CANADIAN NATURAL RESOURCES LTD
Form 40-F
March 27, 2009

United States
Securities and Exchange Commission
Washington, D.C. 20549

# FORM 40-F

[ ] Registration Statement pursuant to section 12 of the Securities Exchange Act of 1934

[X] Annual report pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2008 Commission File Number: 333-146056

CANADIAN NATURAL RESOURCES LIMITED
(Exact name of Registrant as specified in its charter)

ALBERTA, CANADA
(Province or other jurisdiction of incorporation or organization)

1311
(Primary Standard Industrial Classification Code Numbers)

NOT APPLICABLE
(I.R.S. Employer Identification Number (if applicable))

2500, 855-2ND STREET S.W., CALGARY, ALBERTA, CANADA, T2P 4J8
TELEPHONE: (403) 517-7345
(Address and telephone number of Registrant's principal executive offices)

CT CORPORATION SYSTEM, 111-8TH AVENUE, NEW YORK, NEW YORK 10011
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

| Title of Each Class: | Name of each exchange on which registered: |
| --- | --- |
| COMMON SHARES, NO PAR VALUE | NEW YORK STOCK EXCHANGE |

Securities registered or to be registered pursuant to Section 12(g) of the Act:
Title of Each Class: NONE

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: NONE

For annual reports, indicate by check mark the information filed with this Form:

[X] Annual information form [X] Audited annual financial statements

Number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.
540,991,318 COMMON SHARES OUTSTANDING AS OF DECEMBER 31, 2008

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

Yes [ ] No [ X ]

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

This Annual Report on Form 40-F shall be incorporated by reference into, or as an exhibit to, as applicable, the Registrant's Registration Statement on Form F-9 (Registration No. 333-146056) under the Securities Act of 1933.

All dollar amounts in this Annual Report on Form 40-F are expressed in Canadian dollars. As of March 26, 2009, the noon buying rate for Canadian Dollars as expressed by the Bank of Canada was US$0.8110 equals C$ 1.00.

## PRINCIPAL DOCUMENTS

The following documents have been filed as part of this Annual Report on Form 40-F, starting on the following page:

### A. ANNUAL INFORMATION FORM

Annual Information Form of Canadian Natural Resources Limited ("Canadian Natural") for the year ended December 31, 2008.

### B. AUDITED ANNUAL FINANCIAL STATEMENTS

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2008 and 2007, including the auditor's report with respect thereto. For a reconciliation of important differences between Canadian and United States generally accepted accounting

principles, see Note 18 of the notes to the consolidated financial statements.

C. MANAGEMENT'S DISCUSSION AND ANALYSIS

Canadian Natural's Management's Discussion and Analysis for the year ended December 31, 2008.

SUPPLEMENTARY OIL & GAS INFORMATION

For Canadian Natural's Supplementary Oil & Gas Information for the year ended December 31, 2008, see Exhibit 1 of this Annual Report on Form 40-F.

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[CANADIAN NATURAL RESOURCES LIMITED LOGO OMITTED]

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2008

MARCH 25, 2009

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DEFINITIONS

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

"API" means the specific gravity measured in degrees on the American Petroleum Institute scale

"ARO" means Asset Retirement Obligation

"BBL" or "BARREL" means 34.972 Imperial gallons or 42 US gallons

"BCF" means one billion cubic feet

"BBL/D" means barrels per day

"BOE" means barrel of oil equivalent

"BOE/D" means barrel of oil equivalent per day

"CO2" means carbon dioxide

"CO2E" means carbon dioxide equivalents

"CANADIAN GAAP" means Generally Accepted Accounting Principles in Canada

"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

"CBM" means coal bed methane

"CONVENTIONAL CRUDE OIL, NGLS AND NATURAL GAS" includes all of the Company's light/medium, primary heavy, and thermal heavy crude oil, natural gas, coal bed methane and NGLs reserves. It does not include the Company's oil sands mining reserves

"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 unproved territory with the intention to discover commercial quantities of crude oil or natural gas

"FPSO" means a Floating Production, Storage and Offtake vessel

"GHG" means greenhouse gas

"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

"HORIZON PROJECT" means the Horizon Oil Sands Project

"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 ASSET VALUE" means the discounted value of conventional crude oil and natural gas reserves plus the value of undeveloped land, less net debt

"NET WELLS" refers to gross wells multiplied by the percentage working interest therein owned or to be owned by the Company

"PRODUCTIVE WELL" means a well that is not a dry well

"PRT" means Petroleum Revenue Tax

"SAGD" means steam-assisted gravity drainage

"SCO" means synthetic light crude oil

"SEC" means United States Securities and Exchange Commission

"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

"UK" means the United Kingdom

"US" means United States

"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 documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could" "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort" "seeks", "schedule" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, production volumes, royalties, operating costs, capital expenditures, and other guidance provided throughout this document constitute forward looking statements. Disclosure of plans relating to existing and future developments, including but not limited to the Horizon Project, Primrose East, Pelican Lake, Gabon Offshore West Africa, and the Kirby Oil Sands Project also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year if necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, 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. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained and are subject to known and unknown risks, uncertainties and other factors that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete its capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected difficulties in mining, extracting or upgrading the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital

expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, bitumen, natural gas and liquids not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses. Certain of these factors are discussed in more detail under the heading "Risk Factors". The Company's operations have been, and at times in the future may be affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of important factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. 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 crude 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, 2008, the Company retained a qualified independent reserves evaluator, Sproule Associates Limited ("Sproule"), to evaluate 100% of the Company's conventional proved, as well as proved and

probable crude oil, NGLs and natural gas reserves and prepare Evaluation Reports on these reserves. Conventional crude oil, NGLs and natural gas reserves include all of the Company's light/medium, primary heavy, and thermal heavy crude oil, natural gas, coal bed methane and NGLs reserves. They do not include the Company's oil sands mining reserves. The Company has been granted an exemption from certain of the provisions of 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 SEC requirements for certain disclosures required under NI 51-101. There are three principal differences between the two standards. The first is the 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 third is the requirement to disclose a gross reserve reconciliation (before the consideration of royalties). The Company discloses its conventional crude oil, NGLs, and natural gas reserve reconciliations net of royalties in adherence to SEC requirements.

For the year ended December 31, 2008, the Company retained a qualified independent reserves evaluator, GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate 100% of Phases 1 through 3 of the Company's Horizon 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 proved and proved and probable crude oil, NGLs and natural gas reserves.

The Company annually discloses proved conventional reserves and the standardized measure of discounted future net cash flows using year-end constant prices and costs as mandated by the SEC in the supplementary crude oil and natural gas information section of the Company's Annual Report and in its annual Form 40-F filing with the SEC. The Company has elected to provide the net present value of these same conventional proved reserves as well as its conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information. Net present values of conventional reserves are based upon discounted cash flows prior to the consideration of income taxes and existing asset abandonment liabilities. Future development costs and associated material well abandonment liabilities have been applied. The Company has also elected to provide both proved, and proved and probable conventional reserves and the net present value of these reserves using forecast prices and costs as additional voluntary information, which is disclosed in this Annual Information Form.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with both Sproule 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, NGLs and natural gas reserves as well as the Company's quantity of oil sands mining reserves.



SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

This Annual Information Form includes references to financial measures commonly

used in the crude oil and natural gas industry, such as cash flow from operations, adjusted net earnings from operations and net asset value. 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 its performance. 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 non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with Canadian GAAP in the "Financial Highlights" section the Company's MD&A which is incorporated by reference into this document.

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. Significant declines 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, European 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, industrial demand, prices of alternate sources of energy, and the import of liquefied natural gas. 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, including but not limited to the Horizon Project, Primrose East, Pelican Lake, Gabon Offshore West Africa, and the Kirby Oil Sands Project, or curtailment in production at some properties or result in unutilized long-term transportation commitments, all of which could have a material adverse effect on Canadian Natural's revenues, net earnings 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 forecast prices decline, the carrying value of property, plant and equipment could be subject to downward revisions, and net earnings could be adversely affected.

Approximately 28% of the Company's 2008 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 quality difference and the mix of product obtained in the refining process referred to as the "quality differential". 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 quality differentials are uncertain and a significant increase in the heavy crude oil differentials could have a material adverse effect on the Company's business.

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.



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, NGLs and natural gas reserves and the future net cash flow therefrom are based upon a number of factors and assumptions made as of the date on which the reserve estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable crude oil, NGLs and natural gas reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Canadian Natural's actual production, revenues, royalties, 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.

COMPLETION RISK

Canadian Natural has a variety of exploration, development and construction projects underway at any given time. Project delays may result in delayed revenue receipts and cost overruns may result in projects being uneconomic. The Company's ability to complete projects is dependent on general business and market conditions as well as other factors beyond our control including the availability of skilled labour and manpower, the availability and proximity of pipeline capacity, weather, environmental and regulatory matters, ability to access lands, availability of drilling and other equipment, and availability of processing capacity.

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 related 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 include integrated oil and natural gas companies and numerous other senior oil and natural gas companies, some of which may have financial and other resources greater than the Company.

ACCESS TO SOURCES OF LIQUIDITY

The ongoing worldwide financial and economic events have resulted in a significant tightening of the availability and cost of new sources of liquidity, including bank credit facilities and funds derived from debt capital markets. The ability of the Company to fund current and future capital projects and carry out our business plan is dependent on our ability to raise capital in a timely manner under favourable terms and conditions.

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.



The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation, particularly in North America and the North Sea. Existing and expected legislation and regulations will require the Company to address and mitigate the effect of its activities on the environment. Increasingly stringent laws and regulations, including any new regulations the US may impose to limit purchases of crude oil towards less energy intensive sources, may have an adverse effect on the Company's future net earnings and cash flow from operations.

GREENHOUSE GAS AND OTHER AIR EMISSIONS

There are a number of unresolved issues in relation to Canadian federal and provincial GHG regulatory requirements. Key among them is an appropriate common facility emissions threshold, availability and duration of compliance mechanisms and resolution of federal/provincial harmonization agreements. The Company continues to pursue GHG emissions reduction initiatives including solution gas conservation, CO2 capture and sequestration in oil sands tailings, CO2 capture and storage in association with enhanced oil recovery and participation in an industry initiative to promote an integrated CO2 capture and storage network.

Air pollutant standards and guidelines are being developed federally and provincially and the Company is participating in these discussions. Ambient air quality and sector based reductions in air emissions are being reviewed. Through participation of the Company and the industry with stakeholders, guidelines have been developed that adopt a structured process to emissions reductions that is commensurate with technological development and operational requirements.

In Canada, the Federal government has indicated its intent to develop regulations that would be in effect in 2010 to address industrial GHG emissions; however future Federal regulatory requirements currently remain uncertain. The Federal Government has also outlined national and sectoral reduction targets for several categories of air pollutants. In Alberta, GHG regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO2e annually. Two Canadian Natural facilities, the Primrose/Wolf Lake in-situ heavy oil crude oil facilities and the Hays sour natural gas plant, fall under the regulations. In British Columbia, a $10/tonne carbon tax was implemented July 1, 2008, applying to combustion of all fossil fuels, increasing to $30/tonne by July 2012. In the UK, greenhouse gas regulations have been in effect since 2005. During Phase 1 (2005-2007) of the UK National Allocation Plan the Company operated below its CO2 allocation. For Phase 2 (2008-2012) the Company's CO2 allocation has been decreased below the Company's estimated current operations emissions. The compliance costs to the Company relating to the above regulations for 2008 are approximately $24 million.

The additional requirements of enacted or proposed GHG legislation on the Company's operations will increase capital expenditures and operating expenses, especially those related to the Horizon Project and the Company's other existing and planned large oil sands projects. This may have an adverse effect on the Company's net earnings and cash flow from operations.

HEDGING ACTIVITIES

In response to fluctuations in commodity prices, foreign exchange, and interest rates, the Company may utilize various derivative financial instruments and physical sales contracts to manage its exposure under a defined hedging program. The terms of these arrangements may limit the benefit to the Company of favourable changes in these factors and may result in financial or opportunity loss due to paying royalties on a reference price which is higher than the hedged price and counterparty credit risk.

OPERATIONAL RISK

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. The Company has developed a comprehensive health and safety management framework and maintains a comprehensive insurance program, however, Canadian Natural's liability,

property and business interruption insurance may not and possibly will not provide adequate coverage in all 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 Canada or the United States.

Canadian Natural's arrangement for the exploration and development of crude oil and natural gas properties in Canada and the UK sector of the North Sea differs distinctly from its arrangement for the exploration and development in other 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 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 crude 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.

OTHER BUSINESS RISKS

Other business risks relate to the dependency on third party operators for some of the Company's assets, timing and success of integrating the business and operations of acquired companies, credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, risk of litigation, regulatory issues, and risk of increases in government taxes and changes to the royalty regime. The majority of the Company's assets are held in one or more corporate subsidiaries or partnerships. The results of operations and ability to service indebtedness, including debt securities, are dependent upon the results of operations of these subsidiaries and partnerships and, in the case of subsidiaries, the payment of funds to the Company in the form of loans, dividends or other means employed for the payment of funds to the Company. In the event of the liquidation of any corporate subsidiary or partnership, 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 Canada and the UK 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. 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 internal environmental compliance audit and inspection program of its operating facilities; a 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; a due diligence program related to groundwater monitoring; an active program related to preventing spills and reclaiming spill sites; a solution gas reduction and conservation program; a program to replace the majority of fresh water for steaming with brackish water; environmental planning for all projects to assess environmental impacts and to implement avoidance, and mitigation programs; reporting for environmental liabilities; a program to optimize efficiencies at the Company's operating facilities; and continued evaluation of new technologies to reduce



environmental impacts. The Company has also established stringent operating standards in four areas: implementing cost effective ways of reducing GHG per unit of production; exercising care with respect to all waste produced through effective waste management plans; using water-based, environmentally friendly drilling muds whenever possible; and minimizing produced water volumes onshore and offshore through cost-effective measures. Canadian Natural participates in both the Canadian federal and provincial regulated GHG emissions programs. 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 the Companies overall goal of a net reduction of GHG emissions per unit of production.

The Company is concurrently participating with certain industry groups who in turn are working with legislators and regulators to develop and implement new GHG emissions laws and regulations. Internally, the Company is pursuing an integrated emissions reduction strategy. The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new policies encourage innovation,

energy efficiency, targeted research and development while not impacting competitiveness.

The Company remains focused on implementing reduction programs based on efficiency audits of its major facilities to reduce $CO_2$ emissions and on trading mechanisms to ensure compliance with any requirement now in effect. Canadian Natural is committed to managing air emissions through an integrated corporate approach which considers opportunities to reduce both air pollutants and GHG emissions. Air quality programs continue to be an essential part of the Company's environmental work plan and are operated within all regulatory standards and guidelines. The Company strategy for managing GHG emissions is based on four core principles: energy conservation and efficiency; reduced intensity; innovative technology and associated research and development; and, trading capacity, both domestically and globally.

The Company continues to implement flaring, venting and fuel and solution gas conservation programs. In 2008 the Company completed approximately 101 gas conservation projects, resulting in a reduction of 835,000 tonnes/year of $CO_2e$. Over the past five years the Company has spent over $89 million to conserve the equivalent of over 6.3 million tonnes of $CO_2e$. The Company also monitors the performance of its compressor fleet which is continually modified and optimized for maximum efficiency. These programs also influence and direct the Company's plans for new projects and facilities. The Horizon Project has incorporated advancements in technology to further reduce GHG emissions through maximizing heat integration, the use of cogeneration to meet steam and electricity demands and the design of the hydrogen production facility to enable $CO_2$ capture and the sequestration of $CO_2$ in oils sands tailings.

In its North Sea operations the Company continues to focus on implementing reduction programs based on efficiency audits of its major facilities. Projects to reduce GHG emissions included a flare recovery pilot study, change out of flare purge valves and introduction of water washing on turbines. The Produced Water Re-injection on Ninian Central was made permanent in 2008 during which time approximately 1.36 million cubic meters of produced water were re-injected to the reservoir. This resulted in approximately 18 tonnes of oil in produced water not being discharged to sea, a reduction of approximately 6%.

For 2008, the Company's capital expenditures included $38 million for abandonment expenditures (2007 - $71 million).

The Company's estimated undiscounted ARO at December 31, 2008 was as follows:

| Estimated ARO, undiscounted ($millions) | 2008 | 2007 |
|---|---|---|
| North America | $ 3,165 | $ 3,038 |
| North Sea | 1,216 | 1,286 |
| Offshore West Africa | 93 | 102 |
| | 4,474 | 4,426 |
| North Sea PRT recovery | (529) | (555) |
| | $ 3,945 | $ 3,871 |

The estimate of ARO is based on estimates of future costs to abandon and restore the wells, production facilities and offshore production platforms. Factors that affect costs include number of wells drilled, well depth and the specific environmental legislation. The estimated costs are based on engineering estimates using current costs in accordance with present legislation and industry operating practice. The Company's strategy in the North Sea consists of developing commercial hubs around its core operated

properties with the goal of increasing production, lowering costs and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates. The future abandonment costs incurred in the North Sea are estimated to result in a PRT recovery of $529 million (2007 - $555 million), as abandonment costs are an allowable deduction in determining PRT and may be



carried back to reclaim PRT previously paid. The expected PRT recovery reduces the Company's net undiscounted abandonment liability to $3,945 million (2007 - $3,871 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, transportation, prevention of waste and other activities.

The Company's Canadian properties are primarily located in Alberta, British Columbia, Saskatchewan, Manitoba and the Northwest and Yukon 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 are 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 and Yukon 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 Alberta 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, NGLs and natural gas production from leases owned by the province. The royalties are determined by regulation and are generally calculated as a percentage of production varied by a number of different factors including selling prices, production levels, recovery methods, transportation and processing costs, location and date of discovery.

The Alberta Government implemented its New Royalty Framework (NRF) effective January 1, 2009. The NRF includes a number of changes to royalty rates for natural gas, conventional crude oil, and oil sands production. Under the NRF, royalties payable are variable according to commodity prices and the productivity of wells.

The NRF for conventional crude oil and natural gas operates based on sliding scales ranging up to 50% determined by commodity prices and well productivity.

Government royalties on a significant portion of Alberta crude oil production fall under the oil sands royalty regime and are calculated on a project by project basis as a percentage of gross revenue less operating, capital and abandonment costs ("net profit"). For 2008 and prior years, royalties were calculated as 1% of gross revenues until the Company's capital investment in the applicable project were fully recovered, at which time the royalty increased to 25% of net profit. Effective January 1, 2009 the NRF includes the implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout depending on benchmark crude oil pricing.

In addition to government royalties, the Company is currently subject to federal and provincial income taxes in Canada at a combined rate of approximately 29% after allowable deductions.

During 2007, the Canadian Federal Government enacted income tax rate changes which decrease the Federal corporate income tax rate over a five year period from 21% in 2007, 19.5% in 2008, 19% in 2009, to 15% in 2012.



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% 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. There is no PRT on profits of decommissioned fields subsequently redeveloped, subject to certain conditions being met.

The Company is subject to UK Corporation Tax ("CT") on its UK profits at a current rate of 30%. PRT paid is deductible for CT purposes. An additional Supplementary Charge Tax ("SCT") of 20% is charged on crude oil and natural gas profits but excludes any deduction for financing costs. The deduction for crude oil and natural gas expenditures on capital items is generally 100% in the year incurred.

OFFSHORE WEST AFRICA

Terms of licences, including royalties and taxes payable on production or profit sharing arrangements, vary by country and, in some cases, by concession within each country.

Development of the Espoir Field in Block CI-26 and the Baobab Field in Block CI-40, offshore Cote d'Ivoire, are subject to Production Sharing Agreements ("PSA") that deem tax or royalty payments to the Government are met from the Government's share of profit oil. The current Corporate Income Tax rate in Cote d'Ivoire is 25% which is applicable to non PSA income.

The Olowi Field offshore Gabon is also under the terms of a PSA which deems tax or royalty payments to the Government are met from the Government's share of profit oil. The current Corporate Income Tax rate is 35% which is applicable to non PSA income.

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.

On November 2, 2006, pursuant to a Purchase and Sale Agreement, the Company acquired all of the outstanding shares of Anadarko Canada Corporation, a subsidiary of Anadarko Petroleum Corporation. On November 3, 2006 Anadarko Canada Corporation and a wholly owned subsidiary of the Company, 1266701 Alberta Ltd. amalgamated to form ACC-CNR Resources Corporation. On January 1, 2007, ACC-CNR Resources Corporation and the Company amalgamated pursuant to the BUSINESS CORPORATIONS ACT (Alberta) under the name Canadian Natural Resources Limited.



On January 1, 2008 Ranger Oil (International) Ltd., 764968 Alberta Inc., CNR International (Norway) Limited, Renata Resources Inc. and the Company amalgamated pursuant to the BUSINESS CORPORATIONS ACT (Alberta) under the name

Canadian Natural Resources Limited.

The main operating subsidiaries and partnerships of the Company, percentage of voting securities owned either directly or indirectly, and their jurisdictions of incorporation are as follows:

| SUBSIDIARY | 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 Cote d'Ivoire SARL | Cote d'Ivoire |
| CNR International (Olowi) Limited | Bahamas |
| CNR Petro Resources Limited | Alberta |
| Horizon Construction Management Ltd. | Alberta |
| PARTNERSHIP | |
| Canadian Natural Resources Partnership | Alberta |
| Canadian Natural Resources Northern Alberta Partnership | Alberta |
| CNR 2006 Partnership | Alberta |

In the ordinary course of business, Canadian Natural restructures its subsidiaries and partnerships to maintain efficient operations and to facilitate acquisitions and divestitures.

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 - THREE YEAR HISTORY

2006

In January 2006 the Company issued $400 million of 4.50% unsecured notes maturing January 23, 2013 pursuant to a short form Canadian base shelf prospectus dated August 29, 2005.

On August 17, 2006, the Company issued US$250 million of 10 year 6.0% unsecured notes maturing August 15, 2016 and US$450 million of 30 year 6.50% unsecured notes maturing February 15, 2037 pursuant to a US short form base shelf prospectus dated June 3, 2005.

In November 2006, the Company completed the acquisition of Anadarko Canada Corporation ("ACC") for net cash consideration of $4,641 million, including working capital and other adjustments. The Company immediately integrated ACC into its ongoing operations. The land and production base acquired are located substantially in Western Canada and are natural gas weighted assets with a long reserve life. At the time, the assets produced in excess of 350 mmcf/d of natural gas and approximately 9,000 bbl/d of light crude oil and NGLs production. The assets acquired also included approximately 1.5 million net undeveloped acres and key strategic facilities in Northeast British Columbia and Northwest Alberta. In conjunction with the closing of the acquisition of ACC, the Company executed a $3,850 million, three-year non-revolving syndicated credit facility maturing in October 2009. In March 2007, $1,500 million of the credit facility was repaid reducing the facility to $2,350 million. In February 2009, $420 million of the credit facility was repaid reducing the facility to $1,930 million.

During 2006, the Company completed 83 transactions in the normal course to acquire additional interests in crude oil and natural gas properties. The aggregate net expenditure of the transactions was $4,801 million, including the ACC acquisition. The properties acquired are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. As well the Company participated in 48 transactions to dispose of non-core operated and non-operated properties for proceeds of $68 million. Included in this amount is a royalty disposition for $66 million.



2007

On March 19, 2007, the Company issued US$1,100 million of 10 year 5.70% unsecured notes maturing May 15, 2017 and US$1,100 million of 30 year 6.25% unsecured notes maturing March 15, 2038 pursuant to a US short form base shelf prospectus dated November 27, 2006.

On December 18, 2007 the Company issued $400 million of 3 year 5.50% unsecured notes maturing December 17, 2010 pursuant to a Canadian short form base shelf prospectus dated September 25, 2007.

During 2007, the Company completed 67 transactions in the normal course to acquire additional interests in crude oil and natural gas properties. The aggregate net expenditure of the transactions was $70.9 million. The properties acquired are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. As well the Company participated in 33 transactions to dispose of non-core operated and non-operated properties for proceeds of $109.9 million.

2008

On January 17, 2008, the Company issued US$400 million of 5 year 5.15% unsecured notes maturing February 1, 2013, US$400 million of 10 year 5.90% unsecured notes maturing February 1, 2018 and US$400 million of 31 year 6.75% unsecured notes maturing February 1, 2039 pursuant to a US short form base shelf prospectus dated September 25, 2007.

In the third quarter of 2008, the Company committed 120,000 bbl/d to the Keystone Pipeline US Gulf Coast Expansion for a 20 year period, subject to regulatory approval. Concurrently the Company entered into a 20 year supply agreement with a major US refiner for 100,000 bbl/d of heavy crude oil to US Gulf Coast refineries, contingent on the completion of the Keystone Pipeline US Gulf Coast Expansion.

The Company entered into an agreement in August 2005 to obtain pipeline transportation service for the Horizon Project. The initial term of the agreement is 25 years, which commenced on the in-service date of November 1, 2008. The twinning of the existing Alberta Oil Sands Pipeline ("AOSPL"), resulting in two parallel pipelines, one of which is dedicated to Canadian Natural, combined with the 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. In addition to having the option to renew the agreement for successive 10 year terms, the Company has the right to request incremental expansion of the Horizon Pipeline based upon applicable National Energy Board approved multi pipeline economics. This agreement allows the Company to gain access to major sales pipelines out of Edmonton for the Company's synthetic crude oil transportation service for the Horizon Project, while at the same time providing significant quality

benefits associated with being the only shipper on the Horizon Pipeline.

During 2008, the Company completed 55 transactions in the normal course to acquire additional interests in crude oil and natural gas properties. The aggregate net expenditure of the transactions was $381 million. The properties acquired are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. As well, the Company participated in 33 transactions to dispose of non-core operated and non-operated properties for proceeds of $45 million.

2009

First synthetic crude oil production was achieved at the Horizon Project on February 28, 2009. First shipment into the Horizon Pipeline occurred on March 18, 2009. Capital expenditures are expected to be $621 million in 2009 for remaining Phase 1 construction, commissioning and inventory costs, as wells as sustaining capital costs and Tranche 2 expansion.

For 2009, the Company's overall conventional drilling activity in North America is expected to comprise approximately 142 natural gas wells and 465 crude oil wells, excluding stratigraphic and service wells. The company has reduced 2009 natural gas drilling in Alberta due to the anticipated future impact of royalty changes arising under the NRF which became effective January 1, 2009 and the current low prices received for natural gas. Forecasted conventional capital expenditures in North America for 2009 are currently expected to be approximately $1.7 billion, excluding property acquisitions and dispositions.

The Company's drilling activity in 2009 for the North Sea is expected to be 0.9 net platform wells with focus on building drilling and workover inventory for 2010. Capital expenditures are expected to be $141 million.

In Offshore West Africa, capital expenditures are expected to be $553 million in 2009, including $80 million to complete Phase 2 development of the Baobab Field in Cote d'Ivoire, where the Company is currently drilling the fourth and final well which is expected to be completed in the second quarter of 2009.



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 initiates, operates and maintains a large working interest in a majority of the prospects in which it participates. Canadian Natural's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value on a per common share basis through the development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves.

The Company has a full complement of management, technical and support staff to pursue these objectives. As at December 31, 2008 the Company had 3,782 permanent employees in North America and 350 permanent employees in its international operations. Included in the North American numbers are the Horizon Project team, consisting of 1,245 permanent employees.

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, light/medium crude oil and NGLs, Pelican Lake crude oil (14-17(0) API oil, which receives medium quality crude netbacks due to lower production costs and lower royalty rates), 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 44% of 2008 production. Virtually all of the Company's natural gas and NGLs production is located in the Canadian provinces of Alberta, British Columbia and Saskatchewan and is marketed in Canada and the United States. Light/medium crude oil and NGLs, representing 22% of 2008 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 28% of 2008 production. Other heavy crude oil, which accounts for 6% of 2008 production, is produced from the Pelican Lake area in north Alberta. This production is developed through a staged horizontal drilling program complimented by water and polymer flooding. Midstream assets, comprised of three crude oil pipelines and an electricity co-generation facility, provide cost effective infrastructure supporting the primary and thermal heavy and Pelican Lake crude oil operations.

With approximately 12.1 million net acres of core undeveloped land base, 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

DAILY PRODUCTION AND INFRASTRUCTURE

Set forth below is a summary of the conventional crude oil, NGLs and natural gas properties as at December 31, 2008. The information reflects the working interests owned by the Company. FPSO's, included under major infrastructure, are leased by the Company under varying terms.

| Region | 2008 Average Daily Production Rates | | 2007 Average Daily Production Rates | |
|---|---|---|---|---|
| | Crude oil & NGLs (mbbl) | Natural gas (mmcf) | Crude oil & NGLs (mbbl) | Natural (mm |
| NORTH AMERICA | | | | |
| Northeast British Columbia | 5.9 | 377 | 7.0 | |
| Northwest Alberta | 16.4 | 531 | 17.0 | |

| | | | | |
|---|---|---|---|---|
| Northern Plains | 200.7 | 382 | 201.4 | |
| Southern Plains | 12.2 | 177 | 12.7 | |
| Southeast Saskatchewan | 8.4 | 3 | 8.4 | |
| Non-core regions | 0.2 | 2 | 0.3 | |
| INTERNATIONAL | | | | |
| North Sea UK Sector | 45.3 | 10 | 55.9 | |
| Offshore West Africa | | | | |
| Cote d'Ivoire | 26.6 | 13 | 28.5 | |
| Gabon | - | - | - | |
| Non-core regions | | | | |
| South Africa | - | - | - | |
| TOTAL | 315.7 | 1,495 | 331.2 | 1, |



DEVELOPED AND UNDEVELOPED ACREAGE

The following table summarizes the Companies landholdings as at December 31, 2008.

| | Developed Acreage | | Undeveloped Acreage | | Total A |
|---|---|---|---|---|---|
| Region (thousands of acres) | Gross | Net | Gross | Net | Gross |
| NORTH AMERICA | | | | | |
| Northeast British Columbia | 1,478 | 1,107 | 3,037 | 2,227 | 4,515 |
| Northwest Alberta | 1,205 | 859 | 1,808 | 1,352 | 3,013 |
| Northern Plains | 4,126 | 3,326 | 7,354 | 6,452 | 11,480 |
| Southern Plains | 1,603 | 1,251 | 975 | 832 | 2,578 |
| Southeast Saskatchewan | 89 | 73 | 146 | 130 | 235 |
| In-Situ Oil Sands | 23 | 23 | 598 | 495 | 621 |
| Horizon Oil Sands | - | - | 115 | 115 | 115 |
| Non-core regions | 23 | 8 | 1,276 | 179 | 1,299 |
| INTERNATIONAL | | | | | |
| North Sea UK Sector | 108 | 74 | 314 | 258 | 422 |
| Offshore West Africa | | | | | |
| Cote d'Ivoire | 7 | 4 | 95 | 55 | 102 |
| Gabon | - | - | 152 | 137 | 152 |
| Non-core regions | | | | | |
| South Africa | - | - | 4,002 | 4,002 | 4,002 |
| TOTAL | 8,662 | 6,725 | 19,872 | 16,234 | 28,534 |

DRILLING ACTIVITY

Set forth below is a summary of conventional crude oil, NGLs and natural gas drilling activity of the Company for the fiscal year ending December 31, 2008 by geographic region:

| | | 2008 | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Exploration | | | | | | |
| | | Crude Oil | Natural Gas | Dry | Service/ Stratigraphic | Total | Crude Oil | Natural Gas |
| NORTH AMERICA | | | | | | | | |
| Northeast | | | | | | | | |
| British Columbia | Gross | - | 2.0 | 2.0 | - | 4.0 | - | 26.0 |
| | Net | - | 1.5 | 1.5 | - | 3.0 | - | 22.5 |
| Northwest Alberta | Gross | 1.0 | 14.0 | 1.0 | - | 16.0 | 14.0 | 62.0 |
| | Net | 0.6 | 12.6 | 0.9 | - | 14.1 | 8.9 | 54.0 |
| Northern Plains | Gross | 27.0 | 14.0 | 5.0 | - | 46.0 | 583.0 | 131.0 |
| | Net | 26.3 | 11.4 | 5.0 | - | 42.7 | 557.3 | 88.4 |
| Southern Plains | Gross | 4.0 | 6.0 | 1.0 | - | 11.0 | 29.0 | 153.0 |
| | Net | 4.0 | 6.0 | 1.0 | - | 11.0 | 26.9 | 72.8 |
| Southeast | | | | | | | | |
| Saskatchewan | Gross | 6.0 | - | 2.0 | - | 8.0 | 57.0 | - |
| | Net | 4.6 | - | 2.0 | - | 6.6 | 48.9 | - |
| Non-core Regions | Gross | - | - | - | - | - | - | 3.0 |
| | Net | - | - | - | - | - | - | 0.1 |
| NORTH SEA | | | | | | | | |
| UK SECTOR | Gross | 1.0 | - | - | - | 1.0 | 2.0 | - |
| | Net | 0.8 | - | - | - | 0.8 | 1.6 | - |
| OFFSHORE WEST AFRICA | Gross | - | - | - | - | - | 4.0 | - |
| | Net | - | - | - | - | - | 2.3 | - |
| TOTAL | GROSS | 39.0 | 36.0 | 11.0 | - | 86.0 | 689.0 | 375.0 |
| | NET | 36.3 | 31.5 | 10.4 | - | 78.2 | 645.9 | 237.8 |

Total success rate excluding service and stratigraphic test wells for 2008 is 96% (2007 - 91%, 2006 - 91%)

2007

| | | Exploration | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Crude Oil | Natural Gas | Dry | Service/ Stratigraphic | Total | Crude Oil | Natural Gas |
| NORTH AMERICA | | | | | | | | |
| Northeast British Columbia | Gross | - | 7.0 | 7.0 | - | 14.0 | 3.0 | 45.0 |
| | Net | - | 7.0 | 6.0 | - | 13.0 | 2.9 | 35.1 |
| Northwest Alberta | Gross | 1.0 | 23.0 | 5.0 | - | 29.0 | 21.0 | 102.0 |
| | Net | 1.0 | 16.4 | 3.8 | - | 21.2 | 12.1 | 82.1 |
| Northern Plains | Gross | 26.0 | 31.0 | 20.0 | 97.0 | 174.0 | 545.0 | 82.0 |
| | Net | 23.8 | 24.7 | 19.4 | 97.0 | 164.9 | 500.6 | 70.9 |
| Southern Plains | Gross | 1.0 | 14.0 | 1.0 | - | 16.0 | 19.0 | 174.0 |
| | Net | 1.0 | 13.4 | 1.0 | - | 15.4 | 18.1 | 134.1 |
| Southeast Saskatchewan | Gross | 1.0 | - | - | - | 1.0 | 27.0 | - |
| | Net | 1.0 | - | - | - | 1.0 | 23.0 | - |
| Non-core Regions | Gross | - | - | - | - | - | - | - |
| | Net | - | - | - | - | - | - | - |
| NORTH SEA | | | | | | | | |
| UK SECTOR | Gross | - | - | - | - | - | 4.0 | - |
| | Net | - | - | - | - | - | 3.7 | - |
| OFFSHORE WEST AFRICA | Gross | - | - | - | - | - | 7.0 | - |
| | Net | - | - | - | - | - | 4.1 | - |
| TOTAL | Gross | 29.0 | 75.0 | 33.0 | 97.0 | 234.0 | 626.0 | 403.0 |
| | Net | 26.8 | 61.5 | 30.2 | 97.0 | 215.5 | 564.5 | 322.2 |



2006

| | | Exploration | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Crude Oil | Natural Gas | Dry | Service/ Stratigraphic | Total | Crude Oil | Natural Gas |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| NORTH AMERICA | | | | | | | | |
| Northeast British Columbia | Gross | 2.0 | 19.0 | 6.0 | - | 27.0 | 12.0 | 166.0 |
| | Net | 2.0 | 15.1 | 5.6 | - | 22.7 | 10.9 | 148.0 |
| Northwest Alberta | Gross | 2.0 | 22.0 | 10.0 | - | 34.0 | 19.0 | 165.0 |
| | Net | 2.0 | 15.7 | 9.5 | - | 27.2 | 12.5 | 137.1 |
| Northern Plains | Gross | 18.0 | 110.0 | 31.0 | 129.0 | 288.0 | 504.0 | 175.0 |
| | Net | 13.6 | 90.6 | 28.2 | 128.9 | 261.3 | 470.4 | 128.1 |
| Southern Plains | Gross | 2.0 | 34.0 | 9.0 | - | 45.0 | 6.0 | 154.0 |
| | Net | 2.0 | 29.8 | 8.4 | - | 40.2 | 4.2 | 74.4 |
| Southeast Saskatchewan | Gross | - | - | - | - | - | 84.0 | - |
| | Net | - | - | - | - | - | 72.7 | - |
| Non-core Regions | Gross | - | 2.0 | - | - | 2.0 | 2.0 | 8.0 |
| | Net | - | 0.6 | - | - | 0.6 | 0.5 | 2.2 |
| NORTH SEA UK SECTOR | Gross | - | - | - | - | - | 8.0 | - |
| | Net | - | - | - | - | - | 7.4 | - |
| OFFSHORE WEST AFRICA | Gross | - | - | - | - | - | 7.0 | - |
| | Net | - | - | - | - | - | 4.1 | - |
| TOTAL | Gross | 24.0 | 187.0 | 56.0 | 129.0 | 396.0 | 642.0 | 668.0 |
| | Net | 19.6 | 151.8 | 51.7 | 128.9 | 352.0 | 582.7 | 489.8 |



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, 2008:

| | Natural gas wells | | Crude oil wells | |
|---|---|---|---|---|
| | Gross | Net | Gross | Net |
| NORTH AMERICA | | | | |
| Northeast British Columbia | 1,568 | 1,297.5 | 223 | 191.4 |
| Northwest Alberta | 2,173 | 1,696.6 | 588 | 334.5 |
| Northern Plains | 4,057 | 3,281.8 | 5,800 | 5,276.2 |
| Southern Plains | 7,405 | 6,236.6 | 1,169 | 1,073.3 |
| Southeast Saskatchewan | 2 | 2.0 | 1,239 | 878.7 |
| Non-core regions | 69 | 24.2 | 127 | 23.8 |
| UNITED STATES | 4 | 0.4 | 2 | 0.3 |
| NORTH SEA UK SECTOR | 2 | 0.1 | 111 | 93.8 |
| OFFSHORE WEST AFRICA | | | | |
| Cote d'Ivoire | - | - | 23 | 13.4 |
| Total | 15,280 | 12,539.2 | 9,282 | 7,885.4 |

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

NORTHEAST BRITISH COLUMBIA

[GRAPHIC OMITTED -- Map of Canadian Natural Lands in the NE BC Area]

Significant geological variation extends throughout the productive reservoirs in this region located west of the British Columbia and Alberta border to Prince George, producing light crude oil, NGLs and natural gas.

Crude oil reserves are found primarily in the Halfway formation, while natural gas and associated NGLs are found in numerous carbonate and sandstone formations at depths up to 4,500 vertical meters. The exploration strategy focuses on comprehensive evaluation through two-dimensional seismic, three-dimensional seismic and targeting economic prospects close to existing infrastructure. The region has a mix of low risk multi-zone targets, deep higher risk exploration plays and emerging unconventional shale gas plays. The 2006 acquisition of ACC significantly increased the asset base in this area. The southern portion of this region encompasses the Company's BC Foothills assets where natural gas is produced from the deep Mississippian and Triassic aged reservoirs in this highly deformed structural area.



NORTHWEST ALBERTA

[GRAPHIC OMITTED -- Map of Canadian Natural Lands in the NE AB Area]

This region is located along the border of British Columbia and Alberta west of Edmonton. The majority of the Company's initial holdings in the region were obtained through the 2002 acquisition of Rio Alto Exploration; subsequent to 2002 the Company augmented these holdings with additional land purchases, acquisitions and in 2006 the purchase of the ACC assets. The ACC acquisition added two very prospective properties to this region, Wild River and Peace River Arch. The Wild River assets provide a premium developed and undeveloped land base in the deep basin, multi-zone gas fairway and the Peace River Arch assets provide premium lands in a multi-zone region along with key infrastructure. Northwest Alberta provides exploration and exploitation opportunities in combination with an extensive 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 Company is also pursuing development of a Doig shale gas play in this region. The southern portion provides exploration and development opportunities in the regionally extensive Cretaceous Cardium formation and in the deeper, tight gas formations throughout the region. The Cardium is a complex, tight natural gas reservoir where high

productivity may be achieved due to greater matrix porosity or natural fracturing. The south western portion of this region also contains significant Foothills assets with natural gas produced from the deep Mississippian and Triassic aged reservoirs.

NORTHERN PLAINS

[GRAPHIC OMITTED -- Map of Canadian Natural Lands in the Northern Plains Area]



This region extends just south of Edmonton north to Fort McMurray and from the Northwest Alberta area 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.

Natural gas in this region is produced from shallow, low-risk, multi-zone prospects and more recently from the Horseshoe Canyon CBM. The Company targets low-risk exploration and development opportunities and plans to expand its commercial Horseshoe Canyon CBM project. Evaluation of the potential production of CBM from the Mannville coals commenced in 2006 with the drilling of three horizontal wells. The three well pilot was deemed not commercial and the wells were suspended in 2008.

Near Lloydminster, Alberta, reserves of heavy crude oil (averaging 12(Degree)-14(degree) 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% 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.

The Company's holdings in this region of primary heavy oil production are the result of Crown land purchases and several acquisitions including Sceptre Resources, Ranger Oil and Petrovera, as well as acquisitions from Koch Exploration. Included in this area is the 100% owned ECHO Pipeline system which is a high temperature, insulated crude oil transportation pipeline that eliminates the requirement for field condensate blending. The pipeline, which has a capacity of up to 72,000 bbl/d, 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.

Included in the northern part of this region, approximately 200 miles north of Edmonton, are the Company's holdings at Pelican Lake. These assets produce crude oil from the Wabasca formation with gravities of 14(Degree)-17(Degree) API. Production costs are low due to the absence of sand production, its associated 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 economic development of the large crude oil pool located on the lands, including the 62% owned and operated Pelican Lake Pipeline. The Company holds and controls approximately 75% of the known Wabasca crude oil pool in the Pelican Lake area. It is estimated the Wabasca pool contains approximately four billion barrels of original crude oil in place but is only expected to achieve less than a 5% average recovery factor using primary production on the Company's developed leases. The Company is using an Enhanced Oil Recovery ("EOR") scheme through both water and polymer flooding to increase the ultimate recoveries from the field. To date approximately 11% of the field has been converted to waterflood and there are three producing polymer production wells and 70 polymer injection wells. Pelican Lake production averaged approximately 37,000 bbl/d in 2008 (2007-34,000 bbl/d). The Company is continuing to drill and convert wells to polymer injection in 2009.

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 heavy (10(Degree)-11(Degree)API) crude oil. The two processes employed by the Company are Cyclic Steam Stimulation (CSS) 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 119,500 bbl/d, and the 15% Company owned Cold Lake Pipeline. The Company also holds a 50% 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. Since acquiring the assets from BP Amoco in 1999, the Company has successfully converted the field from low-pressure steaming to high-pressure steaming. This conversion resulted in a significant improvement in well productivity and in ultimate oil recovery. A mature SAGD heavy oil project in which the Company holds a 50% interest is also in operation in the Saskatchewan portion of this region. The Regulatory application for the Kirby In-Situ Oil Sands Project located approximately 85 km northeast of Lac La Biche was submitted in September 2007 outlining the Company's plan to build a 45,000 bbl/d in-situ oil sands project. Final corporate sanction and project scope will be impacted by environmental regulations and their associated costs. Subject to regulatory approval, crude oil pricing, and capital costs, the Company may proceed with the detailed engineering and design work.



In 2007 the Company received regulatory approval for 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 Company began construction in 2007 and first oil production was achieved in late October 2008. The expansion added 40,000 bbl/d of capacity. Subsequent to December 31, 2008, operational issues on one of the pads caused steaming to cease on all well pads resulting in the Company switching from the steaming cycle to the production cycle ahead of schedule. The Company is working on rectifying the issue.

SOUTHERN PLAINS AND SOUTHEAST SASKATCHEWAN

[GRAPHIC OMITTED -- Map of Canadian Natural Lands in the Southern Plans / Saskatchewan Areas]

The Southern Plains area is principally located south of the Northern Plains area to the United States border and extending into western Saskatchewan.

Reserves of natural gas, condensate and light 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. It is economic to drill shallow wells with reduced well spacings in this region despite having smaller overall reserves and lower productivity per well since they achieve a favourable rate of return on capital employed with low drilling costs and long life reserves. The Company's extensive shallow gas assets in this region were augmented by the 2006 acquisition of ACC.

The Company maintains a large inventory of drillable locations on its land base in this region. This region is one of the more mature regions 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 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. This region produces primarily light sour crude oil from as many as seven productive horizons found at depths up to 2,700 meters.



HORIZON OIL SANDS PROJECT

[GRAPHIC OMITTED -- Map of Canadian Natural Lands in the Horizon Oil Sands Project]

Canadian Natural owns a 100% working interest in its Athabasca Oil Sands leases in northern Alberta, of which a portion (being lease 18) is subject to a 5% net carried interest in the bitumen development. The Horizon Project is located on these leases, about 70 kilometers north of Fort McMurray. Figure 1 shows the location of the Horizon Project within Alberta and within the region and Table 1 describes the leases the Company holds in the region.

FIGURE 1 - LOCATION OF THE HORIZON OIL SANDS PROJECT

[GRAPHIC OMITTED -- Map of Horizon Oil Sands Project]
[GRAPHIC OMITTED -- second Map of 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.

The leases being developed for the Horizon Project are 18, 25, 10, 19 and 20. The project site is accessible by a private road as well as a private airstrip.

The project includes surface oil sands mining, bitumen extraction, bitumen upgrading and associated infrastructure. Mining of the oil sands is done using conventional truck and shovel technology. The ore is then processed through extraction and froth treatment facilities to produce bitumen, which is upgraded on-site into 34 O API SCO. The SCO is transported from the site by the Horizon Pipeline to the Edmonton area for distribution. An on-site cogeneration plant provides power and steam for the operation.

In June 2002, Canadian Natural filed an application for regulatory approval of the Horizon Project. 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 the Horizon Project was 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.

Site clearing and pre-construction preparation activities commenced in 2004 and the Company received project sanction by the Board of Directors in February 2005, authorizing management to proceed with Phase 1 of the Horizon Project.

First synthetic crude oil production was achieved on February 28, 2009. Full production capacity for Phase 1 is 110,000 bbl/d of SCO and is expected to be achieved in late 2009.

Subsequent planned expansion through Phases 2/3, further broken down into a series of four Tranches, are being re-profiled in order to attain better cost management.

Horizon Project Phase 1 construction costs were approximately $2.7 billion in 2008 and cumulative construction expenditures were approximately $9.5 billion through the end of 2008. In addition, $364 million of expenditures were incurred for commissioning costs and operating and capital inventory for Phase 1 and capital expenditures of $336 million were incurred for Phases 2 and 3. Forecasted expenditures of $621 million are expected to be incurred in 2009 for remaining Phase 1 construction costs, commissioning and inventory costs, as

well as sustaining capital costs and Tranche 2 expansion. The total construction cost to completion is expected to be 43% over the original $6.8 billion estimate. These expenditures are direct project costs only and do not include capitalized interest, stock based compensation or lease evaluation.

During the fourth quarter 2008, the Company drilled 92 stratigraphic test wells (2007 - 98, 2006 - 163) to further delineate the ore body and confirm resource quality and quantity.



As of year-end 2008, key development achievements associated with the Horizon Project were as follows:

- Phase 1 work progress is 98.9% complete.
- Mine operations has removed 87.8 million bank cubic meters of overburden material.

REGIONAL AND PROJECT GEOLOGY

Lease 18, the main oil sands 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.

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 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 general stratigraphy of the Horizon Project is shown in Figure 2.

FIGURE 2 - GENERAL STRATIGRAPHY OF THE HORIZON OIL SANDS PROJECT

[GRAPHIC OMITTED -- General Stratigraphy]



OIL SANDS MINING RESERVES

The following table sets out Canadian Natural's net reserves, after royalties, of synthetic crude oil from the Horizon Project:

Constant Prices

| | As at December 31, 2008 | |
|---|---|---|
| | Proved Total | Proved and Probable |
| Net reserves, after royalties (mmbbl) | | |
| Synthetic crude oil | 1,946 | 2,944 |

NOTE: SYNTHETIC CRUDE OIL RESERVES ARE BASED ON THE UPGRADING OF BITUMEN USING TECHNOLOGIES IMPLEMENTED AT THE HORIZON PROJECT.

For the year ended December 31, 2008, the Company retained GLJ to evaluate 100% of Phase 1 to Phase 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, NGLs and natural gas reserves. The 2.9 billion barrels of net proved and probable synthetic crude oil reserves shown in the table are produced from 38 years of projected production commencing in 2009.

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 Reserves 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

[GRAPHIC OMITTED --- map]



FIGURE 4 - HORIZON OIL SANDS PROJECT CORE HOLE COVERAGE

[GRAPHIC OMITTED -- map]

UNITED KINGDOM NORTH SEA

[GRAPHIC OMITTED -- map]

Through its wholly owned subsidiary CNR International (U.K.) Limited, formerly Ranger Oil (U.K.) Limited, the Company has operated in the North Sea for over 30 years and has developed a significant database, extensive operating experience and an experienced staff. In 2008, the Company produced from 13 crude oil fields.

The northerly fields are centered around the Ninian Field where the Company has an 87.1% 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% to 100%. The Company also has an interest in the Strathspey Field and 12 licences covering 20 exploration blocks and part blocks surrounding the Ninian and Murchison platforms. The Company also has a 66.5% working interest in the abandoned Hutton Field.

In the central portion of the North Sea, the Company holds a 87.6% operated working interest in the Banff Field and also owns a 45.7% operated working interest in the Kyle Field. Production from the Kyle Field is processed through the Banff FPSO facilities resulting in lower combined production costs from these fields.

The Company holds a 100% operated working interest in T-block (comprising the Tiffany, Toni and Thelma Fields).

The Company 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 2008 two production wells were completed at Murchison and one production well was completed at Ninian with an additional well in progress at Ninian at year end. The Company also drilled one water injection well at Ninian and further increased volumes injected in to the Ninian reservoir.

The Company continued with its planned investment in its long-term facilities and infrastructure strategy and successfully carried our maintenance turnarounds at all five installations during the year. With the Murchison turnaround, the Company implemented a new control system which has resulted in improved platform uptime.

In the first quarter 2009, the Company commenced drilling on Deep Banff a high temperature, high pressure, natural gas exploration well. Upon successful discovery the net interest to the Company increases from 18% to 37%. Results are expected in the second quarter of 2009.

OFFSHORE WEST AFRICA

COTE D'IVOIRE

[GRAPHIC OMITTED]

The Company owns interests in two exploration licences offshore Cote d'Ivoire.

The Company has a 58.7% operated interested in the Espoir Field in Block CI-26 which is located in water depths ranging from 100 to 700 meters. Production from East Espoir commenced in 2002 and development drilling of West Espoir was completed in 2008. Crude oil from the East and West Espoir Fields is produced to an FPSO with the associated natural gas delivered onshore through a subsea pipeline for local power generation. Progress on the Facility Upgrade Project to increase capacity of the FPSO continues and is expected to be completed in third quarter 2009.

The Company also has a 58% interest in the Baobab Field, identified in Block CI-40, which is eight kilometers south of the Espoir facilities. Problems with the control of sand and solids production led to five of the ten production wells at Baobab being shut in during 2007. The Company secured a deepwater rig that was mobilized in early second quarter 2008 which enabled work to begin on the restoration of the shut-in production with three wells being onstream by year end. A fourth and final well is expected to be completed in the second quarter of 2009.

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



GABON

[GRAPHIC OMITTED][GRAPHIC OMITTED]

The Company has a permit comprising a 90% operating interest in the production sharing agreement for the block containing the Olowi Field. The field is located about 20 kilometers from the Gabonese coast and in 30 meters water depth. Delays in construction of the FPSO which arrived on location in February 2009, have resulted in first oil being expected in the first half of 2009. Two appraisal wells and two production wells have been drilled and development activity is continuing. It is planned that in total 28 horizontal production wells plus one gas injector well will be drilled. Crude oil production will rely on a gas cap expansion supplemented by re-injection of the produced solution gas. Production is expected to ramp up to a plateau rate of

approximately 20,000 bbl/d in 2010.



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

For the year ended December 31, 2008, the Company retained a qualified independent reserves evaluator, Sproule Associates Limited ("Sproule"), to evaluate 100% of the Company's conventional proved, as well as proved and probable crude oil, NGLs and natural gas reserves and prepare Evaluation Reports on these reserves. Conventional crude oil, NGLs and natural gas reserves include all of the Company's light/medium, primary heavy, and thermal heavy crude oil, natural gas, coal bed methane and NGLs reserves. They do not include the Company's oil sands mining reserves. The Company has been granted an exemption from certain of the provisions of 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 SEC requirements for certain disclosures required under NI 51-101. There are three principal differences between the two standards. The first is the 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 third is the requirement to disclose a gross reserve reconciliation (before the consideration of royalties). The Company discloses its conventional crude oil, NGLs, and natural gas reserve reconciliations net of royalties in adherence to SEC requirements.

The Company annually discloses proved conventional reserves and the standardized measure of discounted future net cash flows using year-end constant prices and costs as mandated by the SEC in the supplementary crude oil and natural gas information section of the Company's Annual Report and in its annual Form 40-F filing with the SEC. The Company has elected to provide the net present value of these same conventional proved reserves as well as its conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information. Net present values of conventional reserves are based upon discounted cash flows prior to the consideration of income taxes and existing asset abandonment liabili