C A N A D I A N N A T U R A L R E S O U R C E S L I M I T E D

ANNUAL INFORMATION FORM

March 30, 2005

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CURRENCY

Unless otherwise indicated, all dollar figures stated in this Annual Information Form represent Canadian dollars.

DEFINITIONS

The following are definitions of selected abbreviations used in this Annual Information Form:

"**ARTC**" means Alberta Royalty Tax Credit.

"**bbl**" or "**barrel**" means 34.972 Imperial gallons or 42 U.S. gallons.

"**Bcf**" means one billion cubic feet.

"**bbls/d**" means barrels per day.

"BOE" or **"boe"** means natural gas is converted to oil equivalent at the rate of six thousand cubic feet equals one barrel of oil equivalent.

"Canadian Natural Resources Limited", **"Canadian Natural", "CNRL"** or **"Company"** means Canadian Natural Resources Limited and includes, where applicable, reference to subsidiaries of and partnership interests held by Canadian Natural Resources Limited and its subsidiaries.

"**FPSO**" means floating production, storage and off-take vessel.

"**gross acres**" means the total number of acres in which the Company holds a working interest or the right to earn a working interest.

"**gross wells**" means the total number of wells in which the Company has a working interest.

"**mbbl**" means one thousand barrels.

"**mcf**" means one thousand cubic feet.

"**mcf/d**" means one thousand cubic feet per day.

"**mmbbl**" means one million barrels.

"**mmbtu**" means one million British thermal units.

"**mmcf**" means one million cubic feet.

"**mmcf/d**" means one million cubic feet per day.

"**NGLs**" means natural gas liquids.

"**net acres**" refers to gross acres multiplied by the percentage working interest therein owned or to be owned by the Company.

"**net wells**" refers to gross wells multiplied by the percentage working interest therein owned or to be owned by the Company.

"**SAGD**" means steam-assisted gravity drainage.

"**undeveloped land**" or "**non-reserve acreage**" refers to lands on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas.

"**working interest**" means the interest held by the Company in a crude oil or natural gas property, which interest normally bears its proportionate share of the costs of exploration, development, and operation as well as any royalties or other production burdens.

"**WTI**" means West Texas Intermediate.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document or incorporated herein by reference may constitute "forward-looking statements" within the meaning of the United States Private Litigation Reform Act of 1995. These forward-looking statements can generally be identified as such because of the context of the statements including words such as the Company "believes", "anticipates", "expects", "plans", "estimates", or words of a similar nature.

The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: the general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; the foreign currency exchange rates; the economic conditions in the countries and regions in which the Company conducts business; the political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; the industry capacity; the ability of the Company to implement its business strategy, including exploration and development activities; the impact of competition, availability and cost of seismic, drilling and other equipment; the ability of the Company to complete its capital programs; the ability of the Company to transport its products to market; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the operating hazards and other difficulties inherent in the exploration for and production and sale of oil and natural gas; the availability and cost of financing; the success of exploration and development activities; the timing and success of integrating the business and operations of acquired companies; the production levels; the uncertainty of reserve estimates; the actions by governmental authorities; the government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); the site restoration costs; and other circumstances affecting revenues and expenses. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors, and management's course of action would depend upon its assessment of the future considering all information then available.

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 can be profitably produced in the future.

Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. The Company assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

Special Note Regarding Currency, Production and Reserves

In this document, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data is presented on a before royalties basis unless otherwise stated. In addition, reference is made to oil and natural gas in common units called barrel of oil equivalent ("boe"). A boe is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6mcf:1bbl). This conversion may be misleading, particularly if used in isolation, since the 6mcf:1bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

Canadian Natural retains qualified independent reserves evaluators to evaluate the Company's proved and probable oil and natural gas reserves and prepare Evaluation Reports on the Company's total reserves. Canadian Natural has been granted an exemption from National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute United States Securities and Exchange Commission (SEC) requirements for certain disclosures required under NI 51-101. The primary difference between the two standards is the additional requirement under NI 51-101 to disclose proved and probable reserves and future net revenues using forecast prices and costs. The Company has disclosed proved reserves using constant prices and costs as mandated by the SEC and has elected to provide proved plus probable reserves and values under the same parameters as well as proved and proved plus probable reserves using forecast prices and costs as additional voluntary information. Another difference between the two standards is in the definition of proved reserves. As discussed in the Canadian Oil and Gas Evaluation Handbook (COGEH), the standards which NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material. The Board of Directors of the Company has a Reserves Committee, which has met with each of the Company's third party reserve evaluators and carried out independent due diligence procedures with them as to the Company's reserves.

Reserves and net asset values presented for years prior to 2003 were evaluated in accordance with the standards of National Policy 2-B which has now been replaced by NI 51-101. The stated reserves were reasonably evaluated as economically productive using year-end costs and prices escalated at appropriate rates throughout the productive life of the properties.

Horizon oil sands mining reserves have been evaluated under SEC Industry Guide 7. Resource potential as determined for thermal oil assets and other potential mining leases are determined using generally accepted industry methodologies for resource delineation based upon stratigraphic well drilling completed on the properties.

Special Note Regarding non-GAAP Financial Measures

Management's discussion and analysis includes references to financial measures commonly used in the oil and gas industry, such as cash flow, cash flow per share and EBITDA (net earnings before interest, taxes, depreciation depletion and amortization, asset retirement obligation accretion, unrealized foreign exchange, stock-based compensation expense and unrealized risk management activity). These financial measures are not defined by generally accepted accounting principles ("GAAP") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate the performance of the Company and of its business segments. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company's performance.

THE COMPANY

Canadian Natural Resources Limited was incorporated under the laws of the Province of British Columbia on November 7, 1973 as AEX Minerals Corporation (N.P.L.) and on December 5, 1975 changed its name to Canadian Natural Resources Limited. CNRL was continued under the *Companies Act of Alberta* on January 6, 1982 and was further continued under the *Business Corporations Act* (Alberta) on November 6, 1985. The head, principal and registered office of the Company is located in Calgary, Alberta, Canada at 2500, 855 – 2nd Street S.W., T2P 4J8.

CNRL formed a wholly owned subsidiary, CanNat Resources Inc. ("CanNat") in January 1995. Pursuant to a Plan of Arrangement, the Company acquired all of the outstanding shares of Sceptre Resources Limited ("Sceptre") in September 1996 and in January 1997, Sceptre and CanNat amalgamated pursuant to the *Business Corporations Act* (Alberta) under the name CanNat Resources Inc.

Pursuant to an Offer to Purchase all of the outstanding shares, the Company completed the acquisition of Ranger Oil Limited, including its subsidiaries, ("Ranger") in July 2000. On October 1, 2000 Ranger and the Company amalgamated pursuant to the *Business Corporations Act* (Alberta) under the name Canadian Natural Resources Limited.

Pursuant to a Plan of Arrangement, the Company acquired all of the outstanding shares of Rio Alto Exploration Ltd. ("RAX") in July 2002. On January 1, 2003 RAX and the Company amalgamated pursuant to the *Business Corporations Act* (Alberta) under the name Canadian Natural Resources Limited.

On January 1, 2004 CanNat and the Company amalgamated pursuant to the *Business Corporations Act* (Alberta) under the name Canadian Natural Resources Limited.

The material operating subsidiaries of the Company, each of which is directly or indirectly wholly-owned, and their jurisdiction of incorporation are as follows:

Name of Company	Jurisdiction of Incorporation
CNR (ECHO) Resources Inc.	Alberta
CNR International (U. K.) Investments Limited	England
CNR International (U. K.) Limited	England
CNR International Côte d'Ivoire SARL	Côte d'Ivoire
Renata Resources Inc.	Alberta

CNRL as the managing partner and CNR (ECHO) Resources Inc. and Renata Resources Inc. are the partners of Canadian Natural Resources, a general partnership. Canadian Natural Resources as the managing partner and Renata Resources Inc. and CNRL are partners of Canadian Natural Resources Northern Alberta Partnership, a general partnership. The two partnerships hold the Canadian crude oil and natural gas properties of CNRL. CNRL also has a 15 per cent interest in Cold Lake Pipeline Ltd., which is the general partner of Cold Lake Pipeline Limited Partnership of which CNRL has a 14.7 per cent interest. CNRL as the managing partner and Renata Resources Inc. are the partners of Canadian Natural Resources 2005 Partnership, a general partnership which holds certain natural gas facilities situated in Alberta.

The consolidated financial statements of CNRL include the accounts of the Company and all of its subsidiaries and partnerships.

GENERAL DEVELOPMENT OF THE BUSINESS

CNRL's business is the acquisition of interests in crude oil and natural gas rights and the exploration, development, production, marketing and sale of crude oil and natural gas.

The Company initiates, operates and maintains a large working interest in a majority of the prospects in which it participates. CNRL's objective is to increase cash flow and earnings through the development of its existing crude oil and natural gas properties and through the discovery and acquisition of new reserves. The Company's principal regions of crude oil and natural gas operations are in the Western Canadian Sedimentary Basin, the United Kingdom (the "UK") sector of the North Sea and Offshore West Africa. The Company has a full complement of management, technical and support staff to pursue these objectives. As at December 31, 2004 the Company had 2,137 full time employees in North America and 273 full time employees in its international operations.

On July 24, 2001, the Company issued US $400.0 million of 10 year 6.70 per cent unsecured notes maturing July 15, 2011 pursuant to a prospectus supplement dated July 19, 2001 to the short form shelf prospectus dated July 6, 2001. Pursuant to a prospectus supplement dated January 15, 2002 to the short form shelf prospectus dated July 6, 2001, the Company issued on January 23, 2002, US $400.0 million of 30 year 7.20 per cent unsecured notes maturing January 15, 2032.

In July 2002, pursuant to the terms of a Plan of Arrangement, the Company acquired 100 per cent of RAX. The total purchase price was $2,393.2 million, comprised of $850.0 million in cash, $522.4 million attributable to the issue of 10,008,218 common shares of the Company, and the assumption of $936.3 million of debt and $84.5 million of working capital deficiency. The acquisition provided the Company with a new core region for natural gas exploration and exploitation activities in Northwest Alberta. The RAX properties included approximately 2.9 million net acres of undeveloped lands and provided additional opportunities for the Company to increase its production and reserves of natural gas and natural gas liquids. The acquisition added additional production, which averaged 376 million cubic feet per day of natural gas and 11 thousand barrels per day of crude oil and natural gas liquids during the second half of 2002 and 2-D and 3-D seismic of 57,820 kilometres and 14,565 square kilometres respectively. Future exploration and development projects will take advantage of the large undeveloped land base, high quality seismic database information and excess capacity within existing facilities. The acquisition solidified the Company as the second largest producer of natural gas in Canada and the second largest undeveloped landholder in western Canada.

During 2002, the Company completed 128 transactions in the normal course to acquire additional interests in crude oil and natural gas properties at an aggregate expenditure of $516.3 million. These properties are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. In addition, the Company disposed of non-operated properties not located in the Company's core regions for proceeds of $76.1 million.

On September 16, 2002, the Company issued US $350.0 million of 10 year 5.45 per cent unsecured notes maturing October 1, 2012 and US $350.0 million of 31 year 6.45 per cent unsecured notes maturing June 30, 2033 pursuant to a prospectus supplement dated September 9, 2002 to a short form shelf prospectus dated August 16, 2002.

During 2003, the Company completed 111 transactions in the normal course to acquire additional interests in crude oil and natural gas properties at an aggregate expenditure of $355.3 million. These properties are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. In addition, the Company disposed of non-operated properties not located in the Company's core regions for proceeds of $19.3 million.

In February 2004, the Company completed the acquisition of certain resource properties located in East Central Alberta and Saskatchewan (collectively known as the Petrovera Partnership) for aggregate consideration of $701 million. In a separate transaction, the Company sold specific resource properties in the Petrovera Partnership, representing approximately one third of the total acquisition, to another independent producer for proceeds of $234 million, resulting in a net cost of $467 million for the retained properties. The net production from the working interests at the time of the acquisition retained by the Company was approximately 27.5 mbbl/d of heavy oil and 9 mmcf/d of natural gas together with volumes associated with royalty interests of 1.2 mbbl/d of heavy oil and 2 mmcf/d of natural gas. All of the retained properties are situated in the Company's core region of Northern Plains.

In April 2004, the Company completed an acquisition of certain oil and natural gas properties located in Northeast British Columbia and Northwest Alberta for consideration of $280 million. The properties at the time of acquisition were producing approximately 68 million cubic feet per day of natural gas and 200 barrels per day of light crude oil and natural gas liquids and contain over 415 thousand acres of developed and undeveloped land. The properties included a further interest in the Ladyfern natural gas field. The portion of the Ladyfern field included in the acquisition included production of approximately 50 million cubic feet per day of natural gas. As part of this acquisition, the Company also acquired undeveloped acreage in the Foothills area of Alberta and British Columbia. This area is characterized by large, undeveloped pools with significant natural gas potential in deeper zones and will add a new exploration base in the Alberta Foothills, complementing the Company's existing holdings and production base in the British Columbia Foothills.

In the third quarter of 2004 the Company's wholly owned subsidiary, CNR International (U.K.) Limited acquired certain oil and natural gas properties in the central North Sea. The acquired properties comprise operated interests in T-Block (Tiffany, Toni and Thelma fields) and B-Block (Balmoral, Stirling and Glamis fields) together with associated production facilities and adjacent exploration acreage.

On December 1, 2004 the Company issued US $350.0 million of 10 year 4.90 per cent unsecured notes maturing December 1, 2014 and US $350.0 million of 30 year 5.85 per cent unsecured notes maturing February 1, 2035 pursuant to a short form shelf prospectus dated May 8, 2003.

In December 2004, the Company acquired certain oil and natural gas properties located in Alberta and British Columbia, for an aggregate cash consideration of approximately $703 million, net of proceeds received from an agreement to concurrently dispose of a portion of such properties for approximately $50 million and cash flows realized from the effective date of September 1, 2004. At the time of the acquisition production from the properties acquired by Canadian Natural, after the above noted disposition, was estimated at 105 million cubic feet per day of natural gas and 7,500 barrels per day of light crude oil and NGLs being approximately 25,000 barrels of oil equivalent of daily production on a six to one basis. The acquisition included over 510,000 net acres of undeveloped land. The vast majority of the acquired properties is located in the Company's core areas and extends its Northern Plains core region into the light oil operating area of Dawson.

During 2004, the Company completed 109 transactions (including the four acquisitions mentioned above) in the normal course to acquire additional interests in crude oil and natural gas properties at an aggregate net expenditure of $1.371 billion (excluding the Petrovera Partnership acquisition described above). These properties are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. In addition, the Company disposed of non-operated properties not located in the Company's core regions for proceeds of $7 million.

In February 2005 the Board of Directors of the Company approved Phase 1 of the Horizon Oil Sands Project. See below "Horizon Oil Sands Project".

REGULATORY MATTERS

The Company's business is subject to regulations generally established by government legislation and governmental agencies. The regulations are summarized in the following paragraphs.

Canada

The petroleum and natural gas industry in Canada operates under various government legislation and regulations, which govern exploration, development, production, refining, marketing, prevention of waste and other activities.

The Company's Canadian properties are located in Alberta, British Columbia, Saskatchewan, Manitoba and the Northwest Territories. Most of these properties are held under leases/licences obtained from the respective provincial or federal governments, which give the holder the right to explore for and produce crude oil and natural gas. The remainder of the properties is held under freehold (private ownership) lands.

Conventional petroleum and natural gas leases issued by the provinces of Alberta, Saskatchewan and Manitoba have a primary term from two to five years, and British Columbia leases/licences presently have a term of up to ten years. Those portions of the leases that are producing or are capable of producing at the end of the primary term will "continue" for the productive life of the lease.

The exploration licences in the Northwest Territories are administered by the Federal Government and only grant the right to explore. They have initial terms of four to five years. A Commercial Discovery Licence must be obtained in order to produce crude oil and natural gas, which requires the approval of a satisfactory development plan.

An oil sands permit and oil sands primary lease is issued for five and fifteen years respectively. If the minimum level of evaluation of an oil sands permit is attained, a primary oil sands lease will be issued out of the permit. A primary oil sands lease is continued based on the minimum level of evaluation attained on such lease. Continued primary oil sands leases that are designated as "producing" will continue for their productive lives while those designated as "non-producing" can be continued by payment of escalating rentals.

The provincial governments regulate the production of crude oil and natural gas as well as the removal of natural gas and natural gas liquids from each province. Government royalties are payable on crude oil and natural gas production from leases owned by the province. The royalties are determined by regulation and are generally calculated as a percentage of production varied by a number of different factors including selling prices, production levels, recovery methods, transportation and processing costs, location and date of discovery.

The Company is subject to federal and provincial income taxes in Canada at a combined rate of approximately 39.3 per cent after allowable deductions.

United Kingdom

Under existing law, the UK Government has broad authority to regulate the petroleum industry, including the power to regulate exploration, development, conservation and rates of production.

Crude oil and natural gas fields granted development approval before March 16, 1993 are subject to UK Petroleum Revenue Tax (“PRT”) of 50 per cent charged on crude oil and natural gas profits. Crude oil and natural gas fields granted development approval on or after March 16, 1993 are exempted from PRT. Profits for PRT purposes are calculated on a field-by-field basis by deducting field operating costs and field development costs from production and third party tariff revenue. In addition, certain statutory allowances are available, which may reduce the PRT payable.

The Company is subject to UK Corporation Tax (“CT”) on its UK profits as adjusted for CT purposes. PRT paid is a deductible for CT purposes. The current CT rate, which became effective April 1, 1999, is 30 per cent.

On April 17, 2002, the UK Government, in its 2002 budget speech by the UK Chancellor of the Exchequer, announced changes to taxation policies on UK North Sea crude oil and natural gas production. A supplementary CT charge of 10 per cent, charged on the same profits as calculated for ‘normal’ CT but excluding any deduction for financing costs, was added to the current 30 per cent CT charge. Also the deduction for expenditures on capital items was changed from 25 per cent per annum to 100 per cent in the year incurred.

Offshore West Africa

Terms of licences, including royalties and taxes payable on production or profit sharing arrangements, vary by country and in some countries by concession within each country. Development of the Espoir field on CI-26, and the Baobab Field on CI-40, Côte d’Ivoire, is under the terms of a production sharing arrangement that provides that tax or royalty payments to the Government are deemed to be met from the Government’s share of profit oil (See “Principal Crude Oil and Natural Gas Properties – Offshore West Africa”).

RISK FACTORS

Volatility of Oil and Natural Gas Prices

The Company’s financial condition will be substantially dependent on, and highly sensitive to, the prevailing prices of crude oil and natural gas. Fluctuations in crude oil or natural gas prices could have a material adverse effect on its operations and financial condition and the value and amount of its 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 Company’s control. 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, the condition of the Canadian, United States and Asian economies, government regulation, political stability in the Middle East and elsewhere, the foreign supply of oil, the price of foreign imports, the availability of alternate fuel sources and weather conditions. Natural gas prices realized by the Company will be affected primarily in North America by supply and demand, weather conditions and prices of alternate sources of energy. Any substantial or extended decline in the prices of crude oil or 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 resulting unutilized long-term transportation commitments, all of which could have a material adverse effect on Canadian Natural's revenues, profitability and cash flows.

Canadian Natural conducts an annual assessment of the carrying value of its assets in accordance with Canadian generally accepted accounting principles. If oil and natural gas prices decline, the carrying value of the assets could be subject to downward revisions, and earnings could be adversely affected.

Approximately 27 percent of the Company's 2004 production on a boe basis was primary and thermal heavy oil. The market prices for this heavy oil differ from the established market indices for light and medium grades of oil, due principally to the higher transportation and refining costs associated with heavy oil. As a result, the price received for heavy oil is generally lower than the price for medium and light oil, and the production costs associated with heavy oil are relatively higher than for lighter grades. Future differentials are uncertain and any increase in the heavy oil differentials could have a material adverse effect on the Company's business.

Environmental Risks

All phases of the oil and natural gas business are subject to environmental regulation pursuant to a variety of Canadian, United States, United Kingdom, European Union and other federal, provincial, state and municipal laws and regulations, as well as international conventions (collectively, "environmental legislation").

Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, 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 the Company'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 significant 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 and failure to comply with environmental legislation may result in the imposition of fines and penalties. The costs of complying with environmental legislation in the future may have a material adverse effect on Canadian Natural's financial condition or results of operations.

Canadian Natural anticipates that changes in environmental legislation may require, among other things, reductions in emissions to the air from its operations which may result in increased capital expenditures. Future changes in environmental legislation could occur and result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on the Company's financial condition or results of operations.

Need to Replace Reserves

Canadian Natural's future oil and natural gas reserves and production, and therefore its cash flows and results of operations, are highly dependent upon success in exploiting its current reserve base and acquiring or discovering additional reserves. Without additions to reserves through exploration, acquisition or development activities, the Company'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 the Company's cash flows from operations are insufficient to fund capital expenditures and external sources of capital become limited or unavailable, the Company's ability to make the necessary capital investments to maintain and expand its oil and natural gas reserves will be impaired. In addition, Canadian Natural may be unable to find and develop or acquire additional reserves to replace its oil and natural gas production at acceptable costs.

Competition in Energy Industry

The energy industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the construction and operation of crude oil and natural gas pipelines and facilities, the acquisition of oil and natural gas interests and the transportation and marketing of crude oil, natural gas, natural gas liquids and electricity. Canadian Natural will compete not only among participants in the energy industry, but also between petroleum products and other energy sources. The Company's competitors will include integrated oil and natural gas companies and numerous other senior oil and natural gas companies, some of which may have greater financial and other resources than the Company.

Other Business Risks

Other business risks include operational risks, the cost of capital available to fund exploration and development programs, regulatory issues and taxation and the requirements of new environmental laws and regulations. Exploring for, producing and transporting petroleum substances involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. These activities are subject to a number of hazards which may result in fires, explosions, spills, blow-outs or other unexpected or dangerous conditions causing personal injury, property damage, environmental damage and interruption of operations. Canadian Natural's liability, property and business interruption insurance may not provide adequate coverage in certain unforeseen circumstances.

Foreign Investments

The Company's foreign investments involve risks typically associated with investments in developing countries such as uncertain political, economic, legal and tax environments. These risks may include, among other things, currency restrictions and exchange rate fluctuations, loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, war, insurrection and other political risks, risks of increases in taxes and governmental royalties, renegotiation of contracts with governmental entities and quasi-governmental agencies, changes in laws and policies governing operations of foreign-based companies and other uncertainties arising out of foreign government sovereignty over the Company's international operations. In addition, if a dispute arises in its foreign operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of a court in the United States or Canada.

Canadian Natural's private ownership of oil and natural gas properties in Canada differs distinctly from its ownership interests in foreign oil and natural gas properties. In some foreign countries in which the Company does and may do business in the future, the state generally retains ownership of the minerals and consequently retains control of, and in many cases participates in, the exploration and production of reserves. Accordingly, operations outside of Canada may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges. In addition, changes in prices and costs of operations, timing of production and other factors may affect estimates of oil and natural gas reserve quantities and future net cash flows attributable to foreign properties in a manner materially different than such changes would affect estimates for Canadian properties. Agreements covering foreign oil and natural gas operations also frequently contain provisions obligating the Company to spend specified amounts on exploration and development or to perform certain operations, or forfeit all or a portion of the acreage subject to the contract.

Uncertainty of Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the Company's control. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flow therefrom are based upon a number of factors and assumptions made as of the date on which the reserve estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, 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 these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, the 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. Canadian Natural's actual production, revenues, taxes and development, abandonment and operating expenditures with respect to its reserves will likely 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.

Priority of Subsidiary Indebtedness; Consequences of Holding Corporation Structure

The Company carries on business through corporate and partnership subsidiaries. The majority of the Company's assets are held in one or more corporate or partnership subsidiaries. The results of operations and ability to service indebtedness, including debt securities, are dependent upon the results of operations of these subsidiaries and the payment of funds by these subsidiaries to the Company in the form of loans, dividends or otherwise. In the event of the liquidation of any corporate or partnership subsidiary, the assets of the subsidiary would be used first to repay the indebtedness of the subsidiary, including trade payables or obligations under any guarantees, prior to being used by the Company to pay its indebtedness.

ENVIRONMENTAL MATTERS

The Company carries out its activities in compliance with all relevant regional, national and international regulations and best industry practice. Environmental specialists in the UK and Canada review the operations of the Company's world-wide interests and report on a regular basis to the senior management of the Company, which in turn reports on environmental matters directly to the Health, Safety and Environmental Committee of the Board of Directors.

The Company regularly meets with, and submits to inspections by the various governments in the regions where the Company operates. At present, the Company believes that it meets all existing environmental standards and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet current environmental protection requirements. Since these requirements apply to all operators in the crude oil and natural gas industry, it is not anticipated that the Company's competitive position within the industry will be adversely affected. The Company has internal procedures designed to ensure that the environmental aspects of new acquisitions and developments are taken into account prior to proceeding. The Company's environmental management plan and operating guidelines focus on minimizing the environmental impact of field operations while meeting regulatory requirements and corporate standards. The Company's proactive program includes: an environmental compliance audit and inspection program of our operating facilities; an aggressive suspended well inspection program to support future development or eventual abandonment; appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment; an effective surface reclamation program; progressive due diligence related to groundwater monitoring; prevention of and reclamation of spill sites, greenhouse gas reduction, and flaring and venting reduction. Canadian Natural has participated in Canada's Climate Change Voluntary Challenge & Registry Inc (VCR) and plans to participate in a new Canadian Standards Association (CSA) program when the transition from VCR to CSA is complete. The Company has participated in the Canadian Association of Petroleum Producers (CAPP) Stewardship Program since 2000 and is currently a Gold Level Reporter. Canadian Natural continues to invest in proven and new technologies and in improved operating strategies that will help us achieve our overall goal of a net reduction of greenhouse gas emissions per unit of production.

The costs incurred by the Company for compliance with environmental matters and site restoration costs amount to less than 3 per cent of the total exploration and development expenditures incurred by the Company in each of the years ended December 31, 2004, 2003, and 2002.

DESCRIPTION OF THE BUSINESS

CNRL is a Canadian based senior independent energy company engaged in the acquisition, exploration, development, production, marketing and sale of crude oil, natural gas liquids and natural gas. The Company's principal core regions of operations are western Canada, the United Kingdom sector of the North Sea and Offshore West Africa.

The Company focuses on exploiting its core properties and actively maintaining cost controls. Whenever possible CNRL takes on significant ownership levels, operates the properties and attempts to dominate the local land position and operating infrastructure. The Company has grown through a combination of internal growth and strategic acquisitions. Acquisitions are made with a view to either entering new core regions or increasing dominance in existing core regions.

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces: namely natural gas, NGLs, light crude oil, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil. The Company's operations are centred on balanced product offerings, which together provide complementary infrastructure and balance throughout the business cycle. Natural gas is the largest single commodity sold, accounting for 45 per cent of 2004 production. Virtually all of the Company's natural gas and natural gas liquids production is located in the Canadian provinces of Alberta and British Columbia and is marketed in Canada and the United States. Light oil and NGLs, representing 24 per cent of 2004 production, is located principally in the Company's North Sea and Offshore West Africa properties, with additional production in the Provinces of Saskatchewan, British Columbia and Alberta. Primary and thermal heavy oil operations in the Provinces of Alberta and Saskatchewan account for 27 per cent of 2004 production. Other heavy oil, which accounts for 4 per cent of 2004 production, is produced from the Pelican Lake area in north Alberta. This production, which has medium oil netback characteristics, is developed through a staged horizontal drilling program. Midstream assets, comprised of three crude oil pipelines and an electricity co-generation facility, provide cost effective infrastructure supporting the heavy and Pelican Lake crude oil operations. CNRL expects its ownership of oil sands leases near Ft. McMurray, Alberta to provide a basis for long-term synthetic oil production growth.

As a result of the Company's core undeveloped land base of 11.5 million net acres in western Canada, its international concessions and the Alberta oil sands leases, the Company believes it has sufficient project portfolios in each of the product offerings to provide growth for the next several years.

A. PRINCIPAL CRUDE OIL AND NATURAL GAS PROPERTIES

Set forth below is a summary of the principal crude oil and natural gas properties as at December 31, 2004. The information is proportionate to the working interests owned by the Company.

	2004 AVERAGE DAILY PRODUCTION RATES		YEAR ENDED DECEMBER 31, 2004	MAJOR INFRASTRUCTURE AS AT DECEMBER 31, 2004
REGION	OIL & NGLs Mbbls	NATURAL GAS MMcf	UNDEVELOPED ACREAGE (thousands)	BATTERIES/ COMPRESSORS & PLANTS/ PLATFORMS /FPSO
North America				
Northeast B. C.	6.8	437.3	2,040	1/8/-/-
Northwest Alberta	10.9	303.2	1,660	-/7/-/ -
Northern Plains	166.3	429.9	6,922	9/5/-/-
Southern Plains	12.7	155.5	661	-/-/-/-
Southeast Saskatchewan	9.3	3.1	123	-/-/-/-
Non – core regions	0.2	1.1	1,822	-/-/-/-
Horizon Oil Sands	-	-	117	-/-/-/-
International				
North Sea	64.7	50.4	565	-/-/5/3
Offshore West Africa				
Côte d'Ivoire	11.6	7.5	276	-/-/1/1
Angola	-	-	610	-/-/-/-
South Africa	-		5,550	-/-/-/-
Total	282.5	1,388.0	20,346	10/20/6/4

Drilling Activity

Set forth below is a summary of the drilling activity, excluding stratigraphic test and service wells, of the Company for each of the last three fiscal years up to December 31, 2004 by geographic region:

2004

	NET EXPLORATORY			NET DEVELOPMENT		
	PRODUCTIVE	DRY HOLES	TOTAL	PRODUCTIVE	DRY HOLES	TOTAL
Canada						
Northeast B. C.	23.8	6.2	30	146.8	14.4	161.2
Northwest Alberta	42.8	7.6	50.4	100.4	3.9	104.3
Northern Plains	116.6	26.6	143.2	333.8	23.2	357
Southern Plains	18.5	7.0	25.5	209.9	4.0	213.9
Southeast Saskatchewan	-	-	-	12.5	0	12.5
Non – core regions	-	-	-	0.5	0.3	0.8
North Sea	-	2.0	2.0	9.2	0.0	9.2
Offshore West Africa						
Cote d'Ivoire	-	0.7	0.7	2.3	0.0	2.3
Angola	-	-	-	-	-	-
Total	201.7	50.1	251.8	815.4	45.8	861.2

2003

	NET EXPLORATORY			NET DEVELOPMENT		
	PRODUCTIVE	DRY HOLES	TOTAL	PRODUCTIVE	DRY HOLES	TOTAL
Canada						
Northeast B. C.	15.5	13.3	28.8	67.8	9.1	76.9
Northwest Alberta	31.7	11.8	43.5	69.9	7.9	77.8
Northern Plains	57.5	26.6	84.1	531.6	37.9	569.5
Southern Plains	33.0	4.0	37.0	387.9	5.0	392.9
Southeast Saskatchewan	-	-	-	26.9	-	26.9
Non – core regions	-	-	-	0.4	-	0.4
North Sea	-	1.0	1.0	11.1	0.8	11.9
Offshore West Africa						
Cote d'Ivoire	0.7	-	0.7	0.7	-	0.7
Angola	-	0.6	0.6	-	-	-
Total	138.4	57.3	195.7	1,096.3	60.7	1,157.0

2002

	NET EXPLORATORY			NET DEVELOPMENT		
	PRODUCTIVE	DRY HOLES	TOTAL	PRODUCTIVE	DRY HOLES	TOTAL
Canada						
Northeast B. C.	16.8	4.4	21.2	25.4	-	25.4
Northwest Alberta	3.9	3.0	6.9	6.1	-	6.1
Northern Plains	31.5	6.0	37.5	278.1	8.6	286.7
Southern Plains	12.0	-	12.0	40.6	2.5	43.1
Southeast Saskatchewan	-	-	-	4.3	1.0	5.3
North Sea	0.4	-	0.4	4.5	-	4.5
Offshore West Africa						
Cote D'Ivoire	0.6	0.9	1.5	1.8	0.6	2.4
Total	65.2	14.3	79.5	360.8	12.7	373.5

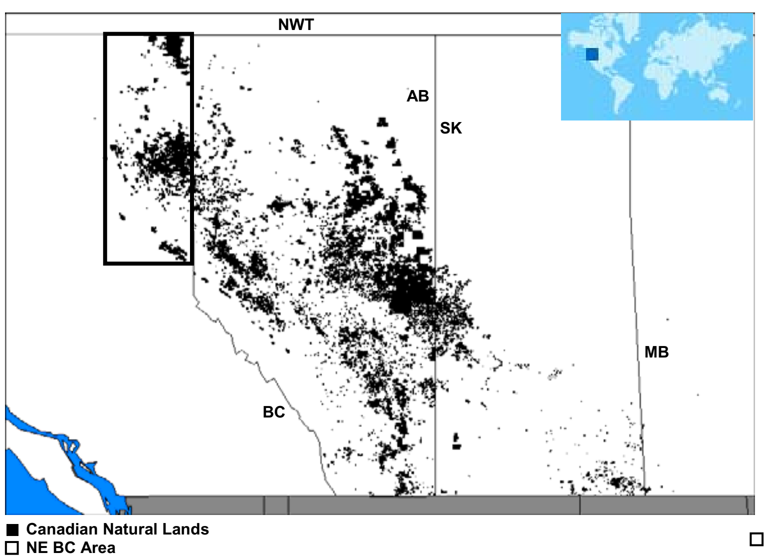
Producing Oil & Natural Gas Wells

Set forth below is a summary of the number of gross and net wells within the Company that were producing or capable of producing as of December 31, 2004:

	NATURAL GAS WELLS		OIL WELLS		TOTAL WELLS	
	GROSS	NET	GROSS	NET	GROSS	NET
Canada						
Northeast B. C.	937	816.0	173	135.6	1,110	951.7
Northwest Alberta	894	745.2	252	149.9	1,146	895.1
Northern Plains	2,619	2,148.4	5,029	4,457.4	7,648	6,605.8
Southern Plains	4,184	3,557.1	1,832	1,705.8	6,016	5,262.9
Southeast Saskatchewan	-	-	991	752.2	991	752.2
Non – core regions	738	107.5	301	160.6	1,039	268.1
United States	4	0.5	2	0.2	6	0.7
North Sea	2	0.1	106	88.5	108	88.6
Offshore West Africa						
Cote d'Ivoire	-	-	5	2.9	5	2.9
Angola	-	-	-	-	-	-
Total	9,378	7,374.8	8,691	7,453.1	18,069	14,827.9

All reserves data in the following property report was based on the applicable independent engineering report. See below "Crude Oil and Natural Gas Reserves".

Northeast British Columbia



This region comprises lands from Fort St. John, British Columbia to the northern border as well as the eastern border of British Columbia. Similar geological attributes extend throughout the region, producing light crude oil, natural gas liquids and natural gas. The Company holds working interests ranging up to 100 per cent and averaging 74 per cent in 3,799,223 gross (2,812,965 net) acres of producing and undeveloped land in the region.

Crude oil reserves are found primarily in the Halfway or lower Halfway formation, while natural gas and associated natural gas liquids are found in numerous zones at depths reaching approximately 2,500 vertical meters. In the southern portion of the region, the Company owns natural gas producing and undeveloped lands in which the productive zones are at deeper depths up to 3,500 meters. The exploration strategy focuses on comprehensive evaluation through two-dimensional seismic, three-dimensional seismic and targeting economic geological areas close to existing infrastructure. Natural gas production from the region averaged 437.3 million cubic feet per day for 2004 compared to the average of 372.3 million cubic feet per day produced for 2003. Crude oil and natural gas liquids production was steady at to 6.8 thousand barrels per day in 2004 from an average of 6.7 thousand barrels per day in 2003.

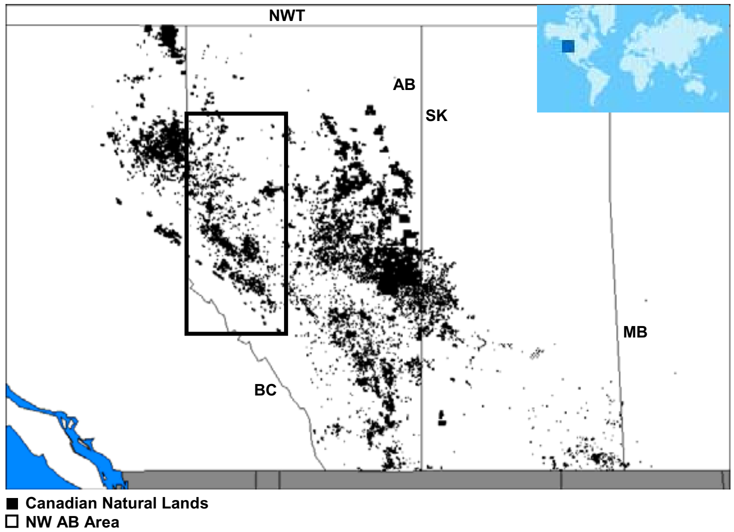
This region also contains the Ladyfern Slave Point natural gas pool, which was placed on production in mid-2001. Prior to the first quarter of 2002, production from the pool had been restricted due to insufficient processing facilities and pipelines, with production exiting 2001 at approximately 150 million cubic feet per day. In the first quarter of 2002, additional facilities were constructed, which enabled the Company to increase production to approximately 210 million cubic feet per day in June 2002. In late August 2002, water encroachment resulted in the commencement of anticipated significant declines from the pool. At the end of 2002, production was at 100 million cubic feet per day, falling to approximately 31 million cubic feet per day in December 2003. In May of 2004 the Company acquired additional lands, facilities and production in the area.

Through the acquisition of Ranger in 2000, the Company acquired an interest and operatorship in extensive acreage adjacent to the northern border of this region. A further acquisition in the fourth quarter of 2001 resulted in the Company obtaining 100 per cent ownership in its producing natural gas assets and undeveloped land in the Helmet area of the region. Further development of this acreage will be enhanced through the facilities and infrastructure owned by the Company in the region. Having identified optimal drilling strategies in the region, the Company implemented a multi-well annual drilling program, which has resulted in 30 to 50 wells being drilled in the area each year.

During 2004, the Company developed a new exploration and development program that targets natural gas found in the shallow Notikewin formation in the Fort St. John area. Wells drilled into this formation produce at rates of up to 500 to 700 thousand cubic feet per day. In combination with the Company’s extensive land base and the recently reduced royalty rates in British Columbia, this shallow gas drilling program will add to the Company’s opportunities in this region.

During 2004 the Company drilled 3.6 (2003- 5.1) net oil wells, 167.0 (2003 – 78.2) net natural gas wells, 1.0 (2003 – 0) net stratigraphic/service wells and 20.6 (2003 – 22.4) net dry wells on its lands in this region for a total of 192.2 (2003 – 105.7) net wells. The Company held an average 92.9 per cent working interest in these wells.

Northwest Alberta



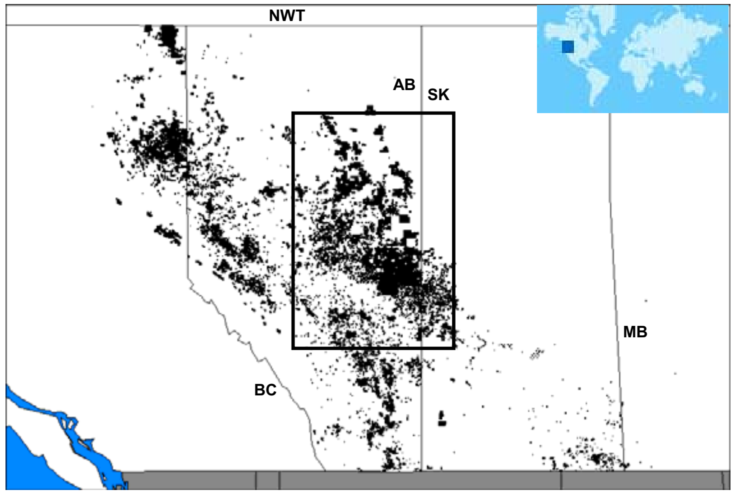
The Company holds working interests ranging up to 100 per cent and averaging 76 per cent in 2,865,122 gross (2,166,652 net) acres of producing and undeveloped land in the region located along the border of British Columbia and Alberta west of Edmonton.

The majority of the Company's holdings in the region were obtained through the Plan of Arrangement in 2002, which facilitated the acquisition of RAX. This region contains exceptional exploration and exploitation opportunities as well as substantial available capacity within an extensively owned and operated infrastructure. In this region, Canadian Natural produces liquids rich natural gas from multiple, often technically complex horizons, with formation depths ranging from 700 to 4,500 metres. The northern portion of this core region provides extensive multi-zone Cretaceous opportunities similar to the geology of the Company's North Alberta core region. The southern portion provides a significant opportunity in the regionally extensive Cretaceous Cardium zone. The Cardium is a complex, tight natural gas reservoir where high productivity may be achieved due to greater matrix porosity or natural fracturing.

Natural gas production from the region averaged 303.2 million cubic feet per day for 2004 compared to an average of 261.3 million cubic feet per day for 2003. Crude oil and natural gas liquids production was steady at 10.9 thousand barrels per day in 2004 from 11.1 thousand barrels per day in 2003.

During 2004 the Company drilled 5.8 (2003-3.7) net oil wells, 137.5 (2003-97.9) net natural gas wells, 1.5 (2003 – 0) net stratigraphic/service wells, and 11.5 (2003-19.7) net dry wells on its lands in this region for a total of 156.3 (2003-121.3) net wells. The Company held an average 82.6 per cent working interest in these wells.

Northern Plains



The Company holds working interests ranging up to 100 per cent and averaging 82 per cent in 11,829,563 gross (9,667,926 net) acres of producing and undeveloped land in the region located just south of Edmonton north to Fort McMurray and from the northwest Alberta border east to the border with Saskatchewan and extending into western Saskatchewan.

Over most of the region both sweet and sour natural gas reserves are produced from numerous productive horizons at depths up to approximately 1,500 meters. In the southwest portion of the region, natural gas liquids and light crude oil are also encountered at slightly deeper depths. The region continues to be one of the Company's largest natural gas producing regions, with natural gas production from the region amounting to 429.9 million cubic feet per day in 2004 compared to 462.4 million cubic feet per day in 2003. Crude oil and natural gas liquids production from this region increased to 166.3 thousand barrels per day in 2004 from 136.7 thousand barrels per day in 2003. Production of natural gas was impacted by the shut-in effective July 1, 2004 of approximately 11 million cubic feet per day in the Athabasca Wabiskaw-McMurray oil sands area pursuant to the decision of the Alberta Energy and Utilities Board.

In the area near Lloydminster, Alberta, reserves of heavy crude oil (averaging 12° - 14° API) and natural gas are produced through conventional vertical, slant and horizontal well bores from a number of productive horizons up to 1,000 meters deep. The energy required to flow the heavy crude oil to the wellbore in this type of heavy oil reservoir comes from solution gas. The crude oil viscosity and the reservoir quality will determine the amount of crude oil produced from the reservoir, which will vary from 3 to 20 per cent of the original oil in place. A key component to maintaining profitability in the production of heavy crude oil is to be a low cost producer. The Company continues to achieve low costs producing heavy oil by holding a dominant position that includes a significant land base and an extensive infrastructure of batteries and disposal facilities.

In the area around Elk Point, Ranger owned significant land and production in this region, with much of its land being contiguous to the Company's holdings. With the operations combined in 2000, future development of the total lands in the region became more effective and provided opportunities for cost savings. As part of the acquisition of Ranger, the Company also acquired a 50 per cent interest in the ECHO Pipeline system, a crude oil transportation pipeline; and, in 2001 the Company acquired the remaining 50 per cent. The pipeline was extended north to the Company operated Beartrap field during 2001, enhancing further development of the Company's extensive holdings in the area. This pipeline was capable of transporting 57 thousand barrels per day of hot unblended crude oil to sales facilities at Hardisty, Alberta and in 2003 its capacity was expanded to handle up to 72 thousand barrels per day. The ECHO Pipeline system is a high temperature, insulated pipeline that eliminates the requirement for field condensate blending. The pipeline enables the Company to transport its own production volumes at a reduced operating cost as well as earn third party transportation revenue. The ECHO Pipeline system permits the Company to transport approximately 80 per cent of its heavy crude oil to the international mainline liquids pipelines. This transportation control enhances the Company's ability to control the full spectrum of costs associated with the development and marketing of its heavy crude oil.

On February 18, 2004 the Company purchased the Petrovera Partnership which added additional properties in this region. Approximately one third of the total acquisition was sold to another independent producer. The properties that were retained further consolidated the Company's position in the area.

Production from the 100% owned Primrose and Wolf Lake fields located near Bonnyville, Alberta involve processes that utilize steam to increase the recovery of the oil. The two processes employed by the Company are cyclic steam stimulation and Steam Assisted Gravity Drainage ("SAGD"). Both recovery processes inject steam to heat the heavy crude oil deposits, reducing the oil viscosity and therefore improving its flow characteristics. There is also an infrastructure of gathering systems, a processing plant with a capacity of 60 thousand barrels per day and a 50 per cent interest in a co-generation facility capable of producing 84 megawatts of electricity for the Company's use and sale into the Alberta power grid at pool prices. In 2000, the Company successfully converted and tested two existing pads of wells from low-pressure steaming to high-pressure steaming. This conversion increased average production at the 20 existing wells from 100 to 190 barrels of crude oil per day per well. An additional 24 wells were drilled using the high-pressure steam process with initial production averaging 600 barrels of crude oil per day per well. These results have confirmed the benefits of converting the Primrose field to high-pressure steaming. In 2001, the Company received regulatory approval to convert an additional six low-pressure cyclic pads to high-pressure cyclic pads, and in 2002 received approval to take high-pressure steam methodologies throughout the field. Canadian Natural drilled 58 high-pressure wells in 2004. Additional development of the leases will be undertaken in phases over the next several years. The Company in 2004 started to proceed with its Primrose North expansion project which is expected to be completed by November 2005. The Primrose North expansion entails a remote steam treating facility and additional high pressure wells which are expected to be on production in 2006. A successful SAGD heavy oil project in which the Company holds a 50 per cent interest is also in operation in the Saskatchewan portion of this region.

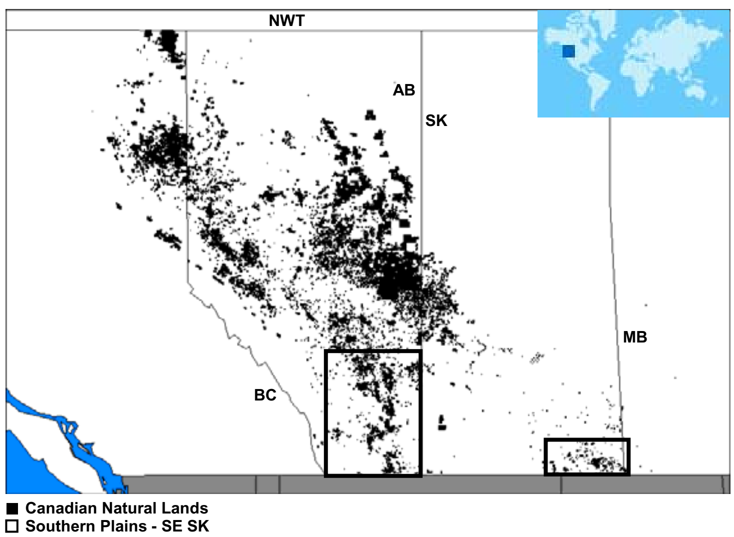
Included in the northern part of this region, approximately 200 miles north of Edmonton, are the Company's approximately 100 per cent owned holdings at Pelican Lake. These lands contain reserves of 14°-17° API heavy oil. Operating costs are low due to no sand production or disposal requirements and the gathering and pipeline facilities in place. The Company has the major ownership position in the necessary infrastructure including roads, drilling pads, gathering and sales pipelines, batteries, gas plants and compressors to ensure future economic development of the large crude oil pool located on the lands. The Company holds and controls approximately 75 percent of the known crude oil pool in this area.

This field contains approximately three billion barrels of original oil-in-place but is only expected to achieve a 5 percent recovery factor using existing primary technologies on the Company's developed leases. Hence, in 2002 the Company embarked upon an Enhanced Oil Recovery

("EOR") scheme using an emulsion flood to increase the ultimate recoveries from the field. The experimental Pelican Lake emulsion flood showed that the recovery mechanism was very efficient; however, response time is slow. In view of the slow response time, the Company has reverted to a waterflood scheme for this field, which will increase the overall recovery factor but not to the extent reached under an emulsion scheme. The implementation plan will result in the conversion of existing producing wells into water injectors and the drilling of additional producing wells. The Company will also examine opportunities to use polymer flooding in conjunction with waterflooding to obtain the highest recovery factor while maximizing value. This pilot is expected to commence in the second quarter of 2005.

During 2004, the Company drilled 287.0 (2003 – 405.7) net oil wells, 163.4 (2003 – 183.4) net natural gas wells, 112.0 (2003 – 63.5) net stratigraphic/service wells, and 49.8 (2003 – 64.5) net wells dry wells for a total of 612.2 (2003 – 717.1) net wells. The Company's average working interest in these wells was 91.4 per cent.

Southern Plains and Southeast Saskatchewan



In the Southern Plains area, the Company holds interests ranging up to 100 per cent and averaging 82 per cent in 1,771,346 gross (1,451,816 net) acres of producing and undeveloped land in the region principally located south of the Northern Plains area to the United States border and to the east bounded by the Alberta-Saskatchewan border.

Reserves of natural gas, condensate and light and medium gravity crude oil are contained in numerous productive horizons at depths up to 2,300 meters. Unlike the Company's other three natural gas producing regions, which have areas with limited or winter access only, drilling can take place in this region throughout the year. With a higher sales price for natural gas, it is economic to drill shallow wells in closer proximity to each other, which may have smaller overall reserves and lower productivity per well but will achieve a high return on capital employed with low drilling costs and longer life reserves

The Company maintains a large inventory of drillable locations on its land base in this region. This region is in the most mature portion of the Western Canadian Sedimentary Basin and requires continual operational cost control through efficient utilization of existing facilities, flexible infrastructure design and consolidation of interests where appropriate.

The Company's share of production in the Southern Plains area averaged 12.7 (2003 – 10.9) thousand barrels of crude oil and natural gas liquids per day and 155.5 (2003- 141.9) million cubic feet of natural gas per day in 2004.

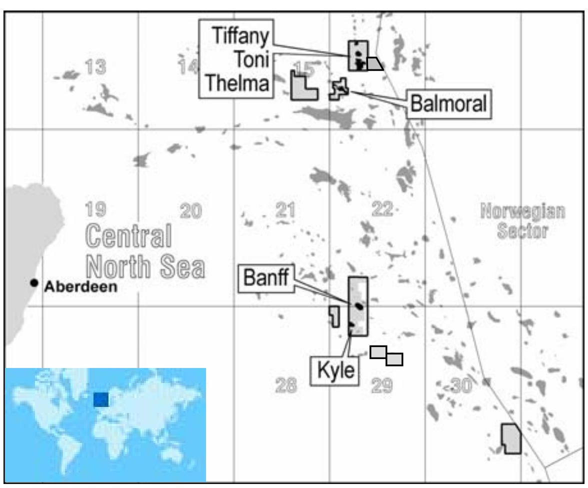
During 2004, the Company drilled a total of 7.8 (2003 – 4.4) net oil wells, 220.6 (2003 – 416.5) net natural gas wells, 1.0 (2003 – 0.0) net stratigraphic/service well and 11.0 (2003 – 9.0) net dry wells in this region for a total of 240.4 (2003 – 429.9) net wells. The Company's average working interest in these wells was 86.5 per cent.

The Williston Basin is located in Southeastern Saskatchewan with lands extending into Manitoba. This region became a core region of the Company in mid 1996 with the acquisition of Sceptre. The Company holds interests ranging up to 100 per cent and averaging 80 per cent in 246,304 gross (196,200 net) acres of producing and undeveloped lands in the region.

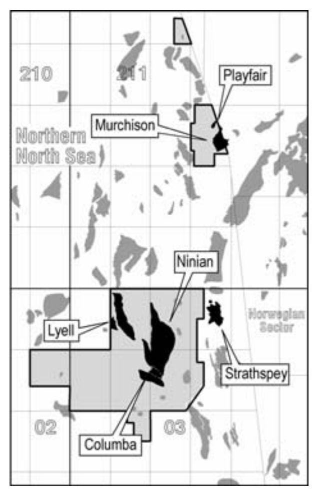
The region produces primarily light sour crude oil from as many as seven productive horizons found at depths up to 2,700 meters. The Company's share of production in the Southeast Saskatchewan area averaged 9.3 (2003 – 9.2) thousand barrels of crude oil and natural gas liquids per day and 3.1 (2003- 3.4) million cubic feet of natural gas per day in 2004.

The Company drilled 12.5 (2003 - 26.9) net oil wells with 0.0 (2003 – 0.0) net dry wells in this region in 2004, for a total of 12.5 (2003 – 26.9) net wells. The Company's average working interest in these wells is 65.9 per cent.

United Kingdom North Sea



■ Canadian Natural Lands - Central North Sea
■ Crude Oil and Natural Gas Fields



■ Canadian Natural Lands - Northern North Sea
■ Crude Oil and Natural Gas Fields

The Company's wholly owned subsidiary CNR International (U.K.) Limited, formerly Ranger Oil (U.K.) Limited, has operated in the North Sea for 30 years and has developed a significant database, extensive operating experience and an experienced staff. The Company owns interests ranging from 7 per cent up to 100 per cent in 876,422 gross (657,802 net) acres of producing and non-producing properties in the UK sector of the North Sea. In 2004, the Company produced from 15 crude oil fields.

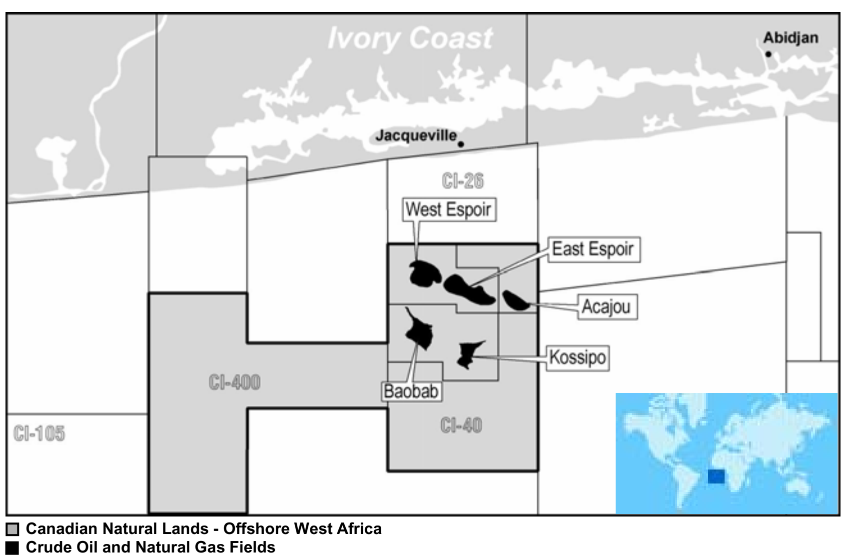
The northerly fields are centered around the Ninian Field where the Company has an 87.1 per cent working interest. The central processing facility is connected to other fields including the Columba Terraces and Lyell Fields where the Company operates with working interests of 91.6 per cent to 100 per cent. In 2002, the Company completed property acquisitions in the northern North Sea that increased ownership levels in the Ninian, Murchison, Lyell and Columba Terraces Fields. As part of the transaction the Company also acquired an interest in the Strathspey Field and 12 licenses covering 20 exploration blocks and part blocks surrounding the Ninian and Murchison platforms. Increased ownership in the Brent and Ninian pipelines and the Sullom voe Terminal was also acquired. In 2003 the Company further consolidated its ownership with the acquisition of additional working interests in the Ninian and Columba Fields, associated facilities and adjacent exploration acreage.

In the central portion of the North Sea, in 2003 the Company increased its equity in the Banff Field to 87.6 per cent and took over as operator. In 2004 the Company acquired 100 per cent working interest in T-block (comprising the Tiffany, Toni and Thelma Fields) and 68.7 per cent to 75.3 per cent interests in the Fields known as B-block (comprising Balmoral, Stirling and Glamis). The Company took over as operator of these fields. The Company also owns a 45.7 per cent operated working interest in the Kyle Field.

Ownership and operatorship levels in the North Sea are now similar to those levels found throughout the Company's other worldwide operations. The Company also receives tariff revenue from other field owners for the processing of crude oil and natural gas through some of the processing facilities. Opportunities for further long-reach well development on adjacent fields are provided from the existing processing facilities.

During 2004, production to the Company from this region averaged 64.7 (2003 – 56.9) thousand barrels of crude oil per day and 50.4 (2003 – 45.6) million cubic feet of natural gas per day. The Company drilled 9.2 (2003 – 11.1) net oil wells, 2.7 (2003 – 4.8) net service wells and 2.0 (2003 – 1.8) net dry wells in 2004 in this region for a total of 13.9 (2003 – 17.7) net wells. The Company's average working interest in these wells is 92.3 per cent.

Offshore West Africa



With the purchase of Ranger in 2000, the Company acquired interests in areas of crude oil and natural gas exploration and development offshore Côte d'Ivoire and Angola, West Africa. The Company owns working interests ranging from 50 per cent to 100 per cent in 1,589,213 gross

(885,541 net) acres in those countries. The Company also has a 100 per cent interest in 5,550,428 acres offshore South Africa where it is shooting and evaluating seismic.

Côte d'Ivoire

The Company owns interests in three exploration licences offshore Côte d'Ivoire comprising 275,625 net acres. During 2001, the Company increased its interest in Block CI-26, which contains the Espoir Field, to a 59 per cent operating interest. The Espoir Field is located in water depths ranging from 100 to 700 meters. During the 1980s, the Espoir Field produced approximately 31 million barrels of crude oil by natural depletion prior to relinquishment by the previous licencees in 1988. The government of Côte d'Ivoire approved a development plan to recover the remaining reserves and the Company will continue its exploitation and development of the field. The first phase of development of East Espoir, which includes the drilling of both producing and water injection wells from a single wellhead tower, was completed in 2003. Finalization of an infill drilling program in East Espoir and development plans for the West Espoir part of the Field were completed in 2004. Oil from the East Espoir is produced into an FPSO with associated natural gas delivered onshore through a subsea pipeline for local power generation. In 2003 the Company drilled a satellite pool, Acajou, which encountered a reservoir with good quality and hydrocarbons. The extent of this accumulation was further appraised by a well drilled in 2004 which did not encounter commercial hydrocarbons.

In the first quarter of 2001, the Company drilled and tested the Baobab exploration prospect, identified on Block CI-40, in which the Company has a 58 per cent interest, eight kilometres south of the Espoir facilities. The well encountered hydrocarbons at a rate of 6.7 thousand barrels of crude oil per day. A second test well in 2002 also produced hydrocarbons at a rate in excess of 10 thousand barrels of crude oil per day. The Company established a field development plan, which was approved by the Government of Cote d'Ivoire in December 2002. In 2003 the Company awarded four major contracts for the development of the Baobab Field. These contracts included the deep water drilling rig to drill 8 producing and 3 water injection wells, the FPSO, supplies for the subsea equipment and the supply of pipeline and risers, and installation of the subsea infrastructure. Development commenced in late 2003 and is progressing according to plan towards first oil in 2005.

To date political unrest in Cote d'Ivoire has had no impact on the Company's operations. The Company has developed contingency plans to continue Cote d'Ivoire operations from another nearby country if the situation warrants such a move.

During 2004, net daily production to the Company averaged 11.6 (2003 – 10.6) thousand barrels of crude oil and 7.5 (2003 – 8.4) million cubic feet of natural gas. In 2004, the Company drilled 2.3 (2003 – 1.3) net oil wells, 0.0 (2003 – 2.0) net service wells and 0.7 (2003 – 0.0) net dry wells for a total of 3.0 (2003 – 3.3) net wells. The Company's average working interest in these wells is 59.3 per cent.

Angola

During 2002, the Company was awarded operatorship and a 50 per cent working interest in exploration Block 16 situated offshore The People's Republic of Angola. 3-D seismic was obtained over the entire Block 16 before obtaining title and identified two targets, Omba in the north and Zenza in the west central portion of the Block. The Company has a two well commitment over a four year time frame expiring August 31, 2006. The first well, Zenza-1, was drilled during the fourth quarter of 2003 and was not considered commercial. Following further evaluation of seismic and the well results during 2004, the Company is considering various options, including divestment.

The Company also owned 100 per cent of and operated the offshore Kiame Field. The field produced from June 1998 to April 2002 through a leased FPSO. The field reached its economic limit of production and production ceased in April 2002. The wells were abandoned and the associated seabed equipment safely recovered during 2003. The Company also had a 25 per cent non-operating interest in Block 19, on which a 3-D seismic survey was completed in 1999. After interpretation of the seismic and drilling of a 25 per cent interest well in 2002 on Block 19, the Company determined the block was not economic to develop and relinquished its license on the block.

Horizon Oil Sands Project

Canadian Natural owns a 100 percent working interest in 116,596 gross acres in the Athabasca Oil Sands area of Northern Alberta. The Horizon Oil Sands Project ("the Horizon Project") is located on these leases, about 80-km north of Fort McMurray. The project includes surface oil sands mining, bitumen extraction, bitumen upgrading to produce a 34-36^{o} API synthetic light crude oil ("SCO"), and associated infrastructure.

The project, which has two aspects; namely, bitumen production and bitumen upgrading to SCO, is designed as a phased development. Site clearing and pre-construction preparation activities commenced in 2004 and construction will continue through 2012. Phase 1 production is planned to begin in the fourth quarter of 2008 at 110 thousand barrels per day of SCO. Phase 2 would increase production to 155 thousand barrels per day of SCO in 2010. Phase 3 would further increase production to 232 thousand barrels per day of SCO in 2012. These projected rates of production represent nominal design capacity. Canadian Natural will seek to maximize resource recovery and overall production through ongoing optimization of operations. The phased approach provides the Company with improved cost and project controls in terms of labour and materials management and directionally mitigates the effects of growth on local infrastructure.

Total estimated capital costs of the phased development are $10.8 billion, of which approximately $6.8 billion including contingency funding of $700 million would be required for Phase 1. When the Horizon Project is fully commissioned, operating costs – including sustaining capital – are expected to be in the range of $14 per barrel.

Canadian Natural filed an application for regulatory approval of the Horizon Project in June 2002. The application included a comprehensive environmental impact assessment, a social and economic assessment and was accompanied by public consultation. A federal-provincial regulatory Joint Review Panel (the "Panel") examined the project in a public hearing in September 2003. The Panel issued its decision report in January 2004, finding that the Horizon Project is in the public interest. An Alberta Order-in-Council approval was received in February 2004. Subsequently, key approvals were received from Alberta Environment under the *Environmental Protection Act* and *Water Act*, and from Fisheries and Oceans Canada under the *Fisheries Act*.

Throughout the first half of 2003, Canadian Natural, along with other major energy project proponents and the Canadian Association of Petroleum Producers actively sought greater clarity from the federal government about the long-term climate change policy framework. Of particular concern was the period beyond 2012 when policies will be derived from Canada's negotiations for a second Kyoto implementation phase. In mid 2003 the Government of Canada acknowledged the need for greater clarity and established eight principles that will guide the Government of Canada's longer-term climate change policies. These eight guiding principles addressed the key concerns of Canadian Natural with regard to equability, efficiency, flexibility and competitiveness issues for the post-2012 period.

Canadian Natural used a structured system called Front End Loading to ensure that project definition is adequate and complete before proceeding with implementation. This system is used successfully worldwide to mitigate risk on large capital projects in a variety of industries. The process is well documented at every step and is audited by an independent organization. In June 2002, the Company commenced the Design Basis Memorandum (DBM), which is the second of three front-end engineering phases. The DBM was completed for all project components in February 2004. In August 2003, the Company commenced work on the third and final front-end engineering phase, completing the work in December 2004. The products of this phase include a detailed project execution plan, Engineering Design Specifications ("EDS") and a detailed cost estimate (plus or minus 10%). The EDS provided sufficient definition for a lump sum inquiry for the Detailed Engineering, Procurement and Construction of the various project components. With this information a "cost certainty" estimate was developed as a basis for project sanction by the Board of Directors which was given in February 2005 authorizing management to proceed with Phase 1 of the Horizon Oil Sands Project.

Horizon is designed to use proven technology and will seek to take advantage of technology improvements that advance environmental performance, enhance the work environment for workers, increase reliability and production and reduce capital and operating costs. By the end of 2004 the Company had acquired all key technologies for the project. At year end, Horizon Project staff, including direct hire and contract, representing the many skill disciplines required to define and implement the project numbered 800, about 75% of the required staff compliment to implement Phase 1.

Canadian Natural expended $291 million on the Horizon Project in 2004. Cumulative expenditures on the project are $672 million to the end of 2004. These expenditures include lease evaluation, engineering definition, technology acquisition, environmental and socio-economic assessment, public consultation, regulatory application, completion of road infrastructure to the site and preliminary site development. Capital expenditures for 2005 are budgeted to be $1.4 billion reflecting the beginning of major expenditures for detailed engineering, procurement and construction of Phase 1 of the Project.

During 2004, the Company drilled 218 (2003 – 370) stratigraphic test wells to further delineate the ore body and confirm resource quality and quantity.

B. CRUDE OIL AND NATURAL GAS RESERVES

The Company retains independent qualified petroleum engineering consultants Sproule Associates Limited ("Sproule") and Ryder Scott Company ("Ryder Scott") to evaluate 100% of the Company's proved and proved and probable crude oil and natural gas reserves and prepare evaluation reports on the Company's total reserves ("Evaluation Reports"). The Evaluation Reports are effective December 31, 2004 as prepared February 18, 2005. The Company has been granted an exemption from the recently adopted National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") which prescribes the standards for the preparation and disclosure of reserves and reserves related information for companies listed on stock exchanges in Canada. This exemption allows the Company to substitute United States Securities and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. The primary difference between the two standards is the additional requirement under NI 51-101 to disclose both proved and proved plus probable reserves as well as related future net revenues using forecast prices and costs. The Company has disclosed proved reserves using constant prices and costs as mandated by the SEC and has elected to provide proved plus probable reserves and values under the same parameters as well as proved and proved plus probable reserves using forecast prices and costs as additional voluntary information. Another difference between the two standards lies in the definition of proved reserves. As discussed in the Canadian Oil and Gas Evaluation handbook ("COGEH"), the standards which NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material.

The Reserves Committee of the Board of Directors of the Company has met with each of Sproule and Ryder Scott and carried out the appropriate independent due diligence procedures with Sproule and Ryder Scott to review the qualifications of and procedures used by Sproule and Ryder Scott in determining the estimate of the Company's quantities and value of remaining petroleum and natural gas reserves.

The following tables summarize the evaluations of reserves and estimated future net revenues at December 31, 2004.

The estimated future net revenues contained in the following tables are not to be construed as a representation of the fair market value of the properties to which they relate. The estimated future net revenues derived from the assets are prepared prior to consideration of income taxes and existing asset abandonment liabilities. No indirect costs such as overhead, interest and administrative expenses have been deducted from the estimated future net revenues. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes to the following tables. There is no assurance that the price and cost assumptions contained in either the constant or forecast cases will be attained and variances could be substantial.

Crude Oil, NGL and Natural Gas Reserves (Net of Royalties)

	Constant Prices and Costs			
	Net Crude Oil & NGL Reserve Volumes (MMbbls)		Net Natural Gas Reserve Volumes (Bcf)	
	Proved Reserves	Total Proved and Probable Reserves	Proved Reserves	Total Proved and Probable Reserves
North America				
Canada	648	926	2,590	3,317
United States	0	0	1	2
International				
United Kingdom	303	415	27	57
Cote d'Ivoire	115	196	72	90
Total	1,066	1,537	2,690	3,466

Crude Oil, NGL and Natural Gas Reserves

	Constant Prices and Costs			
	Crude Oil and Natural Gas Liquids (MMbbls)		Natural Gas (Bcf)	
	Gross	Net	Gross	Net
Proved developed	638	605	2,761	2,230
Proved undeveloped	485	461	549	460
Total proved reserves	1,123	1,066	3,310	2,690
Total proved and probable reserves	1,621	1,537	4,259	3,466

Estimated Future Net Revenues

($Millions)	Constant Prices and Costs			
	Undiscounted	Discounted at		
		10%	15%	20%
Proved developed	21,092	13,739	11,838	10,453
Proved undeveloped	8,059	4,399	3,440	2,748
Total proved reserves	29,151	18,138	15,279	13,201
Total proved and probable reserves	40,088	22,937	18,802	15,899

Crude Oil, NGL and Natural Gas Reserves

	Forecast Prices and Costs			
	Crude Oil and Natural Gas Liquids (MMbbls)		Natural Gas (Bcf)	
	Gross	Net	Gross	Net
Proved developed	627	582	2,702	2,179
Proved undeveloped	487	451	545	456
Total proved reserves	1,114	1,033	3,247	2,635
Total proved and probable reserves	1,617	1,501	4,178	3,394

Estimated Future Net Revenues

($ Millions)	Forecast Prices and Costs			
	Undiscounted	Discounted at		
		10%	15%	20%
Proved developed	17,838	12,708	11,267	10,181
Proved undeveloped	7,856	4,071	3,164	2,528
Total proved reserves	25,694	16,779	14,431	12,709
Total proved and probable reserves	35,579	20,985	17,515	15,080

NOTES

1. “Gross” reserves means the total working interest share of remaining recoverable reserves owned by the Company before deduction of royalties payable to others.

2. “Net” reserves mean the Company’s gross reserves less all royalties payable to others plus royalties receivable from others.

3. “Proved developed” reserves were evaluated using SEC standards and can be expected to be recovered through existing wells with existing equipment and operating methods. SEC standards require that these be evaluated using year-end constant prices and costs and be disclosed net of royalties. The Company has also provided these reserves and their associated values using forecast prices and costs as well as before royalties as additional voluntary information.

4. "Proved undeveloped" reserves were evaluated using SEC standards and are expected to be recovered from new wells on undrilled acreage, or from existing wells where relatively major expenditures are required for the completion of these wells or for the installation of processing and gathering facilities prior to the production of these reserves. Reserves on undrilled acreage are limited to those drilling units offsetting productive wells that are reasonably certain of production when drilled. SEC standards require that these be evaluated using year-end constant prices and costs and be disclosed net of royalties. The Company has also provided these reserves and their associated values using forecast prices and costs as well as before royalties as additional voluntary information.

5. "Proved" reserves were evaluated using SEC standards and are those quantities of crude oil, natural gas and natural gas liquids, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. SEC standards require that these be evaluated using year-end constant prices and costs and be disclosed net of royalties. The Company has also provided these reserves and their associated values using forecast prices and costs as well as before royalties as additional voluntary information.

6. "Total Proved and Probable" reserves were evaluated using the COGEH standards of NI 51-101 and are those reserves where there is at least a 50 per cent probability that the quantities actually recovered will equal or exceed the stated values. The Company has elected to disclose proved plus probable reserves and their associated values using both constant prices and costs as well as forecast prices and costs and has disclosed these before and net of royalties. The calculation of a probable reserves and value component by subtracting the proved reserves from the proved plus probable reserves may be subject to error due to the different standards applied in the determination of each value. The impact, however, is not material.

7. Canadian securities legislation and policies permit the disclosure, which is included or incorporated by reference herein under a multi-jurisdictional disclosure system adopted by the SEC, of probable reserves which may not be disclosed in registration statements otherwise filed with the SEC. Probable reserves are generally believed to be less likely to be recovered than proved reserves. The reserve estimates, included or incorporated by reference in this Annual Information Form could be materially different from the quantities and values ultimately realized.

8. All values are shown in Canadian dollars.

9. The constant price and cost case assumes that prices in effect at the end of the year adjusted for quality and transportation as well as the 2004 costs are held constant over life. The constant price assumptions assume the continuance of current laws, regulations and operating costs in effect on the date of the Evaluation Report. Product prices have not been escalated beyond 2004. In addition, operating and capital costs have not been increased on an inflationary basis.

   The crude oil and natural gas constant prices used in the Evaluation Reports are as follows:

	NATURAL GAS				CRUDE OIL & NGLs				
YEAR	Company Average Price $CDN/Mcf	Henry Hub Louisiana $US/MMBtu	AECO $CDN/MMBtu	Huntingdon/ Sumas $CDN/MMBtu	Company Average Price $CDN/bbl	WTI @ Cushing (i) $US/bbl	Hardisty Heavy 12° API $CDN/bbl	Edmonton Par (ii) $CDN/bbl	North Sea Brent $US/bbl
2004	6.44	6.62(iii)	6.78	6.94	32.14	44.04(iv)	17.45	51.62	40.47

   (i) "WTI @ Cushing" refers to the price of West Texas Intermediate crude oil at Cushing, Oklahoma.

   (ii) "Edmonton Par Price" refers to the price of light gravity (40^o API), low sulphur content crude oil at Edmonton, Alberta.

   (iii) There was no trading of Henry Hub on December 31, 2004. This posted value was determined on the basis of December 30, 2004 posted price for Henry Hub adjusted for the change in the AECO price as posted by the Canadian Gas Price Reporter.

   (iv) There was no trading on WTI on December 31, 2004. This posted value was determined on the basis of December 30, 2004 posted price for WTI adjusted for the change in the Brent price as posted by the Platts Oilgram Price Report.

   (v) Foreign exchange rate used was $0.832 US / $1.00 Cdn.

10. The forecast price and cost cases assume the continuance of current laws and regulations, and any increases in wellhead selling prices also take inflation into account. Sales prices are based on reference prices as detailed below and adjusted for quality and transportation. Reference prices and costs are escalated at 1.5 per cent per year. Future crude oil, natural gas liquids and natural gas price forecasts were based on Sproule's January 1, 2005 crude oil, natural gas liquids and natural gas pricing model.

The Company's weighted average crude oil and NGLs price and the weighted average natural gas price in 2004 were $37.99 per barrel and $6.50 per mcf respectively, before adjustments due to hedging. The crude oil and natural gas forecast prices used in the Evaluation Reports are as follows:

	NATURAL GAS				CRUDE OIL & NGLs				
YEAR	Company Average Price $CDN/Mcf	Henry Hub Louisiana $US/MMBtu	AECO $CDN/MMBtu	Huntingdon/ Sumas $CDN/MMBtu	Company Average Price $CDN/bbl	WTI @ Cushing $US/bbl	Hardisty Heavy 12° API $CDN/bbl	Edmonton Par $CDN/bbl	North Sea Brent $US/bbl
2005	6.63	6.74	6.97	7.13	38.50	44.29	28.91	51.25	42.79
2006	6.31	6.48	6.66	6.92	36.80	41.60	28.12	48.03	40.08
2007	5.84	6.08	6.21	6.47	33.66	37.09	26.19	42.64	34.54
2008	5.36	5.70	5.73	5.99	31.04	33.46	25.06	38.31	31.89
2009	5.01	5.41	5.37	5.63	29.04	31.84	23.60	36.36	30.25
2010	5.10	5.49	5.47	5.73	29.53	32.32	24.12	36.91	30.70
2011	5.24	5.58	5.57	5.83	30.33	32.80	24.64	37.47	31.16
2012	5.32	5.66	5.67	5.93	29.74	33.30	25.17	38.03	31.63
2013	5.40	5.75	5.77	6.03	29.76	33.79	25.71	38.61	32.11
2014	5.49	5.83	5.87	6.13	30.29	34.30	26.26	39.19	32.59
2015	5.59	5.92	5.98	6.24	30.21	34.82	26.82	39.78	33.08

(i) Foreign exchange rate used was $0.84 US / $1.00 Cdn throughout the forecast

11. Estimated future net revenue from all assets is income derived from the sale of net reserves of crude oil, natural gas and natural gas liquids, less all capital costs, production taxes, and operating costs and before provision for income taxes, administrative overhead costs and existing asset abandonment liabilities.

12. The estimated total development capital costs net to the Company necessary to achieve the estimated future net "proved" and "proved and probable" production revenues are:

	PROVED		PROVED AND PROBABLE	
	FORECAST PRICE CASE ($Millions)	CONSTANT PRICE CASE ($Millions)	FORECAST PRICE CASE ($Millions)	CONSTANT PRICE CASE ($Millions)
2005	1,331	1,325	1,465	1,458
2006	541	534	633	621
2007	302	292	472	438
2008	212	199	535	497
2009	133	123	486	452
2010	129	117	402	367
2011	164	305	415	438
2012	81	97	229	151
2013	37	81	171	175
2014	213	62	49	79
2015	120	36	160	46
2016	90	80	54	83
Thereafter	561	460	825	634

13. The Evaluation Reports involved data supplied by the Company with respect to quality, heating value and transportation adjustments, interests owned, royalties payable, operating costs and contractual commitments. This data was audited by Sproule against corporate financial statements and was found to have no material differences. No field inspection was conducted.

A report on conventional reserves data by Sproule and Ryder Scott and a report of the Company's management and directors on oil and natural gas disclosure are provided in Schedules A and B, respectively, to this Annual Information Form. The Company does not file estimates of its total oil and natural gas reserves with any U. S. agency or federal authority other than the SEC.

C. RECONCILIATION OF CHANGES IN NET RESERVES

The following table summarizes the changes during the past year in reserves after deduction of royalties payable to others and using constant prices and costs:

	CRUDE OIL AND NATURAL GAS LIQUIDS (MMbbls)				NATURAL GAS (Bcf)			
	North America	North Sea	Offshore West Africa	Total	North America	North Sea	Offshore West Africa	Total
Proved reserves								
Reserves, December 31, 2003	**588**	**222**	**85**	**895**	**2,426**	**62**	**64**	**2552**
Extensions & Discoveries	17	0	0	17	334	0	0	334
Infill Drilling	24	35	0	59	74	0	0	74
Improved Recovery	1	10	0	11	6	0	0	6
Property purchases	36	38	0	74	182	10	0	192
Property disposals	0	0	0	0	(8)	0	0	(8)
Production	(66)	(24)	(4)	(94)	(383)	(18)	(3)	(404)
Revisions of prior estimates	48	22	34	104	(40)	(27)	11	(56)
Reserves, December 31, 2004	**648**	**303**	**115**	**1,066**	**2591**	**27**	**72**	**2690**
Proved + Probable reserves								
Reserves, December 31, 2003	**857**	**317**	**133**	**1,307**	**2919**	**102**	**72**	**3093**
Extensions & Discoveries	20	0	0	20	418	0	0	418
Infill Drilling	29	49	0	78	106	0	0	106
Improved Recovery	2	10	0	12	6	0	0	6
Property purchases	49	49	0	98	236	18	0	254
Property disposals	0	0	0	0	(10)	0	0	(10)
Production	(66)	(24)	(4)	(94)	(383)	(18)	(3)	(404)
Revisions of prior estimates	35	14	67	116	27	(45)	21	3
Reserves, December 31, 2004	**926**	**415**	**196**	**1,537**	**3319**	**57**	**90**	**3466**

Information on the Company's oil and natural gas reserves is provided in accordance with United States FAS 69, "Disclosures About Oil and Gas Producing Activities" in the Company's 2004 Annual Report under "Supplementary Oil and Gas Information" on pages 91 to 95 and is incorporated herein by reference.

D. OIL SANDS MINING RESERVES

Horizon oil sands mining reserves are not part of Canadian Natural's year-end reserves disclosure. Horizon reserves were evaluated as of February 9, 2005, as reported in their report dated February 18, 2004, with the authorization by the Board of Directors to proceed with Phase 1 of the Horizon Oil Sands Project (the "Horizon Project"). Gilbert Laustsen Jung Associates Ltd. ("GLJ"), a qualified independent reserves evaluator, was retained by the Reserves Committee of Canadian Natural's Board of Directors to evaluate reserves associated with the Horizon Project incorporating both the mining and upgrading projects. These reserves were evaluated under SEC Industry Guide 7. The Reserves Committee has met with GLJ and carried out independent due diligence procedures with GLJ as to the Company's Horizon Project reserves.

The following table sets out, on a gross basis, Canadian Natural's proved and probable reserves of bitumen and synthetic crude oil from its Oil Sands mining leases as of February 9, 2005.

	Gross Oil Sands Mining Reserves (MMbbls)		
	Proved	Probable	Proved and Probable
Bitumen	1,900	1,420	3,320
Synthetic crude oil [1]	1,560	1,230	2,790

(1) Synthetic crude oil reserves are based on upgrading of the bitumen reserves. The reserves shown for bitumen and synthetic crude oil are not additive.

A report on Horizon oil sands mining reserves data by GLJ and a report of the Company's management and directors on mining reserves disclosure are provided in Schedules "A" and "B", respectively, to this Annual Information Form. The Company does not file estimates of its total oil and natural gas reserves and mining reserves with any U. S. agency or federal authority other than the SEC.

E. CRUDE OIL AND NATURAL GAS PRODUCTION

The Company's working interest share of oil, NGLs and natural gas production and revenues received for the last three financial years is summarized in the following tables:

	YEAR ENDED DECEMBER 31		
	2004	2003	2002
Daily Production			
Crude Oil and NGLs (bbls/d)	282,489	242,392	215,335
Natural Gas (MMcf/d)	1,388	1,299	1,232
Annual Production			
Crude Oil and NGLs (Mbbls)	103,391	88,473	78,597
Natural Gas (Bcf)	508	474	450

NETBACKS
INFORMATION BY QUARTER

	YEAR 2004					YEAR 2003				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended
Average Daily Production Volumes										
Crude oil and NGL's (bbl)	261,286	275,398	297,262	295,704	282,489	237,560	240,607	247,016	244,262	242,392
Natural Gas (mcf)	1,294	1,452	1,396	1,410	1,388	1,310	1,325	1,289	1,270	1,299
Product Netbacks										
Crude oil and NGLs ($/bbl)										
Sales Price (1)	$ 34.21	$ 36.72	$ 43.50	$ 36.92	$ 37.99	$39.37	$30.66	$31.45	$29.47	$32.66
Royalties	$ 2.91	$ 3.15	$ 3.59	$ 2.95	$ 3.16	$3.56	$2.78	$2.56	$2.22	$2.77
Production Expenses	$ 9.58	$ 9.92	$ 10.21	$ 10.41	$ 10.05	$10.79	$10.80	$10.14	$9.45	$10.28
Netback	**$ 21.72**	**$ 23.65**	**$ 29.70**	**$ 23.56**	**$ 24.78**	**$25.02**	**$17.08**	**$18.75**	**$17.80**	**$19.61**
Natural Gas ($/Mcf)										
Sales Price (1)	$ 6.31	$ 6.64	$ 6.24	$ 6.77	$ 6.50	$7.75	$6.25	$5.57	$5.26	$6.21
Royalties	$ 1.27	$ 1.38	$ 1.39	$ 1.34	$ 1.35	$1.78	$1.35	$1.11	$1.05	$1.32
Production Expenses	$ 0.65	$ 0.66	$ 0.71	$ 0.68	$ 0.67	$0.57	$0.59	$0.63	$0.63	$0.60
Netback	**$ 4.39**	**$ 4.60**	**$ 4.14**	**$ 4.75**	**$ 4.48**	**$5.40**	**$4.31**	**$3.83**	**$3.58**	**$4.29**
Crude Oil and NGL Netbacks by Type										
Light/Pelican Lake/NGLs ($/bbl)										
Sales Price (1)	$ 40.75	$ 45.28	$ 51.54	$ 48.60	$ 46.71	$44.38	$34.60	$36.06	$35.76	$37.66
Royalties	$ 3.71	$ 3.98	$ 3.99	$ 4.12	$ 3.95	$4.18	$3.32	$3.11	$2.82	$3.35
Production Expenses	$ 9.77	$ 10.36	$ 10.70	$ 11.20	$ 10.53	$10.42	$9.76	$9.53	$9.65	$9.83
Netback	**$ 27.27**	**$ 30.94**	**$ 36.85**	**$ 33.28**	**$ 32.23**	**$29.78**	**$21.52**	**$23.42**	**$23.29**	**$24.48**
Heavy ($/bbl)										
Sales Price (1)	$ 27.00	$ 28.08	$ 35.33	$ 25.16	$ 28.99	$32.44	$25.37	$25.17	$21.45	$25.98
Royalties	$ 2.02	$ 2.31	$ 3.18	$ 1.77	$ 2.34	$2.71	$2.06	$1.83	$1.47	$2.00
Production Expenses	$ 9.38	$ 9.47	$ 9.72	$ 9.62	$ 9.56	$11.30	$12.19	$10.96	$9.19	$10.88
Netback	**$ 15.60**	**$ 16.30**	**$ 22.43**	**$ 13.77**	**$ 17.09**	**$18.43**	**$11.12**	**$12.38**	**$10.79**	**$13.10**

NOTE: Pelican Lake oil has an API of 14º to 17º, but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.

(1) Including transportation and excluding risk management activities

NETBACKS
INFORMATION BY QUARTER

	YEAR 2004					YEAR 2003				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended
SEGMENTED										
North America Product Netbacks										
Light/Pelican Lake/NGLs ($/bbl)										
Sales Price [1]	$ 37.54	$ 41.03	$ 44.89	$ 43.80	$ 41.81	$ 40.89	$ 32.73	$ 32.78	$ 30.95	$ 34.37
Royalties	$ 7.20	$ 7.91	$ 8.59	$ 8.76	$ 8.12	$ 7.65	$ 6.33	$ 6.04	$ 5.51	$ 6.39
Production Expenses	$ 7.30	$ 7.74	$ 7.75	$ 7.85	$ 7.66	$ 6.09	$ 6.42	$ 6.76	$ 7.24	$ 6.62
Netback	**$ 23.04**	**$ 25.38**	**$ 28.55**	**$ 27.19**	**$ 26.03**	**$ 27.15**	**$ 19.98**	**$ 19.98**	**$ 18.20**	**$ 21.36**
Heavy ($/bbl)										
Sales Price [1]	$ 27.00	$ 28.08	$ 35.33	$ 25.16	$ 28.99	$ 32.44	$ 25.37	$ 25.17	$ 21.45	$ 25.98
Royalties	$ 2.02	$ 2.31	$ 3.18	$ 1.77	$ 2.34	$ 2.71	$ 2.06	$ 1.83	$ 1.47	$ 2.00
Production Expenses	$ 9.38	$ 9.47	$ 9.72	$ 9.62	$ 9.56	$ 11.30	$ 12.19	$ 10.96	$ 9.19	$ 10.88
Netback	**$ 15.60**	**$ 16.30**	**$ 22.43**	**$ 13.77**	**$ 17.09**	**$ 18.43**	**$ 11.12**	**$ 12.38**	**$ 10.79**	**$ 13.10**
Natural Gas ($/Mcf)										
Sales Price [1]	$ 6.37	$ 6.78	$ 6.36	$ 6.88	$ 6.61	$ 7.88	$ 6.39	$ 5.70	$ 5.35	$ 6.34
Royalties	$ 1.33	$ 1.44	$ 1.45	$ 1.39	$ 1.40	$ 1.84	$ 1.40	$ 1.16	$ 1.10	$ 1.38
Production Expenses	$ 0.60	$ 0.60	$ 0.63	$ 0.63	$ 0.62	$ 0.55	$ 0.56	$ 0.58	$ 0.60	$ 0.57
Netback	**$ 4.44**	**$ 4.74**	**$ 4.28**	**$ 4.86**	**$ 4.59**	**$ 5.49**	**$ 4.43**	**$ 3.96**	**$ 3.65**	**$ 4.39**
North Sea Product Netbacks										
Light Oil ($/bbl)										
Sales Price [1]	$ 44.27	$ 49.22	$ 57.39	$ 52.77	$ 51.37	$ 49.74	$ 37.08	$ 39.63	$ 41.70	$ 42.00
Royalties	$ 0.06	$ 0.10	$ 0.09	$ 0.08	$ 0.08	$ 0.11	$ (0.19)	$ 0.09	$ (0.15)	$ (0.03)
Production Expenses	$ 13.26	$ 13.84	$ 13.88	$ 14.96	$ 14.03	$ 15.50	$ 14.17	$ 13.25	$ 13.42	$ 14.07
Netback	**$ 30.95**	**$ 35.28**	**$ 43.42**	**$ 37.73**	**$ 37.26**	**$ 34.13**	**$ 23.10**	**$ 26.29**	**$ 28.43**	**$ 27.96**
Natural Gas ($/Mcf)										
Sales Price [1]	$ 5.08	$ 3.28	$ 3.17	$ 3.26	$ 3.73	$ 4.03	$ 2.21	$ 2.57	$ 3.32	$ 3.03
Royalties	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Expenses	$ 1.65	$ 1.92	$ 2.48	$ 2.29	$ 2.07	$ 1.09	$ 1.45	$ 1.60	$ 1.16	$ 1.33
Netback	**$ 3.43**	**$ 1.36**	**$ 0.69**	**$ 0.97**	**$ 1.66**	**$ 2.94**	**$ 0.76**	**$ 0.97**	**$ 2.16**	**$ 1.70**
Offshore West Africa Product Netbacks										
Light Oil ($/bbl)										
Sales Price [1]	$ 42.08	$ 49.34	$ 53.86	$ 51.28	$ 49.05	$ 37.86	$ 34.34	$ 37.37	$ 36.42	$ 36.47
Royalties	$ 1.28	$ 1.52	$ 1.42	$ 1.52	$ 1.43	$ 1.20	$ 0.99	$ 1.13	$ 1.03	$ 1.08
Production Expenses	$ 7.09	$ 7.43	$ 8.05	$ 7.82	$ 7.59	$ 14.03	$ 9.32	$ 7.11	$ 6.67	$ 8.68
Netback	**$ 33.71**	**$ 40.39**	**$ 44.39**	**$ 41.94**	**$ 40.03**	**$ 22.63**	**$ 24.03**	**$ 29.13**	**$ 28.72**	**$ 26.71**
Natural Gas ($/Mcf)										
Sales Price [1]	$ 4.80	$ 5.18	$ 6.31	$ 4.73	$ 5.25	$ 3.80	$ 5.09	$ 4.58	$ 3.95	$ 4.37
Royalties	$ 0.15	$ 0.16	$ 0.17	$ 0.14	$ 0.15	$ 0.11	$ 0.15	$ 0.14	$ 0.11	$ 0.13
Production Expenses	$ 1.23	$ 1.38	$ 1.39	$ 1.31	$ 1.33	$ 2.37	$ 1.45	$ 1.24	$ 1.18	$ 1.39
Netback	**$ 3.42**	**$ 3.64**	**$ 4.75**	**$ 3.28**	**$ 3.77**	**$ 1.32**	**$ 3.49**	**$ 3.20**	**$ 2.66**	**$ 2.85**

NOTE: Pelican Lake oil has an API of 14º to 17º, but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.

(1) Including transportation and excluding risk management activities

NETBACKS
INFORMATION BY QUARTER

	YEAR 2002				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended
Average Daily Production Volumes					
Crude Oil and NGLs (bbls)	188,439	189,386	242,051	240,596	215,335
Natural Gas (Mcf)	1,053	1,078	1,427	1,365	1,232
Product Netbacks					
Crude oil and NGLs ($/bbl)					
Sales Price (1)	$25.00	$30.12	$35.19	$32.83	$31.22
Royalties	$2.28	$3.02	$3.56	$3.53	$3.16
Production Expenses	$7.81	$7.95	$8.67	$9.10	$8.45
Netback	**$14.91**	**$19.15**	**$22.96**	**$20.20**	**$19.61**
Natural Gas ($/Mcf)					
Sales Price (1)	$2.98	$3.77	$3.08	$5.07	$3.77
Royalties	$0.55	$0.77	$0.67	$1.09	$0.78
Production Expenses	$0.58	$0.57	$0.55	$0.57	$0.57
Netback	**$1.85**	**$2.43**	**$1.86**	**$3.41**	**$2.42**
Crude Oil and NGL Netbacks by Type					
Light/Pelican Lake/NGLs ($/bbl)					
Sales Price (1)	$29.09	$33.37	$38.05	$37.97	$35.16
Royalties	$3.25	$4.04	$4.48	$4.39	$4.10
Production Expenses	$7.48	$8.36	$10.06	$9.38	$8.97
Netback	**$18.36**	**$20.97**	**$23.51**	**$24.20**	**$22.09**
Heavy ($/bbl)					
Sales Price (1)	$20.49	$26.42	$31.59	$26.45	$26.52
Royalties	$1.21	$1.86	$2.42	$2.45	$2.03
Production Expenses	$8.18	$7.48	$6.91	$8.77	$7.84
Netback	**$11.10**	**$17.08**	**$22.26**	**$15.23**	**$16.65**

SEGMENTED
North America Product Netbacks

	YEAR 2002				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended
Light/Pelican Lake/NGLs ($/bbl)					
Sales Price (1)	$25.75	$31.10	$35.01	$34.34	$31.88
Royalties	$4.24	$5.11	$5.98	$5.81	$5.35
Production Expenses	$5.25	$5.30	$5.00	$5.28	$5.20
Netback	**$16.26**	**$20.69**	**$24.03**	**$23.25**	**$21.33**
Heavy ($/bbl)					
Sales Price (1)	$20.49	$26.42	$31.59	$26.45	$26.52
Royalties	$1.21	$1.86	$2.42	$2.45	$2.03
Production Expenses	$8.18	$7.48	$6.91	$8.77	$7.84
Netback	**$11.10**	**$17.08**	**$22.26**	**$15.23**	**$16.65**
Natural Gas ($/Mcf)					
Sales Price (1)	$2.96	$3.81	$3.10	$5.11	$3.79
Royalties	$0.57	$0.79	$0.69	$1.11	$0.80
Production Expenses	$0.56	$0.55	$0.52	$0.55	$0.55
Netback	**$1.83**	**$2.47**	**$1.89**	**$3.45**	**$2.44**
North Sea Product Netbacks					
Light Oil ($/bbl)					
Sales Price (1)	$34.43	$39.43	$42.24	$42.46	$40.32
Royalties	$1.54	$1.76	$2.56	$2.79	$2.30
Production Expenses	$10.09	$15.72	$18.30	$14.68	$15.06
Netback	**$22.80**	**$21.95**	**$21.38**	**$24.99**	**$22.96**
Natural Gas ($/Mcf)					
Sales Price (1)	$3.77	$1.80	$1.98	$3.20	$2.75
Royalties	-	-	-	-	-
Production Expenses	$1.33	$1.90	$1.78	$1.25	$1.53
Netback	**$2.44**	**($0.10)**	**$0.20**	**$1.95**	**$1.22**

Offshore West Africa Product Netbacks

	YEAR 2002				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended
Light Oil ($/bbl)					
Sales Price (1)	$37.61	$33.92	$42.78	$43.15	$40.10
Royalties	$1.65	$1.11	$1.34	$1.35	$1.35
Production Expenses	$18.62	$12.76	$11.23	$13.68	$13.63
Netback	**$17.34**	**$20.05**	**$30.21**	**$28.12**	**$25.12**
Natural Gas ($/Mcf)					
Sales Price (1)	-	-	$4.97	$4.63	$4.82
Royalties	-	-	$0.15	$0.15	$0.15
Production Expenses	-	-	$1.77	$1.85	$1.81
Netback	**$ -**	**$ -**	**$3.05**	**$2.63**	**$2.86**

1) Including transportation and excluding risk management activities

F. HISTORICAL DRILLING ACTIVITY BY PRODUCT

The following table sets forth the gross and net wells in which the Company has participated for the period indicated:

	YEAR ENDED DECEMBER 31			
	2004		2003	
	Gross	Net	Gross	Net
Natural Gas	801	689	841	777
Crude Oil	378	328	490	458
Service/Stratigraphic	339	336	447	440
Dry Holes	106	96	126	118
Total	1624	1449	1,904	1,793
*Total Success Rate		91%		91%

*excluding service and stratigraphic test wells

G. CAPITAL EXPENDITURES

Costs incurred by the Company in respect of its programs of acquisition and disposition, and exploration and development of crude oil and natural gas properties, are summarized in the following tables:

	YEAR ENDED DECEMBER 31	
	2004	2003
Net property acquisitions[(1)]	1,835	336
Land acquisition and retention	120	154
Seismic evaluation	89	77
Well drilling, completion and equipping	1,394	1,194
Pipeline and production facilities	821	522
Reserve replacement expenditures	4,259	2,283
Midstream operations	16	11
Horizon Project	291	152
Abandonments	32	40
Head office equipment	35	20
Total Net Capital Expenditures	4,633	2,506

(1) *Includes Business Combinations*

CAPITAL EXPENDITURES BY QUARTER	2004 THREE MONTHS ENDED ($ Millions) MAR. 31	JUNE 30	SEPT. 30	DEC. 31
Net property acquisitions[(1)]	507	277	290	761
Land acquisition and retention	31	39	37	13
Seismic evaluation	32	11	25	21
Well drilling, completion and equipping	583	231	221	359
Pipeline and production facilities	280	166	190	185
Reserve replacement expenditures	1,433	724	763	1,339
Midstream operations	-	3	2	11
Horizon Project	46	103	84	58
Abandonments	7	6	14	5
Head office equipment	7	8	12	8
Total Net Capital Expenditures	1,493	844	875	1,421

(1) *Includes Business Combinations*

CAPITAL EXPENDITURES BY QUARTER	2003 THREE MONTHS ENDED ($ Millions) MAR. 31	JUNE 30	SEPT. 30	DEC. 31
Net property acquisitions[(1)]	178	23	106	29
Land acquisition and retention	21	36	53	44
Seismic evaluation	19	21	12	25
Well drilling, completion and equipping	396	190	256	352
Pipeline and production facilities	149	107	133	133
Reserve replacement expenditures	763	377	560	583
Midstream operations	3	1	5	2
Horizon Project	41	27	32	52
Abandonments	3	3	14	20
Head office equipment	3	2	10	5
Total Net Capital Expenditures	813	410	621	662

(1) *Includes Business Combinations*

H. NON-RESERVE ACREAGE

The following table summarizes the Company's working interest holdings in core region non-reserve acreage as at December 31, 2004:

	Gross Acres (thousands)	Net Acres (thousands)
North America		
Alberta	10,869	9,032
British Columbia	2,436	1,824
Saskatchewan	738	659
Manitoba	8	7
North Sea		
United Kingdom	738	565
Offshore West Africa		
Angola	1,220	610
Côte d'Ivoire	369	276
South Africa	5,550	5,550
Total	21,928	18,523

I. DEVELOPED ACREAGE

The following table summarizes the Company's working interest holdings in core region developed acreage as at December 31, 2004:

	Gross Acres (thousands)	Net Acres (thousands)
North America		
Alberta	5,350	3,960
British Columbia	895	682
Saskatchewan	326	242
Manitoba	6	5
North Sea		
United Kingdom	138	93
Offshore West Africa		
Cote d'Ivoire	8	5
Total	6,723	4,987

SELECTED FINANCIAL INFORMATION

The following table summarizes the consolidated financial statements of the Company, which follows the full cost method of accounting for crude oil and natural gas operations:

	YEAR ENDED DECEMBER 31	
	2004	2003
	($ millions, except per share information)	
Revenues [1] (net of royalties)	6,536	5,283
Cash flow from operations	3,769	3,160
Per common share - basic	14.06	11.77
- diluted	13.98	11.53
Net earnings [4]	1,405	1,403
Per common share - basic	5.24	5.23
- diluted	5.20	5.06
Total assets [4]	18,410	14,643
Total long-term debt[2,3]	3,538	2,748

	2004 THREE MONTHS ENDED			
	MARCH 31	JUNE 30	SEPT. 30	DEC. 31
	($ millions, except per share information)			
Revenues [1] (net of royalties)	1,420	1,603	1,799	1,714
Net earnings	258	259	311	577
Per common share – basic	1.92	0.97	1.16	2.15
- diluted	1.92	0.97	1.13	2.13

	2003 THREE MONTHS ENDED			
	MARCH 31	JUNE 30	SEPT. 30	DEC. 31
	($ millions, except per share information)			
Revenues [1] (net of royalties)	1,554	1,279	1,264	1,186
Net earnings [4]	427	525	201	250
Per common share - basic	1.60	1.96	0.75	0.93
- diluted	1.52	1.89	0.74	0.91

(1) Excluding transportation costs and risk management activities.
(2) Restated to include preferred securities
(3) Excluding current portion of long-term debt.
(4) Restated for asset retirement obligations

CAPITAL STRUCTURE

Common Shares

The Company is authorized to issue an unlimited number of common shares, without nominal or par value. Holders of common shares are entitled to one vote per share at a meeting of shareholders of Canadian Natural, to receive such dividends as declared by the Board of Directors on the common shares and to receive pro-rata the remaining property and assets of the Company upon its dissolution or winding up, subject to any rights having priority over the common shares.

Preferred Shares

The Company has no preferred shares outstanding, however, the Company is authorized to issue two-hundred thousand (200,000) preferred shares designated as Class 1 Preferred Shares. Holders of preferred shares shall not be entitled as such to receive notice of or to attend any meeting of the shareholders of the Company and shall not be entitled to vote at any such meeting except under certain circumstances as described in the Articles of Amalgamation. Holders of preferred shares are entitled to receive such dividends as and when declared by the Board of Directors in priority to common shares and shall be entitled to receive pro-rata in priority to holders of commons shares the remaining property and assets of Canadian Natural upon its dissolution or winding-up. The Company may redeem or purchase for cancellation at any time all or any part of the then outstanding preferred shares and the holders of the preferred shares shall have the right at any time and from time to time to convert such preferred shares into the common shares of the company. There are no preferred shares currently outstanding.

Credit Ratings

Credit ratings accorded to the Company's debt securities are not recommendations to purchase, hold or sell the debt securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant, and if any such rating is so revised or withdrawn.

The Company's senior unsecured long-term debt securities are rated "Baa1" with a stable outlook by Moody's Investor Services, Inc. ("Moody's"), "BBB+" by Standard & Poor's Corporation ("S&P") and "BBB high" with a stable trend by Dominion Bond Rating Service Limited ("DBRS"). S&P assigns a "BBB-" rating to the Company's subordinated notes. S&P assigns a rating outlook to the Company and not to individual debt instruments. S&P has assigned a negative outlook to the Company.

Debt Rated

$125 CAD million 7.40% unsecured note due 2007
$400 US million 6.70% unsecured note due 2011
$400 US million 7.20% unsecured note due 2032
$350 US million 5.45% unsecured note due 2012
$350 US million 6.54% unsecured note due 2033
$125 US million 7.69% unsecured note due 2005
$93 US million 6.45% Adjustable rate note due 2009
$350 US million 4.90% unsecured note due 2014
$350 US million 5.85% unsecured note due 2035
$80 US million 8.30% subordinated note due 2011

Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. According to the Moody's rating system, debt securities rated Baa1 are considered as medium-grade obligations, i.e. they are neither highly protected nor poorly secured. Interest payments and principal security appear adequate for the present but certain protective elements may be lacking or may be characteristically unreliable over any great length of time. Such securities lack outstanding investment characteristics and in fact have speculative characteristics as well. Moody's applies numerical modifiers 1, 2 and 3 in each generic rating classification from Aa through Caa in its corporate bond rating system. 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. A Moody's rating outlook is an opinion regarding the likely direction of a rating over the medium term.

S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the S&P rating system, debt securities rated BBB exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments on the notes. The ratings from AA to B may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. An S&P rating outlook assesses the potential direction of a long term credit rating over the intermediate to longer term. In determining a rating outlook, consideration is given to any changes in the economic and/or fundamental business conditions.

DBRS' credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the DBRS rating system, debt securities rated BBB are of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions. 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. The rating trend is DBRS' opinion regarding the outlook for the rating.

MARKET FOR CANADIAN NATURAL RESOURCES LIMITED SECURITIES

The Company's common shares are listed and posted for trading on Toronto Stock Exchange and the New York Stock Exchange under the symbol CNQ.

2004 Monthly Historical Trading on Toronto Stock Exchange

Month	High	Low	Close	Volume Traded
January	$71.80	$63.82	$64.00	12,121,445
February	73.85	63.99	73.25	9,749,239
March	76.50	70.20	72.70	12,853,959
April	81.65	72.85	75.40	12,279,432
May 1 – 18	81.70	73.80	78.55	8,416,911
*May 19 - 31	39.40	35.08	37.00	12,306,037
June	41.15	35.26	40.05	27,235,021
July	44.27	39.75	44.25	16,359,717
August	45.45	40.52	42.71	22,497,977
September	51.04	41.75	50.50	26,159,733
October	55.15	48.61	51.28	27,437,454
November	52.33	45.90	51.03	31,361,601
December	51.90	45.50	51.25	28,812,709

* Shares began trading on a post two-for-one subdivision basis on May 19, 2004.

On January 21, 2002, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of Toronto Stock Exchange and the New York Stock Exchange, beginning January 23, 2002 and ending January 22, 2003, to purchase for cancellation up to 6,060,180 common shares of the Company, being 5 per cent of the 121,203,603 common shares of the Company outstanding on January 18, 2002. No common shares were purchased during this program.

In January 2002, the Company issued 60,000 flow-through common shares at a price of $39.00 per common share. The value of the common shares was determined as the closing market price on Toronto Stock Exchange on the day prior to the allotment of the common shares.

On January 22, 2003, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of Toronto Stock Exchange and the New York Stock Exchange, beginning January 24, 2003 and ending January 23, 2004, to purchase for cancellation up to 6,692,799 common shares of the Company, being 5 per cent of the 133,855,988 common shares of the Company outstanding on January 17, 2003. Under this program, the Company purchased a total of 2,734,800 common shares for cancellation at an average purchase price of $52.51 for each common share purchased.

On January 22, 2004, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of Toronto Stock Exchange and the New York Stock Exchange, commencing January 24, 2004 and ending January 23, 2005, to purchase for cancellation up to 6,690,385 common shares of the Company, being 5 per cent of the 133,807,695 common shares of the Company outstanding on January 13, 2004. Under this program, the Company purchased a total of 873,400 common shares for cancellation at an average purchase price of $37.98 for each common share purchased; $38.01 after costs.

At the Annual and Special Meeting of Shareholders held May 6, 2004, the shareholders passed a special resolution amending the Articles of the Company to divide the issued and outstanding Common Shares on a two-for-one basis. The subdivision of the Common Shares occurred on May 21, 2004.

On January 20, 2005, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of Toronto Stock Exchange and the New York Stock Exchange, commencing January 24, 2005 and ending January 23, 2006, to purchase for cancellation up to 13,409,006 common shares of the Company, being 5 per cent of the 268,180,123 common shares of the Company outstanding on January 12, 2005. As of the date of this Annual Information Form, no shares have been purchased.

On March 9, 2005, the Board of Directors passed a resolution proposing an amendment to the Articles of the Company to sub-divide the issued and outstanding Common Shares of the Company on a two-for-one basis subject to shareholder approval at the Annual and Special Meeting of Shareholders scheduled for May 5, 2005.

DIVIDEND HISTORY

The dividend policy of the Company undergoes a periodic review by the Board of Directors and is subject to change at any time depending upon the earnings of the Company, its financial requirements and other factors existing at the time. Prior to 2001, dividends had not been paid on the common shares of the Company. On January 17, 2001 the Board of Directors approved a dividend policy for the payment of a regular quarterly dividend of $0.10 per common share. Dividends have been paid on the first day of January, April, July and October of each year since 2001.

The following table restated for the two-for-one subdivision of the common shares which occurred in May 2004 shows the aggregate amount of the cash dividends declared per common share of the Company and accrued in each of its last three years ended December 31.

	2004	2003	2002
Cash dividends declared per common share	$0.40	$0.30	$0.25

TRANSFER AGENTS AND REGISTRAR

The Company’s transfer agent and registrar for its common shares is Computershare Trust Company of Canada in the cities of Calgary and Toronto and Computershare Shareholder Services, Inc. in the city of New York. The registers for transfers of the Company’s common shares are maintained by Computershare Trust Company of Canada.

DIRECTORS AND EXECUTIVE OFFICERS

The names, municipalities of residence, offices held with the Company and principal occupations of the directors and officers of the Company are set forth below:

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Catherine M. Best Calgary, Alberta Canada	Director(2) (4) (age 51)	Executive Vice-President, Risk Management and Chief Financial Officer of the Calgary Health Region from 2002 to present, Vice-President, Corporate Services and Chief Financial Officer of the Calgary Health Region from February 2000 to 2002; prior thereto with Ernst & Young since 1980, most recently as a Corporate Audit Partner from 1991 to 2000. Has served continuously as a director since November 2003.
N. Murray Edwards Calgary/Banff, Alberta Canada	Vice-Chairman and Director(3)(5) (age 45)	President, Edco Financial Holdings Ltd. (a private management and consulting company). Has served continuously as a director of the Company since September 1988. Currently serving on the board of directors of Ensign Resource Service Group Inc.; Magellan Aerospace Corporation; and, Penn West Petroleum Ltd.
Ambassador Gordon D. Giffin Atlanta, Georgia USA	Director(1)(2) (age 55)	Senior Partner, McKenna Long & Aldridge LLP (law firm) since May 2001; prior thereto United States Ambassador to Canada. Has served continuously as a director of the Company since May 2002. Currently serving on the board of directors of Bowater, Inc.; Canadian National Railway; Canadian Imperial Bank of Commerce; and, Transalta Corporation.
John G. Langille Calgary, Alberta Canada	President and Director (age 59)	Officer of the Company. Has served continuously as a director of the Company since June 1982.
Keith A.J. MacPhail Calgary, Alberta Canada	Director(3)(4)(5) (age 48)	Chairman, President and Chief Executive Officer, Bonavista Petroleum Ltd. (independent oil and natural gas company) since November 1997 and Chairman, NuVista Energy Ltd since July 2003. Has served continuously as a director of the Company since October 1993. Currently serving on the board of directors of Bonavista Petroleum Ltd., Bonavista Energy Trust and NuVista Energy Ltd.
Allan P. Markin Calgary, Alberta Canada	Chairman and Director(3)(5) (age 59)	Chairman of the Company. Has served continuously as a director of the Company since January 1989.
James S. Palmer, C.M., A. O. E., Q.C. Calgary, Alberta Canada	Director(3)(4)(5) (age 76)	Chairman, Burnet, Duckworth & Palmer LLP (law firm). Has served continuously as a director of the Company since May 1997. Currently serving on the board of directors of Magellan Aerospace Corporation; Trenton Iron Works; Rally Energy Corp.; and, on the board of trustees for Rogers Sugar Income Fund.
Dr. Eldon R. Smith, M.D. Calgary, Alberta Canada	Director(1)(4)(5) (age 65)	Emeritus Professor and Former Dean, Faculty of Medicine, University of Calgary. Has served continuously as a director of the Company since May 1997. Currently serving on the board of directors of Vasogen Inc.; and, Pheromone Sciences Corp.

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
David A. Tuer Calgary, Alberta Canada	Director(1)(2)(3) (age 55)	An independent businessman. Chairman, Calgary Health Region since October 2001 and President and CEO of Hawker Resources Inc. (independent oil and natural gas company) from January 2003 to March 2005. Prior thereto President and Chief Executive Officer, PanCanadian Energy Corporation. Has served continuously as a director of the Company since May 2002. Currently serving on the board of directors of Rockwater Capital Corporation; and, Argo Energy Ltd.
Steve W. Laut Calgary, Alberta Canada	Chief Operating Officer (age 47)	Officer of the Company.
Réal M. Cusson Calgary, Alberta Canada	Senior Vice-President, Marketing (age 54)	Officer of the Company.
Réal J. H. Doucet Calgary, Alberta Canada	Senior Vice-President, Oil Sands (age 52)	Officer of the Company since October 2000; prior thereto director of various divisions at Suncor Inc. since 1993.
Allen M. Knight Calgary, Alberta Canada	Senior Vice-President, International & Corporate Development (age 55)	Officer of the Company.
Tim S. McKay Calgary, Alberta Canada	Senior Vice-President, Operations (age 43)	Officer of the Company.
Douglas A. Proll Calgary, Alberta Canada	Senior Vice-President, Finance (age 54)	Officer of the Company since April 2001; prior thereto Vice President Finance and Treasurer of Renaissance Energy Ltd. to August 2000 and most recently Vice President Finance and Business Development of Husky Energy Inc. from August 2000 to February 2001.
Lyle G. Stevens Calgary, Alberta Canada	SeniorVice-President, Exploitation (age 50)	Officer of the Company.
Jeffrey W. Wilson Calgary, Alberta Canada	Senior Vice-President, Exploration (age 52)	Officer of the Company since September 2003; prior thereto Exploration Manager of the Company.
Mary-Jo Case Calgary, Alberta Canada	Vice-President, Land (age 46)	Officer of the Company since May 2002; prior thereto Co-ordinator Land at PanCanadian Petroleum Limited to 1999 and most recently Manager Commercial Ventures and Land at PanCanadian Petroleum Limited 1999 to 2002.
William R. Clapperton Calgary, Alberta Canada	Vice-President, Regulatory, Stakeholder and Environmental Affairs (age 42)	Officer of the Company since January 2002; prior thereto Manager, Surface Land and Environment for the Company.
Gordon M. Coveney Calgary, Alberta Canada	Vice-President, Exploration, Northeast District (age 51)	Officer of the Company since September 2003; prior thereto Exploration Manager for the Company.
Randall S. Davis Calgary, Alberta Canada	Vice-President, Financial Accounting and Controls (age 38)	Officer of the Company since July 2004; prior thereto Manager, Financial Reporting of the Company to July 2002 and most recently Financial Controller of the Company from July 2002 to July 2004.

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Jerome W. Harvey Calgary, Alberta Canada	Vice-President, Commercial Operations (age 51)	Officer of the Company since April 2004; prior thereto Manager, Commercial Operations.
Peter Janson Calgary, Alberta Canada	Vice-President, Engineering Integration (age 47)	Officer of the Company since December 2004; prior thereto Director, Production Planning and Control to June 2000 and Director, Health and Safety and Environment from June 2000 to November 2002 at Suncor Oil Sands and most recently Director, Engineering Integration of the Company from November 2002 to December 2004.
Terry J. Jocksch Calgary, Alberta Canada	Vice-President, Exploitation East (age 37)	Officer of the Company since April 2004; prior thereto Exploitation Manager of the Company to April 2004.
Christopher M. Kean Calgary, Alberta Canada	Vice-President, Utilities and Offsite, Horizon Oil Sands Project (age 41)	Officer of the Company since December 2004; prior thereto Manager Facilities Engineering to January 2002 , Utilities and Offsites Project Manager January 2002 to July 2002, Director, Utilities and Offsites July 2002 to July 2003 and most recently General Manager, Utilities and Offsites July 2003 to December 2004.
Philip A. Keele Calgary, Alberta Canada	Vice-President, Mining, Horizon Oil Sands Project (age 45)	Officer of the Company since December 2004; prior thereto from Mine Manager at Fording Coal Limited to February 2001, Chief Mine Engineer of the Company February 2001 to September 2002 and most recently Director, Mine Engineering of the Company from September 2002 to December 2004.
Cameron S. Kramer Calgary, Alberta Canada	Vice-President, Field Operations (age 37)	Officer of the Company since September 2002; prior thereto Production Engineer of the Company to March 2000 and most recently Manager, Field Operations of the Company from April 2000 to September 2002.
Leon Miura Calgary, Alberta Canada	Vice-President, Upgrading (age 50)	Officer of the Company since August 2003; prior thereto held progressively senior positions at Petroleos de Venezuela including Cerro Negro Execution Manager, Heavy Oil Upgrading from 1997 to 2001 and most recently Nitrogen Injection Project Director, Secondary Recovery at Petroleos de Venezuela 2002 to 2003.
John S. J. Parr Calgary, Alberta Canada	Vice-President, Production, East (age 43)	Officer of the Company since April 2004; prior thereto Production Engineer, NE Gas of the Company to July 2001, Manager, Production Engineering of the Company from July 2002 to June 2002 and most recently Production Manager, Heavy Oil of the Company from July 2002 to April 2004.
David A. Payne Calgary, Alberta Canada	Vice-President, Exploitation, West (age 43)	Officer of the Company since October 2004; prior thereto Exploitation Manager, Thermal Heavy of the Company to July 2000, Director, Exploitation of CNR International (U.K.) Limited a wholly-owned subsidiary of the Company from July 2000 to August 2003 and most recently Exploitation Manager, Technical Projects of the Company from August 2003 to October 2004.
William R. Peterson Calgary, Alberta Canada	Vice-President, Production, West (age 38)	Officer of the Company since April 2004; prior thereto Production Manager, West of the Company.
John C. Puckering Calgary, Alberta Canada	Vice President, Site Development (age 58)	Officer of the Company since April 2004; prior thereto General Manager DCL Construction Inc. to November 2001, President of 960925 Alberta Ltd. from November 2001 to April 2002, Manager, Site Development of the Company May 2002 to December 2002 and most recently General Manager Site Development of the Company from January 2003 to April 2004.

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Sheldon L. Schroeder Calgary, Alberta Canada	Vice-President, Project Control (age 37)	Officer of the Company since April 2004; prior thereto engineer with 729248 Alberta Ltd. to June 2001, Project Control Manager of the Company from June 2001 to September 2002 and most recently Director, Project Control of the Company from September 2002 to April 2004.
Kendall W. Stagg Calgary, Alberta Canada	Vice-President, Exploration , West (age 43)	Officer of the Company since October 2004; prior thereto Cardium Geophysicist of the Company to April 2001, Chief Geophysicist of the Company from April 2001 to June 2002 and most recently Manager Exploration, B. C. of the Company from June 2002 to September 2004.
Lynn M. Zeidler Calgary, Alberta Canada	Vice-President, Bitumen Production (age 48)	Officer of the Company since August 2003; prior thereto held progressively senior positions at Shell Canada Limited including on secondment from Shell Canada Limited as Manager-Tier 1 Implementation at Sable Offshore Energy Inc to September 2000 and most recently General Project Manager, Athabasca Oil Sands Project at Shell Canada Limited October 2000 to May 2003 and concurrently as Vice President & Project Director, Muskeg River Mine at Albian Sands Energy Inc. May 2002 to July 2003 and General Manager Claims Athabasca Oil Sands Project at Shell Canada Limited May 2003 to July 2003.
Kimberly I. McKay Calgary, Alberta Canada	Treasurer (age 36)	Officer of the Company since December 2004; prior thereto Financial Accountant of the Company to October 2001, Advisor Capital Markets and Treasury Administration of the Company from October 2001 to July 2002 and most recently Treasury Manager of the Company from July 2002 to December 2004.
Bruce E. McGrath Calgary, Alberta Canada	Corporate Secretary (age 55)	Officer of the Company.

(1) Member of the Nominating and Corporate Governance Committee
(2) Member of the Audit Committee
(3) Member of the Reserves Committee
(4) Member of the Compensation Committee
(5) Member of the Safety, Health and Environmental Committee

All directors stand for election at each Annual General Meeting of CNRL shareholders. All of the current directors were elected to the Board at the last annual meeting of shareholders held on May 6, 2004. All of the current directors are standing for election at the Annual General Meeting of Shareholders scheduled for May 5, 2005.

As at December 31, 2004, the directors and officers of the Company, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, in the aggregate, approximately 4 per cent of the total outstanding common shares (approximately 5 per cent after the exercise of options held by them pursuant to the Company's stock option plan).

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of the Company may become subject in connection with the operations of the Company. Some of the directors and officers have been and will continue to be engaged in the identification and evaluation of businesses and assets with a view to potential acquisition of interests on their own behalf and on behalf of other corporations, and situations may arise where the directors and officers will be in direct competition with the Company. Conflicts, if any, will be subject to the procedures and remedies under the *Business Corporations Act* (Alberta).

AUDIT COMMITTEE INFORMATION

Audit Committee Members

The Audit Committee of the Board of Directors of the Company is comprised of Ms. C. M. Best, Chair, Messrs. G. D. Giffin and D. A. Tuer each of whom is (i) independent as defined under Canadian securities regulations NI 52-110 and the NYSE listing standards as they pertain to audit committees of listed issuers; and, (ii) financially literate.

Ms. C. M. Best is a chartered accountant with 20 years experience as a staff member and partner of an international public accounting firm. During her tenure she was responsible for direct oversight and supervision of a large staff of auditors conducting audits of the financial reporting of significant publicly traded entities, many of which were oil and gas companies. This oversight and supervision required Ms. C. M. Best to maintain a current understanding of generally accepted accounting principles, and be able to assess their application in each of her clients. It also required an understanding of internal controls and financial reporting processes and procedures.

Ambassador G. D. Giffin's education and experience relevant to the performance of his responsibilities as an audit committee member is derived from a thirty year law practice involving complex accounting and audit-related issues associated with complicated commercial transactions and disputes. He has developed extensive practical experience and an understanding of internal controls and procedures for financial reporting from his service on audit committees for several publicly traded issuers and continues pursuit of extensive professional reading and study on related subjects.

Mr. D. A. Tuer's education and experience relevant to the performance of his responsibilities as an audit committee member is derived from professional training and a business career as a Chief Executive Officer in a large publicly traded company which provided experience in analyzing and evaluating financial statements and supervising persons engaged in the preparation, analysis and evaluation of financial statements of publicly traded companies. He has gained an understanding of internal controls and procedures for financial reporting through oversight of those functions, and the understanding of Audit Committee functions through his years of Chief Executive involvement.

Auditor Service Fees

Auditor Service	2004	2003
Audit fees	$1,100,548	$886,000
Audit related fees	$183,663	$12,500
Tax related fees	$39,330	$11,000
All other fees	$0	$10,000

LEGAL PROCEEDINGS

From time to time, CNRL is the subject of litigation arising out of the Company's operations. Damages claimed under such litigation may be material or may be indeterminate and the outcome of such litigation may materially impact the Company's financial condition or results of operations. While the Company assesses the merits of each lawsuit and defends itself accordingly, the Company may be required to incur significant expenses or devote significant resources to defend itself against such litigation. The claims that have been made to date are not currently expected to have a material impact on the Company's financial position.

INTERESTS OF EXPERTS

Canadian Natural's auditor is PricewaterhouseCoopers LLP, Chartered Accountants, 3100, 111-5th Avenue S. W. Calgary, Alberta T2P 5L3. The Company's audited consolidated financial statements for the year ended December 31, 2004 have been filed under National Instrument 51-102 in reliance on the report of PricewaterhouseCoopers LLP, independent chartered accountants, given on their authority as experts in auditing and accounting.

Sproule Associates Limited, Ryder Scott Company and Gilbert Laustsen Jung Associates Ltd. have provided the Report on Reserves Data attached as Schedule "A" to this Annual Information Form in their capacity as the Company's Independent Qualified Reserves Evaluators. Sproule Associates Limited, Ryder Scott Company and Gilbert Laustsen Jung Associates Ltd. and their directors, officers and associates, collectively own less than 1% of the Company's outstanding common shares.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on the SEDAR website at www.sedar.com

Additional information including Directors' and Executive Officers' remuneration and indebtedness, principal holders of the Company's securities, options to purchase the Company's securities and interest of insiders in material transactions is contained in the Company's Notice of Annual and Special Meeting and Information Circular dated March 17, 2005 in connection with the Annual and Special Meeting of Shareholders of Canadian Natural to be held on May 5, 2005 which information is incorporated herein by reference. Additional financial information and discussion of the affairs of the Company and the business environment in which the Company operates is provided in the Company's Management Discussion and Analysis, comparative Consolidated Financial Statements and Supplementary Oil & Gas Information for the most recently completed fiscal year ended December 31, 2004 found on pages 39 to 67, 68 to 90 and 91 to 95 respectively, of the 2004 Annual Report to the Shareholders, which information is incorporated herein by reference.

For additional copies of this Annual Information Form, please contact:

Corporate Secretary of the Corporation at:
2500, 855 – 2nd Street S.W.
Calgary, Alberta T2P 4J8

SCHEDULE "A"

Amended Form 51-101F2

Report on Reserves Data by
Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the Board of Directors of Canadian Natural Resources Limited (the "Corporation"):

1. Except as noted in 1(c) (i), we have evaluated the Corporation's reserves data as at December 31, 2004. The reserves data consist of the following:

(a) (i) proved oil and natural gas reserve quantities estimated as at December 31, 2004 using constant prices and costs;
(ii) the related estimated future net revenue; and
(iii) the related standardized measure calculation for proved oil and natural gas reserve quantities.

(b) (i) proved and proved plus probable oil and natural gas reserves estimated as at December 31, 2004 using forecast prices and costs; and
(ii) the related estimated future net revenue

(c) (i) proved and proved plus probable bitumen and synthetic crude oil reserves relating to surface mineable oil sands projects estimated as at February 9, 2005

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.

3. 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").

4. 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 principles and definitions as outlined above.

5. The following table sets forth the estimated net present value of future cash flows (before deduction of income taxes) attributed to proved oil and natural gas reserves quantities, estimated using 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 except as noted in 1(c)(i), and identifies the respective portions

thereof that we have evaluated and reported on to the Corporation's management and board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Values of Future Cash Flows (Before Income Taxes, 10% Discount Rate)			
			Audited MM$	**Evaluated MM$**	**Reviewed MM$**	**Total MM$**
Sproule Associates Ltd.	Sproule Evaluated the P&NG Reserves as reported February 18, 2005.	Canada, USA	$0	$11,242.36	$0	$11,242.36
Ryder Scott Company	Ryder Scott Evaluated the P&NG Reserves as reported February 18, 2005.	Canada (assets acquired November 2004)	$0	$468.00	$0	$468.00
Ryder Scott Company	Ryder Scott Evaluated the P&NG Reserves as reported February 18, 2005.	United Kingdom and Offshore West Africa	$0	$6,427.80	$0	$6,427.80
Totals			$0	$18,138.16	$0	$18,138.16

In addition all proved and proved plus probable company gross reserves have been evaluated for oil sands mining properties located in Canada. Horizon mining reserves are not part of Canadian Natural's year end. The Horizon reserves were evaluated as at February 9th, 2005. Gilbert Laustsen Jung Associates Ltd ("GLJ"), an independent qualified reserves evaluator, was retained by the Reserves Committee of Canadian Natural's Board of Directors to evaluate reserves associated with the Horizon Project incorporating both the mining and upgrading projects. These reserves were evaluated under SEC Industry Guide 7 and are discussed separately from the Company's conventional oil and gas activities.

6. 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. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our evaluation for events and circumstances occurring after their respective preparation dates.

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

Executed as to our report referred to above:

February 18, 2005

SPROULE ASSOCIATES LIMITED

Original Signed By:

____
Harry J. Helwerda, P.Eng.,
Vice-President, Engineering,

Original Signed By:

____
Doug Ho, P.Eng.
Manager, Engineering, and Associate

Original Signed By:

____
Ken H. Crowther, P.Eng.
President, Canada and U.S.

RYDER SCOTT COMPANY

Original Signed By:

____
Jane Tink, P.Eng.,
Vice-President, Engineering

GILBERT LAUSTSEN JUNG ASSOCIATES LTD.

Original Signed By:

____
James H. Willmon, P.Eng.
Vice-President

SCHEDULE "B"

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Report of Management and Directors on Reserves Data and Other Information

Management of Canadian Natural Resources Limited (the "Corporation") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and natural gas and surface mineable oil sands activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved oil and natural gas reserve quantities estimated as at December 31, 2004 using constant prices and costs;
(ii) the related estimated future net revenue; and
(iii) the related standardized measure calculation for proved oil and natural gas reserve quantities.

(b) (i) proved and proved plus probable oil and natural gas reserves estimated as at December 31, 2004 using forecast prices and costs;
(ii) the related estimated future net revenue; and,

(c) (i) proved and probable working interest oil reserve quantities relating to surface mineable oil sands operations estimated as at February 9, 2005.

Sproule Associates Limited, Ryder Scott Company and Gilbert Laustsen Jung Associates Ltd. all independent qualified reserves evaluators have evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The reserves committee (the "Reserves Committee") of the board of directors (the "Board of Directors") of the Corporation has:

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

(b) met with each of 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 with management and the independent qualified reserves evaluators.

The Reserves Committee of the Board of Directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and natural gas and surface mineable oil sands information;

(b) the filing of the reports of the independent qualified reserves evaluators on the reserves data; 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"
Steve W. Laut
Chief Operating Officer

"Signed"
Douglas A. Proll
Senior Vice President, Finance

"Signed"
David A. Tuer
Independent Director and Chair of the Reserve Committee

"Signed"
Keith A.J. MacPhail
Independent Director and Member of the Reserve Committee

Dated this 18th day of February, 2005
Calgary, Alberta