rating, removed the rating from CreditWatch with negative implications and assigned a negative outlook to the rating. 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 C, representing the range from highest to lowest quality. A-1 (low) is the third highest of seven 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 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 with 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 companies. The assignment of a ''(high)'' or ''(low)'' modifier within each rating category indicates relative standing within such category. The ''high'' and ''low'' grades are not used for the AAA 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 judgement 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 and the New York Stock Exchange under the symbol ECA. The following table outlines the share price trading range and volume of shares traded by month in 2004.

	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)
2004								
January	56.00	51.00	51.58	36.4	43.43	39.00	39.10	9.2
February	58.25	51.29	57.84	27.5	43.60	38.36	43.45	10.4
March	59.27	54.22	56.69	35.5	44.25	40.62	43.12	9.9
April	59.73	53.75	53.80	30.3	44.73	39.18	39.22	13.7
May	57.70	52.99	54.55	29.2	42.05	38.05	39.35	12.5
June	58.85	53.55	57.62	25.8	43.41	39.45	43.16	9.7
July	60.60	56.55	58.90	26.3	45.75	42.83	44.32	10.7
August	59.94	52.30	53.66	28.4	45.50	39.95	41.10	12.1
September	59.46	53.40	58.35	26.7	46.92	41.09	46.30	10.6
October	62.81	57.90	60.40	36.1	50.26	46.10	49.40	15.1
November	68.20	59.61	67.80	40.5	57.43	48.85	57.03	19.8
December	70.02	63.13	68.40	33.1	57.30	51.59	57.06	18.7

In October 2004, EnCana received approval from the Toronto Stock Exchange (''TSX'') to continue to purchase, for cancellation, Common Shares under a Normal Course Issuer Bid (the ''Bid''). Under the Bid, EnCana was entitled to purchase up to 5 percent of the Common Shares issued and outstanding on October 22, 2004, over a period ending October 28, 2005. In February 2005, EnCana received approval from the TSX to amend the Bid. Under the amended Bid, EnCana is entitled to purchase up to 46.1 million Common Shares (10 percent of the public float on October 22, 2004). Purchases may be made through the facilities of the TSX and the New York Stock Exchange, in accordance with the policies and rules of each exchange. As of December 31, 2004, the Corporation had purchased approximately 14.8 million shares under the Bid. During 2004, EnCana purchased a total of approximately 20 million shares, for approximately $1.0 billion, under the terms of its Normal Course Issuer Bids.

The following table outlines the debt securities issued by the Corporation in 2004 that are not listed or quoted on an exchange.

Issuer	Principal Amount	Coupon	Issue Date	Maturity Date	Issue Price
EnCana Holdings Finance Corp.[1]	$1 billion	5.80%	May 13, 2004	May 1, 2014	99.614%
EnCana Corporation	$250 million	4.60%	August 4, 2004	August 15, 2009	99.838%
EnCana Corporation	$750 million	6.50%	August 4, 2004	August 15, 2034	99.123%

Note:

(1) EnCana Holdings Finance Corp. (''EHF'') is an indirect, wholly owned subsidiary of EnCana Corporation. The notes issued by EHF are fully and unconditionally guaranteed by EnCana Corporation.

DIVIDENDS

The declaration of dividends is at the discretion of the Board of Directors and is approved quarterly. In 2002 and 2003, cash dividends were paid to common shareholders at a rate of C$0.40 per share annually (C$0.10 per share quarterly). In 2004, EnCana began paying cash dividends to common shareholders in United States dollars at a rate of $0.40 per share annually ($0.10 per share quarterly). EnCana's Board of Directors has declared a dividend of $0.10 per share payable on March 31, 2005 to common shareholders of record on March 15, 2005.

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 result in unutilized long-term transportation commitments, all of which could have an adverse effect on the Corporation's revenues, profitability and cash flows.

The market prices for heavy oil are lower than the established market indices for light and medium grades of oil, due principally to diluent prices and the higher transportation and refining costs associated with heavy oil. Also, production costs associated with heavy oil are relatively higher than for lighter grades. 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 or discovering 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, interest rates and foreign exchange 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, changes in interest rates or increases in the value of currencies relative to the United States dollar.

The terms of the Corporation's various hedging agreements may limit the benefit to the Corporation of commodity price increases, changes in interest rates or decreases in the value of currencies relative to the United States dollar. 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.

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. 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.

In 1994, the United Nations' Framework Convention on Climate Change came into force and three years later led to the Kyoto Protocol (the ''Protocol'') which requires, upon ratification, nations to reduce their emissions of carbon dioxide and other greenhouse gases. In December 2002, the Canadian federal government ratified the Protocol and on February 16, 2005, the Protocol came into force internationally. Currently the upstream crude oil and natural gas sector is in discussions with various provincial and federal levels of government regarding the development of greenhouse gas regulations for the industry. It is premature to predict what impact these potential regulations could have on EnCana's sector but it is possible that EnCana would face increases in operating costs in order to comply with a greenhouse gas emissions target.

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 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 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 reservoirs, 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;
- 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'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 equipment;
- the ability to access lands;
- inclement 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 and tie-in of wells, production, abandonment of fields and the construction or expansion of facilities. Contract rights can be cancelled or expropriated. Changes to government regulation could impact the Corporation's existing and planned projects.

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 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 to artificially raise the price of natural gas through various means including the illegal sharing of price information through online trading, price indexes and wash trading. The Gallo complaint claims damages in excess of $30 million, before potential trebling under California laws. A motion by EnCana to dismiss the Gallo complaint on the basis that the Federal Energy Regulatory Commission had exclusive jurisdiction regarding this matter was not granted.

In addition, EnCana Corporation and WD, along with other energy companies, have been named as defendants in several class action lawsuits in California and New York federal and state courts. The California lawsuits relate to sales of natural gas in California from 1999 to the present and contain essentially similar allegations as in the Gallo complaint. The New York lawsuits claim that the defendants' alleged manipulation of natural gas price indexes resulted in higher prices of natural gas futures and option contracts traded on the New York Mercantile Exchange (NYMEX) during the period from January 1, 2000 to December 31, 2002. EnCana Corporation has been dismissed from the New York lawsuits, leaving WD and several other companies unrelated to the Corporation as the remaining defendants. Most of the California lawsuits have been consolidated in Nevada District Court and all of the New York lawsuits have been consolidated in New York District Court. The Nevada District Court has remanded the California State Court cases back to the California State Court for hearing. As is customary, none of the class actions 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 these 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:	In the United States:
CIBC Mellon Trust Company	Mellon Investor Services LLC
320 Bay Street	44 Wall Street, 6th Floor
P.O. Box 1	New York, New York
Toronto, ON M5H 4A6	10005
Tel: 1-800-387-0825	Tel: 1-800-387-0825
Web site: www.cibcmellon.com	Web site: 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, 2004. Information relating to reserves in this annual information form dated February 25, 2005 was calculated by Gilbert Laustsen Jung Associates Ltd., McDaniel & Associates Consultants Ltd., Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton as independent qualified reserves evaluators.

The principals of each of Gilbert Laustsen Jung Associates 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, 2004.

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, 2004. The reserves data consist of the following:

   (i) estimated proved oil and gas reserve quantities as at December 31, 2004 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, 2004:

		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 14, 2005	Canada	3,434	146	9,770
Gilbert Laustsen Jung Associates Ltd. January 14, 2005	Canada	2,390	121	6,529
Netherland, Sewell & Associates, Inc. January 14, 2005	United States	3,946	49	9,276
DeGolyer and MacNaughton February 3, 2005	United States	690	42	1,907
Gilbert Laustsen Jung Associates Ltd. January 14, 2005	Ecuador		143	1,752
Totals		10,460	501	29,234

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

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

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

Executed as to our report referred to above:

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

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

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

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

February 14, 2005

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, 2004 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 14, 2005 (the ''IQRE Report''), highlighting the standards they followed and their results, accompanies this Report.

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

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

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

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

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

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

(b) the filing of the IQRE Report; and

(c) the content and filing of this Report.

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

(signed) Gwyn Morgan
President & Chief Executive Officer

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

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

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

February 22, 2005

APPENDIX C

Audit Committee Mandate

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 unrelated Directors and who are free from any relationship that would interfere with the exercise of his or her independent judgement.

All members of the Committee shall be financially literate, as defined by the Board, 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, director's 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.