CANADIAN NATURAL RESOURCES LIMITED

ANNUAL INFORMATION FORM

March 29, 2006

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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.

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

"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",** 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.

"conventional crude oil, NGLs and natural gas" includes all of the Company's light and medium crude oil, heavy crude oil, thermal in-situ, natural gas, coal bed methane and natural gas liquid activities. It does not include the Company's oil sands mining assets**.**

"development well" means a well drilled into a zone that is known to be productive and expected to produce crude oil or natural gas in the future.

"dry well" means a well drilled that is not capable of producing commercial quantities of crude oil or natural gas to justify completion. A dry well will be plugged back, abandoned and reclaimed.

"exploratory well" means a well drilled into an unproven territory with the intention to discover commercial quantities of crude oil or natural gas.

"**FPSO**" means a 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.

“productive well” a well that is not dry.

“**SAGD**” means steam-assisted gravity drainage.

“**undeveloped 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 Securities 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 "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; political uncertainty, including actions of or against terrorists or 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; the 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 ability of the Company to attract the necessary labour required to build its projects; the operating hazards and other difficulties inherent in the exploration for and production and sale of crude 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 asset retirement obligations; 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 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 were 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. Except as required by law, 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.

For the year ended December 31, 2005, Canadian Natural retained qualified independent reserve evaluators, Sproule Associates Limited (“Sproule”) and Ryder Scott Company (“Ryder Scott”), to evaluate 100% of the Company’s conventional proved and probable crude oil, natural gas liquid (“NGL”) and natural gas reserves and prepare Evaluation Reports on these reserves. Sproule evaluated the Company’s North American conventional assets and Ryder Scott evaluated its conventional international assets. The Company has been granted an exemption from the 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. There are two principal differences between the two standards. The first is the additional requirement under NI 51-101 to disclose both proved and proved and probable reserves, as well as the related net present value of future net revenues using forecast prices and costs. The second is in the definition of proved reserves; however, as discussed in the Canadian Oil and Gas Evaluation Handbook (“COGEH”), the standards that NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material.

The Company has disclosed conventional proved reserves and the Standardized Measure of discounted future net cash flows using constant prices and costs as mandated by the SEC in the supplementary oil and gas information section of its Annual Report. The Company has also elected to provide the net present value of these same conventional proved reserves as well as the conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information. In addition to the constant price and cost scenario, the Company has also elected to provide both conventional proved and conventional proved and probable reserves, as well as the net present value of these reserves, using forecast prices and costs as voluntary additional information.

Reserves and net present values of these reserves 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.

For the year ended December 31, 2005, the Company retained a qualified independent reserves evaluator, GLJ Petroleum Consultants (“GLJ”), to evaluate 100% of phases 1 through 3 of the Company’s Horizon Oil Sands Project and prepare an Evaluation Report on the Company’s proved, as well as proved and probable oil sands mining reserves incorporating both the mining and upgrading projects. These reserves were evaluated adhering to the requirements of SEC Industry Guide 7 using year-end constant pricing and have been disclosed separately from the Company’s conventional crude oil, NGL and natural gas reserves.

The Reserves Committee of the Company’s Board of Directors has met with and carried out independent due diligence procedures with each of Sproule, Ryder Scott and GLJ to review the qualifications of and procedures used by each evaluator in determining the estimate of the

Company's quantities and net present value of remaining conventional crude oil, NGL and natural gas reserves, as well as the Company's quantity of oil sands mining reserves.

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, adjusted net earnings 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. 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. Canadian Natural 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.

Canadian Natural 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 ("Ranger"), including its subsidiaries, 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 significant operating subsidiaries of the Company, each of which is directly or indirectly wholly-owned, and their jurisdictions of incorporation are as follows:

Name of Company	Jurisdiction of Incorporation
CanNat Energy Inc.	Delaware
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
CNR International (Gabon) Limited	Bahamas
Horizon Construction Management Ltd.	Alberta
Renata Resources Inc.	Alberta

Canadian Natural, as the managing partner, 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, CNR (ECHO) Resources Inc., Renata Resources Inc., and Canadian Natural are partners of Canadian Natural Resources Northern Alberta Partnership, a general partnership. The two partnerships hold the majority of the producing Canadian crude oil and natural gas properties of Canadian Natural. The Company also has a 15 per cent interest in Cold Lake Pipeline Ltd., which is the general partner of Cold Lake Pipeline Limited Partnership in which Canadian Natural holds a separate 14.7 per cent partnership interest. Canadian Natural, 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. Canadian Natural, as the managing partner, and 1081840 Alberta Ltd. are the partners of 1081840 Alberta Partnership, which holds certain crude oil and natural gas properties of the Company.

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

GENERAL DEVELOPMENT OF THE BUSINESS

Canadian Natural'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. Canadian Natural'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, 2005 the Company had 2,580 permanent employees in North America and 317 permanent employees in its international operations.

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 crude 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 crude 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 mmcf/d of natural gas and 200 bbl/d of light crude oil and NGLs and contained 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 mmcf/d 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 has added 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 crude 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 crude 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 mmcf/d of natural gas and 7.5 mbbl/d of light crude oil and NGLs being approximately 25,000 boe/d. 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 regions and extends its Northern Plains core region into the light crude 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 ("Horizon Project"). The Horizon Project is designed as a phased development and includes the mining of bitumen combined with an onsite upgrader. Phase 1 production is planned to begin in the second half of 2008 at 110 mbbl/d of 34° API light, sweet synthetic crude oil ("SCO"). Phase 2 would increase production to 155 mbbl/d of SCO in 2010. Phase 3 would further increase production to 232 mbbl/d of SCO in 2012. The phased approach provides the Company with improved cost and project controls including labour and materials management, and directionally mitigates the effects of growth on local infrastructure.

Based upon stratigraphic drilling the Company's oil sands leases located near Fort McMurray, Alberta contain an estimated 6 billion barrels of potentially recoverable bitumen using existing mining and upgrading technologies. Additional in-situ potential also exists on the western portions of the leases. The first three phases of the Horizon Project, which encompasses only a portion of these oil sands leases, will deliver approximately 37 years of production without the declines normally associated with petroleum operations. GLJ Petroleum Consultants ("GLJ"), a qualified independent third party petroleum consultant firm, was retained by the Reserves Committee of Canadian Natural's Board of Directors to evaluate the mining reserves associated with the Horizon Project. Their report estimated that 3.4 billion barrels of gross proved and probable bitumen reserves are located on the leases associated with the first three phases of the Horizon Project.

In August 2005, the Company entered into an agreement to obtain pipeline transportation service for the Horizon Project. This agreement allows Canadian Natural to gain access to major sales pipelines out of Edmonton for the Company's synthetic crude oil which will be produced at the Horizon Project, while at the same time provides significant quality benefits associated with being the only shipper on the Horizon Pipeline. The expected twinning of the existing Alberta Oil Sands Pipeline ("AOSPL"), resulting in two parallel pipelines, one of which will be dedicated to Canadian Natural, combined with a new pipeline constructed from the Horizon Project site down to the AOSPL Terminal (collectively, the "Horizon Pipeline"), will provide crude oil transportation service for the Horizon Project. The initial term of the agreement is 25 years, which will commence on the in-service date. In addition to having the option to renew the agreement for successive 10-year terms, Canadian Natural has the right to request incremental expansions of the Horizon Pipeline based upon applicable National Energy Board approved multi-pipeline economics. The construction of the Horizon Pipeline is expected to begin in 2006 and will be fully operational by mid 2008 to coincide with first production at the Horizon Project. See below "Horizon Oil Sands Project".

In April 2005, the Company monetized, through a sale, a large portion of its overriding royalty interests on various producing properties throughout Western Canada and Ontario for proceeds of approximately $345 million. In 2004 these interests produced approximately 3,700 boe/d and over the 2003 and 2004 fiscal years cash flow from these interests averaged approximately $50 million per year. As part of the transaction, the Company purchased 3,858,520 trust units of Freehold Royalty trust for $60 million and, after the mandatory hold period, the trust units were sold to an underwriting group pursuant to an agreement for a net gain of approximately $11 million.

On June 1, 2005, the Company issued $400 million of 10-year 4.95 per cent unsecured notes maturing June 1, 2015 pursuant to a short form shelf prospectus for the issuance of medium term notes in Canada dated August 1, 2003. In January 2006 the Company issued a further $400 million of 4.50 per cent unsecured notes maturing January 23, 2013 as the first issuance under the short form Canadian base shelf prospectus dated August 29, 2005, which allows for the issuance of debt securities in an aggregate principal amount of up to C$2 billion.

During 2005, the Company completed 96 transactions in the normal course to acquire additional interests in crude oil and natural gas properties at an aggregate net expenditure of $134 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 a large portion of its overriding royalty interests and operated and non-operated properties not located in the Company's core regions for proceeds of $454 million.

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 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 approval of a 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 NGLs 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.

In addition to government royalties, the Company is subject to federal and provincial income taxes in Canada at a combined rate of approximately 38.1 per cent after allowable deductions.

United Kingdom

Under existing law, the UK Government has broad authority to regulate the petroleum industry, including 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. Approvals granted on or after March 16, 1993 are exempted from PRT and government royalties. 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 deductible for CT purposes. The CT rate, which became effective April 1, 1999, was set at 30 per cent. In its 2002 budget speech by the UK Chancellor of the Exchequer, the UK Government 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. In December 2005, the UK Chancellor of the Exchequer announced an increase to the Supplementary CT from 10 per cent to 20 per cent, effective January 1, 2006.

Offshore West Africa

Terms of licences, including royalties and taxes payable on production or profit sharing arrangements, vary by country and, in some cases, by concession within each country. Development of the Espoir field on CI-26 and the Baobab Field on CI-40, in 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").

In October 2005, Canadian Natural completed the acquisition of the permit to develop the Olowi Field, offshore Gabon. Development of this field 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.

RISK FACTORS

Volatility of Crude Oil and Natural Gas Prices

The Company's financial condition is 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 the Company's 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. Crude Oil prices are determined by international supply and demand. Factors which affect crude oil prices include the actions of the Organization of Petroleum Exporting Countries, the condition of the Canadian, United States and

Asian economies, government regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil, the price of foreign imports, the availability of alternate fuel sources and weather conditions. Natural gas prices realized by the Company are 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 GAAP. If crude oil and natural gas prices decline, the carrying value of the assets could be subject to downward revisions, and net earnings could be adversely affected.

Approximately 27 percent of the Company's 2005 production on a boe basis was primary and thermal heavy crude oil. The market prices for heavy crude oil differ from the established market indices for light and medium grades of crude oil, due principally to the higher transportation and refining costs associated with heavy crude oil. As a result, the price received for heavy crude oil is generally lower than the price for medium and light crude oil, and the production costs associated with heavy crude oil may be higher than for lighter grades. Future differentials are uncertain and any increase in the heavy crude oil differentials could have a material adverse effect on the Company's business.

Environmental Risks

All phases of the crude 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 crude 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 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 crude 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 crude 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 crude oil and natural gas interests and the transportation and marketing of crude oil, natural gas, NGLs 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 relate to operational risks, the cost of capital available to fund exploration and development programs, fluctuation in foreign exchange rates, the availability of skilled labour and manpower, 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 crude oil and natural gas properties in Canada differs distinctly from its ownership interests in foreign crude 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 crude 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 crude oil, NGL and natural gas reserves and the future net cash flow there from 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 crude oil, NGL 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 there from, 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 industry standards. 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 by changes in applicable legislation. 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 its 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 ("GHG") reduction; and flaring and venting reduction. Canadian Natural participates in both the Canadian federal and provincial regulated GHG emissions reporting for facilities with GHG emissions greater than 100 thousand tonnes of CO2 equivalent per year. The Company continues to quantify annual GHG emissions for internal reporting purposes. 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 to help us achieve our overall goal of a net reduction of GHG emissions per unit of production.

The costs incurred by the Company for compliance with environmental matters and site restoration amounted 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, 2005, 2004 and 2003.

DESCRIPTION OF THE BUSINESS

Canadian Natural is a Canadian based senior independent energy company engaged in the acquisition, exploration, development, production, marketing and sale of crude oil, NGLs, natural gas and bitumen production. 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 Canadian Natural 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 presence 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 43 per cent of 2005 production. Virtually all of the Company's natural gas and NGLs production is located in the Canadian provinces of Alberta and British Columbia and is marketed in Canada and the United States. Light crude oil and NGLs, representing 26 per cent of 2005 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 crude oil operations in the Provinces of Alberta and Saskatchewan account for 27 per cent of 2005 production. Other heavy crude oil, which accounts for 4 per cent of 2005 production, is produced from the Pelican Lake area in north Alberta. This production, which has medium crude oil netback characteristics, is developed through a staged horizontal drilling program complimented by water flooding. 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. Canadian Natural expects its ownership of crude oil sands leases near Fort McMurray, Alberta to provide a basis for long-term synthetic crude oil production growth. The first three phases of the Horizon Project, which encompasses only a portion of these oil sands leases is expected to deliver approximately 37 years of synthetic crude oil production.

As a result of the Company's core undeveloped land base of 10.9 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, NATURAL GAS AND OIL SANDS PROPERTIES

Set forth below is a summary of the principal crude oil, natural gas and oil sands properties as at December 31, 2005. The information reflects the working interests owned by the Company.

	2005 AVERAGE DAILY PRODUCTION RATES		YEAR ENDED DECEMBER 31, 2005	MAJOR INFRASTRUCTURE AS AT DECEMBER 31, 2005
REGION	CRUDE OIL & NGLs mbbl	NATURAL GAS mmcf	UNDEVELOPED ACREAGE (thousands)	BATTERIES/ COMPRESSORS & PLANTS/ PLATFORMS /FPSO
North America				
Northeast B. C.	6.7	434.4	2,027	1/9/-/-
Northwest Alberta	13.5	403.4	1,507	-/8/-/ -
Northern Plains	181.8	419.2	6,594	12/6/-/-
Southern Plains	10.7	155.4	621	-/2/-/-
Southeast Saskatchewan	8.8	3.1	82	-/-/-/-
Non – core regions	0.2	0.8	236	-/-/-/-
Horizon Oil Sands	-	-	115	-/-/-/-
International				
North Sea UK Sector	68.6	18.4	352	-/-/6/1
Offshore West Africa				
Côte d'Ivoire	22.9	4.1	274	-/-/0/2
Gabon	-	-	152	-/-/-/-
Non – core regions				
South Africa	-		4,002	-/-/-/-
Total	313.2	1438.8	15,963	13/25/6/3

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, 2005 by geographic region:

2005

	NET EXPLORATORY			NET DEVELOPMENT		
	PRODUCTIVE	DRY HOLES	TOTAL	PRODUCTIVE	DRY HOLES	TOTAL
Canada						
Northeast B. C.	32.1	7.2	39.3	179.9	21.1	201.0
Northwest Alberta	29.9	9.0	38.9	135.2	7.3	142.5
Northern Plains	63.5	11.5	75.0	671.4	51.9	723.3
Southern Plains	50.6	5.0	55.6	294.9	2.0	296.9
Southeast Saskatchewan	1.0	-	1.0	43.0	-	43.0
Non – core regions	-	-	-	0.3	-	0.3
North Sea UK Sector	-	0.8	0.8	11.5	0.9	12.4
Offshore West Africa						
Côte d'Ivoire	-	0.6	0.6	3.5	-	3.5
Total	177.1	34.1	211.2	1339.7	83.2	1422.9

2004

	NET EXPLORATORY			NET DEVELOPMENT		
	PRODUCTIVE	DRY HOLES	TOTAL	PRODUCTIVE	DRY HOLES	TOTAL
Canada						
Northeast B. C.	23.8	6.2	30.0	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	357.0
Southern Plains	18.5	7.0	25.5	209.9	4.0	213.9
Southeast Saskatchewan	-	-	-	12.5	-	12.5
Non – core regions	-	-	-	0.5	0.3	0.8
North Sea UK Sector	-	2.0	2.0	9.2	-	9.2
Offshore West Africa						
Côte d'Ivoire	-	0.7	0.7	2.3	-	2.3
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 UK Sector	-	1.0	1.0	11.1	0.8	11.9
Offshore West Africa						
Côte 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

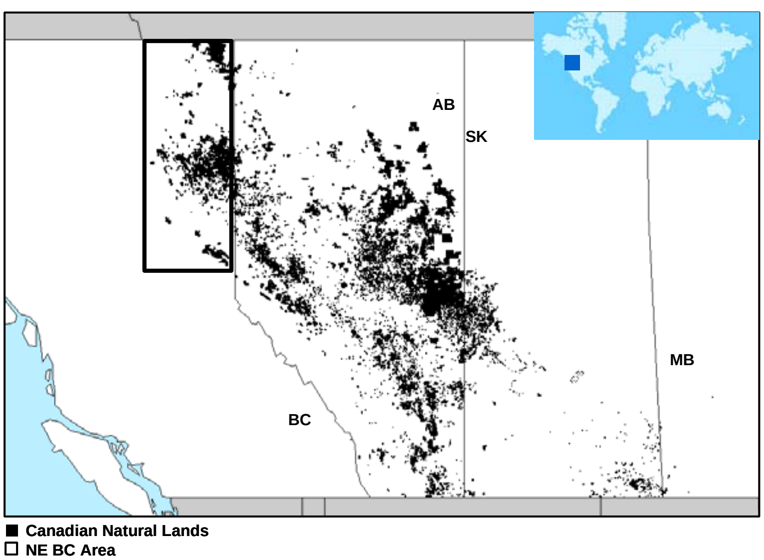
Producing Crude Oil & Natural Gas Wells

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, 2005:

	NATURAL GAS WELLS		CRUDE OIL WELLS		TOTAL WELLS	
	GROSS	NET	GROSS	NET	GROSS	NET
Canada						
Northeast B. C.	1,177	983.7	278	204.4	1,455	1,188.1
Northwest Alberta	1,196	948.7	195	140.1	1,391	1,088.8
Northern Plains	3,502	2,923.7	5,799	5,291.9	9,301	8,215.6
Southern Plains	4,260	3,698.5	1,026	922.0	5,286	4,620.5
Southeast Saskatchewan	-	-	1,092	768.0	1,092	768.0
Non – core regions	837	334.3	1,483	470.0	2,320	804.3
United States	4	0.5	2	0.2	6	0.7
North Sea UK Sector	4	0.3	118	98.4	122	98.7
Offshore West Africa						
Côte d'Ivoire	-	-	15	8.7	15	8.7
Total	10,980	8,889.7	10,008	7,903.7	20,988	16,793.4

All reserves data in the following property report is based on the applicable independent engineering report. See below "Conventional Crude Oil, NGL and Natural Gas Reserves" and "Oil Sands Mining Disclosure".

Northeast British Columbia



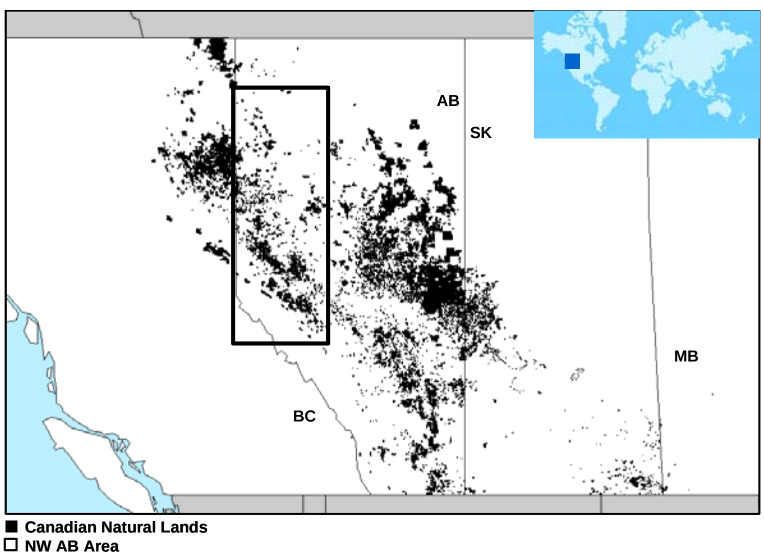
This region comprises lands from Fort St. John, British Columbia to the northern border as well as the eastern border of British Columbia. Similar geological attributes extend throughout the region, producing light crude oil, NGLs and natural gas. The Company holds working interests ranging up to 100 per cent and averaging 77 per cent in 3,776,051 gross (2,895,451 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 NGLs 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 434.4 mmcf/d in 2005 compared to the average of 437.3 mmcf/d in 2004. Crude oil and NGLs production was steady at to 6.7 thousand bbl/d in 2005 from an average of 6.8 thousand bbl/d in 2004.

During 2005, 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 generally 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 2005, the Company drilled 10.9 (2004- 3.6) net crude oil wells, 201.1 (2004 – 167.0) net natural gas wells, 1.0 (2004 – 1.0) net stratigraphic/service wells and 28.3 (2004 – 20.6) net dry wells on its lands in this region for a total of 241.3 (2004 – 192.2) net wells. The Company held an average 85.6 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 2,809,179 gross (2,128,874 net) acres of producing and undeveloped land in the region located along the border of British Columbia and Alberta west of Edmonton.

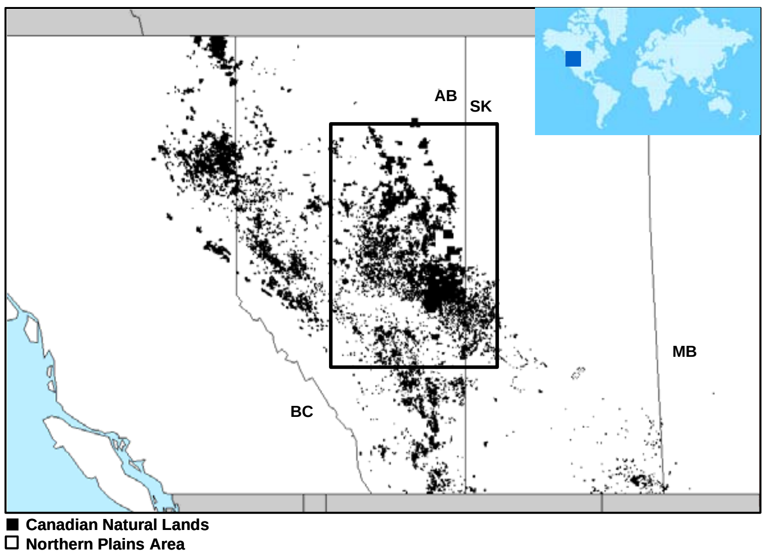
The majority of the Company's holdings in the region were obtained through the Plan of Arrangement in 2002, which facilitated the acquisition of RAX. This region contains exceptional exploration and exploitation opportunities as well as substantial available capacity within an extensively owned and operated 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 meters. The northern portion of this core region provides extensive multi-zone

Cretaceous opportunities similar to the geology of the Company's Northern Plains 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 403.4 mmcf/d in 2005 compared to an average of 303.2 mmcf/d in 2004. Crude oil and NGLs production was steady at 13.5 thousand bbl/d in 2005 from 10.9 thousand bbl/d in 2004.

During 2005, the Company drilled 12.9 (2004-5.8) net crude oil wells, 152.4 (2004-137.5) net natural gas wells, 0.7 (2004 – 1.5) net stratigraphic/service wells, and 16.3 (2004-11.5) net dry wells on its lands in this region for a total of 182.3 (2004-156.3) net wells. The Company held an average 82.1 per cent working interest in these wells.

Northern Plains



The Company holds working interests ranging up to 100 per cent and averaging 84 per cent in 11,608,488 gross (9,806,002 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, NGLs and light crude oil are also encountered at slightly greater 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 419.2 mmcf/d in 2005 compared to 429.9 mmcf/d in 2004. Crude oil and NGLs production from this region increased to 181.8 thousand bbl/d in 2005 from 166.3 thousand bbl/d in 2004. Production of natural gas was negatively impacted by the shut-in effective July 1, 2004 of approximately 11 mmcf/d in the Athabasca Wabiskaw-McMurray oil sands area pursuant to the decision of the Alberta Energy and Utilities Board.

In February 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.

Natural gas in this region is produced from shallow, low-risk, multi-zone prospects and more recently from the Horseshoe Canyon coal bed methane ("CBM"). The Company targets low-risk exploration and development opportunities and plans to expand its commercial CBM project. During 2005, CBM development drilling included 42 net wells and the Company has an inventory of over 500 net Horseshoe Canyon CBM locations.

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 crude 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 crude 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 crude 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 contiguous to the Company's holdings. With the operations combined in 2000, development 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 bbl/d of hot, unblended crude oil to sales facilities at Hardisty, Alberta and in 2003 its capacity was expanded to handle up to 72 thousand bbl/d. 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. 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. The ECHO Pipeline system permits the Company to transport approximately 80 per cent of its heavy crude oil to the international mainline liquids pipelines.

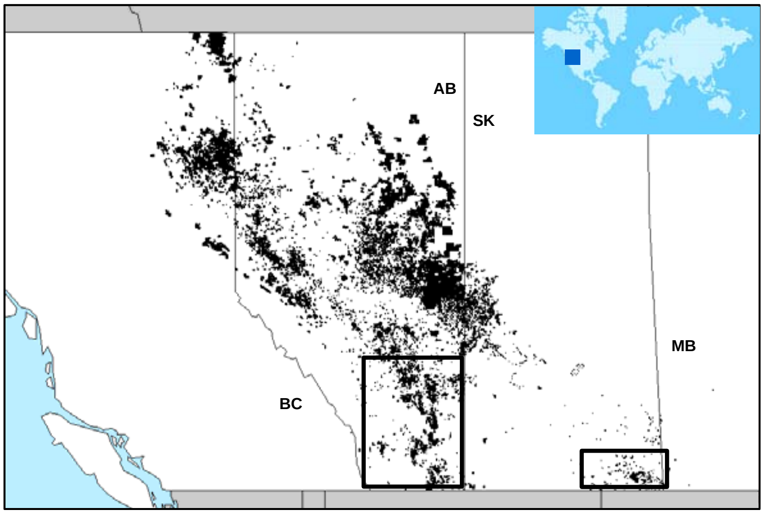
Production from the 100% owned Primrose and Wolf Lake Fields located near Bonnyville, Alberta involves processes that utilize steam to increase the recovery of the crude oil. The two processes employed by the Company are cyclic steam stimulation and Steam Assisted Gravity Drainage ("SAGD"). Both recovery processes inject steam to heat the heavy crude oil deposits, reducing the oil viscosity and thereby improving its flow characteristics. There is also an infrastructure of gathering systems, a processing plant with a capacity of 80 thousand bbl/d of crude oil 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 apply 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 was effectively completed in 2005 with total capital expenditures of approximately $300 million incurred. The Primrose North expansion entails a remote steam treating facility and additional high pressure wells. First crude oil production from the expansion project began in January 2006. Also in 2004 the Company filed a public disclosure document for regulatory approval of its Primrose East project, a new facility located about 15 kilometers from its existing Primrose South steam plant and 25 kilometers from its Wolf Lake central processing facility. The development application was submitted to the Alberta Energy and Utilities Board in January 2006, with potential impacts associated with the use of bitumen as fuel being evaluated in the Environmental Impact Assessment. The Company expects construction to begin in 2007, with the first steam scheduled for January 2009. A 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 holdings at Pelican Lake; generally having a 100 per cent ownership rate by the Company. These lands contain reserves of 12°-17° API heavy crude oil. Operating costs are low due to the absence of sand production and 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 was slow. Due to the slow response time, the Company reverted to a waterflood scheme for this field. The waterflood provided initial production increases as expected and has shown positive waterflood response. To enhance the waterflood scheme, in the second quarter of 2005, the Company installed facilities for a polymer flood pilot test. Initial behaviour of the polymer flood pilot test has been positive, however definitive conclusions regarding the feasibility of the program will not be known until late 2006 or early 2007. In advance of the pilot test results, preparations for commercial polymer flood have commenced including source water development and advance ordering of some of the long lead time equipment.

During 2005, the Company drilled 536.1 (2004 – 287.0) net crude oil wells, 198.9 (2004 – 163.4) net natural gas wells, 108.9 (2004 – 112.0) net stratigraphic/service wells, and 63.4 (2004 – 49.8) net dry wells for a total of 907.3 (2004 – 612.2) net wells. The Company's average working interest in these wells was 91.7 per cent.

Southern Plains and Southeast Saskatchewan



■ Canadian Natural Lands
□ Southern Plains - SE SK Area

In the Southern Plains area, the Company holds interests ranging up to 100 per cent and averaging 83 per cent in 2,037,923 gross (1,699,254 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 higher than average 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 10.7 thousand bbl/d of crude oil and NGLs compared to 12.7 thousand bbl/d in 2005. Natural gas production amounted to 155.4 mmcf/d in 2005 compared to the 155.5 mmcf/d averaged in 2004.

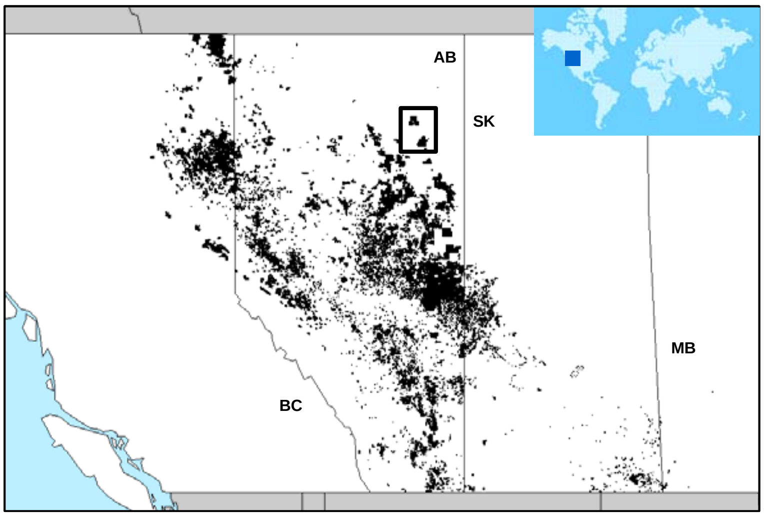
During 2005, the Company drilled a total of 9.0 (2004 – 7.8) net crude oil wells, 336.5 (2004 – 220.6) net natural gas wells, 1.7 (2004 – 1.0) net stratigraphic/service well and 7.0 (2004 – 11.0) net dry wells in this region for a total of 354.2 (2004 – 240.4) net wells. The Company's average working interest in these wells was 81.0 per cent.

The Williston Basin is located in Southeast 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 8.8 thousand bbl/d of crude oil and NGLs in 2005 compared to 9.3 thousand bbl/d in 2004. Natural gas production was steady averaging 3.1 mmcf/d in both 2005 and 2004.

The Company drilled 43.0 (2004 – 12.5) net crude oil wells, 1.0 (2004 – 0.0) net gas well, 7.6 (2004 – 0.0) net stratigraphic/service wells and 0.0 (2004 – 0.0) net dry wells in this region in 2005, for a total of 51.6 (2004 – 12.5) net wells. The Company's average working interest in these wells is 83.2 per cent.

Horizon Oil Sands Project



■ Canadian Natural Lands
□ Horizon Oil Sands Project

Canadian Natural owns a 100 per cent working interest in its Athabasca Oil Sands leases in Northern Alberta, of which a portion (being lease 18) is subject to a 5 per cent net carried interest in the bitumen development. The Horizon Oil Sands Project ("Horizon Project") is located on these leases, about 70 kilometers north of Fort McMurray. The project includes surface oil sands mining, bitumen extraction, bitumen upgrading to produce a 34^{o} -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 2011 or 2012. Phase 1 production is targeted to begin in the second half of 2008 at 110 thousand bbl/d of SCO. Current plans have Phase 2 increasing production to 155 thousand bbl/d of SCO in 2010 and Phase 3 further increasing production to 232 thousand bbl/d of SCO in 2012. These targeted rates of production represent nominal design capacity. The Company is currently evaluating the opportunity to combine Phase 2 and Phase 3 for a joint operational date of 2011. 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 may mitigate any negative effects of growth on local infrastructure.

Using a cost environment associated with a US $45 WTI price per barrel of crude oil, total estimated capital construction 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 $15 per barrel (based upon a natural gas price input of US$ 5.83/mcf).

Canadian Natural filed an application for regulatory approval of the Horizon Project in June 2002. The application included a comprehensive environmental impact assessment and 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 developed in the context of 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.

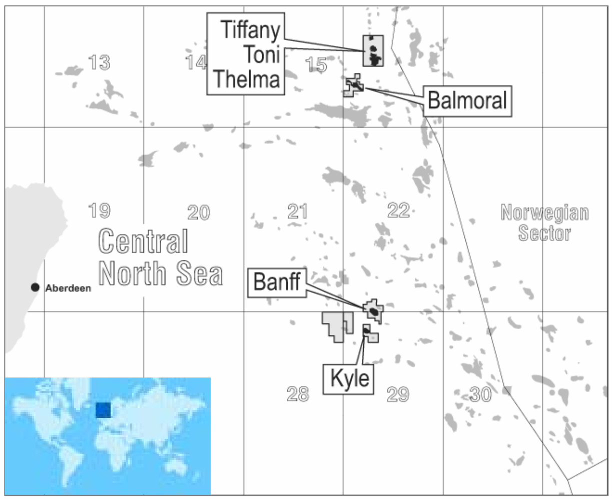
Canadian Natural used a structured system called Front End Loading to ensure that project definition is adequate and complete before proceeding with implementation. This system is used successfully worldwide to mitigate risk on large capital projects in a variety of industries. The process is well documented 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 for Phase 1, 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 Project. The third phase of FEL for Phase 2 is expected to be completed in the first quarter of 2007.

The Horizon Project 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 2005, Canadian Natural's Horizon Project team, consisted of 521 permanent employees. This represents a total of 67 per cent of the 773 staff positions required by year end 2006. Of the 252 outstanding positions, 110 are filled by contractors on an interim basis for total of 82 per cent of our 2006 year end position requirements.

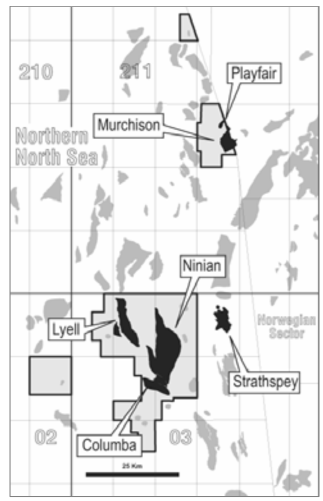
Horizon Project costs were approximately $1.5 billion in 2005 and cumulative expenditures were approximately $2.2 billion through the end of 2005. These expenditures include capitalized interest, stock based compensation, lease evaluation, engineering definition, technology acquisition, completion of road infrastructure to the site, initial camp construction, detailed engineering, significant site development and initial foundation construction. Construction costs for 2006 are budgeted to be approximately $2.6 billion reflecting major expenditures for detailed engineering, procurement and construction of Phase 1 of the Project. In addition, capital expenditures of $128 million are budgeted for Phase 2 EDS development in 2006.

During 2005, the Company drilled 126 (2004 – 218) stratigraphic test wells to further delineate the ore body and confirm resource quality and quantity.

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 595,051 gross (444,314 net) acres of producing and non-producing properties in the UK sector of the North Sea. In 2005, the Company produced from 16 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 its 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. The Company also owns a 45.7 per cent operated working interest in the Kyle Field. Beginning in the third quarter of 2005, all production for the Kyle Field was processed through the Banff FPSO facilities. The consolidation of these production facilities is expected to result in lower combined operating costs from these fields.

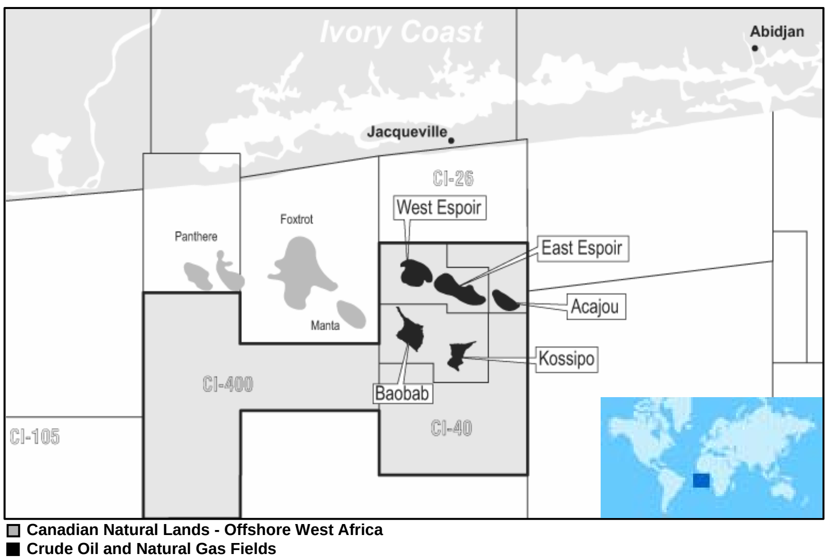
In 2004, the Company acquired 100 per cent working interest in T-block (comprising the Tiffany, Toni and Thelma Fields) and 68.7 per cent to 75.3 per cent interests in the Fields known as B-block (comprising Balmoral, Stirling and Glamis). The Company took over as operator of these fields.

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 by the existing processing facilities.

During 2005, production to the Company from this region averaged 68.6 thousand bbl/d of crude oil, up from 64.7 thousand bbl/d in 2004. Natural gas production averaged 18.4 mmcf/d in 2005, down from 50.4 mmcf/d in 2004 primarily due to the re-injection of associated natural gas production into the Banff Field for improved crude oil recovery.

The Company drilled 11.5 (2004 – 9.2) net crude oil wells, 0.9 (2004 – 2.7) net stratigraphic/service wells and 1.7 (2004 – 2.0) net dry wells in 2004 in this region for a total of 14.1 (2004 – 13.9) net wells. The Company's average working interest in these wells is 88.0 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 1,596,013 gross (887,657 net) acres in those countries. Since 2000, the Company has either relinquished or sold all of its interests in offshore Angola.

In 2005, the Company acquired the permit to develop the Olowi Field, offshore Gabon, West Africa, consisting of 151,818 acres. The Company has a 90 per cent interest in a production sharing agreement for the block.

The Company also has a 100 per cent interest in 4,001,574 acres offshore South Africa where it is shooting and evaluating seismic data and undertaking environmental studies.

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 58.7 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. The construction and installation of a new wellhead tower for the West Espoir part of the field were completed in 2005. An infill drilling program in East Espoir was commenced in 2005 and following its completion development drilling will commence at West Espoir.

Crude oil from the East Espoir Field 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.

The unsuccessful Zaizou exploration well was drilled in block CI-40 in 2005.

In the first quarter of 2001, the Company drilled and tested the Baobab exploration prospect, identified on Block CI-40, eight kilometers south of the Espoir facilities, in which the Company has a 58 per cent interest. 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 Côte 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 first oil was achieved in August 2005 producing at approximately 30 thousand bbl/d net to Canadian Natural from 4 wells. Upon completion of drilling additional wells in 2006, production levels are expected to increase another 5 thousand bbl/d net to the Company. In East Espoir, two of four infill wells were completed in 2005 increasing production by 3 thousand bbl/d in the second quarter of 2005. The remaining two infill wells are expected to be completed in 2006. Construction of the West Espoir drilling tower was completed and installed to facilitate development drilling of the reservoir and it is expected that production will commence in 2006.

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

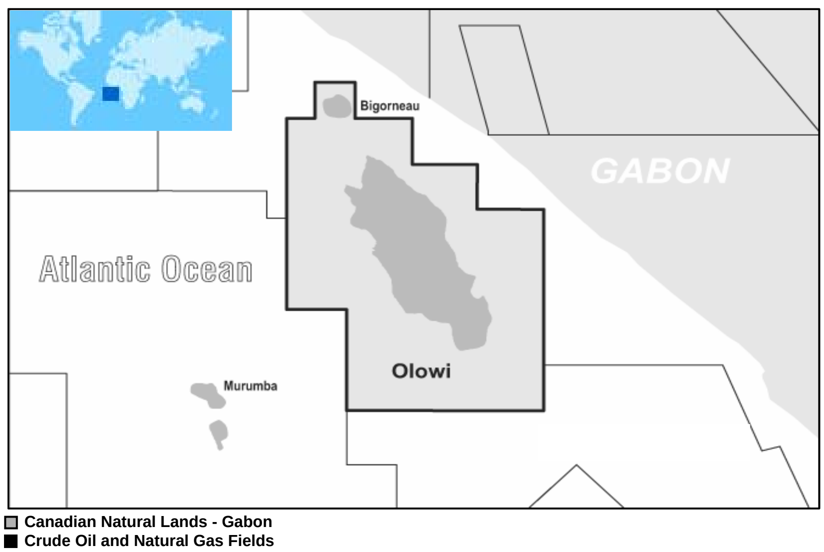
During 2005, Company production averaged 22.9 thousand bbl/d of crude oil compared to 11.6 thousand bbl/d in 2004. Company natural gas production amounted to 4.2 mmcf/d in 2005 compared to 7.5 mmcf/d in 2004.

In 2005, the Company drilled 3.5 (2004 – 2.3) net crude oil wells, 1.1 (2004 – 0.0) net stratigraphic/service wells and 0.6 (2004 – 0.7) net dry wells for a total of 5.2 (2004 – 3.0) net wells. The Company's average working interest in these wells is 58.2 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 data 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 data and the well results during 2004 and even though additional review of seismic and geological data on Block 16 indicates that significant upside remains a possibility, the risk level associated with Block 16 is outside the normal operating parameters of the Company. As a result, the Company entered into an agreement to dispose of its interest in Block 16 effective December 31, 2005. As of the sale of Block 16, the Company no longer has any holdings in Angola.

Gabon



The Company acquired permit (No. G4-187) comprising a 90 per cent operating interest in the production sharing agreement for the block containing the Olowi Field, located about 20 kilometers from the Gabonese coast and in 30 meters water depth. Olowi has been delineated by the drilling of 15 wells on the block and is estimated to potentially contain up to 500 million barrels of 34° API light crude original oil in place. The crude oil reservoir is overlain by a large gas cap with potentially up to 1 trillion cubic feet of original gas in place. A development plan, comprising an FPSO and four drilling towers, was filed with the Gabonese Government in late 2005 and approved in February 2006. The development of the crude oil reserves will commence in late 2006 with first production targeted for late 2008 at a rate of 20 thousand bbl/d.

B. CONVENTIONAL CRUDE OIL, NGL, AND NATURAL GAS RESERVES

For the year ended December 31, 2005, Canadian Natural retained qualified independent reserve evaluators, Sproule Associates Limited ("Sproule") and Ryder Scott Company ("Ryder Scott"), to evaluate 100% of the Company's conventional proved and probable crude oil, NGL and natural gas reserves and prepare Evaluation Reports on these reserves. Sproule evaluated the Company's North America conventional assets and Ryder Scott evaluated its international conventional assets. The Company has been granted an exemption from the 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. There are two principal differences between the two standards. The first is the additional requirement under NI 51-101 to disclose both proved, proved and probable reserves, as well as the related net present value of future net revenues using forecast prices and costs. The second is in the definition of proved reserves; however, as discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards that NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material.

The Company has disclosed proved conventional reserves and the Standardized Measure of discounted future net cash flows using constant prices and costs as mandated by the SEC in the supplemental oil and gas information section of its annual report. The Company has also elected to provide the net present value of these same conventional proved reserves as well as the conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information. In addition to the constant price and cost scenario, the Company has also elected to provide both conventional proved and conventional proved and probable reserves, as well as the net present value of these reserves, using forecast prices and costs as voluntary additional information.

Reserves and net present values of these reserves 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.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of Sproule and Ryder Scott to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and net present value of remaining conventional crude oil, NGL and natural gas reserves.

The following tables summarize the evaluations of conventional reserves and estimated net present values of these reserves at December 31, 2005.

The estimated net present values of reserves 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. Only future development costs and associated future material well abandonment liabilities have been applied with the exception of Offshore West Africa where all existing and future abandonment liabilities have been included. 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.

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

	Constant Prices and Costs			
	Crude Oil & NGLs (mmbbl)		Natural Gas (bcf)	
	Total Proved Reserves	Total Proved and Probable Reserves	Total Proved Reserves	Total Proved and Probable Reserves
North America				
Canada	694	1,035	2,739	3,546
United States	-	-	2	2
International				
United Kingdom	290	417	29	69
Côte d'Ivoire	119	189	72	110
Gabon	15	17	-	-
Total	**1,118**	**1,658**	**2,842**	**3,727**

Conventional Crude Oil, NGL and Natural Gas Reserves

	Constant Prices and Costs			
	Crude Oil & NGLs (mmbbl)		Natural Gas (Bcf)	
	Company Gross	Net	Company Gross	Net
Proved developed reserves	762	696	2,871	2,326
Proved undeveloped reserves	461	422	619	516
Total proved reserves	**1,223**	**1,118**	**3,490**	**2,842**
Total proved and probable reserves	**1,801**	**1,658**	**4,568**	**3,727**

Estimated Net Present Values

($ millions)	Constant Prices and Costs			
	Undiscounted	Discounted at		
		10%	15%	20%
Proved developed reserves	37,183	24,275	20,939	18,514
Proved undeveloped reserves	12,035	6,342	4,881	3,843
Total proved reserves	**49,218**	**30,617**	**25,820**	**22,357**
Total proved and probable reserves	**68,543**	**38,682**	**31,642**	**26,764**

Conventional Crude Oil, NGL and Natural Gas Reserves

	Forecast Prices and Costs			
	Crude Oil & NGLs (mmbbl)		Natural Gas (bcf)	
	Company Gross	Net	Company Gross	Net
Proved developed reserves	752	685	2,814	2,276
Proved undeveloped reserves	462	421	617	517
Total proved reserves	**1,214**	**1,106**	**3,431**	**2,793**
Total proved and probable reserves	**1,792**	**1,642**	**4,485**	**3,657**

Estimated Net Present Values

($ millions)	Forecast Prices and Costs			
	Undiscounted	Discounted at		
		10%	15%	20%
Proved developed reserves	31,154	22,175	19,662	17,774
Proved undeveloped reserves	10,543	5,501	4,232	3,338
Total proved reserves	**41,697**	**27,676**	**23,894**	**21,112**
Total proved and probable reserves	**57,892**	**34,446**	**28,800**	**24,849**

NOTES

1. "Company Gross" reserves means the total working interest share of remaining recoverable reserves owned by the Company before consideration of royalties.

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 net present 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 net present 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 NGLs, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. 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 net present 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 net present 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 year-end 2005 adjusted for quality and transportation as well as the 2005 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 been held constant at the 2006 values shown below. 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 C$/mcf	Henry Hub Louisiana US$/mmbtu	AECO C$/mmbtu	Huntingdon/ Sumas C$/mmbtu	Company Average Price C$/bbl	WTI @ Cushing(i) US$/bbl	Hardisty Heavy 12° API C$/bbl	Edmonton Par (ii) C$/bbl	North Sea Brent US$/bbl
2006	9.45	10.08	9.99	9.53	46.12	61.04	32.64	68.12	58.21

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

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

(iii) Foreign exchange rate used was US$0.8598/C$1.00

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, NGLs and natural gas price forecasts were based on Sproule's December 31, 2005 crude oil, NGLs and natural gas pricing model.
The Company's weighted average crude oil and NGLs price and the weighted average natural gas price in 2005 were $46.86 per barrel and $8.57 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 C$/mcf	Henry Hub Louisiana US$/mmbtu	AECO C$/mmbtu	Huntingdon/ Sumas C$/mmbtu	Company Average Price C$/bbl	WTI @ Cushing US$/bbl	Hardisty Heavy 12° API C$/bbl	Edmonton Par C$/bbl	North Sea Brent US$/bbl
2006	11.07	11.59	11.58	11.34	48.30	60.81	37.07	70.07	58.81
2007	10.33	10.11	10.84	10.70	49.59	61.61	37.29	70.99	59.58
2008	8.43	8.50	8.95	8.81	45.31	54.60	34.23	62.73	52.54
2009	7.35	7.58	7.87	7.73	42.12	50.19	32.27	57.53	48.10
2010	7.05	7.32	7.57	7.43	39.53	47.76	31.15	54.65	45.64
2011	7.21	7.43	7.70	7.56	40.57	48.48	31.94	55.47	46.32
2012	7.34	7.54	7.83	7.69	40.14	49.20	32.74	56.31	47.02
2013	7.48	7.66	7.96	7.82	41.22	49.94	33.56	57.16	47.72
2014	7.61	7.77	8.09	7.95	41.34	50.69	34.39	58.02	48.44
2015	7.75	7.89	8.23	8.09	42.02	51.45	35.23	58.89	49.17
2016	7.86	8.01	8.37	8.23	42.03	52.22	36.08	59.78	49.90

(i) Foreign exchange rate used was US$0.8598/C$1.00 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 NGLs, less all capital costs, production taxes, and operating costs and before provision for income taxes, administrative overhead costs and existing asset abandonment liabilities with the exception of Offshore West Africa where existing asset liabilities were included.

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)
2006	1,433	1,412	1,614	1,593
2007	815	774	1,140	1,087
2008	1,017	930	1,774	1,645
2009	428	373	1,144	1,023
2010	315	286	794	718
2011	173	154	306	273
2012	223	191	362	313
2013	180	102	200	168
2014	87	115	222	140
2015	143	120	247	249
2016	182	141	220	173
2017	174	136	238	188
Thereafter	555	398	773	554

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 found by Sproule and Ryder Scott to be reasonable and no field inspection was conducted.

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

C. RECONCILIATION OF CHANGES IN NET CONVENTIONAL 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 & NGLs (mmbbl)				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**	**2,552**
Extensions & Discoveries	17	-	-	17	334	-	-	334
Infill Drilling	24	35	-	59	74	-	-	74
Improved Recovery	1	10	-	11	6	-	-	6
Property purchases	36	38	-	74	182	10	-	192
Property disposals	-	-	-	-	(8)	-	-	(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**	**2,591**	**27**	**72**	**2,690**
Extensions & Discoveries	98	-	-	98	506	-	-	506
Infill Drilling	3	3	2	8	22	-	-	22
Improved Recovery	-	-	-	-	8	-	-	8
Property purchases	-	-	15	15	6	-	-	6
Property disposals	(3)	-	-	(3)	(23)	-	-	(23)
Production	(70)	(25)	(8)	(103)	(411)	(7)	(1)	(419)
Revisions of prior estimates	18	9	10	37	42	9	1	52
Reserves, December 31, 2005	**694**	**290**	**134**	**1,118**	**2,741**	**29**	**72**	**2,842**
Proved and probable reserves								
Reserves, December 31, 2003	**857**	**317**	**133**	**1,307**	**2,919**	**102**	**72**	**3,093**
Extensions & Discoveries	20	-	-	20	418	-	-	418
Infill Drilling	29	49	-	78	106	-	-	106
Improved Recovery	2	10	-	12	6	-	-	6
Property purchases	49	49	-	98	236	18	-	254
Property disposals	-	-	-	-	(10)	-	-	(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**	**3,319**	**57**	**90**	**3,466**
Extensions & Discoveries	200	-	-	200	645	-	-	645
Infill Drilling	3	5	6	14	23	-	1	24
Improved Recovery	-	-	-	-	14	-	-	14
Property purchases	-	-	17	17	8	-	-	8
Property disposals	(4)	-	-	(4)	(30)	-	-	(30)
Production	(70)	(25)	(8)	(103)	(411)	(7)	(1)	(419)
Revisions of prior estimates	(20)	22	(5)	(3)	(20)	19	20	19
Reserves, December 31, 2005	**1,035**	**417**	**206**	**1,658**	**3,548**	**69**	**110**	**3,727**

Information on the Company's conventional crude oil, NGLs and natural gas reserves is provided in accordance with United States FAS 69, "Disclosures About Oil and Gas Producing Activities" in the Company's 2005 Annual Report under "Supplementary Oil and Gas Information" on pages 97 to 101 and is incorporated herein by reference.

D. OIL SANDS MINING DISCLOSURE

Introduction

Canadian Natural holds a 100 per cent working interest in its Athabasca Oil Sands leases in Northern Alberta, of which a portion (being lease 18), is subject to a 5 per cent net carried interest in the bitumen development. The Horizon Project was initiated in 2000 to evaluate the potential for mining and processing the oil sands on these leases.

The Horizon Project is located in northeastern Alberta approximately 70 kilometers north of Fort McMurray in Townships 96 and 97, Ranges 11, 12 and 13, west of the 4th Meridian. The project site is accessible by a private road as well as a private airstrip. Figure 1 shows the location of the Horizon Project within Alberta, Canada and within the region. The leases being developed for the Horizon Project are 18, 25, 10, 19 and 20. Canadian Natural's development plan for the Horizon Project is to produce 232,000 barrels of synthetic crude oil per day. The project production schedule has been developed such that production rates are increased over three phases. Synthetic crude oil production is planned for the second half of 2008 at 110 thousand bbl/d, increasing to 232 thousand bbl/d by the third quarter of 2011. Mining of the oil sands will be done using conventional truck and shovel technology. The ore is then processed through extraction and froth treatment to produce bitumen, which is upgraded on-site into synthetic crude oil. The synthetic crude oil is transported from the site by pipeline to the Edmonton area for distribution. An on-site cogeneration plant provides power and steam for the operation. Preparation for construction of Phase 1 of the Horizon Project began in late 2004. Total targeted capital costs for all three phases of the development are projected to be approximately $10.8 billion at a cost environment associated with a US $45 WTI price per barrel of crude oil.

An independent qualified reserves evaluator, GLJ Petroleum Consultants ("GLJ"), was retained to evaluate 100 per cent of the first three phases of the Horizon Project's development plan. GLJ's Evaluation Report indicates that the gross proved and probable reserves associated with the Horizon Project are 2.9 billion barrels of synthetic crude oil with a production life of 37 years.

Since 1999, Canadian Natural has acquired over 46,000 hectares, comprising 11 leases in the Fort McMurray area.

Figure 1 – Location of the Horizon Oil Sands Project

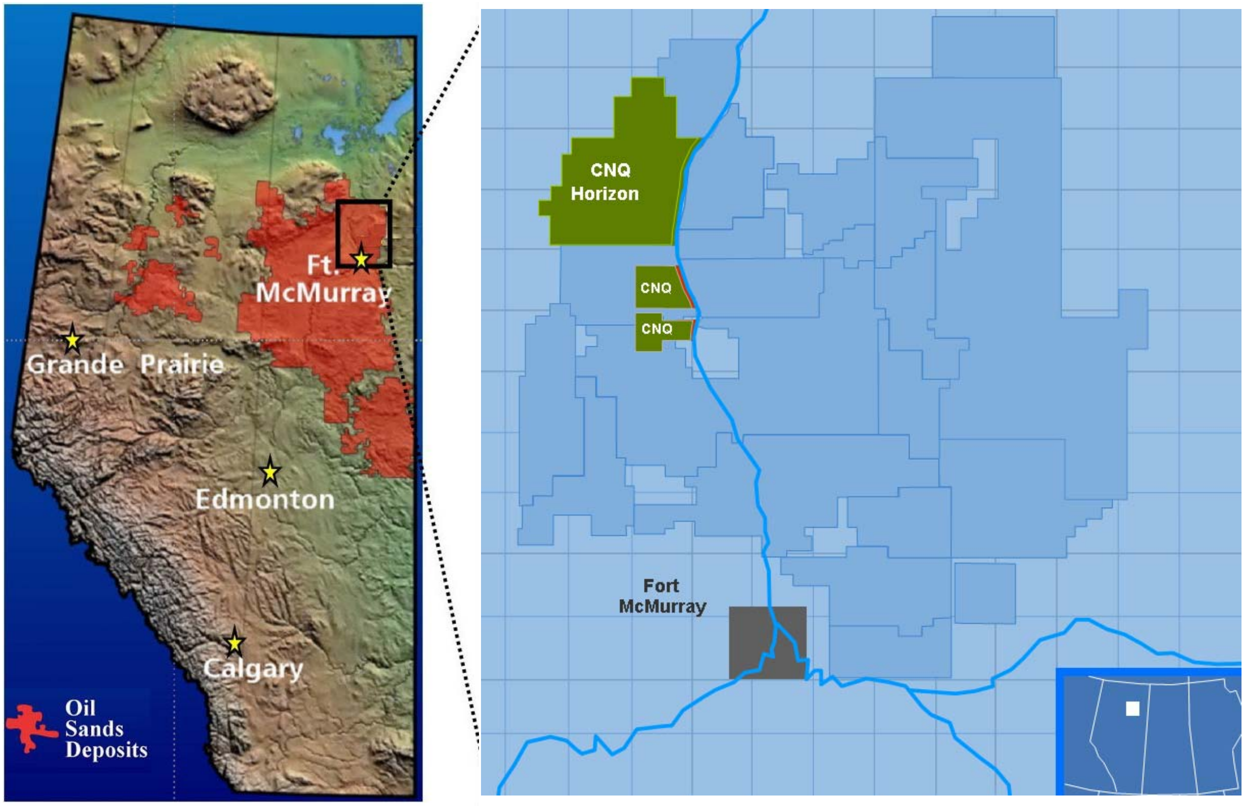


Table 1 – Canadian Natural Athabasca Region Oil Sand Leases

Short Lease Name	Official Lease Number	Lease Expiry Date[1]	Area in Hectares
Lease 18	727912T18	Continued Producing[2]	19,988
Lease 10	7400120010	December 14, 2015	3,840
Lease 25	7401050025	May 17, 2016	1,536
Lease 11	7400120011	December 14, 2015	518
Lease 12	7400120012	December 14, 2015	9,216
Lease 13	7400120013	December 14, 2015	69
Lease 15	7400120015	December 14, 2015	1,536
Lease 19	7402050019	May 30, 2017	5,120
Lease 20	7402050020	May 30, 2017	768
Lease 6	7597050T06	May 6, 2012	2,584
Lease 7	7597050T07	May 6, 2012	1,144

[1] The Company can apply for an extension of the leases past the expiry date.
[2] Pursuant to section 14 of the Oil Sands Tenure Regulation.

Lease 18, the main oil sand lease for the Horizon Project, has a gradual topographic slope from west to east. To the west, the topography begins to rise into the Birch Mountains and reaches an elevation of 485 meters above sea level in the northwest corner of the lease. To the east, the elevation drops sharply at the Athabasca River escarpment to 230 meters above sea level along the river. The Tar and Calumet Rivers flow through the lease.

Project Development

On June 28, 2002, Pursuant to Sections 10 and 11 of the Oil Sands Conservation Act, Canadian Natural filed Application No. 1273113 for approval for an oil sands mine, a bitumen extraction plant, a bitumen upgrader and associated facilities for the proposed Horizon Project. As part of the application to the Energy and Utilities Board, the Company also submitted an Environmental Impact Assessment ("EIA") report to the Director of the Regulatory Assurance Division, Alberta Environment, pursuant to the Environmental Protection Enhancement Act ("EPEA"). On June 26, 2003, the Federal Minister of Fisheries and Oceans referred the EIA of the project to a review panel charged with fulfilling the review as required by both the Canadian Environmental Assessment Act ("CEAA") and the Energy Resources Conservation Act ("ERCA"). A public hearing was held in Fort McMurray, Alberta on September 15-19, 22-26 and 29, 2003. The application and hearing provided significant background detail on the geology, mine planning and development scheme and formed the basis for the approval from the EUB in February 2004 and Alberta Environment ("AENV") under the Environmental Protection and Enhancement Act, in April 2004.

The following are the primary regulatory applications and approvals for the Horizon Project, which contain information pertaining to the project of a material engineering, geologic or metallurgic nature:

1. Application for Approval of Horizon Oil Sands Project submitted in June 2002 to the EUB (Application No.1273113) and AENV (Application No. 001-149968) (available at the EUB library, 640 5th Ave. SW, Calgary, Alberta – Tel: (403) 297-8311).

2. Supplemental Information for the Horizon Oil Sands Project (Application No. 1273113 and Application No. 001-149968) submitted in March 2003 to the EUB and AENV) (available at the EUB library, 640 5th Ave. SW, Calgary, Alberta – Tel: (403) 297-8311).

3. Horizon Oil Sands Project Decision 2004-005 by a joint panel review established by the EUB and the Government of Canada dated January 27, 2004 (available online at www.eub.gov.ab.ca).

4. Horizon Oil Sands Project Order in Council Authorization 26/2004 by the Province of Alberta dated February 4, 2004 (available at the EUB library, 640 5th Ave. SW, Calgary, Alberta – Tel: (403) 297-8311).

5. Horizon Oil Sands Project Approval No. 9752 by the EUB dated February 10, 2004 (available at the EUB library, 640 5th Ave. SW, Calgary, Alberta – Tel: (403) 297-8311).

6. Horizon Oil Sands Project Environmental Protection and Enhancement Act Approval No. 149968-00-01 from AENV dated April 6, 2004 (available online at www.gov.ab.ca/env/water/approvalviewer.html search parameter - Approval No. 149968-00-01).

7. Horizon Oil Sands Project Water Act Approval No. 00201931-00-00 from AENV dated April 6, 2004 (available online at www.gov.ab.ca/env/water/approvalviewer.html search parameter - Approval No. 149968-00-01).

As of year-end 2005, key development achievements associated with the Horizon Project were as follows:

- Phase 1 Construction is 19% complete.
- Mine overburden is at 6.7 million bank cubic meters of material removed.
- Coker and Extraction Separation Cell foundations are complete.
- Critical path underground piping is complete.

The Coker Drums and Naphtha Reactor arrived on site in January 2006

Regional and Project Geology

In the area of the Horizon Project, the oil sands resource is found within the Cretaceous McMurray Formation. The McMurray Formation is comprised of a sequence of uncemented quartz sands and associated shales that reside above the unconformity with the underlying Upper Devonian carbonates (limestone) of the Waterways Formation. The general stratigraphy of the Horizon Oil Sands Project is shown in Figure 2.

The McMurray Formation was formed by the infilling of a broad northwest trending depression in the exposed Devonian limestone landscape by mostly non-marine and estuarine sediments about 115 million years ago. The deposition of these terrestrial derived sediments ended when the Boreal Sea transgressed the entire region, ushering in marine conditions that formed the Clearwater Formation shales and glauconitic Wabiskaw member. This interplay between rising sea level and sediment transport from the northeast gave rise to various depositional environments (fluvial, estuarine, and marine). The entire McMurray/Clearwater succession was (most recently about 10,000 years ago) covered by unconsolidated sands, silts, and clays (glacial drift) deposited by glaciers as they melted and receded from the region at the end of the last ice age.

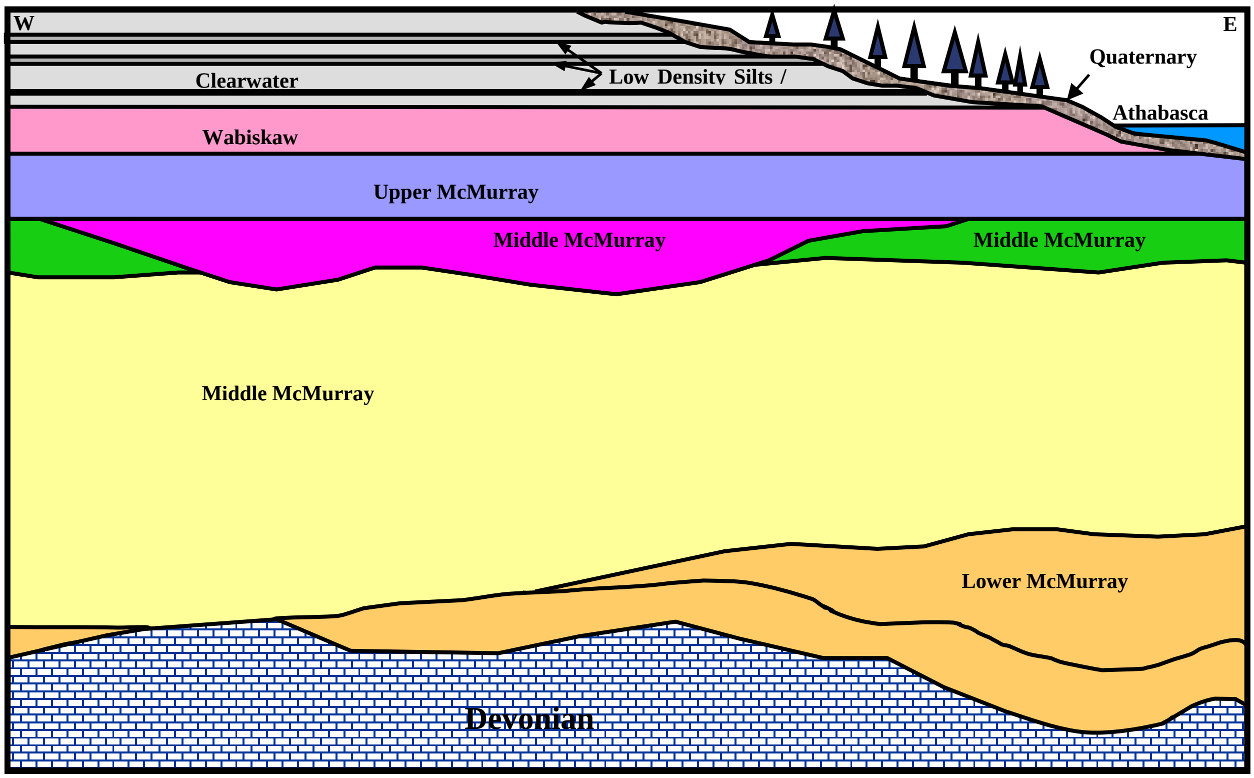
The McMurray Formation at the site of the Horizon Project is subdivided into three informal members: lower, middle, and upper. These informal divisions correspond to changes in the depositional environments within the McMurray from predominantly fluvial to tidal/estuarine through to tidal/marine conditions. Most of the Horizon Project's oil sands resource is found within the lower and middle McMurray.

The lower McMurray, where present, is comprised of predominantly fluvial channel deposits. The lower McMurray occupies lows on the Devonian (Paleozoic) surface resulting in the thickest McMurray intervals. Clean sands in these fluvial channels result in excellent quality ore. Flood plain deposits of significant thickness are found in the upper portions of the lower McMurray and are typically removed as waste. In the deepest portions of the mine area, the lower McMurray is comprised of "water sands". These sands are barren of bitumen; having never been saturated with bitumen or, in some places, originally containing bitumen that has since been removed from the sands through the movement of basal waters over time producing "swept" zones.

The middle McMurray is comprised of thick estuarine channel successions and tidal flat deposits resulting in interbedded sands and muds. The estuarine channel sands provide good quality ore. The muddier intervals within the channels and the tidal flat deposits within the middle McMurray represent zones of interburden in the mining area.

The upper McMurray consists of shoreface/channel transition deposits and is typically thin, less than 5 meters. Locally, this member may be entirely eroded. Exceptional thickness of about 15 meters can be found within the upper McMurray. In most cases, the bitumen saturation in the upper McMurray is poor and the material is included with the overburden.

Figure 2 – General Stratigraphy of the Horizon Oil Sands Project



Horizon Oil Sands Project Mining Reserves

For the year ended December 31, 2005, the Company retained GLJ to evaluate 100 per cent of phases 1, 2 and 3 of the Horizon Project and prepare an Evaluation Report on the Company's proved and probable oil sands mining reserves incorporating both the mining and upgrading projects. These reserves were evaluated adhering to the requirements of SEC Industry Guide 7 using constant pricing and have been disclosed separately from the Company's conventional proved and probable crude oil, NGL and natural gas reserves.

The pit limits and mine plans were updated in 2005 incorporating the results from the most recent and past drilling programs. Figure 3 shows the mining areas associated with the reserves and Figure 4 shows the drill hole coverage used to develop the mine plan. The oil sands mining reserves from GLJ's Evaluation Report are provided in Table 2. The 2.9 million barrels of gross proved and probable synthetic crude oil reserves shown in the table are produced from 37 years of projected production from the first three phases of the project commencing in 2008.

The Reserve Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with GLJ to review the qualifications of and procedures used by the evaluator in determining the estimate of the Company's oil sands mining reserves.

Figure 3 – Horizon Oil Sands Project Resource Areas and General Layout

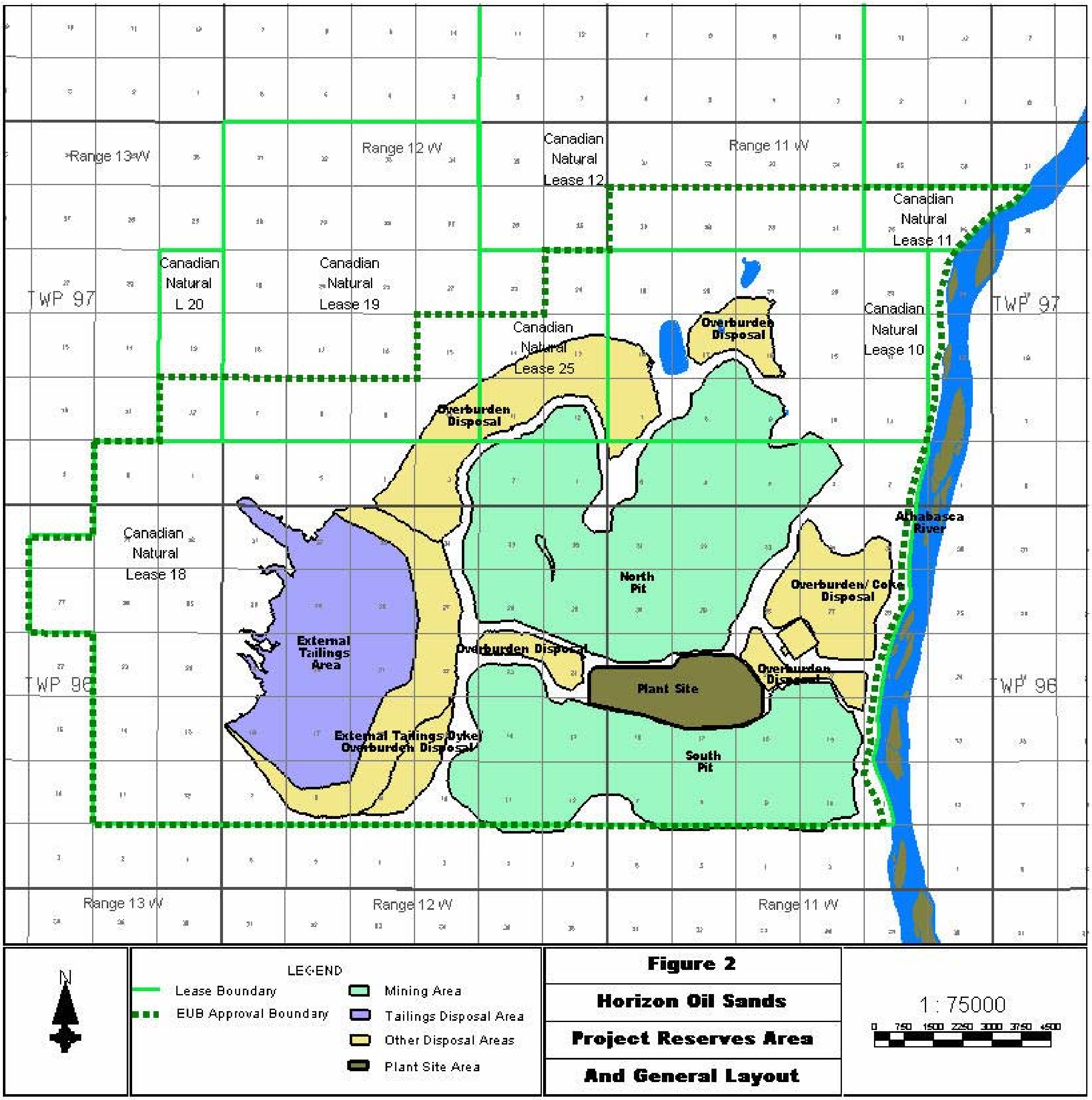
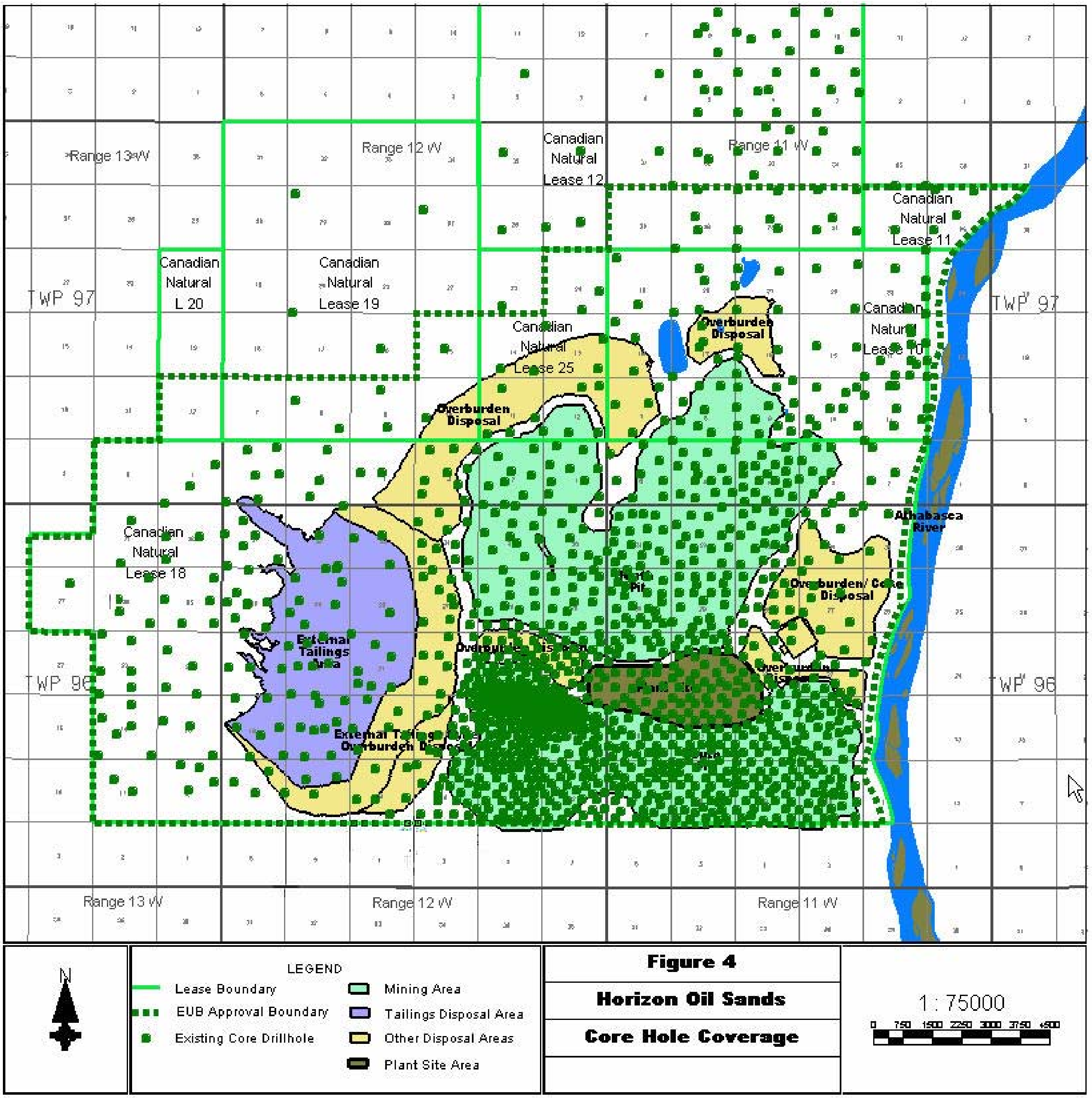


Figure 4 – Horizon Oil Sands Project Core Hole Coverage



Oil Sands Mining Reserves

The following table sets out Canadian Natural's reserves of bitumen and synthetic crude oil from the Horizon Project as of December 31, 2005:

	Constant Prices			
	Bitumen (mmbbl)		Synthetic Crude Oil [1] (mmbbl)	
	Gross [2]	Net	Gross [2]	Net
Total proved reserves	2,235	1,848	1,833	1,626
Total proved and probable reserves	3,430	2,848	2,878	2,566

[1] Synthetic crude oil reserves are based on the upgrading of Bitumen using technologies implemented at the Horizon Project. The reserves shown for bitumen and synthetic crude oil are not additive.

[2] Gross reserves mean the total remaining recoverable reserves before consideration of company interests or royalties.

E. CRUDE OIL, NGLS AND NATURAL GAS PRODUCTION

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

	YEAR ENDED DECEMBER 31		
	2005	2004	2003
Daily Production, before royalties			
Crude Oil and NGLs (bbl/d)	313,168	282,489	242,392
Natural Gas (mmcf/d)	1,439	1,388	1,299
Annual Production, before royalties			
Crude Oil and NGLs (mbbl)	114,306	103,391	88,473
Natural Gas (bcf)	525	508	474

NETBACKS
INFORMATION BY QUARTER

	YEAR 2005					YEAR 2004				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended
Average Daily Production Volumes, before royalties										
Crude oil and NGLs (bbl/d)	287,803	289,064	334,724	340,268	313,168	261,286	275,398	297,262	295,704	282,489
Natural Gas (mcf/d)	1,455	1,454	1,423	1,423	1,439	1,294	1,452	1,396	1,410	1,388
Product Netbacks										
Crude oil and NGLs ($/bbl)										
Sales Price (1)	$ 39.81	$ 42.51	$ 57.35	$ 46.38	$ 46.86	$ 34.21	$ 36.72	$ 43.50	$ 36.92	$ 37.99
Royalties	$ 3.39	$ 3.33	$ 5.11	$ 3.89	$ 3.97	$ 2.91	$ 3.15	$ 3.59	$ 2.95	$ 3.16
Production Expenses	$ 11.30	$ 11.66	$ 11.48	$ 10.33	$ 11.17	$ 9.58	$ 9.92	$ 10.21	$ 10.41	$ 10.05
Netback	**$ 25.12**	**$ 27.52**	**$ 40.76**	**$ 32.16**	**$ 31.72**	**$ 21.72**	**$ 23.65**	**$ 29.70**	**$ 23.56**	**$ 24.78**
Natural Gas ($mcf)										
Sales Price (1)	$ 6.68	$ 7.33	$ 8.61	$ 11.67	$ 8.57	$ 6.31	$ 6.64	$ 6.24	$ 6.77	$ 6.50
Royalties	$ 1.30	$ 1.48	$ 1.93	$ 2.30	$ 1.75	$ 1.27	$ 1.38	$ 1.39	$ 1.34	$ 1.35
Production Expenses	$ 0.69	$ 0.71	$ 0.76	$ 0.76	$ 0.73	$ 0.65	$ 0.66	$ 0.71	$ 0.68	$ 0.67
Netback	**$ 4.69**	**$ 5.14**	**$ 5.92**	**$ 8.61**	**$ 6.09**	**$ 4.39**	**$ 4.60**	**$ 4.14**	**$ 4.75**	**$ 4.48**
Crude Oil and NGL Netbacks by Type										
Light/Pelican Lake/NGLs ($/bbl)										
Sales Price (1)	$ 53.14	$ 56.85	$ 66.81	$ 58.87	$ 59.16	$ 40.75	$ 45.28	$ 51.54	$ 48.60	$ 46.71
Royalties	$ 5.20	$ 4.55	$ 5.50	$ 4.40	$ 4.90	$ 3.71	$ 3.98	$ 3.99	$ 4.12	$ 3.95
Production Expenses	$ 11.58	$ 12.28	$ 11.47	$ 8.90	$ 10.93	$ 9.77	$ 10.36	$ 10.70	$ 11.20	$ 10.53
Netback	**$ 36.36**	**$ 40.02**	**$ 49.84**	**$ 45.57**	**$ 43.33**	**$ 27.27**	**$ 30.94**	**$ 36.85**	**$ 33.28**	**$ 32.23**
Heavy Crude Oil ($/bbl)										
Sales Price (1)	$ 25.21	$ 27.82	$ 47.25	$ 30.27	$ 33.09	$ 27.00	$ 28.08	$ 35.33	$ 25.16	$ 28.99
Royalties	$ 1.41	$ 2.07	$ 4.83	$ 3.08	$ 2.92	$ 2.02	$ 2.31	$ 3.18	$ 1.77	$ 2.34
Production Expenses	$ 11.00	$ 11.03	$ 11.50	$ 12.18	$ 11.44	$ 9.38	$ 9.47	$ 9.72	$ 9.62	$ 9.56
Netback	**$ 12.80**	**$ 14.72**	**$ 30.92**	**$ 15.01**	**$ 18.73**	**$ 15.60**	**$ 16.30**	**$ 22.43**	**$ 13.77**	**$ 17.09**

NOTE: Pelican Lake crude oil has an API of 12º 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 2005					YEAR 2004				
	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)]	$ 45.80	$ 49.78	$ 61.21	$ 52.10	$ 52.35	$ 37.54	$ 41.03	$ 44.89	$ 43.80	$ 41.81
Royalties	$ 10.64	$ 8.77	$ 11.49	$ 9.62	$ 10.13	$ 7.20	$ 7.91	$ 8.59	$ 8.76	$ 8.12
Production Expenses	$ 8.30	$ 8.40	$ 9.27	$ 8.60	$ 8.65	$ 7.30	$ 7.74	$ 7.75	$ 7.85	$ 7.66
Netback	**$ 26.86**	**$ 32.61**	**$ 40.45**	**$ 33.88**	**$ 33.57**	**$ 23.04**	**$ 25.38**	**$ 28.55**	**$ 27.19**	**$ 26.03**
Heavy Crude Oil ($/bbl)										
Sales Price [(1)]	$ 25.21	$ 27.82	$ 47.25	$ 30.27	$ 33.09	$ 27.00	$ 28.08	$ 35.33	$ 25.16	$ 28.99
Royalties	$ 1.41	$ 2.07	$ 4.83	$ 3.08	$ 2.92	$ 2.02	$ 2.31	$ 3.18	$ 1.77	$ 2.34
Production Expenses	$ 11.00	$ 11.03	$ 11.50	$ 12.18	$ 11.44	$ 9.38	$ 9.47	$ 9.72	$ 9.62	$ 9.56
Netback	**$ 12.80**	**$ 14.72**	**$ 30.92**	**$ 15.01**	**$ 18.73**	**$ 15.60**	**$ 16.30**	**$ 22.43**	**$ 13.77**	**$ 17.09**
Natural Gas ($/mcf)										
Sales Price [(1)]	$ 6.73	$ 7.38	$ 8.69	$ 11.79	$ 8.65	$ 6.37	$ 6.78	$ 6.36	$ 6.88	$ 6.61
Royalties	$ 1.33	$ 1.50	$ 1.96	$ 2.34	$ 1.78	$ 1.33	$ 1.44	$ 1.45	$ 1.39	$ 1.40
Production Expenses	$ 0.66	$ 0.68	$ 0.74	$ 0.74	$ 0.71	$ 0.60	$ 0.60	$ 0.63	$ 0.63	$ 0.62
Netback	**$ 4.74**	**$ 5.20**	**$ 5.99**	**$ 8.71**	**$ 6.16**	**$ 4.44**	**$ 4.74**	**$ 4.28**	**$ 4.86**	**$ 4.59**
North Sea Product Netbacks										
Light Oil ($/bbl)										
Sales Price [(1)]	$ 59.56	$ 64.81	$ 74.46	$ 66.88	$ 66.57	$ 44.27	$ 49.22	$ 57.39	$ 52.77	$ 51.37
Royalties	$ 0.05	$ 0.11	$ 0.12	$ 0.14	$ 0.10	$ 0.06	$ 0.10	$ 0.09	$ 0.08	$ 0.08
Production Expenses	$ 14.91	$ 17.41	$ 15.15	$ 12.11	$ 14.94	$ 13.26	$ 13.84	$ 13.88	$ 14.96	$ 14.03
Netback	**$ 44.60**	**$ 47.29**	**$ 59.19**	**$ 54.63**	**$ 51.53**	**$ 30.95**	**$ 35.28**	**$ 43.42**	**$ 37.73**	**$ 37.26**
Natural Gas ($/mcf)										
Sales Price [(1)]	$ 3.52	$ 3.07	$ 2.64	$ 3.40	$ 3.17	$ 5.08	$ 3.28	$ 3.17	$ 3.26	$ 3.73
Royalties	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Expenses	$ 2.52	$ 2.92	$ 2.30	$ 1.96	$ 2.44	$ 1.65	$ 1.92	$ 2.48	$ 2.29	$ 2.07
Netback	**$ 1.00**	**$ 0.15**	**$ 0.34**	**$ 1.44**	**$ 0.73**	**$ 3.43**	**$ 1.36**	**$ 0.69**	**$ 0.97**	**$ 1.66**
Offshore West Africa Product Netbacks										
Light Oil ($/bbl)										
Sales Price [(1)]	$ 62.34	$ 58.24	$ 59.09	$ 60.19	$ 59.91	$ 42.08	$ 49.34	$ 53.86	$ 51.28	$ 49.05
Royalties	$ 1.90	$ 1.81	$ 1.54	$ 1.57	$ 1.62	$ 1.28	$ 1.52	$ 1.42	$ 1.52	$ 1.43
Production Expenses	$ 11.43	$ 8.47	$ 5.81	$ 5.62	$ 6.50	$ 7.09	$ 7.43	$ 8.05	$ 7.82	$ 7.59
Netback	**$ 49.01**	**$ 47.96**	**$ 51.74**	**$ 53.00**	**$ 51.79**	**$ 33.71**	**$ 40.39**	**$ 44.39**	**$ 41.94**	**$ 40.03**
Natural Gas ($/mcf)										
Sales Price [(1)]	$ 7.67	$ 6.88	$ 5.52	$ 5.13	$ 5.91	$ 4.80	$ 5.18	$ 6.31	$ 4.73	$ 5.25
Royalties	$ 0.23	$ 0.21	$ 0.13	$ 0.14	$ 0.16	$ 0.15	$ 0.16	$ 0.17	$ 0.14	$ 0.15
Production Expenses	$ 1.25	$ 1.37	$ 1.09	$ 0.80	$ 1.05	$ 1.23	$ 1.38	$ 1.39	$ 1.31	$ 1.33
Netback	**$ 6.19**	**$ 5.30**	**$ 4.30**	**$ 4.19**	**$ 4.70**	**$ 3.42**	**$ 3.64**	**$ 4.75**	**$ 3.28**	**$ 3.77**

NOTE: Pelican Lake crude oil has an API of 12º 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 2003				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended
Average Daily Production Volumes					
Crude oil and NGLs (bbl/d)	237,560	240,607	247,016	244,262	242,392
Natural Gas (mcf/d)	1,310	1,325	1,289	1,270	1,299
Product Netbacks					
Crude oil and NGLs ($/bbl)					
Sales Price (1)	$ 39.37	$ 30.66	$ 31.45	$ 29.47	$ 32.66
Royalties	$ 3.56	$ 2.78	$ 2.56	$ 2.22	$ 2.77
Production Expenses	$ 10.79	$ 10.80	$ 10.14	$ 9.45	$ 10.28
Netback	**$ 25.02**	**$ 17.08**	**$ 18.75**	**$ 17.80**	**$ 19.61**
Natural Gas ($/mcf)					
Sales Price (1)	$ 7.75	$ 6.25	$ 5.57	$ 5.26	$ 6.21
Royalties	$ 1.78	$ 1.35	$ 1.11	$ 1.05	$ 1.32
Production Expenses	$ 0.57	$ 0.59	$ 0.63	$ 0.63	$ 0.60
Netback	**$ 5.40**	**$ 4.31**	**$ 3.83**	**$ 3.58**	**$ 4.29**
Crude Oil and NGLs Netbacks by Type					
Light/Pelican Lake/NGLs ($/bbl)					
Sales Price (1)	$ 44.38	$ 34.60	$ 36.06	$ 35.76	$ 37.66
Royalties	$ 4.18	$ 3.32	$ 3.11	$ 2.82	$ 3.35
Production Expenses	$ 10.42	$ 9.76	$ 9.53	$ 9.65	$ 9.83
Netback	**$ 29.78**	**$ 21.52**	**$ 23.42**	**$ 23.29**	**$ 24.48**
Heavy Crude Oil ($/bbl)					
Sales Price (1)	$ 32.44	$ 25.37	$ 25.17	$ 21.45	$ 25.98
Royalties	$ 2.71	$ 2.06	$ 1.83	$ 1.47	$ 2.00
Production Expenses	$ 11.30	$ 12.19	$ 10.96	$ 9.19	$ 10.88
Netback	**$ 18.43**	**$ 11.12**	**$ 12.38**	**$ 10.79**	**$ 13.10**

NOTE: Pelican Lake crude oil has an API of 12º 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 2003				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended
SEGMENTED					
North America Product Netbacks					
Light/Pelican Lake/NGLs ($/bbl)					
Sales Price (1)	$ 40.89	$ 32.73	$ 32.78	$ 30.95	$ 34.37
Royalties	$ 7.65	$ 6.33	$ 6.04	$ 5.51	$ 6.39
Production Expenses	$ 6.09	$ 6.42	$ 6.76	$ 7.24	$ 6.62
Netback	**$ 27.15**	**$ 19.98**	**$ 19.98**	**$ 18.20**	**$ 21.36**
Heavy Crude Oil ($/bbl)					
Sales Price (1)	$ 32.44	$ 25.37	$ 25.17	$ 21.45	$ 25.98
Royalties	$ 2.71	$ 2.06	$ 1.83	$ 1.47	$ 2.00
Production Expenses	$ 11.30	$ 12.19	$ 10.96	$ 9.19	$ 10.88
Netback	**$ 18.43**	**$ 11.12**	**$ 12.38**	**$ 10.79**	**$ 13.10**
Natural Gas ($/mcf)					
Sales Price (1)	$ 7.88	$ 6.39	$ 5.70	$ 5.35	$ 6.34
Royalties	$ 1.84	$ 1.40	$ 1.16	$ 1.10	$ 1.38
Production Expenses	$ 0.55	$ 0.56	$ 0.58	$ 0.60	$ 0.57
Netback	**$ 5.49**	**$ 4.43**	**$ 3.96**	**$ 3.65**	**$ 4.39**
North Sea Product Netbacks					
Light Crude oil ($/bbl)					
Sales Price (1)	$ 49.74	$ 37.08	$ 39.63	$ 41.70	$ 42.00
Royalties	$ 0.11	$ (0.19)	$ 0.09	$ (0.15)	$ (0.03)
Production Expenses	$ 15.50	$ 14.17	$ 13.25	$ 13.42	$ 14.07
Netback	**$ 34.13**	**$ 23.10**	**$ 26.29**	**$ 28.43**	**$ 27.96**
Natural Gas ($/mcf)					
Sales Price (1)	$ 4.03	$ 2.21	$ 2.57	$ 3.32	$ 3.03
Royalties	$ -	$ -	$ -	$ -	$ -
Production Expenses	$ 1.09	$ 1.45	$ 1.60	$ 1.16	$ 1.33
Netback	**$ 2.94**	**$ 0.76**	**$ 0.97**	**$ 2.16**	**$ 1.70**
Offshore West Africa Product Netbacks					
Light Crude oil ($/bbl)					
Sales Price (1)	$ 37.86	$ 34.34	$ 37.37	$ 36.42	$ 36.47
Royalties	$ 1.20	$ 0.99	$ 1.13	$ 1.03	$ 1.08
Production Expenses	$ 14.03	$ 9.32	$ 7.11	$ 6.67	$ 8.68
Netback	**$ 22.63**	**$ 24.03**	**$ 29.13**	**$ 28.72**	**$ 26.71**
Natural Gas ($/mcf)					
Sales Price (1)	$ 3.80	$ 5.09	$ 4.58	$ 3.95	$ 4.37
Royalties	$ 0.11	$ 0.15	$ 0.14	$ 0.11	$ 0.13
Production Expenses	$ 2.37	$ 1.45	$ 1.24	$ 1.18	$ 1.39
Netback	**$ 1.32**	**$ 3.49**	**$ 3.20**	**$ 2.66**	**$ 2.85**

NOTE: Pelican Lake crude oil has an API of 12º to 17º, but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.
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			
	2005		2004	
	Gross	Net	Gross	Net
Natural Gas	1,071	890	801	689
Crude Oil	685	627	378	328
Service/Stratigraphic	251	248	339	336
Dry Holes	136	117	106	96
Total	2,143	1,882	1,624	1,449
*Total Success Rate		93%		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	
	2005	2004
Net property (dispositions) acquisitions[1]	(320)	1,835
Land acquisition and retention	254	120
Seismic evaluation	132	89
Well drilling, completion and equipping	2,000	1,394
Pipeline and production facilities	1,295	821
Reserve replacement expenditures	3,361	4,259
Horizon Project:		
Phase 1 construction costs	1,329	-
Capitalized interest and other	170	291
Total Horizon Project	1,499	291
Midstream operations	4	16
Abandonments[2]	46	32
Head office equipment	22	35
Total Net Capital Expenditures	4,932	4,633

(1) Includes Business Combinations.

(2) Abandonments represent expenditures to settle retirement obligations and have been reflected as capital expenditures in this table.

CAPITAL EXPENDITURES BY QUARTER	2005 THREE MONTHS ENDED ($ millions) MAR. 31	JUNE 30	SEPT. 30	DEC. 31
Net property (dispositions) acquisitions(1)	2	(341)	0	19
Land acquisition and retention	36	52	69	97
Seismic evaluation	41	20	31	40
Well drilling, completion and equipping	634	306	431	629
Pipeline and production facilities	432	283	266	314
Reserve replacement expenditures	1,145	320	797	1,099
Horizon Project				
Phase 1 construction costs	132	259	432	506
Capitalized interest and other	83	16	20	51
Total Horizon Project	215	275	452	557
Midstream operations	4	-	(1)	1
Abandonments(2)	4	7	19	16
Head office equipment	4	7	5	6
Total Net Capital Expenditures	1,372	609	1,272	1,679

(1) Includes Business Combinations.

(2) Abandonments represent expenditures to settle retirement obligations and have been reflected as capital expenditures in this table.

CAPITAL EXPENDITURES(1) 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(2)	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.

(2) Abandonments represent expenditures to settle retirement obligations and have been reflected as capital expenditures in this table.

H. UNDEVELOPED ACREAGE

The following table summarizes the Company's working interest holdings in core region non-reserve acreage as at December 31, 2005:

	Gross Acres (thousands)	Net Acres (thousands)
North America		
Alberta	9,892	8,376
British Columbia	2,645	2,010
Saskatchewan	615	549
Manitoba	11	11
North Sea		
United Kingdom	457	352
Offshore West Africa		
Côte d'Ivoire	369	274
Gabon	152	152
Total	14,141	11,724

I. DEVELOPED ACREAGE

The following table summarizes the Company's working interest holdings in core region developed acreage as at December 31, 2005:

	Gross Acres (thousands)	Net Acres (thousands)
North America		
Alberta	5,727	4,545
British Columbia	1,111	870
Saskatchewan	341	279
Manitoba	5	5
North Sea		
United Kingdom	138	93
Offshore West Africa		
Côte d'Ivoire	7	4
Total	7,329	5,796

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	
	2005	2004
	($ millions, except per share information)	
Revenues [1] (net of royalties)	8,741	6,536
Cash flow from operations	5,021	3,769
Per common share – basic [3]	9.36	7.03
– diluted[3]	9.33	6.98
Net earnings	1,050	1,405
Per common share – basic[3]	1.96	2.62
– diluted[3]	1.95	2.60
Total assets	21,852	18,372
Total long-term debt[2]	3,321	3,538

	2005 THREE MONTHS ENDED			
	MARCH 31	JUNE 30	SEPT. 30	DEC. 31
	($ millions, except per share information)			
Revenues [1] (net of royalties)	1,734	1,881	2,515	2,611
Net earnings (loss)	(424)	219	151	1,104
Per common share – basic[3]	(0.79)	0.41	0.28	2.06
– diluted[3]	(0.79)	0.41	0.28	2.06

	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[3]	0.49	0.48	0.58	1.07
– diluted[3]	0.48	0.48	0.57	1.06

(1) Excluding transportation costs and risk management activities.
(2) Excluding current portion of long-term debt.
(3) Restated to reflect two-for-one-share split in May 2005.

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, we are under no obligation to update this Annual Information Form.

The Company's senior unsecured long-term debt securities are rated "Baa1" with a stable trend 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 rating outlook to the Company and not to individual debt instruments. S&P has assigned a negative outlook to the Company.

Rated Debt Issuances

$125 CAD million 7.40% unsecured note due 2007
$400 CAD million 4.95% unsecured note due 2015
$93 US million 6.45% adjustable rate note due 2009
$400 US million 6.70% unsecured note due 2011
$350 US million 5.45% unsecured note due 2012
$350 US million 4.90% unsecured note due 2014
$400 US million 7.20% unsecured note due 2032
$350 US million 6.54% unsecured note due 2033
$350 US million 5.85% unsecured note due 2035

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 ("TSX") and the New York Stock Exchange ("NYSE") under the symbol CNQ.

2005 Monthly Historical Trading on Toronto Stock Exchange

Month	High	Low	Close	Volume Traded
January	$55.70	$48.55	$54.74	23,564,720
February	74.25	54.60	70.09	31,090,409
March	74.75	63.79	68.36	29,853,739
April	71.88	61.07	62.40	27,675,887
May 1 – 17	71.09	61.90	67.00	13,881,359
*May 18 – 31	37.60	33.36	36.25	18,362,198
June	46.98	36.68	44.40	53,797,555
July	51.45	45.52	51.00	52,706,687
August	59.96	50.61	58.47	57,286,467
September	60.00	51.25	52.50	50,127,673
October	53.34	43.55	48.29	66,484,410
November	58.24	48.25	52.87	55,369,037
December	62.00	53.31	57.63	31,725,589

* Shares began trading on a post two-for-one subdivision basis on May 18, 2005.

On January 22, 2003, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of TSX and the NYSE, 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 TSX and the NYSE, commencing January 24, 2004 and ending January 23, 2005, to purchase for cancellation up to 6,690,385 (13,380,770 post May 21, 2004 two-for-one stock split) common shares of the Company, being 5 per cent of the 133,807,695 (267,615,390 post May 21, 2004 two-for-one stock split) 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 (26,818,012 post May 20, 2005 two-for-one stock split) common shares of the Company, being 5 per cent of the 268,180,123 (536,360,246 post May 20, 2005 two-for-one stock split) common shares of the Company outstanding on January 12, 2005. Under this program, the Company purchased a total of 850,000 common shares for cancellation at a weighted average purchase price of $53.26 for each common share purchased; $53.29 after costs.

At the Annual and Special Meeting of Shareholders held May 5, 2005, 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 20, 2005.

On January 20, 2006, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of TSE and the NYSE, commencing January 24, 2006 and ending January 23, 2007, to purchase for cancellation up to 26,852,545 common shares of the Company, being 5 per cent of the 537,050,902 common shares of the Company outstanding on January 17, 2006. As of the date of this Annual Information Form, no shares have been purchased.

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 regular quarterly dividends. 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 and May 2005 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.

	2005	2004	2003
Cash dividends declared per common share	$0.24	$0.20	$0.15

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 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 52)	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 of the Company since November 2003.
N. Murray Edwards Calgary/Banff, Alberta Canada	Vice-Chairman and Director(3) (age 46)	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 Energy Services Inc. and Magellan Aerospace Corporation.
Honourable Gary A. Filmon Winnipeg, Manitoba Canada	Director (1)(2) (age 63)	Consultant, Exchange Group (business consulting firm based in Winnipeg, Manitoba). Prior thereto, served as Premier of Manitoba from 1988 to 1999. Has served continuously as a director of the Company since February 2006. Currently serving on the board of directors of Manitoba Telecom Services Inc., Pollard Banknote Income Fund, Arctic Glacier Income Trust, Exchange Industrial Income Fund, and as a member of the Advisory Board of Marsh Canada.
Ambassador Gordon D. Giffin Atlanta, Georgia USA	Director(1)(2) (age 56)	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	Vice-Chairman and Director (age 60)	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)(5) (age 49)	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 Energy Trust and NuVista Energy Ltd.
Allan P. Markin Calgary, Alberta Canada	Chairman and Director(5) (age 60)	Chairman of the Company. Has served continuously as a director of the Company since January 1989.
Norman F. McIntyre Calgary, Alberta Canada	Director(3)(4)(5) (age 60)	An independent businessman. Prior thereto Executive Vice-President, Petro-Canada from 1995 to 2002 and most recently President, Petro-Canada 2002 to 2004. Has served continuously as a director of the Company since July 2005. Currently serving on the board of directors of Signal Energy Inc. and Petro Andina Resources, a private company.

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
James S. Palmer, C.M., A. O. E., Q.C. Calgary, Alberta Canada	Director(3)(4)(5) (age 77)	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 66)	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., Pheromone Sciences Corp. and Overlord Financial Inc.
David A. Tuer Calgary, Alberta Canada	Director(1)(2)(3) (age 56)	An independent businessman. Chairman, Calgary Health Region since October 2001 and President, Value Creation Inc. since April 2005. Prior thereto President and Chief Executive Officer, PanCanadian Energy Corporation and most recently President and CEO of Hawker Resources Inc. (independent oil and natural gas company) from January 2003 to March 2005. Has served continuously as a director of the Company since May 2002. Currently serving on the board of directors of Sequoia Oil and Gas Trust, Rockwater Capital Corporation; and, Norquay Capital Corporation.
Steve W. Laut Calgary, Alberta Canada	President and Chief Operating Officer (age 48)	Officer of the Company.
Réal M. Cusson Calgary, Alberta Canada	Senior Vice-President, Marketing (age 55)	Officer of the Company.
Réal J. H. Doucet Calgary, Alberta Canada	Senior Vice-President, Oil Sands (age 53)	Officer of the Company.
Allen M. Knight Calgary, Alberta Canada	Senior Vice-President, International & Corporate Development (age 56)	Officer of the Company.
Tim S. McKay Calgary, Alberta Canada	Senior Vice-President, Operations (age 44)	Officer of the Company.
Douglas A. Proll Calgary, Alberta Canada	Chief Financial Officer and Senior Vice-President, Finance (age 55)	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	Senior Vice-President, Exploitation (age 51)	Officer of the Company.
Jeffrey W. Wilson Calgary, Alberta Canada	Senior Vice-President, Exploration (age 53)	Officer of the Company since September 2003; prior thereto Exploration Manager of the Company.

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Corey B. Bieber Calgary, Alberta Canada	Vice-President, Investor Relations (age 42)	Officer of the Company since April 2005; prior thereto Director of Corporate Accounting of Enbridge Inc. to March 2001, Treasurer of the Company March 2001 to July 2002 and most recently Director, Investor Relations of the Company from July 2002 to April 2005.
Mary-Jo Case Calgary, Alberta Canada	Vice-President, Land (age 47)	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.
Wayne M. Chorney Calgary, Alberta Canada	Vice-President, Development Operations (age 46)	Officer of the Company since April 2004; prior thereto Production Manager, Thermal Operations of the Company October 1999 to August 2001, General Manager, Production of CNR International (U.K.) Limited ("CNRI") a wholly owned subsidiary of the Company September 2000 to August 2001 and most recently Director, Production Operations of CNRI August 2001 to April 2004.
William R. Clapperton Calgary, Alberta Canada	Vice-President, Regulatory, Stakeholder and Environmental Affairs (age 43)	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 52)	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 39)	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.
Larry C. Galea Calgary, Alberta Canada	Vice-President, Operations Planning (age 40)	Officer of the Company since April 2005; prior thereto Exploitation Manager of the Company to January 2002, Manager, Operations Planning January 2002 to April 2004, and most recently Exploitation Manager from April 2004 to April 2005.
Jerome W. Harvey Calgary, Alberta Canada	Vice-President, Commercial Operations (age 52)	Officer of the Company since April 2004; prior thereto Manager, Commercial Operations.
Peter Janson Calgary, Alberta Canada	Vice-President, Engineering Integration (age 48)	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 38)	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 42)	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.

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Philip A. Keele Calgary, Alberta Canada	Vice-President, Mining, Horizon Oil Sands Project (age 46)	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 38)	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 51)	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 44)	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 44)	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 39)	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 59)	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 from May 2002 to December 2002 and most recently General Manager Site Development of the Company from January 2003 to April 2004.
Sheldon L. Schroeder Calgary, Alberta Canada	Vice-President, Project Control (age 38)	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 44)	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 49)	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.

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Kimberly I. McKay Calgary, Alberta Canada	Treasurer (age 37)	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 56)	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 Canadian Natural shareholders. With the exception of Messrs. N. F. McIntyre and G. A. Filmon who were appointed to the Board effective July 29, 2005 and February 21, 2006 respectively, all of the current directors were elected to the Board at the last annual meeting of shareholders held on May 5, 2005. All of the current directors are standing for election at the Annual General Meeting of Shareholders scheduled for May 4, 2006.

As at December 31, 2005, 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).

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No, director, executive officer or principal shareholder of Canadian Natural, or associate or affiliate of those persons, has any material interest, direct or indirect, in any transaction within the last three years that has materially affected or will materially affect the Company.

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. A. Filmon, G. D. Giffin and D. A. Tuer each of whom is independent and financially literate as those terms are defined under Canadian securities regulations MI 52-110 and the NYSE listing standards as they pertain to audit committees of listed issuers. The education and experience of each member of the Audit Committee relevant to their responsibilities as an Audit Committee member is described below.

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.

Honourable G. A. Filmon holds both a Bachelor of Science degree and a Master of Science degree in Civil Engineering. He was Premier of the Province of Manitoba for several years and during that time chaired the Treasury Board for a period of five years. He was President of Success Commercial College for 11 years and is currently a business management consultant. Mr. G. A. Filmon is a director of other public companies and is an active member of other audit committees, one of which he chairs.

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.

The Audit Committee in 2005 approved specified audit and non-audit services to be performed by PricewaterhouseCoopers LLP ("PwC") the independent auditor of the Corporation. The following table lists the fees accrued to PwC for fiscal year 2005.

Auditor Service Fees

Auditor Service	2005	2004
Audit fees	$1,200,235	$1,100,548
Audit related fees	$266,923	$183,663
Tax related fees	$39,331	$39,330
All other fees	$7,290	$0
Total Accrued Fees	$1,513,779	$1,323,541

The Charter of the Audit Committee of the Company is attached as Schedule "C" to this Annual Information Form.

LEGAL PROCEEDINGS

From time to time, Canadian Natural 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.

MATERIAL CONTRACTS

Other than contracts entered into in the ordinary course of business, the Company has not entered into any material contracts in the most recently completed financial year nor has it entered into any material contracts before the most recently completed financial year and which are still in effect.

INTERESTS OF EXPERTS

PricewaterhouseCoopers LLP, Chartered Accountants, are the Company's auditors and such firm has prepared an opinion with respect to the Company's consolidated financial statements as at and for the year ended December 31, 2005. PricewaterhouseCoopers LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta.

Sproule Associates Limited, Ryder Scott Company and GLJ Petroleum Consultants 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 GLJ Petroleum Consultants 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 General Meeting and Information Circular dated March 15, 2006 in connection with the Annual General Meeting of Shareholders of Canadian Natural to be held on May 4, 2006 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, 2005 found on pages 45 to 73, 74 to 96 and 97 to 101 respectively, of the 2005 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. We have evaluated the Corporation's reserves data as at December 31, 2005. The reserves data consist of the following:

(a) (i) proved conventional crude oil, natural gas liquids and natural gas reserve quantities estimated as at December 31, 2005 using constant prices and costs;
(ii) the related estimated net present value; and
(iii) the related standardized measure calculation for proved conventional crude oil, natural gas liquids and natural gas reserve quantities.

(b) (i) both proved, and proved and probable conventional crude oil, natural gas liquids and natural gas reserve quantities estimated as at December 31, 2005 using forecast prices and costs; and
(ii) the related estimated net present value.

(c) (i) both proved, and proved and probable bitumen and synthetic crude oil reserve quantities relating to surface mineable oil sands projects estimated as at December 31, 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 conventional reserves (before deduction of income taxes) attributed to proved conventional crude oil, NGL 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, 2005, 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 Conventional Reserves (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 7, 2006.	Canada, USA	$0	$20,727	$0	$20,727
Ryder Scott Company	Ryder Scott Evaluated the P&NG Reserves as reported February 7, 2006.	United Kingdom and Offshore West Africa	$0	$9,890	$0	$9,890
Totals			$0	$30,617	$0	$30,617

In addition, both proved, and proved and probable reserves have been evaluated for oil sands mining properties located in Canada. The Horizon Project reserves were evaluated as at December 31, 2005. GLJ Petroleum Consultants ("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 disclosed separately from the Company's conventional crude oil and natural 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 7, 2006

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

GLJ PETROLEUM CONSULTANTS

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 conventional crude oil, 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 conventional crude oil, NGLs and natural gas reserve quantities estimated as at December 31, 2005 using constant prices and costs;
(ii) the related estimated net present value; and
(iii) the related standardized measure calculation for proved conventional crude oil, NGL and natural gas reserve quantities.

(b) (i) both proved, and proved and probable conventional crude oil, NGL and natural gas reserve quantities estimated as at December 31, 2005 using forecast prices and costs;
(ii) the related estimated net present value; and,

(c) (i) both proved, and proved and probable bitumen and synthetic crude oil reserve quantities relating to surface mineable oil sands operations estimated as at December 31, 2005.

Sproule Associates Limited, Ryder Scott Company and GLJ Petroleum Consultants, 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 crude 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 crude 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
President and Chief Operating Officer

"Signed"
Douglas A. Proll
Chief Financial Officer and Senior Vice President, Finance

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

"Signed"
Norman F. McIntyre
Independent Director and Member of the Reserve Committee

Dated this 21st day of February, 2006
Calgary, Alberta

SCHEDULE "C"

CANADIAN NATURAL RESOURCES LIMITED
(the "Corporation")

Charter of the Audit Committee of the Board of Directors

I Audit Committee Purpose

The Audit Committee is appointed by the Board of Directors (the "Board") to assist the Board in fulfilling its responsibility for the stewardship of the Corporation in overseeing the business and affairs of the Corporation. The Audit Committee's primary duties and responsibilities are to:

1. ensure that the Corporation's management has designed and implemented an effective system of internal financial controls;

2. monitor and report on the integrity of the Corporation's financial statements, financial reporting processes and systems of internal controls regarding financial, accounting and compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and disclosure of material facts;

3. select and recommend for appointment by the shareholders, the Corporation's independent auditors, pre-approve all audit and non-audit services to be provided to the Corporation by the Corporation's independent auditors consistent with all applicable laws, and establish the fees and other compensation to be paid to the independent auditors;

4. monitor the independence and performance of the Corporation's independent auditors;

5. monitor the performance of the internal auditing function;

6. establish procedures for the receipt, retention, response to and treatment of complaints, including confidential, anonymous submissions by the Corporation's employees, regarding accounting, internal controls or auditing matters; and,

7. provide an avenue of communication among the independent auditors, management, the internal auditing function and the Board.

II Audit Committee Composition, Procedures and Organization

1. The Audit Committee shall consist of at least three (3) directors as determined by the Board, each of whom shall be independent, non-executive directors, free from any relationship that would interfere with the exercise of his or her independent judgment. Audit Committee members shall meet the independence and experience requirements of the regulatory bodies to which the Corporation is subject to. All members of the Audit Committee shall have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements at the time of their appointment to the Audit Committee. At least one member of the Audit Committee shall have accounting or related financial management expertise and qualify as a

"financial expert" or similar designation in accordance with the requirements of the regulatory bodies to which the Corporation may be subject to.

2. The Board at its organizational meeting held in conjunction with each annual general meeting of the shareholders shall appoint the members of the Audit Committee for the ensuing year. The Board may at any time remove or replace any member of the Audit Committee and may fill any vacancy in the Audit Committee.

3. The Board shall appoint a member of the Audit Committee as chair of the Audit Committee. If an Audit Committee Chair is not designated by the Board, or is not present at a meeting of the Audit Committee, the members of the Audit Committee may designate a chair by majority vote of the Audit Committee membership.

4. The Secretary or the Assistant Secretary of the Corporation shall be secretary of the Audit Committee unless the Audit Committee appoints a secretary of the Audit Committee.

5. The quorum for meetings shall be one half (or where one half of the members of the Audit Committee is not a whole number, the whole number which is closest to and less than one half) of the members of the Audit Committee subject to a minimum of two members of the Audit Committee present in person or by telephone or other telecommunications device that permits all persons participating in the meeting to speak and to hear each other.

6. Meetings of the Audit Committee shall be conducted as follows:

   (a) the Audit Committee shall meet at least four (4) times annually at such times and at such locations as may be requested by the Chair of the Audit Committee;

   (b) the Audit Committee shall meet privately in executive sessions at each meeting with management, the manager of internal auditing, the independent auditors, and as a committee to discuss any matters that the Audit Committee or each of these groups believe should be discussed.

7. The independent auditors and internal auditors shall have a direct line of communication to the Audit Committee through its chair and may bypass management if deemed necessary. Any employee may bring before the Audit Committee directly and may bypass management if deemed necessary any matter involving questionable, illegal or improper financial practices or transactions.

III Audit Committee Duties and Responsibilities

1. The overall duties and responsibilities of the Audit Committee shall be as follows:

   a. to assist the Board in the discharge of its responsibilities relating to the Corporation's accounting principles, reporting practices and internal controls and its approval of the Corporation's annual and quarterly consolidated financial statements;

b. to establish and maintain a direct line of communication with the Corporation's internal auditors and independent auditors and assess their performance;

c. to ensure that the management of the Corporation has designed, implemented and is maintaining an effective system of internal controls;

d. to report regularly to the Board on the fulfillment of its duties and responsibilities; and,

e. to review annually the Audit Committee Charter and recommend any changes to the Nominating and Corporate Governance Committee for approval by the Board.

2. The duties and responsibilities of the Audit Committee as they relate to the independent auditors shall be as follows:

a. to select and recommend for appointment by the shareholders, the Corporation's independent auditors, review the independence and performance of the independent auditors and approve any discharge of auditors when circumstances warrant;

b. to approve the fees and other significant compensation to be paid to the independent auditors, scope and timing of the audit and other related services rendered by the independent auditors;

c. to approve the independent auditor's annual audit plan, including scope, staffing, locations and reliance upon management and internal audit department prior to the commencement of the audit;

d. to approve proposed non-audit services to be provided by the independent auditors except those non-audit services prohibited by legislation;

e. on an annual basis, obtain and review a report by the independent auditors describing (i) the independent auditor's internal quality control procedures; (ii) any material issues raised by the most recent quality-control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the firm; and, (iii) any steps taken to address any such issues arising from the review, inquiry or investigation, and, receive a written statement from the independent auditors outlining all significant relationships they have with the Corporation that could impair the auditor's independence. The Corporation's independent auditors may not be engaged to perform prohibited activities under the Sarbanes-Oxley Act of 2002 or the rules of the Public Company Accounting Oversight Board or other regulatory bodies, which the Corporation is governed by;

f. to review and discuss with the independent auditors, upon completion of their audit and prior to the filing or releasing annual financial statements:

(i) contents of their report, including :

(a) all critical accounting policies and practices used;
(b) all alternative treatments of financial information within GAAP that have been discussed with management, ramifications of the use of such treatments and the treatment preferred by the independent auditor;
(c) other material written communications between the independent auditor and management;

(ii) scope and quality of the audit work performed;
(iii) adequacy of the Corporation's financial and auditing personnel;
(iv) cooperation received from the Corporation's personnel during the audit;
(v) internal resources used;
(vi) significant transactions outside of the normal business of the Corporation;
(vii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems;
(viii) the non-audit services provided by the independent auditors; and,
(ix) consider the independent auditor's judgments about the quality and appropriateness of the Corporation's accounting principles and critical accounting estimates as applied in its financial reporting; and,

g. to review and approve a report to shareholders as required, to be included in the Corporation's Information Circular and Proxy Statement, disclosing any non-audit services approved by the Audit Committee.

3. The duties and responsibilities of the Audit Committee as they relate to the internal auditors shall be as follows:

a. to review the budget, internal audit function with respect to the organization structure, staffing, effectiveness and qualifications of the Corporation's internal audit department;

b. to review and approve the internal audit plan; and

c. to review significant internal audit findings and recommendations together with management's response and follow-up thereto.

4. The duties and responsibilities of the Audit Committee as they relate to the internal control procedures of the Corporation shall be as follows:

a. to review the appropriateness and effectiveness of the Corporation's policies and business practices which impact on the financial integrity of the Corporation, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting and risk management;

b. to review any unresolved issues between management and the independent auditors that could affect the financial reporting or internal controls of the Corporation; and

c. to periodically review the Corporation's financial and auditing procedures and the extent to which recommendations made by the internal audit staff or by the independent auditors have been implemented.

5. Other duties and responsibilities of the Audit Committee shall be as follows:

a. to review the Corporation's unaudited quarterly consolidated financial statements and related Management Discussion & Analysis including the impact of unusual items and changes in accounting principles and estimates and report to the Board with respect thereto;

b. to review the Corporation's audited annual consolidated financial statements and related Management Discussion & Analysis including the impact of unusual items and changes in accounting principles and estimates and report to the Board with respect thereto;

c. to review and approve regulatory filings and decisions as they relate to the Corporation's consolidated financial statements and related Management Discussion & Analysis and report to the Board thereto with respect to:

(i) the annual report to shareholders;
(ii) the annual information form;
(iii) the annual information form on Form 40-F;
(iv) prospectuses; and,
(v) other disclosure reports requiring approval by the Board;

d. to review the appropriateness of the policies and procedures used in the preparation of the Corporation's consolidated financial statements and other required disclosure documents and consider recommendations for any material change to such policies;

e. to review with management, the independent auditors and if necessary with legal counsel, any litigation, claim or other contingency, including tax assessments that could have a material affect upon the financial position or operating results of the Corporation and the manner in which such matters have been disclosed in the consolidated financial statements;

f. to co-ordinate meetings with the Reserves Committee of the Corporation, the Corporation's senior engineering management, independent evaluating engineers and auditors as required and consider such further inquiries as are necessary to approve the consolidated financial statements;

g. to develop a calendar of activities to be undertaken by the Audit Committee for each ensuing year and to submit the calendar in the appropriate format to the Board following each annual general meeting of shareholders;

h. to perform any other activities consistent with this Charter, the Corporation's By-laws and governing law, as the Audit Committee or the Board deems necessary or appropriate; and,

i. to maintain minutes of meetings and to report on a regular basis to the Board on significant results of the foregoing activities.

The Audit Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to the independent auditors as well as officers and employees of the Corporation. The Audit Committee has the authority to retain, at the Corporation's expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties. The Corporation shall at all times make adequate provisions for the payment of all fees and other compensation approved by the Audit Committee, to the Company's independent auditors in connection with the issuance of its audit report, or to any consultants or experts employed by the Audit Committee.