CANADIAN NATURAL RESOURCES LTD
Form 40-F
April 01, 2010

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, 2009 Commission File Number: 333-12138

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-Eighth 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.

542,327,240 Common Shares outstanding as of December 31, 2009

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 [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (s.232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes __ 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 (File No. 333-162270) 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, 2010, the noon buying rate for Canadian Dollars as expressed by the Federal Reserve Bank of New York was US$1.00 equals C$1.0283.

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, 2009.

B. Audited Annual Financial Statements

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2009 and 2008, 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 17 of the notes to the audited consolidated financial statements.

C. Management's Discussion and Analysis

Canadian Natural's Management's Discussion and Analysis for the year ended December 31, 2009.

Supplementary Oil & Gas Information

For Canadian Natural's Supplementary Oil & Gas Information for the year ended December 31, 2009, see Exhibit 1 of this Annual Report on Form 40-F.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2009

MARCH 25, 2010

TABLE OF CONTENTS

DEFINITIONS AND ABBREVIATIONS

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", "Company", or "Corporation" means Canadian Natura 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

"crude oil, NGLs and natural gas" includes all of the Company's crude oil, synthetic crude oil, bitumen, coal bed methane, NGLs and natural gas reserves “development well” means a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive

“dry well” means an exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well

“exploratory well” means a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir

“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 has a working interest

“gross wells” means the total number of wells in which the Company has a working interest

“Horizon” means Horizon Oil Sands

“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

“net asset value” means the discounted pre-tax value of forecast price proved and probable crude oil and natural gas reserves (net of future development costs and associated material well abandonment costs) plus the value of core undeveloped land, less net debt.

“net wells” refers to gross wells multiplied by the percentage working interest therein owned by the Company

“NYSE” means New York Stock Exchange

“productive well” means an exploratory, development or extension well that is not dry

“PRT” means Petroleum Revenue Tax

“SAGD” means Steam-Assisted Gravity Drainage

“SCO” means Synthetic Crude Oil

“SEC” means United States Securities and Exchange Commission

“TSX” means Toronto Stock Exchange

“undeveloped acreage” refers to lands on which wells have not been drilled or completed to a point that would permit the production of economic quantities of crude oil and natural gas regardless of whether such acreage contains proved reserves.

“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 relating to the Company 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
“project”, “forecast”, “goal”, “guidance”, “outlook”, “effort” “seeks”, “schedule” or expressions of a similar nature suggesti
outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, production volumes, royalties, operating costs, capital expenditures, and other guidance provided in the 2010 outlook section and throughout this document and the documents incorporated herein by reference constitute forward looking statements. Disclosure of plans relating to existing and future developments including but not limited to Horizon, Primrose East, Pelican Lake, Olowi Field (Offshore Gabon), and the Kirby Thermal 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. 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 risks and uncertainties 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 data is presented on a net of royalties basis 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, 2009, the Company retained qualified independent reserves evaluators, Sproule Associates Limited ("Sproule"), and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved, as well as probable crude oil, synthetic crude oil, bitumen, coal bed methane, NGLs and natural gas reserves and prepare Evaluation Reports on these reserves. Sproule evaluated and reviewed all of the Company's crude oil, bitumen, natural gas, coal bed methane and NGLs reserves. GLJ evaluated all of the synthetic crude oil reserves related to the Company's oil sands mine. The Company has been granted an exemption from certain 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 under Regulations S-K and S-X for certain disclosures required under NI 51-101. On December 31, 2008, the SEC released its final rules for the modernization of oil and gas reporting ("Final Rule"). The material changes include the ability to include oil sands mining as an oil and gas activity, ability to use reliable technology to establish undeveloped reserves, the optional ability to report probable reserves, the requirement to track undeveloped locations, as well as the directive to use 12-month average prices and current costs. These resulting changes are more in line with NI 51-101 however there are material differences to the type of volumes disclosed and the basis from which the volumes are determined. NI 51-101 requires gross reserves and future net revenue under forecast pricing and costs, however, the SEC, as discussed, requires disclosure of net reserves, after royalties, under 12-month average prices and current costs. The difference between the reported numbers under the two disclosure standards can be material.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with Sproule and GLJ as to the Company's reserves.

The Company annually discloses proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current 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.

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 Horizon, Primrose East, Pelican Lake, Olowi Field (Offshore Gabon), and the Kirby Thermal 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 the Company's financial condition.

Approximately 26% of the Company's 2009 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 financial condition.

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.

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, NGLs, natural gas, 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 crude 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 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 the Company's financial condition.

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 may 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 in favour of less energy intensive sources, may have a material adverse effect on the Company's financial condition.

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 the form of regulation, 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, compressor optimization to improve fuel gas efficiency, 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 the near term to address industrial GHG emissions, as part of the national GHG reduction target. 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 of the Company's facilities, the Primrose/Wolf Lake in-situ heavy crude oil facilities and the Hays sour natural gas plant, fall under the regulations. The British Columbia carbon tax is currently being assessed at $15/tonne of CO2e on fuel consumed and gas flared in the province. This rate is scheduled to increase to $20/tonne on July 1, 2010, and to $30/tonne by July 1, 2012. As part of its involvement with the Western Climate Initiative, British Columbia has also announced that certain upstream oil and gas facilities will be included in a regional cap and trade system beginning in 2012. It is estimated that six facilities in BC will be included under the cap and trade system, based on a proposed 25 kilotonne of CO2e threshold. Saskatchewan is expected to release GHG regulation in 2010 that may require the North Tangleflags in-situ heavy oil facility to meet a reduction target for its GHG emissions intensity. In the UK, GHG 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 2009 are approximately $26 million.

Legislation to regulate GHGs in the United States through a cap and trade system is currently before the US Congress, although there is no certainty as to the form or stringency of the final legislation. In the absence of legislation, the US Environmental Protection Agency (EPA) is authorized under the Clean Air Act to regulate GHGs, although EPA action would be subject to legal and political challenges. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the US. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oils with higher emissions intensity.

The additional requirements of enacted or proposed GHG legislation on the Company's operations will increase capital expenditures and production expense, especially those related to Horizon and the Company's other existing and planned large oil sands projects. Depending on the legislation enacted, this may have an adverse effect on the Company's financial condition.

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 also result in royalties being paid on a reference price which is higher than the hedged price. There is also increased exposure to 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 Horizon operations are subject to loss of production, potential shutdowns and increased production costs due to the integration of the various component parts, as well as severe winter weather conditions.

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 utilized for the payment of funds to the Company. In the event of the liquidation of any corporate subsidiary, the assets of the subsidiary would be used first to repay the indebtedness of the subsidiary, including trade payables or obligations under any guarantees, prior to being used by the Company to pay its indebtedness.

ENVIRONMENTAL MATTERS

The Company carries out its activities in compliance with all relevant regional, national and international regulations and industry standards. Environmental specialists in 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 conservation program; a program to replace the majority of fresh water for steaming with brackish water; water management programs to improve efficiency of use, recycle rates and water storage; 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; continued evaluation of new technologies to reduce environmental impacts; development of a tailings management plan; and CO2 reduction programs including the injection of CO2 into tailings and for use in enhanced oil recovery. The Company has also established operating standards in the following areas: 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 offshore through cost-effective measures. Canadian Natural participates in both the Canadian federal and provincial regulated GHG emissions reporting 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. Canadian Natural continues to invest in proven and new technologies and in improved operating strategies to help us achieve the Company's overall GHG management goals.

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. 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 continues to focus on reducing GHG emissions through improved efficiency, and on trading mechanisms to ensure compliance with requirements 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 six core principles: improving energy conservation and efficiency; reducing emission intensity; developing and adopting innovative technology and supporting associated research and development; trading capacity, both domestically and globally; offsetting emissions; and considering life cycle costs of emission reductions in decision-making about project development.

The Company continues to implement flaring, venting and fuel and solution gas conservation programs. In 2009 the Company completed approximately 93 gas conservation projects in its primary heavy oil operations, resulting in a reduction of 1.35 million tonnes/year of CO_2e. Over the past five years the Company has spent over $64.3 million in its primary heavy crude oil and in-situ oil sands operations to conserve the equivalent of over 8.7 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. Horizon 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 oil sands tailings.

In its North Sea operations the Company continues to focus on implementing reduction programs based on efficiency audits of its major facilities. A number of CO_2 reduction initiatives were carried out in 2009 including turbine washing on Ninian Northern Platform and an operational focus on reducing flaring. The Produced Water Re-injection on Ninian Central was made permanent in 2008. The Company continues to work at improving produced water quality and reducing oil discharged to sea.

For 2009, the Company's capital expenditures included $48 million for abandonment expenditures (2008 - $38 million).

The Company's estimated undiscounted ARO at December 31, 2009 was as follows:

Estimated ARO, undiscounted ($millions)	2009	2008
North America	$ 3,346	$ 3,072
Oil Sands Mining and Upgrading (1)	1,485	93
North Sea	1,522	1,216
Offshore West Africa	253	93
	6,606	4,474
North Sea PRT recovery	(568)	(529)
	$ 6,038	$ 3,945

(1) Prior period amounts have been reclassified to conform to the presentation adopted in 2009.

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 $568 million (2008 - $529 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 $6,038 million (2008 - $3,945 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 crude oil 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. 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.

Effective January 1, 2009, changes were made to the Alberta royalty regime under the Alberta Royalty Framework (“ARF”). The ARF includes a number of changes to royalty rates for natural gas, conventional crude oil, and oil sands production. Under the ARF, royalties payable are variable according to commodity prices and the productivity and depth of wells. The ARF 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 ARF 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 March 2009, the Government of Alberta announced new incentive programs to stimulate activity in Alberta. These programs provide for:

- A royalty credit of $200 per meter on new conventional crude oil and natural gas wells drilled between April 1, 2009 and March 31, 2010 to a maximum of 10% of conventional Crown royalties paid in Alberta.
- Reduced royalty rates that set the maximum royalty at 5% for the first 12 months of production, up to a maximum of 50,000 boe or 500 mmcfe for new conventional crude oil and natural gas wells that commence production between April 1, 2009 and March 31, 2010.

In June 2009, the Government of Alberta extended the two incentive programs described above by one year, to March 31, 2011.

In March 2010, the Government of Alberta further modified the conventional oil and natural gas royalty rates. These changes, effective January 1, 2011, include:

- Permanently imbedding in the royalty system the reduced royalty rate of a maximum of 5% on new natural gas and conventional oil wells with the same time and volume limits.
- Reducing the maximum royalty rate for conventional crude oil from 50% to 40% and reducing the maximum royalty rate for conventional and unconventional gas from 50% to 36%.

All royalty curves are to be finalized and announced by May 31, 2010.

Effective September 1, 2009, the Province of British Columbia announced an oil and gas stimulus package that includes:

- A one-year, 2% royalty rate for all natural gas wells drilled between September 1, 2009 and June 30, 2010. Qualifying wells must commence production before December 31, 2010.
- A permanent increase of 15% in the existing royalty holiday credits for the Deep Royalty Program.
- A permanent qualification of horizontal wells drilled to a vertical depth between 1,900 and 2,300 meters into the Deep Royalty Program.
- An additional $50 million allocation for the Infrastructure Royalty Credit Programs to stimulate investment in oil and gas roads and pipelines.

In addition to government royalties, the Company is subject to federal and provincial income taxes in Canada at a combined rate of approximately 29% after allowable deductions for 2009.

During 2007, the Canadian Federal Government enacted income tax rate changes which decrease the Federal corporate income tax rate over a five year period. The income tax rate in 2009 was 19%, is 18% in 2010 and decreases 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 Côte 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 Côte 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 (“ACC”), a subsidiary of Anadarko Petroleum Corporation. On November 3, 2006, ACC 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:

	Jurisdiction of Incorporation	% Ownership
Subsidiary		
CanNat Energy Inc.	Delaware	100
CNR (ECHO) Resources Inc.	Alberta	100
CNR International (U.K.) Investments Limited	England	100
CNR International (U.K.) Limited	England	100
CNR International Côte d'Ivoire SARL	Côte d'Ivoire	100
CNR International (Olowi) Limited	Bahamas	100
Horizon Construction Management Ltd.	Alberta	100
Partnership		
Canadian Natural Resources Partnership	Alberta	100
Canadian Natural Resources Northern Alberta Partnership	Alberta	100
Canadian Natural Resources 2005 Partnership	Alberta	100

Canadian Natural, as the managing partner, CNR (ECHO) Resources Inc. and Canadian Natural Resources 2005 Partnership are the partners of Canadian Natural Resources, a general partnership. Canadian Natural, as the managing partner, CNR (ECHO) Resources Inc., Canadian Natural Resources and Canadian Natural Resources 2005 Partnership are partners of Canadian Natural Resources Northern Alberta Partnership, a general partnership. Canadian Natural, as the managing partner, and CNR (ECHO) Resources Inc. are the partners of Canadian Natural Resources 2005 Partnership.

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

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.

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 $71 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 27 transactions to dispose of non-core operated and non-operated properties for proceeds of $110 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. Deliveries under the agreements are expected to commence in 2012 contingent upon Keystone receiving the regulatory approvals for the pipeline expansion and subsequent completion of the expansion.

The Company entered into an agreement in August 2005 to obtain pipeline transportation service for Horizon. 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 site down to the AOSPL Terminal (collectively, the "Horizon Pipeline") will provide crude oil transportation service for Horizon. 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 SCO transportation service for Horizon, while at the same time providing significant quality benefits associated with being the only shipper on the Horizon Pipeline.

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 $356 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 22 transactions to dispose of non-core operated and non-operated properties for proceeds of $20 million.

2009

Construction of Phase 1 of Horizon was completed and commercial operations began.

The Company repaid the $2,350 million remaining on the non-revolving syndicated credit facility related to the 2006 acquisition of ACC and cancelled the facility.

The Company completed 59 transactions in the normal course to acquire additional interests in crude oil and natural gas properties. The aggregate net expenditure of the transactions was $42 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 24 transactions to dispose of non-core operated and non-operated properties and seismic for proceeds of $36 million.

2010 Outlook

In January 2010, the Company announced that, together with North West Upgrading Inc. (“NWU”), it had submitted a joint proposal to the Alberta Government to construct and operate a bitumen refinery near Redwater, Alberta. This proposal was submitted in response to a request for proposal under the Alberta Royalty Framework’s Bitumen Royalty in Kind (BRIK) program. Canadian Natural agreed, subject to a number of conditions, to acquire 50% of the assets of NWU and form a partnership to construct and operate the facility. Closing of the acquisition is targeted for later in 2010 and remains subject to the satisfaction of a number of conditions. Phase 1 of the proposed facility includes a one step conversion process of 50,000 bbl/d of bitumen to finished products and an integrated CO2 management solution. The proposed facility can be expanded in two additional identical phases of 50,000 bbl/d of bitumen, provided economics justify the investment. Canadian Natural has agreed to supply 12,500 bbl/d of its own bitumen production to Phase 1 of the proposed facility.

For 2010, the Company’s overall conventional drilling activity in North America is expected to comprise approximately 93 natural gas wells and 966 crude oil wells, excluding stratigraphic and service wells. Conventional capital expenditures in North America for 2010 are currently expected to be approximately $2.6 billion, excluding property acquisitions and dispositions. Capital expenditures related to Oil Sands Mining and Upgrading are expected to be $738 million excluding capitalized interest.

For 2010, capital expenditures in the North Sea are estimated to be $199 million and are expected to be $264 million for Offshore West Africa.

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, and natural gas 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, 2009, the Company had 3,827 full time equivalent permanent employees in North America and 337 full time equivalent permanent employees in its international operations.

The Company focuses on exploiting its core properties and actively maintaining cost controls. Whenever possible Canadian Natural maintains 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 (14-17º API oil, which receives medium quality crude netbacks due to lower production costs and lower royalty rates), primary heavy crude oil, thermal heavy crude oil and SCO. The Company’s operations are centered 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 38% of 2009 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 21% of 2009 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 26% of 2009 production. SCO accounts for approximately 9% of 2009 production. Pelican Lake crude oil, which accounts for 6% of 2009 production, is produced from the Pelican Lake area in northern 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 11 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 AND NATURAL GAS PROPERTIES

Daily Production

Set forth below is a summary of the crude oil, NGLs and natural gas properties for the fiscal years ended December 31, 2009 and 2008.

	2009 Average Daily Production Rates		2008 Average Daily Production Rates	
Region	Crude oil & NGLs (mbbl)	Natural gas (mmcf)	Crude oil & NGLs (mbbl)	Natural gas (mmcf)
North America				
Northeast British Columbia	5.5	329	5.9	377
Northwest Alberta	14.8	455	16.4	531
Northern Plains	194.6	341	200.7	382
Southern Plains	11.4	158	12.2	177
Southeast Saskatchewan	7.9	3	8.4	3
Oil sands Mining & Upgrading	50.3	-	-	-
Non-core regions	0.3	1	0.2	2
North America Total	284.8	1,287	243.8	1,472
International				
North Sea UK Sector	37.8	10	45.3	10
Offshore West Africa				
Côte d’Ivoire	30.3	18	26.6	13
Gabon	2.6	-	-	-
International Total	70.7	28	71.9	23
Company Total	355.5	1,315	315.7	1,495

Developed and Undeveloped Acreage

The following table summarizes the Company's landholdings as at December 31, 2009.

	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
Region (thousands of acres)	Gross	Net	Gross	Net	Gross	Net	%
North America							
Northeast British Columbia	1,493	1,132	2,838	2,068	4,331	3,200	74
Northwest Alberta	1,229	883	1,531	1,154	2,760	2,037	74
Northern Plains	4,111	3,351	6,696	5,885	10,807	9,236	85
Southern Plains	1,530	1,216	950	804	2,480	2,020	81
Southeast Saskatchewan	93	76	154	139	247	215	87
Thermal In-Situ Oil Sands	29	29	588	486	617	515	83
Oil Sands Mining & Upgrading	1	1	115	115	116	116	100
Non-core regions	42	14	1,341	201	1,383	215	16
North America Total	8,528	6,702	14,213	10,852	22,741	17,554	77
International							
North Sea UK Sector	68	57	184	150	252	207	82
Offshore West Africa							
Côte d'Ivoire	10	6	92	54	102	60	59
Gabon	2	2	150	138	152	140	92
Non-core regions South Africa	-	-	4,002	4,002	4,002	4,002	100
International Total	80	65	4,428	4,344	4,508	4,409	98
Company Total	8,608	6,767	18,641	15,196	27,249	21,963	81

Drilling Activity

Set forth below are summaries of crude oil, NGLs and natural gas drilling activities of the Company for the fiscal years ended December 31, 2009, 2008 and 2007 by geographic region.

		2009									
		Exploratory					Development				
		Crude Oil	Natural Gas	Dry	Service/ Stratigraphic	Total	Crude Oil	Natural Gas	Dry	Service/ Stratigraphic	Total
North America											
Northeast British Columbia	Gross	-	1.0	3.0	-	4.0	-	20.0	1.0	-	21.0
	Net	-	0.5	2.4	-	2.9	-	17.6	1.0	-	18.6
Northwest Alberta	Gross	4.0	24.0	-	-	28.0	4.0	24.0	1.0	-	29.0
	Net	3.5	22.3	-	-	25.8	3.3	23.4	1.0	-	27.7
Northern Plains	Gross	39.0	8.0	6.0	7.0	60.0	601.0	37.0	35.0	203.0	876.0
	Net	38.5	7.1	6.0	7.0	58.6	565.9	27.9	33.5	203.0	830.3
Southern Plains	Gross	3.0	2.0	1.0	-	6.0	5.0	25.0	1.0	1.0	32.0
	Net	2.1	2.0	1.0	-	5.1	3.6	8.3	1.0	1.0	13.9
Southeast Saskatchewan	Gross	3.0	-	-	-	3.0	20.0	-	-	2.0	22.0
	Net	2.1	-	-	-	2.1	18.4	-	-	2.0	20.4
Oil Sands Mining and Upgrading	Gross	-	-	-	-	-	-	-	-	115.0	115.0
	Net	-	-	-	-	-	-	-	-	115.0	115.0
Non-core Regions	Gross	-	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-	-
North America Total	Gross	49.0	35.0	10.0	7.0	101.0	630.0	106.0	38.0	321.0	1,095.0
	Net	46.2	31.9	9.4	7.0	94.5	591.2	77.2	36.5	321.0	1,025.9
North Sea UK Sector	Gross	-	-	1.0	-	1.0	1.0	-	-	-	1.0
	Net	-	-	0.3	-	0.3	0.9	-	-	-	0.9
Offshore West Africa	Gross	-	-	-	-	-	6.0	-	-	1.0	7.0
	Net	-	-	-	-	-	5.2	-	-	0.9	6.1
Company Total	Gross	49.0	35.0	11.0	7.0	102.0	637.0	106.0	38.0	322.0	1,103.0
	Net	46.2	31.9	9.7	7.0	94.8	597.3	77.2	36.5	321.9	1,032.9

Total success rate excluding service and stratigraphic test wells for 2009 is 94% (2008 - 96%, 2007 - 91%)

At December 31, 2009, Canadian Natural was in the process of drilling 10 gross wells (9.5 net wells) in Canada and 1 gross well (0.93 net wells) in Offshore West Africa.

		2008									
		Exploratory					Development				
		Crude Oil	Natural Gas	Dry	Service/ Stratigraphic	Total	Crude Oil	Natural Gas	Dry	Service/ Stratigraphic	Total
North America											
Northeast British Columbia	Gross	-	2.0	2.0	-	4.0	-	26.0	4.0	-	30.0
	Net	-	1.5	1.5	-	3.0	-	22.5	1.9	-	24.4
Northwest Alberta	Gross	1.0	14.0	1.0	-	16.0	14.0	62.0	3.0	3.0	82.0
	Net	0.6	12.6	0.9	-	14.1	8.9	54.0	2.6	2.2	67.7
Northern Plains	Gross	27.0	14.0	5.0	-	46.0	583.0	131.0	22.0	33.0	769.0
	Net	26.3	11.4	5.0	-	42.7	557.3	88.4	21.5	32.4	699.6
Southern Plains	Gross	4.0	6.0	1.0	-	11.0	29.0	153.0	1.0	-	183.0
	Net	4.0	6.0	1.0	-	11.0	26.9	72.8	1.0	-	100.7
Southeast Saskatchewan	Gross	6.0	-	2.0	-	8.0	57.0	-	-	2.0	59.0
	Net	4.6	-	2.0	-	6.6	48.9	-	-	1.7	50.6
Oil Sands Mining and Upgrading	Gross	-	-	-	-	-	-	-	-	92.0	92.0
	Net	-	-	-	-	-	-	-	-	92.0	92.0
Non-core Regions	Gross	-	-	-	-	-	-	3.0	2.0	-	5.0
	Net	-	-	-	-	-	-	0.1	0.4	-	0.5
North America Total	Gross	38.0	36.0	11.0	-	85.0	683.0	375.0	32.0	130.0	1,220.0
	Net	35.5	31.5	10.4	-	77.4	642.0	237.8	27.4	128.3	1,035.5
North Sea UK Sector	Gross	1.0	-	-	-	1.0	2.0	-	1.0	1.0	4.0
	Net	0.8	-	-	-	0.8	1.6	-	0.8	0.9	3.3
Offshore West Africa	Gross	-	-	-	-	-	4.0	-	-	2.0	6.0
	Net	-	-	-	-	-	2.3	-	-	1.8	4.1
Company Total	Gross	39.0	36.0	11.0	-	86.0	689.0	375.0	33.0	133.0	1,230.0
	Net	36.3	31.5	10.4	-	78.2	645.9	237.8	28.2	131.0	1,042.9

		2007									
		Exploratory					Development				
		Crude Oil	Natural Gas	Dry	Service/ Stratigraphic	Total	Crude Oil	Natural Gas	Dry	Service/ Stratigraphic	Total
North America											
Northeast British Columbia	Gross	-	7.0	7.0	-	14.0	3.0	45.0	12.0	-	60.0
	Net	-	7.0	6.0	-	13.0	2.9	35.1	10.1	-	48.1
Northwest Alberta	Gross	1.0	23.0	5.0	-	29.0	21.0	102.0	14.0	2.0	139.0
	Net	1.0	16.4	3.8	-	21.2	12.1	82.1	8.9	1.5	104.6
Northern Plains	Gross	26.0	31.0	20.0	97.0	174.0	545.0	82.0	44.0	49.0	720.0
	Net	23.8	24.7	19.4	97.0	164.9	500.6	70.9	42.4	48.8	662.7
Southern Plains	Gross	1.0	14.0	1.0	-	16.0	19.0	174.0	2.0	1.0	196.0
	Net	1.0	13.4	1.0	-	15.4	18.1	134.1	0.6	1.0	153.8
Southeast Saskatchewan	Gross	1.0	-	-	-	1.0	27.0	-	2.0	4.0	33.0
	Net	1.0	-	-	-	1.0	23.0	-	0.4	4.0	27.4
Oil Sands Mining and Upgrading	Gross	-	-	-	-	-	-	-	-	98.0	98.0
	Net	-	-	-	-	-	-	-	-	98.0	98.0
Non-core Regions	Gross	-	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-	-
North America Total	Gross	29.0	75.0	33.0	97.0	234.0	615.0	403.0	74.0	154.0	1,246.0
	Net	26.8	61.5	30.2	97.0	215.5	556.7	322.2	62.4	153.3	1,094.6
North Sea UK Sector	Gross	-	-	-	-	-	4.0	-	-	4.0	8.0
	Net	-	-	-	-	-	3.7	-	-	3.5	7.2
Offshore West Africa	Gross	-	-	-	-	-	7.0	-	-	1.0	8.0
	Net	-	-	-	-	-	4.1	-	-	0.6	4.7
Company Total	Gross	29.0	75.0	33.0	97.0	234.0	626.0	403.0	74.0	159.0	1,262.0
	Net	26.8	61.5	30.2	97.0	215.5	564.5	322.2	62.4	157.4	1,106.5

Productive Crude Oil & Natural Gas Wells

Set forth below is a summary of the number of gross and net wells of the Company that were producing or mechanically capable of producing as of December 31, 2009.

	Natural gas wells		Crude oil wells		Total wells	
	Gross	Net	Gross	Net	Gross	Net
Canada						
Northeast British Columbia	1,545	1,281.2	218	187.4	1,763	1,468.6
Northwest Alberta	2,138	1,677.5	555	342.4	2,693	2,019.9
Northern Plains	3,788	3,077.9	6,009	5,529.6	9,797	8,607.5
Southern Plains	7,366	6,094.4	1,227	1,121.5	8,593	7,215.9
Southeast Saskatchewan	-	-	1,198	876.6	1,198	876.6
Non-core regions	77	20.9	121	24.8	198	45.7
Total Canada	14,914	12,151.9	9,328	8,082.3	24,242	20,234.2
United States	3	0.3	2	0.3	5	0.6
North Sea UK Sector	2	0.1	108	91.1	110	91.2
Offshore West Africa						
Gabon	-	-	5	4.6	5	4.6
Côte d'Ivoire	-	-	23	13.4	23	13.4
Total	14,919	12,152.3	9,466	8,191.7	24,385	20,344.0

Any reserves data in the following property report is based on the applicable independent engineering report. See the section entitled "Crude Oil, NGLs and Natural Gas Reserves" in this Annual Information Form.

Northeast British Columbia

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

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 RAX; 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

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°-14° API) and natural gas are produced through conventional vertical, slant and horizontal well bores from a number of productive horizons at depths up to 1,000 meters. 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 crude oil production are the result of Crown land purchases and several acquisitions including Sceptre, Ranger 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°-17° 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 28% of the field has been converted to waterflood and there are 227 polymer injection wells supporting approximately 259 production wells. Pelican Lake production averaged approximately 37,000 bbl/d in 2009 (2008-37,000 bbl/d). The Company is continuing to drill and convert wells in 2010 and anticipates approximately 40% of the field will be converted to polymer injection by the end of 2010.

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°-11°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. Canadian Natural is proceeding with the detailed engineering and design work and project sanction and scope is targeted for late 2010.

In 2007, the Company received regulatory approval for its Primrose East expansion, 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. During the first quarter of 2009, 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 formalized and received approval for a plan to begin diagnostic steaming which commenced in August 2009 and is proceeding according to plan with steaming targeted to ramp up again in 2010.

Southern Plains and Southeast Saskatchewan

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.

Oil Sands Mining and Upgrading

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. Horizon is located on these leases, about 70 kilometers north of Fort McMurray. Figure 1 shows the location of Horizon within Alberta and within the region. Figure 2 shows the mining area associated with the reserves and the general layout of the site. Table 1 describes the leases the Company holds in the region.

Figure 1 - Location of Horizon Oil Sands

Figure 2 - Horizon Oil Sands Resource Areas and General Layout

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 6	7597050T06	May 6, 2012	2,584
Lease 7	7597050T07	May 6, 2012	1,144
Lease 10	7400120010	December 14, 2015	3,840
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 25	7401050025	May 17, 2016	1,536
Lease 19	7402050019	May 30, 2017	5,120
Lease 20	7402050020	May 30, 2017	768

(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 Horizon are 18, 25, 10, 19 and 20. The site is accessible by a private road as well as a private airstrip.

Horizon Oil Sands 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 34o API SCO. The upgrader capacity is 110,000 bbl/day of SCO. The SCO is transported from the site by the Horizon Pipeline with a design capacity of 232,000 bbl/day to the Edmonton area for distribution. An on-site cogeneration plant with a design capacity of 115 MW provides power and steam for the operation.

In June 2002, Canadian Natural filed an application with the Energy Resources Conservation Board (ERCB) (formerly the Alberta Energy and Utilities Board) for regulatory approval of Horizon. 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") established by the ERCB and the Government of Canada examined the project in a public hearing in September 2003. The Panel issued its decision report in January 2004, finding Horizon was in the public interest. An Alberta Order-in-Council approval was received from the ERCB 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. In 2009, Canadian Natural submitted an administrative amendment to its ERCB approval to incorporate changes to development timing at Horizon and approval is expected in 2010. A Tailings Management Plan was also submitted to the ERCB in September 2009 and approval is expected in 2010.

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 Horizon.

First SCO production was achieved during 2009 and the Company continues to ramp up to sustainable production of 110,000 bbl/d of SCO which is expected to be achieved in 2010.

Engineering and procurement for Tranche 2 of the Phase 2/3 expansion is progressing with a focus on increasing reliability and uptime. Tranches 3 and 4 of Phase 2/3 continue to be re-profiled with the Company continuing to work on completing its lessons learned from the construction of Phase 1 and implementing these into the development of future expansions.

Regional and Horizon Oil Sands Geology

Lease 18, the main oil sands lease for Horizon, 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 Horizon, 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 clays that reside above the unconformity with the underlying Upper Devonian carbonates (limestone) of the Waterways Formation. The McMurray Formation at the site of Horizon 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 Horizon's oil sands resource is found within the lower and middle McMurray. The general stratigraphy of Horizon is shown in Figure 3.

Figure 3 - General Stratigraphy of Horizon

United Kingdom North Sea

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 2009, 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 an 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 2009, one production well was completed at Ninian. The Company continued to focus on maturing and high grading infill drilling opportunities in preparation for the restart of platform drilling operations in the second quarter of 2010.

The Company continued with its planned investment in its long-term facilities and infrastructure strategy and successfully carried out maintenance turnarounds at four of the five installations during the year.

In the first quarter 2009, the Company commenced drilling on Deep Banff a high temperature, high pressure, natural gas exploration well which did not find commercial hydrocarbons and was plugged and abandoned early in the third quarter of 2009.

Offshore West Africa

Côte d'Ivoire

The Company owns interests in two exploration licences offshore Côte 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 processing capacity of the FPSO has reverted to the original schedule to accommodate effective utilization of the installation vessel at the Olowi Field. Commissioning is targeted to be complete during the second quarter of 2010.

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 2008. A fourth and final well was completed in the second quarter of 2009.

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

Gabon

The Company has a permit comprising a 92.5% 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, resulted in first oil commencing in the second quarter of 2009. Production to date from the first platform is below expectations. The Company is currently reviewing drilling results and production data in order to develop appropriate remediation strategies and determine the impact on future production from the field, the impact on recoverable reserves and the scope of the overall development plan. The Company continues drilling the next scheduled platform with production targeted for the second quarter of 2010.

B. CRUDE OIL, NGLs, AND NATURAL GAS RESERVES

For the year ended December 31, 2009, the Company retained qualified independent reserves evaluators, Sproule Associates Limited ("Sproule"), and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved, as well as probable crude oil, synthetic crude oil, bitumen, coal bed methane, NGLs and natural gas reserves and prepare Evaluation Reports on these reserves. Sproule evaluated and reviewed all of the Company's crude oil, bitumen, natural gas, coal bed methane and NGLs reserves. GLJ evaluated all of the synthetic crude oil reserves related to the Company's oil sands mine. The Company has been granted an exemption from certain 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 under Regulations S-K and S-X for certain disclosures required under NI 51-101. On December 31, 2008, the SEC released its final rules for the modernization of oil and gas reporting ("Final Rule"). The material changes include the ability to include oil sands mining as an oil and gas activity, ability to use reliable technology to establish undeveloped reserves, the optional ability to report probable reserves, the requirement to track undeveloped locations, as well as the directive to use 12-month average prices and current costs. These resulting changes are more in line with NI 51-101 however there are material differences to the type of volumes disclosed and the basis from which the volumes are determined. NI 51-101 requires gross reserves and future net revenue under forecast pricing and costs, however, the SEC, as discussed, requires disclosure of net reserves, after royalties, under 12-month average prices and current costs. The difference between the reported numbers under the two disclosure standards can be material.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with Sproule and GLJ as to the Company's reserves.

The Company annually discloses proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current 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.

There is no assurance that the price and cost assumptions contained in either the 12-month average case or forecast case will be attained and variances could be material.

In the ordinary course of business, the Company has a number of delivery commitments to provide crude oil and natural gas under existing contracts and agreements. The Company has sufficient crude oil and natural gas reserves to meet these commitments.

Summary of Crude Oil, NGLs and Natural Gas Net Reserves

The following tables summarize the evaluations of the reserves as at December 31, 2009.

Reserves Category	Crude Oil & NGLs (mmbbl)	Bitumen (mmbbl)	Synthetic Crude Oil (mmbbl)	Total Liquids (mmbbl)	Natural Gas (bcf)	Total Reserves (mmboe)
PROVED						
Developed:						
North America	204	268	1,589	2,061	2,333	2,450
International						
United Kingdom – North Sea	94	-	-	94	45	101
Offshore West Africa	106	-	-	106	81	120
Total Developed:	404	268	1,589	2,261	2,459	2,671
Undeveloped:						
North America	115	427	61	603	694	719
International						
United Kingdom – North Sea	146	-	-	146	22	149
Offshore West Africa	17	-	-	17	4	18
Total Undeveloped:	278	427	61	766	720	886
TOTAL PROVED:	682	695	1,650	3,027	3,179	3,557

Reserves Category	Crude Oil & NGLs (mmbbl)	Bitumen (mmbbl)	Synthetic Crude Oil (mmbbl)	Total Liquids (mmbbl)	Natural Gas (bcf)	Total Reserves (mmboe)
PROBABLE						
Developed:						
North America	72	23	79	174	709	292
International						
United Kingdom – North Sea	35	-	-	35	8	36
Offshore West Africa	5	-	-	5	26	9
Total Developed:	112	23	79	214	743	337
Undeveloped:						
North America	56	495	783	1,334	256	1,377
International						
United Kingdom – North Sea	112	-	-	112	19	116
Offshore West Africa	51	-	-	51	13	53
Total Undeveloped:	219	495	783	1,497	288	1,546
TOTAL PROBABLE:	331	518	862	1,711	1,031	1,883

Undeveloped Reserves

The Company’s proved undeveloped reserves make up 25% of our 3,557 mmboe proved reserves. In 2009, the Company spent $774 million to convert 135 mmboe of pre-existing undeveloped reserves to developed reserves. The total estimated future capital, based on 2009 costs, required to develop the Company’s 886 mmboe proved undeveloped reserves is $9.4 billion dollars. The total estimated future capital, based on 2009 costs, required to develop the Company’s 1,546 mmboe of probable undeveloped reserves is $3.5 billion dollars.

Reserves which have remained undeveloped for 5 years or more are 363 mmboe of proved undeveloped and 404 mmboe of probable undeveloped. Of these reserves, 354 mmboe proved undeveloped and 402 mmboe probable undeveloped are associated with our long life large project thermal reserves. The remaining undeveloped reserves are associated with our offshore international projects and future uphole potential reserves associated with existing producing well bores.

Sensitivity of Reserves to Prices by Principal Product Type

Price Case	Proved Reserves					
	Crude Oil & NGLs (mmbbl)	Bitumen (mmbbl)	Synthetic Crude Oil (mmbbl)	Total Liquids (mmbbl)	Natural Gas (bcf)	Total Reserves (mmboe)
December 31, 2009 Forecast Pricing	684	652	1,564	2,900	3,491	3,482

Price Case	Probable Reserves					
	Crude Oil & NGLs (mmbbl)	Bitumen (mmbbl)	Synthetic Crude Oil (mmbbl)	Total Liquids (mmbbl)	Natural Gas (bcf)	Total Reserves (mmboe)
December 31, 2009 Forecast Pricing	295	482	820	1,597	1,174	1,793

NOTES

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

2. Bitumen as defined by the SEC, under the Final Rule, “is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis.” Under this definition, all the Company’s primary and thermal heavy crude oil reserves have been reclassified as bitumen. Prior to December 31, 2009, these reserves would have been classified within the Company’s conventional crude oil and NGLs totals.

3. Prior to December 31, 2009, the Company’s Horizon SCO reserves were reported separately in accordance to the SEC’s Industry Guide 7. With SEC’s Final Rule in effect January 1, 2010, for fiscal years ending on or after December 31, 2009, this SCO is now included in the Company’s crude oil and natural gas reserve totals.

4. “Proved” oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. Under the Final Rule it is required that these reserves be evaluated using 12-month average prices and current costs and be disclosed net of royalties. The Company has also provided these reserves using forecast prices and costs in a sensitivity table as permitted by the SEC under the Final Rule.

5. “Developed” oil and gas reserves are reserves of any category that are expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of required equipment is relatively minor to the cost of drilling a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

6.

"Undeveloped" reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where relatively major expenditures are required for the completion of these wells or for the installation of processing and gathering facilities prior to the production of these reserves. Reserves on undrilled acreage are limited to those drilling units directly offsetting development spacing areas that are reasonably certain of production when drilled unless reliable technology exists that establishes reasonable certainty of economic producibilty at greater distances.

7. "Probable" reserves estimates are provided as optional disclosure under the Final Rule. Probable reserves are those additional reserves that are less certain to be recovered than proved, however, together with proved are as likely as not to be recovered. Under the Final Rule it is required that these be evaluated using 12-month average prices and current costs and be disclosed net of royalties. The reserve estimates could be materially different from the quantities ultimately realized. The Company has also provided these reserves using forecast prices and costs in a sensitivity table as permitted by the SEC under the Final Rule.

8. The 12-month average price and current cost case assumes that the 2009 average prices adjusted for quality and transportation, as well as the 2009 costs, are held constant over life. The 12-month average prices are determined by calculating the arithmetic unweighted average of the first-day-of-month price for each month of the 12-month period prior to December 31, 2009. These price assumptions assume the continuance of current laws, regulations and operating costs in effect on the date of the Evaluation Report. Product prices have been held constant at the 2009 values shown below. In addition, operating and capital costs have not been increased on an inflationary basis. The following table outlines the prices calculated and used (based on a foreign exchange rate of US$0.87/C$1.00):

	Natural gas 12-month average price				Crude oil & NGLs 12-month average price				
(Year)	Company average price (C$/mcf)	Henry Hub Louisiana (US$/mmbtu)	AECO (C$/mmbtu)	Huntingdon/Sumas (C$/mmbtu)	Company average price (C$/bbl)	WTI @ Cushing(1) (US$/bbl)	WCS(2) (C$/bbl)	Edmonton Par(3) (C$/bbl)	North Sea Brent (US$/bbl)
2009	4.02	3.87	3.87	3.92	59.39	61.18	58.49	66.07	59.91

(1) "WTI @ Cushing" refers to the price of West Texas Intermediate crude oil at Cushing, Oklahoma.
(2) "WCS" refers to the price of Western Canada Select at Hardisty, Alberta.
(3) "Edmonton Par" refers to the price of light gravity (40° API), low sulphur content crude oil at Edmonton, Alberta.

9. The forecast price and cost case assumes the continuance of current laws and regulations, and any increases in wellhead selling prices also take inflation into account. Sales prices are based on reference prices as detailed below and adjusted for quality and transportation. Capital and operating costs are escalated at 2% per year. Future crude oil, NGLs and natural gas price forecasts were based on Sproule's December 31, 2009 crude oil, NGLs and natural gas pricing model.

The Company's weighted average crude oil and NGLs price and the weighted average natural gas price in the 2009 evaluation for 2010 were $75.92 per barrel and $5.48 per mcf respectively. The crude oil, NGLs and natural gas forecast prices used in the Evaluation Reports are as follows:

	Natural gas				Crude oil & NGLs				
(Year)	Company average price (C$/mcf)	Henry Hub Louisiana (US$/mmbtu)	AECO (C$/mmbtu)	Huntingdon/ Sumas (C$/mmbtu)	Company average price (C$/bbl)	WTI @ Cushing (US$/bbl)	WCS (C$/bbl)	Edmonton Par (C$/bbl)	North Sea Brent (US$/bbl)
2010	5.48	5.70	5.36	5.61	75.92	79.17	74.14	84.25	77.92
2011	6.36	6.48	6.21	6.46	80.82	84.46	78.29	89.99	83.19
2012	6.60	6.70	6.44	6.69	82.83	86.89	76.86	92.61	85.59
2013	7.43	7.43	7.23	7.48	85.32	90.20	78.87	96.19	88.88
2014	8.20	8.12	7.98	8.23	87.11	92.01	79.49	98.13	90.65
2015	8.39	8.28	8.16	8.41	89.18	93.85	81.09	100.11	92.47
2016	8.53	8.45	8.34	8.59	90.73	95.72	82.73	102.13	94.32
2017	8.70	8.62	8.52	8.77	93.64	97.64	84.40	104.19	96.20
2018	8.87	8.79	8.71	8.96	95.97	99.59	86.10	106.30	98.13
2019	9.06	8.96	8.90	9.15	99.53	101.58	87.84	108.44	100.09

2020	9.26	9.14	9.10	9.35	101.42	103.61	89.61	110.63	102.09

Note: Foreign exchange rate used was US$0.92/C$1.00.

10. The estimated total development capital costs, net to the Company, necessary to develop the reported reserves:

	Proved		Probable	
(C$millions)	12-Month Average case	Forecast Price Case	12-Month Average case	Forecast Price Case
2010	2,003	2,033	298	292
2011	2,250	2,382	1,578	1,615
2012	1,868	2,028	2,616	2,735
2013	1,711	1,907	3,552	3,832
2014	1,173	1,331	3,155	3,419
2015	941	1,115	1,557	1,727
2016	1,023	1,200	1,369	1,551
2017	736	894	285	3,331
2018	564	704	309	346
2019	575	701	283	341
2020	533	655	273	376
Thereafter	2,207	30,694	20,500	23,422

11. The Evaluation Reports involved data supplied by the Company with respect to quality, heating value and transportation adjustments, interests owned, royalties payable, operating costs and contractual commitments. This data was found by GLJ and Sproule to be reasonable.

A report on reserves data by the independent qualified reserves evaluators are provided in Schedule "A" to this Annual Information Form. A report by the Company's management and directors on crude oil and natural gas disclosure is provided in Schedule "B" to this Annual Information Form. The Company does not file estimates of its total crude oil and natural gas reserves with any U. S. agency or federal authority other than the SEC.

C. RECONCILIATION OF CHANGES IN NET RESERVES

The following table summarizes the changes during the past year in reserves after deduction of royalties payable to others and using 12-month average prices and costs for 2009 and year end prices and costs for 2008 and 2007.

Crude Oil and NGLs Reserves Reconciliation, Net of Royalties

	North America				International		Total
Net Proved Reserves (mmbbl)	Synthetic Crude Oil(1)	Bitumen	Crude Oil & NGLs	Total	North Sea	Offshore West Africa	
Reserves, December 31, 2007(1)				920	310	128	1,358
Extensions and discoveries				51	-	-	51
Improved recovery				17	6	4	27
Purchases of reserves in place				-	-	-	-
Sales of reserves in place				-	-	-	-
Production				(76)	(17)	(8)	(101)
Economic revisions due to prices				28	(81)	8	(45)
Revisions of prior estimates				8	38	10	56
Reserves, December 31, 2008(1)	–	690	258	948	256	142	1,346
Extensions and discoveries	–	24	6	30	–	–	30
Improved recovery	–	8	75	83	–	–	83
SEC Reliable Technology (2)	–	7	–	7	–	–	7
SEC Rule Transition (3)	1,650	–	–	1,650	–	–	1,650
Purchases of reserves in place	–	–	1	1	–	–	1
Sales of reserves in place	–	–	–	–	–	–	–
Production	–	(49)	(24)	(73)	(14)	(11)	(98)
Economic revisions due to prices	–	(64)	(8)	(72)	57	(4)	(19)
Revisions of prior estimates	–	79	11	90	(59)	(4)	27
Reserves, December 31, 2009	1,650	695	319	2,664	240	123	3,027

Net Probable Reserves (mmbbl)(4)	North America Synthetic Crude Oil (1)	Bitumen	Crude Oil & NGLs	Total	International North Sea	Offshore West Africa	Total
Reserves, December 31, 2007(1)				625	95	58	778
Extensions and discoveries				25	-	-	25
Improved recovery				15	(2)	(4)	9
Purchases of reserves in place				6	-	-	6
Sales of reserves in place				-	-	-	-
Production				-	-	-	-
Economic revisions due to prices				31	36	-	67
Revisions of prior estimates				(51)	14	(5)	(42)
Reserves, December 31, 2008(1)	-	548	103	651	143	49	843
Extensions and discoveries	-	11	5	16	-	-	16
Improved recovery	-	4	37	41	-	-	41
SEC Reliable Technology (2)	-	3	-	3	-	-	3
SEC Rule Transition (3)	862	-	-	862	-	-	862
Purchases of reserves in place	-	-	1	1	-	-	1
Sales of reserves in place	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-
Economic revisions due to prices	-	(71)	5	(66)	(44)	(2)	(112)
Revisions of prior estimates	-	23	(23)	-	48	9	57
Reserves, December 31, 2009	862	518	128	1,508	147	56	1,711

Natural Gas Reserves Reconciliation, Net of Royalties

Net Proved Reserves (bcf)	North America	North Sea	Offshore West Africa	Total
Reserves, December 31, 2007(1)	3,521	81	64	3,666
Extensions and discoveries	140	-	-	140
Improved recovery	52	(1)	6	57
Property purchases	77	-	-	77
Property disposals	(1)	-	-	(1)
Production	(449)	(4)	(4)	(457)
Economic revisions due to prices	(19)	(56)	6	(69)
Revisions of prior estimates	202	47	22	271
Reserves, December 31, 2008(1)	3,523	67	94	3,684
Extensions and discoveries	92	-	-	92
Improved recovery	11	-	-	11
SEC Reliable Technology (2)	-	-	-	-
Property purchases	15	-	-	15
Property disposals	(6)	-	-	(6)
Production	(443)	(4)	(6)	(453)
Economic revisions due to prices	(335)	12	(4)	(327)
Revisions of prior estimates	170	(8)	1	163
Reserves, December 31, 2009	3,027	67	85	3,179

Net Probable Reserves (bcf)(4)	North America	North Sea	Offshore West Africa	Total
Reserves, December 31, 2007(1)	1,081	32	24	1,137
Extensions and discoveries	42	-	-	42
Improved recovery	14	(2)	(6)	6
Property purchases	16	-	-	16
Property disposals	(5)	-	-	(5)
Production	-	-	-	-
Economic revisions due to prices	(8)	(7)	2	(13)
Revisions of prior estimates	(44)	4	17	(23)
Reserves, December 31, 2008(1)	1,096	27	37	1,160
Extensions and discoveries	19	-	-	19
Improved recovery	2	-	-	2
SEC Reliable Technology (2)	-	-	-	-
Property purchases	4	-	-	4
Property disposals	(1)	-	-	(1)
Production	-	-	-	-
Economic revisions due to prices	(94)	(5)	(1)	(100)
Revisions of prior estimates	(61)	5	3	(53)
Reserves, December 31, 2009	965	27	39	1,031

1. Reserves evaluated prior to December 31, 2009 were evaluated based on year end prices and costs. Previous year totals do not include SCO reserves.
2. SEC Reliable Technology accounts for reserves volumes added due to the reserves rule changes to allow booking of undeveloped reserves beyond one spacing unit with supporting geoscience and engineering data. Canadian Natural uses the combination of seismic, well logs, core analysis, production history and analogies to support the booking of undeveloped reserves.
3. SEC Rule Transition accounts for the inclusion of Horizon SCO reserves volume additions as a result of oil sands mining being included as a crude oil and natural gas activity effective December 31, 2009. For continuity purposes, with respect to the transition from Industry Guide 7 into the SEC's Final Rule, the following table has been provided to illustrate the changes in the Company's Horizon SCO reserves for the 2009 year.

Horizon SCO Reserves	Net Proved (mmbbl)	Probable (mmbbl)
Reserves, December 31, 2008	1,946	998
Production	(18)	-
Economic revisions due to prices	(307)	(127)
Revisions of prior estimates	29	(9)
Reserves, December 31, 2009	1,650	862

4. Prior to December 31, 2009, probable reserve estimates were evaluated in accordance with the standards of COGEH.

Information on the Company's crude oil, NGLs and natural gas reserves is provided in accordance with United States FASB Topic 932 "Extractive Activities - Oil and Gas" in the Company's Form 40-F filed with the SEC and in the Company's 2009 Annual Report under "Supplementary Oil and Gas Information" on pages 81 to 87 and is incorporated herein by reference.

D. CRUDE OIL, NGLs, AND NATURAL GAS PRODUCTION

The Company's working interest share and net of royalty share of crude oil, NGLs and natural gas production for the last three financial years is summarized below:

	Year Ended December 31		
Daily Production, before royalties	2009	2008	2007
Crude oil and NGLs production, (bbl/d)			
North America - Conventional	234,523	243,826	246,779
North America – Oil sands Mining and Upgrading	50,250	-	-
North Sea	37,761	45,274	55,933
Offshore West Africa	32,929	26,567	28,520
	355,463	315,667	331,232
Natural gas production (mmcf/d)			
North America	1,287	1,472	1,643
North Sea	10	10	13
Offshore West Africa	18	13	12
	1,315	1,495	1,668
Total Production boe/d	574,730	564,845	609,206

	Year Ended December 31		
Daily Production, net of royalties	2009	2008	2007
Crude oil and NGLs production, (bbl/d)			
North America - Conventional	201,873	207,933	210,769
North America – Oil sands Mining and Upgrading	48,833	-	-
North Sea	37,683	45,182	55,825
Offshore West Africa	29,922	22,641	26,012
	318,311	275,756	292,606
Natural gas production (mmcf/d)			
North America	1,214	1,225	1,378
North Sea	10	10	13
Offshore West Africa	17	11	11
	1,241	1,246	1,402
Total Production boe/d	525,103	483,541	526,193

NETBACKS
INFORMATION BY QUARTER

	2009					2008			
	Q1	Q2	Q3	Q4	Year Ended	Q1	Q2	Q3	Q4
Average daily production volumes, before royalties									
Conventional Crude oil and NGLs (bbl/d)	326,633	306,073	292,363	296,257	305,213	327,217	319,077	306,970	309,570
SCO (bbl/d)	3,384	59,599	66,907	70,194	50,250	-	-	-	-
Natural gas (mmcf/d)	1,369	1,352	1,293	1,250	1,315	1,538	1,526	1,490	1,427
Product netbacks (1)									
Conventional Crude oil and NGLs ($/bbl)									
Sales price (2)	$41.25	$59.56	$62.90	$68.00	$57.68	$78.99	$103.70	$102.30	$45.81
Royalties	3.98	7.27	7.89	7.96	6.73	8.70	14.82	14.17	4.49
Production expenses	15.02	16.59	16.71	15.45	15.92	14.81	16.39	17.61	16.33
Netback	$22.25	$35.70	$38.30	$44.59	$35.03	$55.48	$72.52	$70.52	$24.99
SCO ($/bbl)									
Sales price (2)	$-	$65.40	$69.11	$76.33	$70.83	$-	$-	$-	$-
Royalties	-	0.76	2.19	3.06	2.15	-	-	-	-
Production expenses		42.65	36.85	41.21	39.89	-	-	-	-
Netback	$-	$21.99	$30.07	$32.06	$28.79	$-	$-	$-	$-
Natural gas ($/mcf)									
Sales price (2)	$5.46	$4.11	$3.80	$4.75	$4.53	$7.77	$9.89	$8.82	$7.03
Royalties(3)	0.72	0.06	0.13	0.35	0.32	1.35	1.86	1.55	1.08
Production expenses	1.18	1.05	1.05	1.03	1.08	1.03	0.94	1.05	1.06
Netback	$3.56	$3.00	$2.62	$3.37	$3.13	$5.39	$7.09	$6.22	$4.89
Conventional Crude oil and NGLs netbacks by type(1)									
Light/Medium/Pelican Lake/NGLs ($/bbl)									
Sales price (2)	$47.93	$60.87	$65.58	$70.82	$61.37	$89.68	$114.69	$107.33	$53.16
Royalties	4.94	6.70	9.27	7.96	7.20	11.43	14.59	15.84	5.71
Production expenses	15.02	16.87	17.48	16.79	16.53	15.09	16.13	17.18	17.92
Netback	$27.97	$37.30	$38.83	$46.07	$37.64	$63.15	$83.97	$74.30	$29.53

Primary and Thermal Heavy crude oil ($/bbl)										
Sales price (2)	$34.80	$58.14	$60.08	$64.73	$53.76	$67.46	$92.55	$97.20	$38.21	$
Royalties	3.06	7.89	6.43	7.97	6.23	5.74	15.05	12.47	3.22	
Production expenses	15.02	16.29	15.91	13.89	15.27	14.50	16.65	18.05	14.68	
Netback	$16.72	$33.96	$37.74	$42.87	$32.26	$47.22	$60.85	$66.68	$20.31	$

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of transportation and blending costs and excluding risk management activities.

(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

NETBACKS
INFORMATION BY QUARTER

	2007				
	Q1	Q2	Q3	Q4	Year Ended
Average daily production volumes, before royalties					
Conventional Crude oil and NGLs (bbl/d)	327,001	327,494	333,062	337,240	331,232
Natural gas (mmcf/d)	1,717	1,722	1,647	1,589	1,668
Product netbacks(1)					
Conventional Crude oil and NGLs ($/bbl)					
Sales price (2)	$51.71	$53.74	$58.10	$58.03	$55.45
Royalties	4.92	5.46	6.65	6.66	5.94
Production expenses	13.81	15.01	13.13	11.53	13.34
Netback	$32.98	$33.27	$38.32	$39.84	$36.17
Natural gas ($/mcf)					
Sales price (2)	$7.74	$7.44	$5.87	$6.28	$6.85
Royalties	1.48	1.10	0.89	0.94	1.11
Production expenses	0.97	0.89	0.88	0.91	0.91
Netback	$5.29	$5.45	$4.10	$4.43	$4.83
Conventional Crude oil and NGLs netbacks by type(1)					
Light/Medium/Pelican Lake/NGLs ($/bbl)					
Sales price (2)	$60.19	$64.10	$67.34	$72.62	$65.99
Royalties	4.89	5.87	7.24	8.34	6.57
Production expenses	13.85	14.91	14.40	12.64	13.95
Netback	$41.45	$43.32	$45.70	$51.64	$45.47
Primary and Thermal Heavy crude oil ($/bbl)					
Sales price (2)	$41.24	$41.85	$48.10	$43.06	$43.66
Royalties	4.96	4.98	6.00	4.95	5.23
Production expenses	13.76	15.12	11.75	10.38	12.66
Netback	$22.52	$21.75	$30.35	$27.73	$25.77

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

	2009					2008				
	Q1	Q2	Q3	Q4	Year Ended	Q1	Q2	Q3	Q4	Year Ended
SEGMENTED										
North America product netbacks(1)										
Light/Medium/Pelican Lake/NGLs ($/bbl)										
Sales price (2)	$ 42.39	$57.67	$60.06	$65.80	$56.38	$82.25	$107.38	$102.17	$44.21	$84.00
Royalties	7.37	10.49	12.75	13.21	10.93	16.40	21.68	21.29	8.80	17.20
Production expenses	13.80	13.54	14.00	12.67	13.51	12.80	13.32	13.17	13.68	13.24
Netback	$ 21.22	$33.64	$33.31	$39.92	$31.94	$53.05	$72.38	$67.70	$21.73	$53.72
Primary and Thermal Heavy crude oil ($/bbl)										
Sales price (2)	$ 34.80	$58.14	$60.08	$64.73	$53.76	$67.46	$92.55	$97.20	$38.21	$73.62
Royalties	3.06	7.89	6.43	7.97	6.23	5.74	15.05	12.47	3.22	9.08
Production expenses	15.02	16.29	15.91	13.89	15.27	14.50	16.65	18.05	14.68	15.95
Netback	$ 16.72	$33.96	$37.74	$42.87	$32.26	$47.22	$60.85	$66.68	$20.31	$48.59
SCO ($/bbl)										
Sales price (2)	$ -	$65.40	$69.11	$76.33	$70.83	$-	$-	$-	$-	$-
Royalties	-	0.76	2.19	3.06	2.15	-	-	-	-	-
Production expenses	-	42.65	36.85	41.21	39.89	-	-	-	-	-
Netback	$ -	$21.99	$30.07	$32.06	$28.79	$-	$-	$-	$-	$-
Natural gas ($/mcf)										
Sales price (2)	$ 5.46	$4.06	$3.76	$4.75	$4.51	$7.74	$9.89	$8.76	$6.94	$8.41
Royalties(3)	0.73	0.05	0.12	0.35	0.32	1.36	1.88	1.55	1.09	1.47
Production expenses	1.17	1.04	1.04	1.01	1.07	1.01	0.98	1.03	1.04	1.00
Netback	$ 3.56	$2.97	$2.60	$3.39	$3.12	$5.37	$7.08	$6.18	$4.81	$5.88

North Sea product netbacks(1)										
Light crude oil ($/bbl)										
Sales price (2)	$ 54.67	$65.52	$75.91	$78.89	$68.84	$99.01	$129.57	$109.82	$63.07	$100.31
Royalties	0.13	0.11	0.16	0.15	0.14	0.91	0.27	0.24	0.12	0.21
Production expenses	22.39	27.36	31.30	27.03	26.98	22.35	25.61	29.21	28.77	26.29
Netback	$ 32.15	$38.05	$44.45	$51.71	$41.72	$76.47	$103.69	$80.37	$34.18	$73.81
Natural Gas ($/mcf)										
Sales price (2)	$ 4.28	$3.84	$5.70	$4.94	$4.66	$3.30	$4.27	$3.65	$5.19	$4.09
Royalties						-	-	-	-	-
Production expenses	1.86	1.62	1.57	3.23	2.16	2.33	2.68	3.09	1.96	2.51
Netback	$ 2.42	$2.22	$4.13	$1.71	$2.50	$0.97	$1.59	$0.56	$3.23	$1.58
Offshore West Africa product netbacks(1)										
Light crude oil ($/bbl)										
Sales price (2)	$ 54.27	$63.00	$70.05	$72.88	$65.27	$96.31	$114.56	$125.71	$65.80	$97.96
Royalties	3.73	5.82	8.94	5.24	5.79	17.43	14.49	26.90	4.71	14.81
Production expenses	11.39	10.45	13.35	15.26	12.83	8.03	9.79	7.74	14.47	10.29
Netback	$ 39.15	$46.73	$47.76	$52.38	$46.65	$70.85	$90.28	$91.07	$46.62	$72.86
Natural Gas ($/mcf)										
Sales price (2)	$ 6.68	$7.34	$5.72	$5.04	$6.11	$7.89	$8.97	$11.18	$12.54	$10.03
Royalties	0.46	0.63	0.74	0.27	0.53	1.43	1.13	2.24	1.26	1.52
Production expenses	1.70	1.36	1.37	0.70	1.23	1.25	1.27	1.58	2.51	1.61
Netback	$ 4.52	$5.35	$3.61	$4.07	$4.35	$5.21	$6.57	$7.36	$8.77	$6.90

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.
(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

	2007				
	Q1	Q2	Q3	Q4	Year Ended
SEGMENTED					
North America product netbacks(1)					
Light/Medium/Pelican Lake/NGLs ($/bbl)					
Sales price (2)	$54.13	$56.06	$60.26	$63.94	$58.66
Royalties	8.84	9.22	11.55	12.56	10.57
Production expense	11.74	12.11	11.58	10.82	11.56
Netback	$33.55	$34.73	$37.13	$40.56	$36.53
Primary and Thermal Heavy crude oil ($/bbl)					
Sales price (2)	$41.24	$41.85	$48.10	$43.06	$43.66
Royalties	4.96	4.98	6.00	4.95	5.23
Production expense	13.76	15.12	11.75	10.38	12.66
Netback	$22.52	$21.75	$30.35	$27.73	$25.77
Natural gas ($/mcf)					
Sales price (2)	$7.79	$7.47	$5.88	$6.31	$6.87
Royalties	1.50	1.11	0.90	0.95	1.12
Production expense	0.95	0.87	0.87	0.90	0.90
Netback	$5.34	$5.49	$4.11	$4.46	$4.85
North Sea product netbacks(1)					
Light crude oil ($/bbl)					
Sales price (2)	$68.83	$73.18	$77.55	$83.44	$74.99
Royalties	0.13	0.13	0.14	0.19	0.14
Production expense	18.57	22.11	23.61	18.95	20.78
Netback	$50.13	$50.94	$53.80	$64.30	$54.07
Natural gas ($/mcf)					
Sales price (2)	$4.49	$3.92	$5.26	$3.62	$4.26
Royalties	-	-	-	-	-
Production expense	2.58	2.26	2.29	1.50	2.17
Netback	$1.91	$1.66	$2.97	$2.12	$2.09
Offshore West Africa product netbacks(1)					
Light crude oil ($/bbl)					
Sales price (2)	$58.60	$72.84	$70.52	$81.89	$71.68
Royalties	3.70	7.12	6.81	7.59	6.40
Production expense	8.93	7.98	7.00	9.32	8.32
Netback	$45.97	$57.74	$56.71	$64.98	$56.96
Natural gas ($/mcf)					
Sales price (2)	$5.97	$6.22	$5.31	$5.49	$5.68
Royalties	0.38	0.59	0.51	0.52	0.51
Production expense	1.48	1.10	1.39	1.89	1.48
Netback	$4.11	$4.53	$3.41	$3.08	$3.69

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

E. NET CAPITAL EXPENDITURES

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

NET CAPITAL EXPENDITURES BY YEAR (1)

	Year Ended December 31	
($ millions)	2009	2008
Net property acquisitions (dispositions)	$6	$336
Land acquisition and retention	77	86
Seismic evaluations	73	107
Well drilling, completion and equipping	1,244	1,664
Production and related facilities	977	1,282
Total net reserve replacement expenditures	2,377	3,475
Oil Sands Mining and Upgrading		
Horizon Phase 1 construction costs	69	2,732
Horizon Phase 1 commissioning and other costs	202	364
Horizon Phase 2/3 costs	104	336
Capitalized interest, stock-based compensation and other	98	480
Sustaining Capital	80	-
Total Oil Sands Mining and Upgrading (2)	553	3,912
Midstream	6	9
Abandonments (3)	48	38
Head office	13	17
Total net capital expenditures	$2,997	$7,451

NET CAPITAL EXPENDITURES BY QUARTER (1)

	2009 Three Months Ended			
($ millions)	Mar 31	Jun 30	Sep 30	Dec 31
Net property acquisitions (dispositions)	$27	(2)	(30)	11
Land acquisition and retention	13	18	18	28
Seismic evaluation	28	11	21	13
Well drilling, completion and equipping	498	194	261	291
Production and related facilities	290	230	235	222
Total net reserve replacement expenditures	856	451	505	565
Oil Sands Mining and Upgrading				
Horizon Phase 1 construction costs	128	(59)	-	-
Horizon Phase 1 commissioning and other costs	156	46	-	-
Horizon Phase 2/3 costs	19	22	21	42
Capitalized interest, stock-based compensation and other	79	(4)	11	12
Sustaining Capital	-	4	23	53
Total Oil Sands Mining and Upgrading (2)	382	9	55	107
Midstream	5	-	-	1
Abandonments (3)	9	10	12	17
Head office	4	3	2	4
Total net capital expenditures	$1,256	473	574	694

NET CAPITAL EXPENDITURES BY QUARTER (1)

	2008 Three Months Ended			
($ millions)	Mar 31	Jun 30	Sep 30	Dec 31
Net property acquisitions (dispositions)	$(8)	$263	$47	$34
Land acquisition and retention	12	24	32	18
Seismic evaluation	27	18	40	22
Well drilling, completion and equipping	452	286	421	505
Production and related facilities	319	270	311	382
Total net reserve replacement expenditures	802	861	851	961
Oil Sands Mining and Upgrading				
Horizon Phase 1 construction costs	665	875	635	557
Horizon Phase 1 commissioning and other costs	91	48	111	115
Horizon Phase 2/3 costs	77	82	83	94
Capitalized interest, stock-based compensation and other	109	247	46	78
Sustaining Capital	-	-	-	-
Total Oil Sands Mining and Upgrading (2)	941	1,252	875	844
Midstream	1	3	2	3
Abandonments (3)	6	7	10	15
Head office	3	4	6	4
Total net capital expenditures	$1,753	$2,127	$1,744	$1,827

(1) Net capital expenditures exclude adjustments related to differences between carrying value and tax value, and other fair value adjustments.
(2) Net capital expenditures for the Oil Sands Mining and Upgrading assets also include the impact of intersegment eliminations.
(3) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

F. DEVELOPED AND UNDEVELOPED ACREAGE

The following table summarizes the Company's working interest holdings in core region developed and undeveloped acreage as at December 31, 2009:

(thousands)	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
North America						
Alberta	6,255	5,003	9,238	7,901	15,493	12,904
British Columbia	1,485	1,125	2,814	2,046	4,299	3,171
Saskatchewan	739	554	803	687	1,542	1,241
Manitoba	7	6	17	17	24	23
North Sea						
United Kingdom	68	57	184	150	252	207
Offshore West Africa						
Côte d'Ivoire	10	6	92	54	102	60
Gabon	2	2	150	138	152	140
Total	8,566	6,753	13,298	10,993	21,864	17,746

SELECTED FINANCIAL INFORMATION

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

	Year Ended Dec 31	
($ millions, except per common share information)	2009	2008
Revenues, before royalties	$11,078	$16,173
Net earnings	$1,580	$4,985
Per common share - basic and diluted	$2.92	$9.22
Adjusted net earnings from operations (1)	$2,689	$3,492
Per common share - basic and diluted	$4.96	$6.46
Cash flow from operations (1)	$6,090	$6,969
Per common share - basic and diluted	$11.24	$12.89
Total assets	$41,024	$42,650
Total long-term liabilities	$19,193	$20,856

(1) These non-GAAP measures are reconciled to net earnings as determined in accordance with Canadian GAAP in the "Financial Highlights" section of the Company's MD&A which is incorporated by reference into this document.

	2009 Three Months Ended			
($ millions, except per common share information)	Mar 31	Jun 30	Sep 30	Dec 31
Revenues, before royalties	$ 2,186	2,750	2,823	3,319
Net earnings (loss)	$ 305	162	658	455
Per common share - basic and diluted	$ 0.56	0.30	1.21	0.85

	2008 Three Months Ended			
($ millions, except per common share information)	Mar 31	Jun 30	Sep 30	Dec 31
Revenues, before royalties	$ 3,967	$ 5,112	$ 4,583	$ 2,511
Net earnings	$ 727	$ (347)	$ 2,835	$ 1,770
Per common share - basic and diluted	$ 1.35	$ (0.65)	$ 5.25	$ 3.27

CAPITAL STRUCTURE

Common Shares

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

Preferred Shares

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

Credit Ratings

Credit ratings accorded to the Company's debt securities are not recommendations to purchase, hold or sell the debt securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant, and if any such rating is so revised or withdrawn, we are under no obligation to update this Annual Information Form.

Canadian Natural's senior unsecured debt securities are rated "Baa2" with a stable outlook by Moody's Investor's Service, Inc. ("Moody's"), "BBB" by Standard & Poor's Corporation ("S&P") and "BBB (high)" with a stable trend by DBRS Limit ("DBRS"). S&P assigns a rating outlook to Canadian Natural and not to individual debt instruments. S&P has assigned a stable outlook to Canadian Natural. Credit ratings are intended to provide investors with an independent measure of credit quality of any issue of securities.

Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. A rating of Baa2 by Moody's is within the fourth highest of nine categories and is assigned to debt securities which are considered medium-grade obligations, i.e., they are subject to moderate credit risk. Such securities may possess certain speculative characteristics. Moody's applies numerical modifiers 1, 2 and 3 in each generic rating classification from Aa through Caa in its corporate bond rating system. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the issue ranks in the lower end of its generic rating category. A Moody's rating outlook is an opinion regarding the likely direction of a rating over the medium term.

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

DBRS' credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the DBRS rating system, debt securities rated BBB are of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its related securities. The assignment of a "high" or "low" modifier within each rating category indicates relative standing within such category. The rating trend is DBRS' opinion regarding the outlook for the rating.

MARKET FOR CANADIAN NATURAL RESOURCES LIMITED SECURITIES

The Company’s common shares are listed and posted for trading on Toronto Stock Exchange (“TSX”) and the New York Stock Exchange (“NYSE”) under the symbol CNQ.

2009 Monthly Historical Trading on TSX

Month	High	Low	Close	Volume Traded
January	$57.20	41.06	43.89	51,057,171
February	$48.44	36.50	40.90	50,126,029
March	$53.50	35.85	48.91	72,570,396
April	$61.15	47.70	55.01	46,587,159
May	$65.69	55.27	64.71	45,089,003
June	$68.69	54.08	61.19	43,417,767
July	$66.19	52.71	64.76	37,118,226
August	$68.54	61.55	62.71	29,996,464
September	$76.91	60.65	72.30	44,597,734
October	$79.00	67.38	70.22	33,029,358
November	$73.15	66.51	70.47	35,763,690
December	$76.46	65.97	76.00	30,807,147

On March 3, 2010 the Company’s Board of Directors approved a resolution to file with the Toronto Stock Exchange a Notice of Intention to purchase by way of normal course issuer bid up to 2.5% of its issued and outstanding common shares. Subject to acceptance by the TSX of the Notice of Intention, the purchases would be made through the facilities of the TSX and the NYSE.

Also on March 3, 2010, the Company announced its intention to subdivide the Company’s common shares on a two for one basis, subject to shareholder approval. The proposal will be voted on at the Company’s Annual and Special Meeting of Shareholders to be held on May 6, 2010.

DIVIDEND HISTORY

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

The following table shows the aggregate amount of the cash dividends declared per common share of the Company and accrued in each of its last three years ended December 31.

	2009	2008	2007
Cash dividends declared per common share	$0.42	$0.40	$0.34

In March 2010, the Board of Directors approved a 43% increase in the 2009 quarterly dividend from $0.105 per common share to $0.15 per common share, effective with the April 1, 2010 payment.

TRANSFER AGENTS AND REGISTRAR

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

DIRECTORS AND OFFICERS

The names, municipalities of residence, offices held with the Company and principal occupations of the directors and officers of the Company are set forth below. Further detail on the Directors and Named Executive Officers are found in the Company's Information Circular dated March 17, 2010 incorporated by reference.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Catherine M. Best, FCA, ICD.D Calgary, Alberta Canada	Director (2)(4)(5) (age 56)	Corporate Director. Until May 2009, Interim Chief Financial Officer of Alberta Health Services which was formed in 2008 when the Alberta government consolidated all of the health regions of the province under one board. Executive Vice-President, Risk Management and Chief Financial Officer of the Calgary Health Region (fully integrated publicly funded health care system) from 2002 to 2008; has served continuously as a director of the Company since November 2003. Currently serving on the board of directors of Enbridge Income Fund and Superior Plus Income Fund. She is also a member of the Board of the Alberta Children's Hospital Foundation and serves as a volunteer member of the Audit Committee of the Calgary Exhibition and Stampede.
N. Murray Edwards Calgary/Banff, Alberta Canada	Vice-Chairman and Director (3) (age 50)	President, Edco Financial Holdings Ltd. (private management and consulting company). Has served continuously as a director of the Company since September 1988. Currently is Chairman and serving on the board of directors of Ensign Energy Services Inc. and Magellan Aerospace Corporation.
Honourable Gary A. Filmon, P.C., O.C., O.M. Winnipeg, Manitoba Canada	Director (1)(2) (age 67)	Consultant, The Exchange Group (business consulting firm). Has served continuously as a director of the Company since February 2006. Currently serving on the board of directors of MTS Allstream Inc., Arctic Glacier Income Trust, Exchange Income Corporation, Wellington West Capital Inc. and FWS Construction Inc. and serves as Chair of Canada's Security and Intelligence Review Committee.
Ambassador Gordon D. Giffin Atlanta, Georgia USA	Director (1)(2)(3) (age 60)	Senior Partner, McKenna Long & Aldridge LLP (law firm) since May 2001. Has served continuously as a director of the Company since May 2002. Currently serving on the board of directors of Canadian National Railway Company, Canadian Imperial Bank of Commerce, Just Energy Corp., and Transalta Corporation.
John G. Langille		

Calgary, Alberta Canada	Vice-Chairman and Director (age 64)	Officer of the Company. Has served continuously as a director of the Company since June 1982.
Steve W. Laut Calgary, Alberta Canada	President and Director (age 52)	Officer of the Company. Has served continuously as a director of the Company since August 2006.
Keith A.J. MacPhail Calgary, Alberta Canada	Director (3)(5) (age 53)	Chairman and Chief Executive Officer, Bonavista Energy Trust (oil and gas energy trust) since November 1997 and Chairman, NuVista Energy Ltd. (an oil and gas exploration, development and production company) since July 2003. Has served continuously as a director of the Company since October 1993. Currently serving on the board of directors of Bonavista Energy Trust and NuVista Energy Ltd.

Allan P. Markin, O.C. Calgary, Alberta Canada	Chairman and Director (5) (age 64)	Chairman of the Company. Has served continuously as a director of the Company since January 1989.
Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C. Cap Pelé, New Brunswick Canada	Director (1)(4) (age 62)	Deputy Chair, TD Bank Financial Group (financial services). Counsel to Atlantic Canada law firm McInnes Cooper from 1998 to 2005, and most recently Canadian Ambassador to the United States from 2005 to 2006. He has served continuously as a director of the Company since August 2006. Currently serving on the board of directors of Brookfield Asset Management Inc.
James S. Palmer, C.M., A.O.E., Q.C. Calgary, Alberta Canada	Director (3)(4)(5) (age 81)	Chairman and a Partner of Burnet, Duckworth & Palmer LLP (law firm). Has served continuously as a director of the Company since May 1997. Currently serving on the board of directors of Magellan Aerospace Corporation and is Director Emeritus of Frontier Oil Corporation.
Dr. Eldon R. Smith, O.C., M.D. Calgary, Alberta Canada	Director (4)(5) (age 70)	President of Eldon R. Smith & Associates Ltd., (a private health care consulting company), and Emeritus Professor of Medicine and Former Dean, Faculty of Medicine, University of Calgary. Has served continuously as a director of the Company since May 1997. Currently serving on the board of directors of Intellipharmaceutics International Inc. and Aston Hill Financial.
David A. Tuer Calgary, Alberta Canada	Director (1)(2)(3) (age 60)	Vice-Chairman and Chief Executive Officer of Marble Point Energy Ltd. (private oil and gas exploration company); Chairman, Calgary Health Region from 2001 to 2008 and Executive Vice-Chairman BA Energy Inc. from April 2005 to February 2008 when it was acquired by its parent company Value Creations Inc. through a Plan of Arrangement and which until recently was engaged in the development, building and operations of a merchant heavy oil upgrader in Northern Alberta for the purpose of upgrading bitumen and heavy oil feedstock into high-quality crude oils. Prior thereto President, CEO and a director of Hawker Resources Inc. from January 2003 to March 2005. Has served continuously as a director of the Company since May 2002. Currently serving on the board of directors of Daylight Resources Trust, Xtreme Coil Drilling Corp., Canadian Phoenix Resources and Altalink Management LLP., a private limited partnership.
Jeffrey J. Bergeson Calgary, Alberta	Vice-President, Exploitation West	Officer of the Company since May 2007; prior thereto Exploitation Manager of the Company.

Canada	(age 53)	
Corey B. Bieber Calgary, Alberta Canada	Vice-President, Finance and Investor Relations (age 46)	Officer of the Company since April 2005; prior thereto Director, Investor Relations of the Company from July 2002 to April 2005 and most recently Vice-President, Investor Relations April 2005 to February 2007.
Mary-Jo E. Case Calgary, Alberta Canada	Vice-President, Land (age 51)	Officer of the Company.
William R. Clapperton Calgary, Alberta Canada	Vice-President, Regulatory, Stakeholder and Environmental Affairs (age 47)	Officer of the Company.

James F. Corson Calgary, Alberta Canada	Vice-President, Human Resources, Horizon (age 59)	Officer of the Company since January 2007; prior thereto Vice-President, Human Resources of Qatar Petroleum Corp. from March 1997 to July 2005 and most recently Director Human Resources and Stakeholder Relations of the Company from July 2005 to 2007.
Réal M. Cusson Calgary, Alberta Canada	Senior Vice-President, Marketing (age 59)	Officer of the Company.
Randall S. Davis Calgary, Alberta Canada	Vice-President, Finance & Accounting (age 43)	Officer of the Company.
Réal J. H. Doucet Calgary, Alberta Canada	Senior Vice-President, Horizon Projects (age 57)	Officer of the Company.
Allan E. Frankiw Calgary, Alberta Canada	Vice-President, Production, Central (age 53)	Officer of the Company since March 2007; prior thereto Manager Midstream for Anadarko Canada Corporation from November 1998 to March 2005, Manager Facilities & Construction for Anadarko Canada Corporation from April 2005 to November 2006, and most recently Production Manager, Edson of the Company from November 2006 to March 2007.
Tim Hamilton Calgary, Alberta Canada	Vice-President, Developments (age 54)	Officer of the Company since February 2010; prior thereto Manager Production, Southern Alberta from 2000 to 2006, Manager Production, Southern Alberta, S.E. Saskatchewan and Manitoba 2006 to 2007, Manager Production, British Columbia South 2007 to September 2009 and most recently Manager Production, British Columbia from September 2009 to February 2010.
Peter J. Janson Calgary, Alberta Canada	Senior Vice-President, Horizon Operations (age 52)	Officer of the Company.
Terry Jocksch Calgary, Alberta Canada	Senior Vice-President, Thermal and International (age 42)	Officer of the Company since June 2009; prior thereto Exploitation Manager of the Company to April 2004, Vice-President Exploitation West April 2004 to May 2007, and most recently Managing Director, International May 2007 to June 2009.
Philip A. Keele Calgary, Alberta Canada	Vice-President, Mining, Horizon Oil Sands Project	Officer of the Company.

	(age 50)	
Allen M. Knight Calgary, Alberta Canada	Senior Vice-President, International & Corporate Development (age 60)	Officer of the Company.
Cameron S. Kramer Calgary, Alberta Canada	Senior Vice-President, North America Operations (age 42)	Officer of the Company.
Ronald K. Laing Calgary, Alberta Canada	Vice-President, Commercial Operations (age 40)	Officer of the Company since March 2009; prior thereto Manager, Commercial Operations of the Company from April 2004 to March 2009.

Reno G. Laseur Fort McMurray, Alberta Canada	Vice-President, Upgrading (age 54)	Officer of the Company since August 2008; prior thereto Operations Manager, Upgrading of the Company November 2002 to October 2007, and most recently Operations Director, Upgrading of the Company from October 2007 to August 2008.
Bruce E. McGrath Calgary, Alberta Canada	Corporate Secretary (age 60)	Officer of the Company.
Tim S. McKay Calgary, Alberta Canada	Chief Operating Officer (age 48)	Officer of the Company.
Paul Mendes Calgary, Alberta Canada	Vice-President Legal and General Counsel (age 44)	Officer of the Company since February 2010; prior thereto Manager, Legal Services, Horizon January 2005 to January 2007 and most recently Director, Legal Services Horizon from January 2007 to February 2010.
Leon Miura Calgary, Alberta Canada	Vice-President, Horizon Downstream Projects (age 55)	Officer of the Company.
S. John Parr Calgary, Alberta Canada	Vice-President, Production, East (age 48)	Officer of the Company.
David A. Payne Calgary, Alberta Canada	Vice-President, Exploitation, Central (age 48)	Officer of the Company.
William R. Peterson Calgary, Alberta Canada	Vice-President, Production, West (age 43)	Officer of the Company.
Douglas A. Proll Calgary, Alberta Canada	Chief Financial Officer and Senior Vice-President, Finance (age 59)	Officer of the Company.
Timothy G. Reed Calgary, Alberta Canada	Vice-President, Human Resources (age 53)	Officer of the Company since January 2007; prior thereto Manager, Human Resources of the Company 2000 to 2005 and most recently Director, Human Resources 2005 to January 2007.
Joy P. Romero Calgary, Alberta Canada	Vice President, Bitumen Production (age 53)	Officer of the Company since March 2008; prior thereto Director, Bitumen Production Process of the Company from September 2002 to March 2008.

Sheldon L. Schroeder Fort McMurray, Alberta Canada	Vice-President, Horizon Upstream Projects (age 42)	Officer of the Company.
Kendall W. Stagg Calgary, Alberta Canada	Vice-President, Exploration, West (age 48)	Officer of the Company.
Scott G. Stauth Calgary, Alberta Canada	Vice-President, Field Operations (age 52)	Officer of the Company since November 2006; prior thereto Manager, Eastern Field Operations of the Company from April 2003 to November 2006.
Lyle G. Stevens Calgary, Alberta Canada	Senior Vice-President, Exploitation (age 55)	Officer of the Company.

Stephen C. Suche Calgary, Alberta Canada	Vice-President, Information and Corporate Services (age 50)	Officer of the Company since July 2006; prior thereto Manager Information and Corporate Services of the Company from January 2000 to July 2006.
Domenic Torriero Calgary, Alberta Canada	Vice-President, Exploration, Central (age 45)	Officer of the Company since November 2006; prior thereto Exploration Manager of the Company from March 2004 to November 2006.
Grant M. Williams Calgary, Alberta Canada	Vice-President, Exploration, East (age 52)	Officer of the Company since March 2007; prior thereto Manager, Exploration Heavy Oil of the Company from October 2003 to April 2007.
Jeffrey W. Wilson Calgary, Alberta Canada	Senior Vice-President, Exploration (age 57)	Officer of the Company.
Daryl G. Youck Calgary, Alberta Canada	Vice-President, Exploitation, East (age 41)	Officer of the Company since February 2008; prior thereto Manager, Exploitation of the Company from July 2002 to February 2008.
Lynn M. Zeidler Calgary, Alberta Canada	Vice-President, Horizon Operations and Project Services (age 53)	Officer of the Company.

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

All directors stand for election at each Annual General Meeting of Canadian Natural shareholders. All of the current directors were elected to the Board at the last annual general meeting of shareholders held on May 7, 2009.

As at December 31, 2009, the directors and officers of the Company, as a group, beneficially owned or controlled or directed, directly or indirectly, in the aggregate, approximately 4.2% of the total outstanding common shares (approximately 5.8% after the exercise of options held by them pursuant to the Company's stock option plan).

CONFLICTS OF INTEREST

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

AUDIT COMMITTEE INFORMATION

Audit Committee Members

The Audit Committee of the Board of Directors of the Company is comprised of Ms. C. M. Best, Chair, Messrs. G. A. Filmon, G. D. Giffin and D. A. Tuer each of whom is independent and financially literate as those terms are defined under Canadian securities regulations, National Instrument 52-110 and the NYSE listing standards as they pertain to audit committees of listed issuers. The education and experience of each member of the Audit Committee relevant to their responsibilities as an Audit Committee member is described below.

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

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

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

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

Auditor Service Fees

The Audit Committee of the Board of Directors in 2009 approved specified audit and non-audit services to be performed by PricewaterhouseCoopers LLP ("PwC"). The services provided include: (i) the annual audit of the Corporation's consolidated financial statements and internal controls over financial reporting, reviews of the Corporation's quarterly unaudited consolidated financial statements, audits of certain of the Corporation's subsidiary companies' annual financial statements, assistance related to the Corporation's conversion to International Financial Reporting Standards, as well as other audit services provided in connection with statutory and regulatory filings; (ii) audit related services including debt covenant compliance and Crown Royalty Statements; (iii) tax related services related to expatriate personal tax and compliance as well as other corporate tax return matters; and (iv) non-audit services related to accessing resource materials through PwC's accounting literature library.

Fees accrued to PwC are shown in the table below.

Auditor service	2009	2008
Audit fees	$2,710,100	$2,685,800
Audit related fees	154,300	156,300
Tax related fees	131,650	91,500
All other fees	9,500	9,500
	$3,005,550	$2,943,100

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

LEGAL PROCEEDINGS

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

MATERIAL CONTRACTS

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

INTERESTS OF EXPERTS

The Company's auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have prepared an independent auditors' report dated March 3, 2010 in respect of the Company's consolidated financial statements as at December 31, 2009 and December 31, 2008 with accompanying notes for each of the years in the three year period ended December 31, 2009 and the Company's internal control over financial reporting as at December 31, 2009. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and the rules of the SEC.

Based on information provided by the relevant persons or companies, there are beneficial interests, direct or indirect, in less than 1% of the Company's securities or property or securities or property of our associates or affiliates held by Sproule Associates Limited or GLJ Petroleum Consultants Ltd. or any partners, employees or consultants of such independent reserves evaluators who participated in and who were in a position to directly influence the preparation of the relevant report, or any such person who, at the time of the preparation of the report was in a position to directly influence the outcome of the preparation of the report.

ADDITIONAL INFORMATION

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

Additional information including Directors' and Executive Officers' remuneration and indebtedness, Director nominees standing for re-election, principal holders of the Company's securities, options to purchase the Company's securities and interest of insiders in material transactions is contained in the Company's Notice of Annual and Special Meeting and Information Circular dated March 17, 2010 in connection with the Annual and Special Meeting of Shareholders of Canadian Natural to be held on May 6, 2010 which information is incorporated herein by reference. Additional financial information and discussion of the affairs of the Company and the business environment in which the Company operates is provided in the Company's Management Discussion and Analysis, comparative Consolidated Financial Statements and Supplementary Oil & Gas Information for the most recently completed fiscal year ended December 31, 2009 found on pages 20 to 51, 52 to 80 and 81 to 87 respectively, of the 2009 Annual Report to the Shareholders, which information is incorporated herein by reference.

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

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

SCHEDULE "A"
FORM 51-101F2

REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Report on Reserves Data

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

1. We have reviewed and evaluated the Corporation's reserves data as at December 31, 2009. The reserves data consist of the following:

(a)	(i)	both proved, and proved and probable crude oil, synthetic crude oil, NGLs and natural gas reserve quantities estimated as at December 31, 2009 using 12-month average prices and current costs;
	(ii)	the related future net revenue; and
	(iii)	the related standardized measure calculation for proved crude oil, synthetic crude oil, NGL and natural gas reserve quantities.
(b)	(i)	both proved, and proved and probable crude oil, synthetic crude oil, NGL and natural gas reserve quantities estimated as at December 31, 2009 using forecast prices and costs;
	(ii)	the related future net revenue.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2009 and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's management and board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate) ($millions Cdn) Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	Evaluation and review of the P&NG Reserves, February 8th, 2010	Canada and USA	$0	$37,994	$3,041	$41,035
Sproule Associates Limited	Evaluation and review of the P&NG Reserves, February 8th, 2010	United Kingdom and Offshore West Africa	$0	$10,053	$3,682	$13,735
GLJ Petroleum Consultants Limited	Evaluation of the oil sands mining reserves, March 2nd, 2010	Canada	$0	$23,064	$0	$23,064
Totals			$0	$71,111	$6,723	$77,834

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook as modified by the FASB Standards and SEC requirements. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

Sproule Associates Limited, Calgary, Alberta, Canada, March 3, 2010

Original Signed By:

SIGNED “HARRY J. HELWERDA”
Harry J. Helwerda, P.Eng.,
Executive Vice-President

Original Signed By:

SIGNED “DOUG HO”
Doug Ho, P.Eng.
Vice-President, Unconventional

Original Signed By:

SIGNED: "R. KEITH MACLEOD"
R. Keith MacLeod, P.Eng.
President

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 3, 2010

Original Signed By:

SIGNED: "JAMES H. WILLMON"
James H. Willmon, P.Eng.
Vice-President

SCHEDULE “B”

REPORT OF
MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE

Report of Management and Directors on Reserves Data and Other Information

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

(a) (i) both proved, and proved and probable crude oil, synthetic crude oil, NGLs and natural gas reserve quantities estimated as at December 31, 2009 using 12-month average prices and current costs;
(ii) the related future net revenue; and
(iii) the related standardized measure calculation for proved crude oil, synthetic crude oil, NGL and natural gas reserve quantities.

(b) (i) both proved, and proved and probable crude oil, synthetic crude oil, NGL and natural gas reserve quantities estimated as at December 31, 2009 using forecast prices and costs;
(ii) the related future net revenue.

Sproule Associates Limited and GLJ Petroleum Consultants Ltd., both independent qualified reserves evaluators, have evaluated the Corporation’s reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

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

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

(b) met with each of the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation and in the event of a proposal to change the independent qualified reserves evaluators, to inquire whether there had been disputes between the previous independent qualified reserves evaluators and management; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

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

(a) the content and filing with securities regulatory authorities of reserves data and other oil, gas and surface mineable oil sands information contained in the Company's Annual Information Form to which this report is attached as Schedule "B";

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Original Signed By:

SIGNED: "STEVE W. LAUT"
Steve W. Laut
President

Original Signed By:

SIGNED: "DOUGLAS A. PROLL"
Douglas A. Proll
Chief Financial Officer and Senior Vice President, Finance

Original Signed By:

SIGNED: "DAVID A. TUER"
David A. Tuer
Independent Director and Chair of the Reserves Committee

Original Signed By:

SIGNED: "JAMES S. PALMER"
James S. Palmer
Independent Director and Member of the Reserves Committee

Dated this 3rd day of March, 2010
Calgary, Alberta

SCHEDULE “C”

CANADIAN NATURAL RESOURCES LIMITED
(the “Corporation”)

Charter of the Audit Committee of the Board of Directors

I. Audit Committee Purpose

The Audit Committee is appointed by the Board of Directors (the “Board”) to assist the Board in fulfilling its responsibility for the stewardship of the Corporation in overseeing the business and affairs of the Corporation. Although the Audit Committee has the powers and responsibilities set forth in this Charter, the role of the Audit Committee is oversight. The Audit Committee’s primary duties and responsibilities are to:

1. ensure that the Corporation’s management implemented an effective system of internal controls over financial reporting;

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

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

4. monitor the independence, qualifications and performance of the Corporation’s independent auditors and oversee the audit of the Corporation’s financial statements;

5. monitor the performance of the internal audit function;

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

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

II. Audit Committee Composition, Procedures and Organization

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

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

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

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

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

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

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

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

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

III. Audit Committee Duties and Responsibilities

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

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

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

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

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

e.

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

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

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

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

c. to review and discuss with management and the independent auditors prior to the annual audit the independent auditor's annual audit plan, including scope, staffing, locations and reliance upon management and internal audit department and oversee the audit of the Corporation's financial statements;

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

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

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

(i) contents of their report, including :

(a) all critical accounting policies and practices used;

(b) all alternative treatments of financial information within GAAP that have been discussed with management, ramifications of the use of such treatments and the treatment preferred by the independent auditor;

(c) other material written communications between the independent auditor and management;

(ii) scope and quality of the audit work performed;

(iii) adequacy of the Corporation's financial and auditing personnel;

(iv) cooperation received from the Corporation's personnel during the audit;

(v) internal resources used;

(vi) significant transactions outside of the normal business of the Corporation;

(vii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems;

(viii) the non-audit services provided by the independent auditors; and,

(ix) consider the independent auditor's judgments about the quality and appropriateness of the Corporation's accounting principles and critical accounting estimates as applied in its financial reporting.

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

h.

to review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former independent auditor of the Corporation.

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

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

b. to review the internal audit plan; and

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

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

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

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

c. to periodically review the extent to which recommendations made by the internal audit staff or by the independent auditors have been implemented.

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

a. to review and discuss with management, the internal audit group and the independent auditors, the Corporation's unaudited quarterly consolidated financial statements and related Management Discussion & Analysis including the impact of unusual items and changes in accounting principles and estimates, the earnings press releases before disclosure to the public and report to the Board with respect thereto;

b. to review and discuss with management, the internal audit group and the independent auditors, the Corporation's audited annual consolidated financial statements and related Management Discussion & Analysis including the impact of unusual items and changes in accounting principles and estimates, the earnings press releases before disclosure to the public and report to the Board with respect thereto;

c. to ensure adequate procedures are in place for the review of the Corporation's public disclosure of financial information extracted or derived from the Corporation's financial statements, other than the quarterly and annual earnings press releases, and periodically assess the adequacy of those procedures;

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

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

f. to establish procedures for:

(i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters; and

(ii) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

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

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

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

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

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

Management's Report

The accompanying consolidated financial statements and all other information contained elsewhere in this Annual Report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies described in the accompanying notes. Where necessary, management has made informed judgements and estimates in accounting for transactions that were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared in accordance with Canadian generally accepted accounting principles appropriate in the circumstances. The financial information presented elsewhere in the Annual Report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized and recorded, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to audit and provide their independent audit opinions on the following:

- the Company's consolidated financial statements as at December 31, 2009; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2009.

Their report is presented with the consolidated financial statements.

The Board of Directors (the "Board") is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board exercises this responsibility through the Audit Committee of the Board, which is comprised entirely of independent directors. The Audit Committee meets with management and the independent auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board for approval. The consolidated financial statements have been approved by the Board on the recommendation of the Audit Committee.

(signed) "Steve W. Laut"	(signed) "Douglas A. Proll"	(signed) "Randall S. Davis"
Steve W. Laut	Douglas A. Proll, CA	Randall S. Davis, CA
President	Chief Financial Officer &	Vice-President, Finance &
	Senior Vice-President, Finance	Accounting

Calgary, Alberta, Canada
March 3, 2010

Management's Assessment of Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company as defined in Rules 13a–15(f) and 15(d)–15(f) under the United States Securities Exchange Act of 1934, as amended.

Management, including the Company's President and the Company's Chief Financial Officer and Senior Vice-President, Finance, performed an assessment of the Company's internal control over financial reporting based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on the assessment, management has concluded that the Company's internal control over financial reporting is effective as at December 31, 2009. Management recognizes that all internal control systems have inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has provided an opinion on the Company's internal control over financial reporting as at December 31, 2009, as stated in their Auditors' Report.

(signed) "Steve W. Laut"
Steve W. Laut
President

(signed) "Douglas A. Proll"
Douglas A. Proll, CA
Chief Financial Officer &
Senior Vice-President, Finance

Calgary, Alberta, Canada
March 3, 2010

Independent Auditors' Report

To the Shareholders of Canadian Natural Resources Limited

We have completed integrated audits of Canadian Natural Resources Limited's 2009, 2008 and 2007 consolidated financial statements and of its internal control over financial reporting as at December 31, 2009. Our opinions, based on our audits, are presented below.

Consolidated Financial statements

We have audited the accompanying consolidated balance sheets of Canadian Natural Resources Limited (the "Company") as at December 31, 2009 and December 31, 2008, and the related consolidated statements of earnings, shareholders' equity, comprehensive income and cash flows for each of the years in the three year period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits of the Company's financial statements as at December 31, 2009 and for each of the years in the three year period then ended in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and December 31, 2008 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2009 in accordance with Canadian generally accepted accounting principles.

Internal control over financial reporting

We have also audited Canadian Natural Resources Limited's internal control over financial reporting as at December 31, 2009, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2009 based on criteria established in Internal Control — Integrated Framework issued by the COSO.

(signed) "PricewaterhouseCoopers LLP"
Chartered Accountants
March 3, 2010

4

Consolidated Balance Sheets

As at December 31 (millions of Canadian dollars)	2009	2008
ASSETS		
Current assets		
Cash and cash equivalents	$13	$27
Accounts receivable	1,148	1,059
Inventory, prepaids and other	584	455
Future income tax (note 8)	146	–
Current portion of other long-term assets (note 3)	–	1,851
	1,891	3,392
Property, plant and equipment (note 4)	39,115	38,966
Other long-term assets (note 3)	18	292
	$41,024	$42,650
LIABILITIES		
Current liabilities		
Accounts payable	$240	$383
Accrued liabilities	1,522	1,802
Future income tax (note 8)	–	585
Current portion of long-term debt (note 5)	–	420
Current portion of other long-term liabilities (note 6)	643	230
	2,405	3,420
Long-term debt (note 5)	9,658	12,596
Other long-term liabilities (note 6)	1,848	1,124
Future income tax (note 8)	7,687	7,136
	21,598	24,276
SHAREHOLDERS' EQUITY		
Share capital (note 9)	2,834	2,768
Retained earnings	16,696	15,344
Accumulated other comprehensive (loss) income (note 10)	(104)	262
	19,426	18,374
	$41,024	$42,650

Commitments and contingencies (note 14)

Approved by the Board of Directors:

(signed) "Catherine M. Best"
Catherine M. Best
Chair of the Audit Committee and Director

(signed) " N. Murray Edwards"
N. Murray Edwards
Vice-Chairman of the Board of Directors and Director

5

Consolidated Statements of Earnings

For the years ended December 31 (millions of Canadian dollars, except per common share amounts)	2009	2008	2007
Revenue	$11,078	$16,173	$12,543
Less: royalties	(936)	(2,017)	(1,391)
Revenue, net of royalties	10,142	14,156	11,152
Expenses			
Production	2,987	2,451	2,184
Transportation and blending	1,218	1,936	1,570
Depletion, depreciation and amortization	2,819	2,683	2,863
Asset retirement obligation accretion (note 6)	90	71	70
Administration	181	180	208
Stock-based compensation expense (recovery) (note 6)	355	(52)	193
Interest, net	410	128	276
Risk management activities (note 13)	738	(1,230)	1,562
Foreign exchange (gain) loss	(631)	718	(471)
	8,167	6,885	8,455
Earnings before taxes	1,975	7,271	2,697
Taxes other than income tax (note 8)	106	178	165
Current income tax expense (note 8)	388	501	380
Future income tax (recovery) expense (note 8)	(99)	1,607	(456)
Net earnings	$1,580	$4,985	$2,608
Net earnings per common share (note 12)			
Basic and diluted	$2.92	$9.22	$4.84

Consolidated Statements of Shareholders' Equity

For the years ended December 31 (millions of Canadian dollars)	2009	2008	2007
Share capital (note 9)			
Balance – beginning of year	$2,768	$2,674	$2,562
Issued upon exercise of stock options	24	18	21
Previously recognized liability on stock options exercised for common shares	42	76	91
Balance – end of year	2,834	2,768	2,674
Retained earnings			
Balance – beginning of year, as originally reported	15,344	10,575	8,141
Transition adjustment on adoption of financial instruments standards	–	–	10
Balance – beginning of year, as restated	15,344	10,575	8,151
Net earnings	1,580	4,985	2,608
Dividends on common shares (note 9)	(228)	(216)	(184)
Balance – end of year	16,696	15,344	10,575
Accumulated other comprehensive (loss) income (note 10)			
Balance – beginning of year, as originally reported	262	72	(13)
Transition adjustment on adoption of financial instruments standards	–	–	159
Balance – beginning of year, as restated	262	72	146
Other comprehensive (loss) income, net of taxes	(366)	190	(74)
Balance – end of year	(104)	262	72
Shareholders' equity	$19,426	$18,374	$13,321

Consolidated Statements of Comprehensive Income

For the years ended December 31 (millions of Canadian dollars)	2009	2008	2007
Net earnings	$1,580	$4,985	$2,608
Net change in derivative financial instruments designated as cash flow hedges			
Unrealized (loss) income during the year, net of taxes of $5 million (2008 – $1 million, 2007 – $6 million)	(33)	30	38
Reclassification to net earnings, net of taxes of $1 million (2008 – $6 million, 2007 – $45 million)	(10)	(12)	(96)
	(43)	18	(58)
Foreign currency translation adjustment			
Translation of net investment	(323)	172	(16)
Other comprehensive (loss) income, net of taxes	(366)	190	(74)
Comprehensive income	$1,214	$5,175	$2,534

Consolidated Statements of Cash Flows

For the years ended December 31 (millions of Canadian dollars)	2009	2008	2007
Operating activities			
Net earnings	$1,580	$4,985	$2,608
Non-cash items			
Depletion, depreciation and amortization	2,819	2,683	2,863
Asset retirement obligation accretion	90	71	70
Stock-based compensation expense (recovery)	355	(52)	193
Unrealized risk management loss (gain)	1,991	(3,090)	1,400
Unrealized foreign exchange (gain) loss	(661)	832	(524)
Deferred petroleum revenue tax expense (recovery)	15	(67)	44
Future income tax (recovery) expense	(99)	1,607	(456)
Other	5	25	38
Abandonment expenditures	(48)	(38)	(71)
Net change in non-cash working capital (note 15)	(235)	(189)	(346)
	5,812	6,767	5,819
Financing activities			
Repayment of bank credit facilities, net	(2,021)	(623)	(1,925)
Issue of medium-term notes	–	–	273
Repayment of senior unsecured notes	(34)	(31)	(33)
Issue of US dollar debt securities	–	1,215	2,553
Issue of common shares on exercise of stock options	24	18	21
Dividends on common shares	(225)	(208)	(178)
Net change in non-cash working capital (note 15)	(12)	46	8
	(2,268)	417	719
Investing activities			
Expenditures on property, plant and equipment	(2,985)	(7,433)	(6,464)
Net proceeds on sale of property, plant and equipment	36	20	110
Net expenditures on property, plant and equipment	(2,949)	(7,413)	(6,354)
Net change in non-cash working capital (note 15)	(609)	235	(186)
	(3,558)	(7,178)	(6,540)
(Decrease) increase in cash and cash equivalents	(14)	6	(2)
Cash and cash equivalents – beginning of year	27	21	23
Cash and cash equivalents – end of year	$13	$27	$21

Supplemental disclosure of cash flow information (note 15)

Notes to the Consolidated Financial Statements

(tabular amounts in millions of Canadian dollars, unless otherwise stated)

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the “Company”) is a senior independent crude oil and natural gas exploration, development and production company head-quartered in Calgary, Alberta, Canada. The Company’s conventional crude oil and natural gas operations are focused in North America, largely in Western Canada; the United Kingdom (“UK”) portion of the North Sea; and Côte d’Ivoire and Gabon in Offshore West Africa.

Horizon oil sands properties (“Horizon”) produce synthetic crude oil through bitumen mining and upgrading operations. During 2009, Horizon Phase 1 assets were completed and available for their intended use. All Horizon related financial results are included in the “Oil Sands Mining and Upgrading” segment.

Also within Western Canada, the Company maintains certain midstream activities that include pipeline operations and an electricity co-generation system.

The consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada (“Canadian GAAP”). A summary of differences between accounting principles in Canada and those generally accepted in the United States (“US GAAP”) is contained in note 17.

Significant accounting policies are summarized as follows:

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and partnerships. A significant portion of the Company’s activities are conducted jointly with others and the consolidated financial statements reflect only the Company’s proportionate interest in such activities.

(B) MEASUREMENT UNCERTAINTY

Management has made estimates and assumptions regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts.

Purchase price allocations, depletion, depreciation and amortization, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. The estimation of reserves involves the exercise of judgement. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that, over time, its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices. As a result, the impact of differences between actual and estimated oil and gas reserves amounts on the consolidated financial statements of future periods may be material.

The calculation of asset retirement obligations includes estimates of the future costs to settle the asset retirement obligation, the timing of the cash flows to settle the obligation, and the future inflation rates. The impact of differences between actual and estimated costs, timing and inflation on the consolidated financial statements of future periods may be material.

The calculation of income taxes requires judgement in applying tax laws and regulations, estimating the timing of temporary difference reversals, and estimating the realizability of future tax assets. These estimates impact current and future income tax assets and liabilities, and current and future income tax expense (recovery).

The measurement of petroleum revenue tax expense in the United Kingdom and the related provision in the consolidated financial statements are subject to uncertainty associated with future recoverability of crude oil and natural gas reserves, commodity prices and the timing of future events, which may result in material changes to deferred amounts.

The estimation of fair value for derivative financial instruments requires the use of assumptions. In determining these assumptions, the Company has relied primarily on external, readily observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

(C) CASH AND CASH EQUIVALENTS

Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) with an original term to maturity at purchase of three months or less are reported as cash equivalents on the balance sheet.

(D) INVENTORIES

Inventories are carried at the lower of cost and net realizable value. Cost consists of purchase costs, direct production costs, direct overhead and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Inventories are primarily comprised of crude oil production held for sale.

(E) PROPERTY, PLANT AND EQUIPMENT

Conventional Crude Oil and Natural Gas

The Company follows the full cost method of accounting for its conventional crude oil and natural gas properties and equipment as prescribed by Accounting Guideline 16 (“AcG 16”) issued by the Canadian Institute of Chartered Accountants (“CICA”). Accordingly, all costs relating to the exploration for and development of conventional crude oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. Directly attributable administrative overhead incurred during the development of certain large capital projects is capitalized until the projects are available for their intended use. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of a gain or loss except where such dispositions result in a change in the depletion rate of the specific cost centre of 20% or more.

Oil Sands Mining and Upgrading

Horizon is comprised of both mining and upgrading operations and accordingly, capitalized costs are accounted for separately from the Company’s Canadian conventional crude oil and natural gas costs. Capitalized mining activity costs include property acquisition, construction and development costs. Construction and development costs are capitalized separately to each Phase of Horizon. The construction and development of a particular Phase of Horizon is considered complete once the Phase is available for its intended use. Costs related to major maintenance turnaround activities are capitalized and amortized on a straight-line basis over the period to the next scheduled major maintenance turnaround. During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs ceased and depletion, depreciation and amortization of these assets commenced.

Midstream and Other

The Company capitalizes all costs that expand the capacity or extend the useful life of the assets.

(F) OVERBURDEN REMOVAL COSTS

Overburden removal costs incurred during development of the Horizon mine are capitalized to property, plant and equipment. Overburden removal costs incurred during production of the Horizon mine are included in the cost of inventory, unless the overburden removal activity has resulted in a betterment of the mineral property, in which case the costs are capitalized to property, plant and equipment. Capitalized overburden removal costs are amortized over the life of the mining reserves that directly benefit from the overburden removal activity.

(G) CAPITALIZED INTEREST

The Company capitalizes construction period interest based on major qualifying costs incurred and the Company's cost of borrowing. Interest capitalization on a particular project ceases once this project is available for its intended use.

(H) LEASES

Leases that transfer substantially all of the benefits and risks of ownership to the Company are accounted for as capital leases and are recorded as property, plant and equipment with an offsetting liability. All other leases are accounted for as operating leases whereby lease costs are expensed as incurred. Contractual arrangements that meet the definition of a lease are accounted for as capital leases or operating leases as appropriate.

(I) DEPLETION, DEPRECIATION, AMORTIZATION AND IMPAIRMENT

Conventional Crude Oil and Natural Gas

Substantially all costs related to each country-by-country cost centre are depleted on the unit-of-production method based on the estimated proved reserves of that country. Volumes of net production and net reserves before royalties are converted to equivalent units on the basis of estimated relative energy content. In determining its depletion base, the Company includes estimated future costs to be incurred in developing proved reserves and excludes the cost of unproved properties and major development projects. Costs for major development projects, as identified by management, are not subject to depletion until the projects are available for their intended use. Unproved properties and major development projects are assessed periodically to determine whether impairment has occurred. When proved reserves are assigned or the value of an unproved property or major development project is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion. Processing and production facilities are depreciated on a straight-line basis over their estimated lives.

The Company reviews the carrying amount of its conventional crude oil and natural gas properties (“the properties”) relative to their recoverable amount (“the ceiling test”) for each cost centre at each annual balance sheet date, or more frequently if circumstances or events indicate impairment may have occurred. The recoverable amount is calculated as the undiscounted cash flow from the properties using proved reserves and expected future prices and costs. If the carrying amount of the properties exceeds their recoverable amount, an impairment loss is recognized in depletion and depreciation expense equal to the amount by which the carrying amount of the properties exceeds their fair value. Fair value is calculated as the cash flow from those properties using proved and probable reserves and expected future prices and costs, discounted at a risk-free interest rate.

Oil Sands Mining and Upgrading

Mine-related costs and costs of the upgrader and related infrastructure located on the Horizon site are amortized on the unit-of-production method based on the estimated proved reserves of Horizon or productive capacity, respectively. Moveable mine-related equipment is depreciated on a straight-line basis over its estimated useful life.

The Company reviews the carrying amount of Horizon relative to its recoverable amount if circumstances or events indicate impairment may have occurred. The recoverable amount is calculated as the undiscounted cash flow from Horizon assets using proved and probable reserves and expected future prices and costs. If the carrying amount exceeds the recoverable amount, an impairment loss is recognized in depletion equal to the amount by which the carrying amount of the assets exceeds fair value. Fair value is calculated as the discounted cash flow from Horizon using proved and probable reserves and expected future prices and costs.

Midstream and Other

Midstream assets are depreciated on a straight-line basis over their estimated lives. The Company reviews the recoverability of the carrying amount of the midstream assets when events or circumstances indicate that the carrying amount might not be recoverable. If the carrying amount of the midstream assets exceeds their recoverable amount, an impairment loss equal to the amount by which the carrying amount of the midstream assets exceeds their fair value is recognized in depreciation. Other capital assets are amortized on a declining balance basis.

(J) ASSET RETIREMENT OBLIGATIONS

The Company provides for future asset retirement obligations on its resource properties, facilities, production platforms, gathering systems, and oil sands mining operations and tailings ponds based on current legislation and industry operating practices. The fair values of asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred. Retirement costs equal to the fair value of the asset retirement obligations are capitalized as part of the cost of the associated property, plant and equipment and are amortized to expense through depletion and depreciation over the lives of the respective assets. The fair value of an asset retirement obligation is estimated by discounting the expected future cash flows to settle the asset retirement obligation at the Company's average credit-adjusted risk-free interest rate. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and for changes in the amount or timing of the underlying future cash flows. Actual expenditures are charged against the accumulated asset retirement obligation as incurred.

The Company's Horizon upgrader and related infrastructure and its midstream pipelines have an indeterminate life and therefore the fair values of the related asset retirement obligations cannot be reasonably determined. The asset retirement obligations for these assets will be recorded in the year in which the lives of the assets are determinable.

(K) FOREIGN CURRENCY TRANSLATION

Foreign operations that are self-sustaining are translated using the current rate method. Under this method, assets and liabilities are translated to Canadian dollars from their functional currency using the exchange rate in effect at the consolidated balance sheet date. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Gains or losses on translation are included in accumulated other comprehensive income (loss) in shareholders' equity in the consolidated balance sheets.

Foreign operations that are integrated are translated using the temporal method. For foreign currency balances and integrated subsidiaries, monetary assets and liabilities are translated to Canadian dollars at the exchange rate in effect at the consolidated balance sheet date. Non-monetary assets and liabilities are translated at the exchange rate in effect when the assets were acquired or obligations incurred. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Provisions for depletion, depreciation and amortization are translated at the same rate as the related assets. Gains or losses on translation of integrated foreign operations and foreign currency balances are included in the consolidated statements of earnings.

(L) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer, delivery has taken place and collection is reasonably assured. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Revenue as reported represents the Company's share and is presented before royalty payments to governments and other mineral interest owners. Revenue, net of royalties represents the Company's share after royalty payments to governments and other mineral interest owners.

Related costs of goods sold are comprised of production; transportation and blending; and depletion, depreciation and amortization expenses. These amounts have been separately presented in the consolidated statements of earnings.

(M) PRODUCTION SHARING CONTRACTS

Production generated from Offshore West Africa is currently shared under the terms of various Production Sharing Contracts ("PSCs"). Revenues are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the respective Government State Oil Companies (the "Governments"). Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Governments. The Governments' share of profit oil attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the terms of the PSCs.

(N) PETROLEUM REVENUE TAX

The Company accounts for the UK petroleum revenue tax ("PRT") over the life of the field. The total future liability or recovery of PRT is estimated using proved and probable reserves and anticipated future sales prices and costs. The estimated future PRT is then apportioned to accounting periods on the basis of total estimated future operating income. Changes in the estimated total future PRT are accounted for prospectively.

(O) INCOME TAX

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted or enacted as of the consolidated balance sheet date. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in net earnings in the period of the change.

Taxable income arising from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. Accordingly, North America current and future income taxes have been provided on the basis of this corporate structure.

(P) STOCK-BASED COMPENSATION PLANS

The Company accounts for stock-based compensation using the intrinsic value method as the Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. A liability for potential cash settlements under the Option Plan is accrued over the vesting period of the stock options based on the difference between the exercise price of the stock options and the market price of the Company's common shares, after consideration of an estimated forfeiture rate. This liability is revalued at each reporting date to reflect changes in the market price of the Company's common shares and actual forfeitures, with the net change recognized in net earnings, or capitalized during the construction period in the case of Horizon. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by employees and any previously recognized liability associated with the stock options are recorded as share capital.

The Company has an employee stock savings plan and a stock bonus plan. Contributions to the employee stock savings plan are recorded as compensation expense at the time of the contribution. Contributions to the stock bonus plan are recognized as compensation expense over the related vesting period.

(Q) FINANCIAL INSTRUMENTS

The Company classifies its financial instruments into one of the following categories: held-for-trading financial assets and financial liabilities; held-to-maturity investments; loans and receivables; available-for-sale financial assets; and other financial liabilities. All financial instruments are required to be measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Held-for-trading financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. Available-for-sale financial assets are subsequently measured at fair value with changes in fair value recognized in other comprehensive income, net of tax. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash and cash equivalents are classified as held-for-trading and are measured at fair value. Accounts receivable are classified as loans and receivables. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as other financial liabilities. Although the Company does not intend to trade its derivative financial instruments, risk management assets and liabilities are classified as held-for-trading for accounting purposes.

Financial assets and liabilities are categorized using a three-level hierarchy that reflects the significance of the inputs used in making fair value measurements for these assets and liabilities. The fair values of financial assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair values of financial assets and liabilities in Level 2 are based on inputs other than Level 1 quoted prices that are observable for the asset or liability either directly (as prices) or indirectly (derived from prices). The fair values of Level 3 financial assets and liabilities are not based on observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability.

Transaction costs that are directly attributable to the acquisition or issue of a financial asset or liability and original issue discounts on long-term debt have been included in the carrying value of the related financial asset or liability and are amortized to consolidated net earnings over the life of the financial instrument using the effective interest method.

(R) RISK MANAGEMENT ACTIVITIES

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized on the consolidated balance sheet at estimated fair value at each balance sheet date. The estimated fair value of derivative financial instruments is determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates.

The Company documents all derivative financial instruments that are formally designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company periodically enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts formally designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in consolidated net earnings in the same period or periods in which the commodity is sold. The ineffective portion of changes in the fair value of these designated contracts is immediately recognized in risk management activities in consolidated net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in consolidated net earnings.

The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on certain of its long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are included in interest expense in consolidated net earnings. Changes in the fair value of non-designated interest rate swap contracts are included in risk management activities in consolidated net earnings.

Cross currency swap contracts are periodically used to manage currency exposure on US dollar denominated long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Changes in the fair value of the foreign exchange component of cross currency swap contracts designated as cash flow hedges are included in foreign exchange in consolidated net earnings. The effective portion of changes in the fair value of the interest rate component of cross currency swap contracts designated as cash flow hedges is initially included in other comprehensive income and is reclassified to interest expense when realized, with the ineffective portion recognized in risk management activities in consolidated net earnings. Changes in the fair value of non-designated cross currency swap contracts are included in risk management activities in consolidated net earnings.

Realized gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income on the consolidated balance sheets and amortized into consolidated net earnings in the period in which the underlying hedged item is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized immediately in consolidated net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in consolidated net earnings immediately.

Upon termination of an interest rate swap designated as a fair value hedge, the interest rate swap is de-recognized on the balance sheet and the related long-term debt hedged is no longer revalued for changes in fair value. The fair value adjustment on the long-term debt at the date of termination of the interest rate swap is amortized to interest expense over the remaining term of the debt.

Foreign currency forward contracts are periodically used to manage foreign currency cash management requirements. The foreign currency forward contracts involve the purchase or sale of an agreed upon amount of US dollars at a specified future date at forward exchange rates. Changes in the fair value of foreign currency forward contracts designated as cash flow hedges are initially recorded in other comprehensive income and are reclassified to foreign exchange loss (gain) when realized. Changes in the fair value of foreign currency forward contracts not included as hedges are included in risk management activities in consolidated net earnings.

Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not clearly and closely related to the host contract.

(S) COMPREHENSIVE INCOME

Comprehensive income is comprised of the Company's net earnings and other comprehensive income. Other comprehensive income includes the effective portion of changes in the fair value of derivative financial instruments designated as cash flow hedges and foreign currency translation gains and losses on the net investment in self-sustaining foreign operations. Other comprehensive income is shown net of related income taxes.

(T) PER COMMON SHARE AMOUNTS

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. This method assumes that proceeds received from the exercise of in-the-money stock options not accounted for as a liability are used to purchase common shares at the average market price during the year. The Company's Option Plan described in note 9 results in a liability and expense for all outstanding stock options. As such, the potential common shares associated with the stock options are not included in the calculation of diluted earnings per share. The dilutive effect of other convertible securities is calculated by applying the "if-converted" method, which assumes that the securities are converted at the beginning of the period and that income items are adjusted to net earnings.

(U) RECENTLY ISSUED ACCOUNTING STANDARDS UNDER CANADIAN GAAP

The following standards will be effective for the Company's year beginning on January 1, 2011:

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

Section 1582 – "Business Combinations", 1601 – "Consolidated Financial Statements", and 1602 – "Non-Controllin Interests" replace Section 1581 – "Business Combinations", and 1600 – "Consolidated Financial Statements". The new standards are the Canadian equivalent of IFRS 3 "Business Combinations" and IAS 27 "Consolidated and Separate Financial Statements". Section 1582 is effective for business combinations for acquisition dates on or after January 1, 2011. Earlier adoption is permitted, provided all three new standards are adopted simultaneously. Section 1582 requires equity instruments issued as part of the purchase consideration to be measured at fair value at the acquisition date, rather than the date when the acquisition was agreed to and announced. In addition, most acquisition costs are expensed as incurred, instead of being included in the purchase consideration. The new standard also requires non-controlling interests to be measured at fair value instead of carrying amounts. Section 1602 provides guidance on the treatment of non-controlling interests after acquisition. Section 1601 carries forward existing guidance on the preparation of consolidated financial statements, other than non-controlling interests. There is no impact on the Company's results of operations or financial position at this time.

(V) INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable entities will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board in place of Canadian GAAP effective January 1, 2011. The Company has assessed which accounting policies will be affected by the change to IFRS and continues to assess the potential impact of these changes on its financial position and results of operations.

(W) COMPARATIVE FIGURES

Certain prior year figures have been reclassified to conform to the presentation adopted in 2009.

2. CHANGES IN ACCOUNTING POLICIES

During 2009, the Company adopted the following new accounting standards issued by the CICA:

Goodwill and Intangible Assets

Effective January 1, 2009 Section 3064 – "Goodwill and Intangible Assets" replaced Section 3062 – "Goodwill and Other Intangible Assets" and Section 3450 – "Research and Development Costs". In addition, EIC-27 – "Revenue and

Expenditures during the Pre-Operating Period" was withdrawn. The new standard addresses when an internally generated intangible asset meets the definition of an asset. The adoption of this standard, which was adopted retroactively, did not have an impact on the Company's results of operations or financial position.

Credit Risk and the Fair Value of Financial Assets and Liabilities

On January 20, 2009 the Emerging Issues Committee ("EIC") issued a new abstract EIC–173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". This abstract concludes that an entity's own credit risk and the credit risk of the counterparty should be taken into account when determining the fair value of financial assets and financial liabilities, including derivative financial instruments. This abstract applies to all financial assets and liabilities measured at fair value in interim and annual financial statements for periods ending on or after January 20, 2009. The adoption of this abstract did not have a material impact on the Company's results of operations or financial position.

The Company also adopted the following amendments to accounting standards issued by the CICA:
Financial Instruments

Effective July 1, 2009 Section 3855 – “Financial Instruments – Recognition and Measurement” was amended to add guidance on the assessment of embedded derivatives upon reclassification of a financial asset from the held-for-trading category. This amendment did not have any impact on the Company’s results of operations or financial position.

Financial Instruments – Disclosures

- Effective October 1, 2009 Section 3862 – “Financial Instruments – Disclosures” was amended to include additional disclosure requirements for fair value measurements of financial instruments and to enhance liquidity risk disclosure requirements. The amendment requires the classification and disclosure of fair value measurements using a three-level hierarchy that reflects the significance of the inputs used in making the fair value measurements. This amendment affected disclosure only and did not impact the Company’s accounting for financial instruments (note 13).

3. OTHER LONG-TERM ASSETS

	2009	2008
Risk management (note 13)	$–	$2,119
Other	18	24
	18	2,143
Less: current portion	–	1,851
	$18	$292

4. PROPERTY, PLANT AND EQUIPMENT

	2009			2008		
	Cost	Accumulated depletion and depreciation	Net	Cost	Accumulated depletion and depreciation	Net
Conventional crude oil and natural gas						
North America	$38,259	$ 16,425	$21,834	$36,532	$ 14,381	$22,151
North Sea	3,879	2,067	1,812	4,167	2,119	2,048
Offshore West Africa	2,861	978	1,883	2,671	777	1,894
Other	42	14	28	40	14	26
Oil Sands Mining and Upgrading	13,481	186	13,295	12,573	–	12,573
Midstream	284	81	203	278	72	206
Head office	200	140	60	190	122	68
	$59,006	$ 19,891	$39,115	$56,451	$ 17,485	$38,966

During the year ended December 31, 2009, the Company capitalized directly attributable administrative costs of $41 million (2008 – $55 million, 2007 – $47 million) in the North Sea and Offshore West Africa, related to exploration and development and $79 million (2008 – $404 million, 2007 – $312 million) in North America, related to Oil Sands Mining and Upgrading.

During the year ended December 31, 2009, the Company capitalized $106 million (2008 – $481 million, 2007 – $356 million) in construction period interest costs related to Oil Sands Mining and Upgrading.

Included in property, plant and equipment are unproved land and major development projects that are not currently subject to depletion or depreciation:

	2009	2008
Conventional crude oil and natural gas		
North America	$2,102	$2,271
North Sea	4	12
Offshore West Africa	666	595
Other	28	26
Oil Sands Mining and Upgrading	752	12,573
	$3,552	$15,477

The Company has used the following estimated benchmark future prices ("escalated pricing") in its full cost ceiling tests for conventional crude oil and natural gas activities prepared in accordance with Canadian GAAP, as at December 31, 2009:

	2010	2011	2012	2013	2014	Average annual increase thereafter
Crude oil and NGLs						
North America						
WTI at Cushing (US$/bbl)	$79.17	$84.46	$86.89	$90.20	$92.01	2%
Western Canada Select (C$/bbl)	$74.14	$78.29	$76.86	$78.87	$79.49	2%
Edmonton Par (C$/bbl)	$84.25	$89.99	$92.61	$96.19	$98.13	2%
North Sea and Offshore West Africa						
North Sea Brent (US$/bbl)	$77.92	$83.19	$85.59	$88.88	$90.65	2%
Natural gas						
North America						
Henry Hub Louisiana (US$/mmbtu)	$5.70	$6.48	$6.70	$7.43	$8.12	2%
AECO (C$/mmbtu)	$5.36	$6.21	$6.44	$7.23	$7.98	2%
Huntingdon/Sumas (C$/mmbtu)	$5.61	$6.46	$6.69	$7.48	$8.23	2%

Offshore West Africa property, plant and equipment has been reduced by $115 million to reflect the impact of a ceiling test impairment charge as at December 31, 2009. The impairment charge has been included in depletion, depreciation and amortization expenses.

5. LONG-TERM DEBT

	2009	2008
Canadian dollar denominated debt		
Bank credit facilities		
Bankers' acceptances	$1,897	$4,073
Medium-term notes		
5.50% unsecured debentures due December 17, 2010	400	400
4.50% unsecured debentures due January 23, 2013	400	400
4.95% unsecured debentures due June 1, 2015	400	400
	3,097	5,273
US dollar denominated debt		
Senior unsecured notes		
Adjustable rate due May 27, 2009 (2009 – US$nil, 2008 – US$31 million)	–	38
US dollar debt securities		
6.70% due July 15, 2011 (2009 and 2008 – US$400 million)	419	490
5.45% due October 1, 2012 (2009 and 2008 – US$350 million)	366	429
5.15% due February 1, 2013 (2009 and 2008 – US$400 million)	419	490
4.90% due December 1, 2014 (2009 and 2008 – US$350 million)	366	429
6.00% due August 15, 2016 (2009 and 2008 – US$250 million)	262	306
5.70% due May 15, 2017 (2009 and 2008 – US$1,100 million)	1,151	1,346
5.90% due February 1, 2018 (2009 and 2008 – US$400 million)	419	490
7.20% due January 15, 2032 (2009 and 2008 – US$400 million)	419	490
6.45% due June 30, 2033 (2009 and 2008 – US$350 million)	366	429
5.85% due February 1, 2035 (2009 and 2008 – US$350 million)	366	429
6.50% due February 15, 2037 (2009 and 2008 – US$450 million)	471	551
6.25% due March 15, 2038 (2009 and 2008 – US$1,100 million)	1,151	1,346
6.75% due February 1, 2039 (2009 and 2008 – US$400 million)	419	490
Less – original issue discount on senior unsecured notes and US dollar debt securities (1)	(22)	(23)
	6,572	7,730
Fair value impact of interest rate swaps on US dollar debt securities (2)	38	68
	6,610	7,798
Long-term debt before transaction costs	9,707	13,071
Less: transaction costs (1) (3)	(49)	(55)
	9,658	13,016
Less: current portion	–	420
	$9,658	$12,596

(1) The Company has included unamortized original issue discounts and directly attributable transaction costs in the carrying value of the outstanding debt.

(2) The carrying value of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $38 million (2008 – $68 million) to reflect the fair value impact of hedge accounting.

(3) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.

Bank Credit Facilities

As at December 31, 2009, the Company had in place unsecured bank credit facilities of $3,955 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $2,230 million maturing June 2012;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities can be made by way of Canadian dollar and US dollar bankers' acceptances, and LIBOR, US base rate and Canadian prime loans.

During 2009, the Company repaid the remaining $2,350 million outstanding on the non-revolving syndicated credit facility related to the acquisition of Anadarko Canada Corporation ("ACC") and cancelled the facility. In March 2007, $1,500 million was repaid.

During 2009, the Company renegotiated its demand credit facility, increasing it to $200 million.

The Company's weighted average interest rate on bank credit facilities outstanding as at December 31, 2009, was 0.8% (2008 – 2.2%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $358 million, including $300 million related to Horizon, were outstanding at December 31, 2009.

Medium-Term Notes

During 2009, the Company filed a base shelf prospectus that allows for the issue of up to $3,000 million of medium-term notes in Canada until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

Senior Unsecured Notes

During 2009, the remaining US$31 million of senior unsecured notes bearing interest at 6.54% was repaid.

US Dollar Debt Securities

During 2009, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

In January 2008, the Company issued US$1,200 million of unsecured notes under a previous US base shelf prospectus, comprised of US$400 million of 5.15% unsecured notes due February 2013, US$400 million of 5.90% unsecured notes due February 2018, and US$400 million of 6.75% unsecured notes due February 2039. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

During 2008, US$8 million of US dollar debt securities was repaid.

During 2008, the Company terminated the interest rate swaps that had been designated as a fair value hedge of US$350 million of 5.45% unsecured notes due October 2012. Accordingly, the Company ceased revaluing the related debt for subsequent changes in fair value from the date of termination of the interest rate swaps. The fair value adjustment of $20 million at the date of termination is being amortized to interest expense over the remaining term of the debt, with $14 million remaining at December 31, 2009.

Required Debt Repayments

Required debt repayments are as follows:

Year	Repayment
2010	$400
2011	$419
2012	$366
2013	$819
2014	$366
Thereafter	$5,424

No debt repayments are reflected in the above table for $1,897 million of revolving bank credit facilities due to the extendable nature of the facilities. Should the bank credit facilities not be extended by mutual agreement of the Company and the lenders, the amounts outstanding under these facilities would be due in 2012.

6. OTHER LONG-TERM LIABILITIES

	2009	2008
Asset retirement obligations	$1,610	$1,064
Stock-based compensation	392	171
Risk management (note 13)	309	-
Other	180	119
	2,491	1,354
Less: current portion	643	230
	$1,848	$1,124

Asset Retirement Obligations

At December 31, 2009, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $6,606 million (2008 – $4,474 million; 2007 – $4,426 million). Payments to settle these asset retirement obligations will occur on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average credit-adjusted risk-free interest rate of 6.9% (2008 – 6.7%; 2007 – 6.6%). A reconciliation of the discounted asset retirement obligations is as follows:

	2009	2008	2007
Balance – beginning of year	$1,064	$1,074	$1,166
Liabilities incurred (1)	299	18	21
Liabilities acquired	–	3	–
Liabilities disposed	–	–	(65)
Liabilities settled	(48)	(38)	(71)
Asset retirement obligation accretion	90	71	70
Revision of estimates	276	(156)	35
Foreign exchange	(71)	92	(82)
Balance – end of year	$1,610	$1,064	$1,074

(1) During 2009, the Company recognized additional asset retirement obligations related to Horizon and Gabon, Offshore West Africa.

Stock-Based Compensation

The Company recognizes a liability for potential cash settlements under its Option Plan. The current portion represents the maximum amount of the liability payable within the next twelve–month period if all vested options are surrendered for cash settlement.

	2009	2008	2007
Balance – beginning of year	$171	$529	$744
Stock-based compensation expense (recovery)	355	(52)	193
Cash payment for options surrendered	(94)	(207)	(375)
Transferred to common shares	(42)	(76)	(91)
Capitalized (recovery) to Oil Sands Mining and Upgrading	2	(23)	58
Balance – end of year	392	171	529
Less: current portion	365	159	390
	$27	$12	$139

19

7. EMPLOYEE FUTURE BENEFITS

In connection with the acquisition of ACC, the Company assumed obligations to provide defined contribution pension benefits to certain ACC employees continuing their employment with the Company, and defined benefit pension and other post-retirement benefits to former ACC employees, under registered and unregistered pension plans.

The estimated future cost of providing defined benefit pension and other post-retirement benefits to former ACC employees is actuarially determined using management's best estimates of demographic and financial assumptions. The discount rate of 5.5% (2008 – 7.0%) used to determine accrued benefit obligations is based on a year-end market rate of interest for high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Company contributions to the defined contribution plan are expensed as incurred.

The benefit obligation under the registered pension plan at December 31, 2009 was $29 million (2008 – $27 million). As required by government regulations, the Company has set aside funds with an independent trustee to meet these benefit obligations. As at December 31, 2009, these plan assets had a fair value of $32 million (2008 – $34 million). The unregistered pension plan and other post-retirement benefits are unfunded and have a benefit obligation of $10 million at December 31, 2009 (2008 – $9 million).

8. TAXES

Taxes Other Than Income Tax

	2009	2008	2007
Current PRT expense	$70	$210	$97
Deferred PRT expense (recovery)	15	(67)	44
Provincial capital taxes and surcharges	21	35	24
	$106	$178	$165

Income Tax

The provision for income tax is as follows:

	2009	2008	2007
Current income tax – North America	$28	$33	$96
Current income tax – North Sea	278	340	210
Current income tax – Offshore West Africa	82	128	74
Current income tax expense	388	501	380
Future income tax (recovery) expense	(99)	1,607	(456)
Income tax expense (recovery)	$289	$2,108	$(76)

The provision for income tax is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings before taxes. The reasons for the difference are as follows:

	2009	2008	2007
Canadian statutory income tax rate	29.1%	29.8%	32.5%
Income tax provision at statutory rate	$576	$2,166	$877
Effect on income taxes of:			
Deductible UK petroleum revenue tax	(43)	(72)	(71)
Foreign and domestic tax rate differentials	(127)	(5)	(25)
North America income tax rate and other legislative changes	(19)	(19)	(864)
Côte d'Ivoire income tax rate changes	–	(22)	–

Non-taxable portion of foreign exchange (gain) loss	(92)	127	(96)
Stock options exercised in shares	27	6	63
Other	(33)	(73)	40
Income tax expense (recovery)	$289	$2,108	$(76)

The following table summarizes the temporary differences that give rise to the net future income tax asset and liability:

	2009	2008
Future income tax liabilities		
Property, plant and equipment	$6,992	$6,303
Timing of partnership items	1,127	1,276
Unrealized foreign exchange gain on long-term debt	152	13
Unrealized risk management activities	–	651
Other	31	–
Future income tax assets		
Asset retirement obligations	(499)	(372)
Loss carryforwards for income tax	(84)	(62)
Stock-based compensation	(83)	(38)
Unrealized risk management activities	(69)	–
Other	–	(7)
Deferred petroleum revenue tax	(26)	(43)
Net future income tax liability	7,541	7,721
Less: current portion of future income tax (asset) liability	(146)	585
Future income tax liability	$7,687	$7,136

During 2009, substantively enacted or enacted income tax rate changes resulted in a reduction of future income tax liabilities of $19 million in British Columbia.

During 2008, substantively enacted or enacted income tax rate changes resulted in a reduction of future income tax liabilities of approximately $19 million in British Columbia and approximately $22 million in Côte d'Ivoire.

During 2007, substantively enacted or enacted income tax rate and other legislative changes resulted in a reduction of future income tax liabilities of approximately $864 million in North America.

As a result of enacted income tax rate changes in 2007, the Canadian Federal corporate income tax rate is being reduced from 21% in 2007 to 15% in 2012.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities ultimately arising from these reassessments will be material.

9. SHARE CAPITAL

Authorized
200,000 Class 1 preferred shares with a stated value of $10.00 each.

Unlimited number of common shares without par value.

Issued

	2009		2008	
Common shares	Number of shares (thousands)	Amount	Number of shares (thousands)	Amount
Balance – beginning of year	540,991	$2,768	539,729	$2,674
Issued upon exercise of stock options	1,336	24	1,262	18

Previously recognized liability on stock options exercised for common shares	-	42	-	76
Balance – end of year	542,327	$2,834	540,991	$2,768

Dividend Policy

The Company has paid regular quarterly dividends in January, April, July and October of each year since 2001. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

On March 3, 2010, the Board of Directors set the Company's regular quarterly dividend at $0.15 per common share (2009 – $0.105 per common share, 2008 – $0.10 per common share).

Normal Course Issuer Bid

On March 3, 2010 the Board of Directors approved a resolution to file with the Toronto Stock Exchange a notice of intention to purchase by way of normal course issuer bid up to 2.5% of the Company's issued and outstanding common shares. Subject to acceptance by the Toronto Stock Exchange of the Notice of Intention, the purchases would be made through the facilities of the Toronto Stock Exchange and the New York Stock Exchange.

Share split

On March 3, 2010, the Company's Board of Directors approved a resolution to subdivide the Company's common shares on a two for one basis, subject to shareholder approval. The proposal will be voted on at the Company's Annual and Special Meeting of Shareholders to be held on May 6, 2010.

Stock Options

The Company's Option Plan provides for the granting of stock options to employees. Stock options granted under the Option Plan have terms ranging from five to six years to expiry and vest over a five-year period. The exercise price of each stock option granted is determined at the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the grant. Each stock option granted provides the holder the choice to purchase one common share of the Company at the stated exercise price or receive a cash payment equal to the difference between the stated exercise price and the market price of the Company's common shares on the date of surrender of the option.

The following table summarizes information relating to stock options outstanding at December 31, 2009 and 2008:

	2009		2008	
	Stock options (thousands)	Weighted average exercise price	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	30,962	$51.94	30,659	$47.23
Granted	6,736	$67.91	7,705	$53.38
Surrendered for cash settlement	(2,833)	$27.31	(3,702)	$25.60
Exercised for common shares	(1,336)	$17.99	(1,262)	$14.61
Forfeited	(1,423)	$59.55	(2,438)	$56.56
Outstanding – end of year	32,106	$58.54	30,962	$51.94
Exercisable – end of year	10,969	$53.90	8,809	$44.58

The range of exercise prices of stock options outstanding and exercisable at December 31, 2009 was as follows:

Stock options outstanding Stock options exercisable

Range of exercise prices	Stock options outstanding (thousands)	Weighted average remaining term (years)	Weighted average exercise price	Stock options exercisable (thousands)	Weighted average exercise price
16.89 – $$19.99	338	0.28	$17.36	331	$17.36
20.00 – $$29.99	1,993	0.35	$25.61	1,342	$25.35
30.00 – $$39.99	755	0.63	$33.28	528	$33.29
40.00 – $$49.99	6,523	4.06	$46.38	1,252	$45.96
50.00 – $$59.99	4,700	1.85	$58.11	2,609	$58.04
60.00 – $$69.99	10,601	3.84	$65.58	2,503	$61.54
70.00 – $$79.99	6,412	3.32	$70.82	2,363	$70.72
80.00 – $$89.99	-	-	$-	-	$-
90.00 – $$92.50	784	4.53	$92.50	41	$92.50
	32,106	3.18	$58.54	10,969	$53.90

10. ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

The components of accumulated other comprehensive income, net of taxes, were as follows:

	2009	2008
Derivative financial instruments designated as cash flow hedges	$76	$119
Foreign currency translation adjustment	(180)	143
	$(104)	$262

During the next twelve months, $1 million is expected to be reclassified to net earnings from accumulated other comprehensive income.

During 2008, the Company determined that its operations in Offshore West Africa were operationally and financially independent and the current rate method of translation was adopted for translation of the financial statements of its Offshore West African subsidiaries. This change was applied prospectively and increased assets by $32 million, decreased liabilities by $4 million and increased accumulated other comprehensive income by $36 million.

11. CAPITAL DISCLOSURES

The Company does not have any externally imposed regulatory capital requirements for managing capital. The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined each reporting date. The Company is subject to certain financial covenants in its long-term debt agreements and is in compliance with these covenants.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived non-GAAP financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company aims over time to maintain its debt to book capitalization ratio in the range of 35% to 45%. However, the Company may exceed the high end of such target range if it is investing in capital projects, undertaking acquisitions, or in periods of lower commodity prices. The Company may be below the low end of the target range when cash flow from operating activities is greater than current investment activities. The ratio is currently below the target range at 33%.

Readers are cautioned that the debt to book capitalization ratio is not defined by GAAP and this financial measure may not be comparable to similar measures presented by other companies. Further, there can be no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure at some point in the future.

	2009	2008
Long-term debt (1)	$9,658	$13,016
Total shareholders' equity	$19,426	$18,374
Debt to book capitalization	33 %	41 %

(1) Includes the current portion of long-term debt.

12. NET EARNINGS PER COMMON SHARE

	2009	2008	2007
	541,925	540,647	539,336

Weighted average common shares outstanding – basic and diluted (thousands of shares)			
Net earnings – basic and diluted	$1,580	$4,985	$2,608
Net earnings per common share – basic and diluted	$2.92	$9.22	$4.84

13. FINANCIAL INSTRUMENTS

The carrying values of the Company's financial instruments by category are as follows:

	2009		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$–	$13	$–
Accounts receivable	1,148	–	–
Other long-term assets	–	–	–
Accounts payable	–	–	(240)
Accrued liabilities	–	–	(1,522)
Other long-term liabilities	–	(309)	(167)
Long-term debt	–	–	(9,658)
	$1,148	$(296)	$(11,587)

	2008		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$–	$27	$–
Accounts receivable	1,059	–	–
Other long-term assets	–	2,119	–
Accounts payable	–	–	(383)
Accrued liabilities	–	–	(1,802)
Other long-term liabilities	–	–	(105)
Long-term debt (1)	–	–	(13,016)
	$1,059	$2,146	$(15,306)

(1) Includes the current portion of long-term debt.

24

The carrying value of the Company's financial instruments approximates their fair value, except for fixed-rate long-term debt as noted below. The fair values of the Company's financial assets and liabilities are outlined below:

	2009		
	Carrying value	Fair value	
Asset (liability) (1)		Level 1	Level 2
Other long-term assets	$–	$–	$–
Other long-term liabilities	(309)	–	(309)
Fixed-rate long-term debt(2) (3)	(7,761)	(8,212)	–
	$(8,070)	$(8,212)	$(309)

	2008		
	Carrying value	Fair value	
Asset (liability) (1)		Level 1	Level 2
Other long-term assets	$2,119	$–	$2,119
Other long-term liabilities	–	–	–
Fixed-rate long-term debt(2) (3)	(8,943)	(7,649)	–
	$(6,824)	$(7,649)	$2,119

(1) Excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities).

(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $38 million (2008 – $68 million) to reflect the fair value impact of hedge accounting.

(3) The fair value of fixed-rate long-term debt has been determined based on quoted market prices.

Risk Management

The changes in estimated fair values of derivative financial instruments included in the risk management asset (liability) were recognized in the financial statements as follows:

Asset (liability)	2009 Risk management mark-to-market	2008 Risk management mark-to-market
Balance – beginning of year	$ 2,119	$ (1,474)
Net cost of outstanding put options	–	297
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	(1,991)	3,090
Interest expense	(25)	60
Foreign exchange	(338)	449
Other comprehensive income	(78)	18
Settlement of interest rate swaps	4	(20)
	(309)	2,420

Add: put premium financing obligations (1)	–	(301)
Balance – end of year	(309)	2,119
Less: current portion	(182)	1,851
	$ (127)	$ 268

(1) The Company negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective options. These obligations were reflected in the net risk management asset (liability).

Net (gains) losses from risk management activities for the years ended December 31 were as follows:

	2009	2008	2007
Net realized risk management (gain) loss	$(1,253)	$1,860	$162
Net unrealized risk management loss (gain)	1,991	(3,090)	1,400
	$738	$(1,230)	$1,562

Financial Risk Factors

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk management

The Company uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production. At December 31, 2009, the Company had the following net derivative financial instruments outstanding to manage its commodity price exposures:

	Remaining term	Volume	Weighted average price	Index
Crude oil				
Crude oil price collars	Jan 2010 – Mar 2010	6,000 bbl/d	US$60.00 – US$105.15	WTI
	Jan 2010 – Jun 2010	100,000 bbl/d	US$60.00 – US$90.13	WTI
	Jan 2010 – Sep 2010	50,000 bbl/d	US$65.00 – US$105.49	WTI
	Jan 2010 – Dec 2010	50,000 bbl/d	US$60.00 – US$75.08	WTI
	Jul 2010 – Dec 2010	50,000 bbl/d	US$65.00 – US$108.94	WTI

	Remaining term	Volume	Weighted average price	Index
Natural gas				
Natural gas price collars(1)	Jan 2010 – Dec 2010	220,000 GJ/d	C$6.00 – C$8.00	AECO

(1) Subsequent to December 31, 2009, the Company entered into 400,000 GJ/d of C$4.50 – C$6.30 natural gas AECO collars for the period April to September 2010.

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

There were no commodity derivative financial instruments designated as hedges at December 31, 2009.

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At December 31, 2009, the Company had the following interest rate swap contracts outstanding:

	Remaining term	Amount ($ millions)	Fixed rate	Floating rate
Interest rate				
Swaps – fixed to floating	Jan 2010 – Dec 2014	US$350	4.90%	LIBOR (1) + 0.38%
Swaps – floating to fixed	Jan 2010 – Feb 2011	C$300	1.0680%	3 month CDOR (2)
	Jan 2010 – Feb 2012	C$200	1.4475%	3 month CDOR (2)

(1) London Interbank Offered Rate
(2) Canadian Dealer Offered Rate

All fixed to floating interest rate related derivative financial instruments designated as hedges at December 31, 2009 were classified as fair value hedges.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies in its subsidiaries and in the carrying value of its self-sustaining foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At December 31, 2009, the Company had the following cross currency swap contracts outstanding:

	Remaining term	Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency					
Swaps	Jan 2010 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2010 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2010 – Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments designated as hedges at December 31, 2009 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2009, the Company had US$1,062 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less.

Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company's net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2009, resulting from changes in the specified variable, with all other variables held constant. These sensitivities are prepared on a different basis than those sensitivities disclosed in the Company's other continuous disclosure documents, are limited to the impact of changes in a specified variable applied to financial instruments only and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally can not be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

	Impact on net earnings	Impact on other comprehensive income
Commodity price risk		
Increase WTI US$1.00/bbl	$(21)	$ –

Decrease WTI US$1.00/bbl	$20	$ –
Increase AECO C$0.10/mcf	$(4)	$ –
Decrease AECO C$0.10/mcf	$4	$ –
Interest rate risk		
Increase interest rate 1%	$(12)	$ 14
Decrease interest rate 1%	$8	$ (18)
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$(29)	$ –
Decrease exchange rate by US$0.01	$29	$ –

b) Credit Risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management
The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At December 31, 2009, substantially all of the Company's accounts receivables were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At December 31, 2009, the Company had net risk management assets of $7 million with specific counterparties related to derivative financial instruments (December 31, 2008 – $2,119 million).

Liquidity Risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

The maturity dates for financial liabilities are as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$240	$–	$–	$–
Accrued liabilities	$1,522	$–	$–	$–
Risk management	$182	$15	$48	$64
Other long-term liabilities	$96	$18	$32	$21
Long-term debt (1)	$400	$419	$1,551	$5,424

(1) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,897 million of revolving bank credit facilities due to the extendable nature of the facilities.

14. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2010	2011	2012	2013	2014	Thereafter
Product transportation and pipeline	$207	$162	$136	$125	$126	$1,051
Offshore equipment operating leases	$155	$124	$103	$102	$101	$261
Offshore drilling	$49	$-	$-	$-	$-	$-
Asset retirement obligations (1)	$16	$20	$21	$31	$39	$6,479
Office leases	$25	$19	$3	$2	$2	$-
Other	$271	$67	$23	$15	$12	$34

(1) Amounts represent management’s estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2010 – 2014 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. In addition, the Company is subject to certain contractor claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

15. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Changes in non-cash working capital were as follows:

	2009	2008	2007
Changes in non-cash working capital			
Accounts receivable and other	$(276)	$111	$334
Accounts payable	(151)	(4)	(456)
Accrued liabilities	(429)	(15)	(402)
Net changes in non-cash working capital	$(856)	$92	$(524)
Relating to:			
Operating activities	$(235)	$(189)	$(346)
Financing activities	(12)	46	8
Investing activities	(609)	235	(186)
	$(856)	$92	$(524)

Other cash flow information:	2009	2008	2007
Interest paid	$516	$574	$556
Taxes other than income tax paid	$52	$300	$116
Current income tax paid	$216	$258	$302

16. SEGMENTED INFORMATION

The Company's conventional crude oil and natural gas activities are conducted in three geographic segments: North America, North Sea and Offshore West Africa. These activities include the exploration, development, production and marketing of conventional crude oil, natural gas liquids and natural gas.

The Company's Oil Sands Mining and Upgrading is a separate segment from conventional crude oil and natural gas activities as the bitumen will be recovered through mining operations.

Midstream activities include the Company's pipeline operations and an electricity co-generation system. Activities that are not included in the above segments are reported in the segmented information as other. Inter-segment eliminations include internal transportation, electricity charges and natural gas sales.

	Conventional Crude Oil and Natural Gas											
	North America			North Sea			Offshore West Africa			Total		
	2009	2008	2007	2009	2008	2007	2009	2008	2007	2009	2008	2007
Segmented revenue	$7,973	$13,496	$10,149	$961	$1,769	$1,597	$913	$944	$776	$9,847	$16,209	$12,522
Less: royalties	(825)	(1,876)	(1,318)	(2)	(4)	(3)	(81)	(143)	(70)	(908)	(2,023)	(1,391)
Revenue, net of royalties	7,148	11,620	8,831	959	1,765	1,594	832	801	706	8,939	14,186	11,131
Segmented expenses												
Production	1,748	1,881	1,642	376	457	432	179	102	94	2,303	2,440	2,168
Transportation and blending	1,213	1,975	1,595	8	10	16	1	1	1	1,222	1,986	1,612
Depletion, depreciation and amortization	2,060	2,236	2,350	261	317	340	335	132	165	2,656	2,685	2,855
Asset retirement obligation accretion	41	42	38	24	27	30	4	2	2	69	71	70
Realized risk management activities	(880)	1,861	129	(373)	(1)	33	–	–	–	(1,253)	1,860	162
Total segmented expenses	4,182	7,995	5,754	296	810	851	519	237	262	4,997	9,042	6,867
Segmented earnings before the following	$2,966	$ 3,625	$3,077	$663	$955	$743	$313	$564	$444	$3,942	$5,144	$4,264
Non–segmented expenses												
Administration												
Stock-based compensation expense (recovery)												

Interest, net
Unrealized risk management activities
Foreign exchange (gain) loss
Total non-segmented expenses
Earnings before taxes
Taxes other than income tax
Current income tax expense
Future income tax (recovery) expense
Net earnings

30

	Oil Sands Mining and Upgrading			Midstream			Inter–segment elimination and other			Total		
	2009	2008	2007	2009	2008	2007	2009	2008	2007	2009	2008	2007
Segmented revenue	$1,253	$–	$–	$72	$77	$74	$(94)	$(113)	$(53)	$11,078	$16,173	$12,543
Less: royalties	(36)	–	–	–	–	–	8	6	–	(936)	(2,017)	(1,391)
Revenue, net of royalties	1,217	–	–	72	77	74	(86)	(107)	(53)	10,142	14,156	11,152
Segmented expenses												
Production	683	–	–	19	25	22	(18)	(14)	(6)	2,987	2,451	2,184
Transportation and blending	41	–	–	–	–	–	(45)	(50)	(42)	1,218	1,936	1,570
Depletion, depreciation and amortization	187	–	–	9	8	8	(33)	(10)	–	2,819	2,683	2,863
Asset retirement obligation accretion	21	–	–	–	–	–	–	–	–	90	71	70
Realized risk management activities	–	–	–	–	–	–	–	–	–	(1,253)	1,860	162
Total segmented expenses	932	–	–	28	33	30	(96)	(74)	(48)	5,861	9,001	6,849
Segmented earnings before the following	$285	$–	$–	$44	$44	$44	$10	$(33)	$(5)	$4,281	$5,155	$4,303
Non–segmented expenses												
Administration										181	180	208
Stock-based compensation expense (recovery)										355	(52)	193
Interest, net										410	128	276
Unrealized risk management activities										1,991	(3,090)	1,400
Foreign exchange (gain) loss										(631)	718	(471)
Total non–segmented expenses										2,306	(2,116)	1,606
Earnings before taxes										1,975	7,271	2,697
Taxes other than income tax										106	178	165

Current income tax expense	388	501	380
Future income tax (recovery) expense	(99)	1,607	(456)
Net earnings	$1,580	$4,985	$2,608

31

Capital Expenditures

	2009			2008		
	Net expenditures	Non cash and fair value changes(1)	Capitalized costs	Net expenditures	Non cash and fair value changes(1)	Capitalized costs
Conventional crude oil and natural gas						
North America	$1,663	$65	$1,728	$ 2,344	$(7)	$2,337
North Sea	168	146	314	319	(127)	192
Offshore West Africa	544	111	655	811	6	817
Other	2	-	2	1	-	1
	2,377	322	2,699	3,475	(128)	3,347
Oil Sands Mining and Upgrading(2)	553	355	908	3,912	10	3,922
Midstream	6	-	6	9	-	9
Head office	13	-	13	17	-	17
	$2,949	$677	$3,626	$ 7,413	$(118)	$7,295

(1) Asset retirement obligations, future income tax adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest, stock-based compensation, and the impact of intersegment eliminations.

Segmented Assets

	2009	2008
Conventional crude oil and natural gas		
North America	$22,994	$24,875
North Sea	1,968	2,638
Offshore West Africa	2,033	2,013
Other	42	64
Oil Sands Mining and Upgrading	13,621	12,677
Midstream	306	315
Head office	60	68
	$41,024	$42,650

17. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company's consolidated financial statements have been prepared in accordance with Canadian GAAP. These principles conform in all material respects with US GAAP except for those noted below. Certain differences arising from US GAAP disclosure requirements are not addressed.

The application of US GAAP would have the following effects on consolidated net earnings (loss) as reported:

(millions of Canadian dollars, except per common share amounts)	Notes	2009	2008	2007
Net earnings – Canadian GAAP		$1,580	$4,985	$2,608
Adjustments				
Depletion, net of taxes of $7 million (2008 – $2,503 million, 2007 – $1 million)	(A,B,C,D)	(273)	(6,169)	(10)
Stock-based compensation, net of taxes of $51 million (2008 – $32 million, 2007 – $3 million)	(B)	(154)	(76)	(22)
Future income taxes	(F)	-	234	(234)
Net earnings (loss) – US GAAP		$1,153	$(1,026)	$2,342
Net earnings (loss) – US GAAP per common share				
Basic		$2.13	$(1.90)	$4.34
Diluted	(E)	$2.13	$(1.90)	$4.32

Comprehensive income (loss) under US GAAP would be as follows:

(millions of Canadian dollars)	Notes	2009	2008	2007
Comprehensive income – Canadian GAAP		$1,214	$5,175	$2,534
US GAAP earnings adjustments		(427)	(6,011)	(266)
Comprehensive income (loss) – US GAAP		$787	$(836)	$2,268

The application of US GAAP would have the following effects on the consolidated balance sheets as reported:

		2009		
(millions of Canadian dollars)	Notes	Canadian GAAP	Increase (Decrease)	US GAAP
Current assets		$1,891	$103	$1,994
Property, plant and equipment	(A,B,C,D)	39,115	(8,824)	30,291
Other long-term assets	(G)	18	49	67
		$41,024	$(8,672)	$32,352
Current liabilities	(B)	$2,405	$387	$2,792
Long-term debt	(G)	9,658	49	9,707
Other long-term liabilities	(B)	1,848	35	1,883
Future income tax	(A,B,C,D,F)	7,687	(2,474)	5,213
Share capital		2,834	-	2,834
Retained earnings		16,696	(6,669)	10,027
Accumulated other comprehensive income		(104)	-	(104)
		$41,024	$(8,672)	$32,352

(millions of Canadian dollars)	Notes	Canadian GAAP	2008 Increase (Decrease)	US GAAP
Current assets		$3,392	$-	$3,392
Property, plant and equipment	(A,B,C,D)	38,966	(8,551)	30,415
Other long-term assets	(G)	292	55	347
		$42,650	$(8,496)	$34,154
Current liabilities	(B)	$3,420	$150	$3,570
Long-term debt	(G)	12,596	55	12,651
Other long-term liabilities	(B)	1,124	15	1,139
Future income tax	(A,B,C,D,F)	7,136	(2,474)	4,662
Share capital		2,768	-	2,768
Retained earnings		15,344	(6,242)	9,102
Accumulated other comprehensive income		262	-	262
		$42,650	$(8,496)	$34,154

Notes:

(A) Under Canadian full cost accounting guidance, costs capitalized in each country cost centre are limited to an amount equal to the future net revenues from proved and probable reserves using estimated future prices and costs discounted at the risk-free rate, plus the carrying amount of unproved properties and major development projects (the "ceiling test") as described in note 1(I). Under the full cost method of accounting as set forth by the US Securities and Exchange Commission, the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are based on prices using the average first-day-of-the-month price during the previous twelve-month period and costs as at the balance sheet date, and are discounted at 10%. Capitalized costs and future net revenues are determined on a net of tax basis. In addition, beginning in 2009, the Company's Oil Sands Mining and Upgrading activities are included in the Company's US GAAP full cost oil and gas cost center for Canada for ceiling test purposes. These differences in applying the ceiling test to current and prior years resulted in the recognition of ceiling test impairments under US GAAP, which reduced property, plant and equipment by $8,951 million in 2009 (2008 – $8,697 million, 2007 – $36 million).

For the year ended December 31, 2009, US GAAP net earnings would have decreased by $815 million (2008 – $6,164 million), net of income taxes of $178 million (2008 – $2,501 million) to reflect the impact of a current year ceiling test impairment. In addition, the impact of prior ceiling test impairments would have increased US GAAP net earnings by $551 million (2008 – increased by $3 million, 2007 – decreased by $4 million), net of income taxes of $188 million (2008 – $1 million, 2007 – $8 million) to reflect the impact of lower depletion charges. The 2007 income tax effect includes the effect of enacted Canadian income tax rate changes on this item.

During 2009, the US Securities and Exchange Commission adopted revisions to its oil and gas reporting disclosures contained in Regulation S-K and Topic 932 "Extractive Activities – Oil and Gas" (a summary of the requirements included in Regulation S-X). These revisions change the price basis for calculating oil and gas reserves from a single-day, year-end price to a monthly average price based on "first-day-of-the-month" prices. These revisions impacted the reserves used in the Company's calculation of the ceiling test under US GAAP at December 31, 2009 and will impact the calculation of depletion in future periods. In addition, oil and gas activities are now determined based on the end product, rather than the method of extraction. As a result, the Company's Oil and Sands Mining and

Upgrading operations are now included in its full cost oil and gas cost center for Canada. These revisions are effective for filings made on or after January 1, 2010, and will be applied prospectively with no retroactive restatement.

(B) The Company accounts for its stock-based compensation liability under Canadian GAAP using the intrinsic value method, as described in note 1(P). Under US GAAP, effective January 1, 2006, the Company would have adopted Financial Accounting Standards Board Statement (FASB) Topic 718 "Compensation – Stock Compensation" (previously FAS 123(R)), which requires companies to account for all stock-based compensation liabilities using the fair value method, where fair value is measured using an option pricing model. The Company uses the Black Scholes option pricing model to determine the fair value of its stock-based compensation liability for US GAAP purposes. The previous US GAAP standard, FAS 123, required companies to account for cash settled stock-based compensation liabilities using the intrinsic value method. For the year ended December 31, 2009, US GAAP net earnings would have decreased by $154 million (2008 – $76 million, 2007 – $22 million), net of income taxes of $51 million (2008 – $32 million, 2007 – $3 million) related to the different valuation methodologies. The 2007 income tax effect includes the effect of enacted Canadian income tax rate changes on this item. In addition, US GAAP net earnings would have decreased by $1 million (2008 - $nil, 2007 - $nil), net of income taxes of $nil (2008 - $nil, 2007 - $nil) related to the impact of the change in capitalized stock-based compensation on depletion, depreciation and amortization expenses.

(C) Under US GAAP, the foreign currency component of a business combination is not eligible for cash flow hedging. The impact of prior year adjustments would have decreased US GAAP net earnings by $7 million for the year ended December 31, 2009 (2008 – $8 million, 2007 – $6 million), net of income taxes of $3 million (2008 – $3 million, 2007 – $7 million), to reflect the impact of higher depletion charges. The 2007 income tax effect includes the effect of enacted Canadian income tax rate changes on this item.

(D) Under Canadian GAAP, the Company began capitalizing interest on the Horizon Project when the Board of Directors approval was received in 2005. For US GAAP, capitalization of interest on projects constructed over time is mandatory and interest would have been capitalized to the costs of construction beginning in 2004. As a result of applying US GAAP, an additional $27 million would have been capitalized to property, plant and equipment in 2004. During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest ceased and depletion, depreciation and amortization of these assets commenced. For the year ended December 31, 2009, US GAAP net earnings would have decreased by $1 million (2008 – nil, 2007 – nil), net of income taxes of $nil (2008 – $nil, 2007 – $nil).

(E) Under Canadian GAAP, the Company is not required to include potential common shares related to stock options in the calculation of diluted earnings per share as the Company has recorded the potential settlement of the stock options as a liability. Under US GAAP Topic 260 "Earnings Per Share" (previously FAS 128 "Earnings Per Share"), the Company would have included potential common shares related to stock options in the calculation of diluted earnings per share. For the year ended December 31, 2009, nil additional shares would have been included in the calculation of diluted earnings per share for US GAAP (2008 – nil additional shares, 2007 – 3,376,000 additional shares).

(F) Under Canadian GAAP, the effects of income tax changes are recognized when the changes are considered substantively enacted. Under US GAAP, the income tax changes would not be recognized until the changes are enacted into law. For the years ended December 31, 2008 and 2007, the differences between substantively enacted and enacted tax legislation resulted in a difference in timing of the recognition of a $234 million future income tax recovery.

(G) Under Canadian GAAP, debt issue costs on long-term debt must be included in the carrying value of the related debt. Under US GAAP, these items must be recorded as a deferred charge. Application of US GAAP would have resulted in the balance sheet reclassification of $49 million of debt issue costs from long-term debt to deferred charges in 2009 (2008 – $55 million, 2007 – $51 million).

(H) In December 2007, the FASB issued Topic 805 "Business Combinations" (previously FAS 141(R) "Business Combinations"), which replaced FAS 141 effective for fiscal years beginning after December 15, 2008. Topic 805 retains the purchase method of accounting and requires assets acquired and liabilities assumed in a business combination to be measured at fair value at the date of acquisition. The standard also requires acquisition-related costs and restructuring costs to be recognized separately from the business combination. This standard is to be applied prospectively to all business combinations subsequent to the effective date and does not require restatement of previously completed business combinations. The adoption of this standard did not result in a US GAAP reconciling item.

MANAGEMENT'S DISCUSSION AND ANALYSIS

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the "Company") 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", "int "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "se 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 Management's Discussion and Analysis ("MD&A") including the information in the "Outlook" section and the sensitivity analysis constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands, Primrose East, Pelican Lake, Olowi Field (Offshore Gabon), and the Kirby Thermal 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 and uncertainties 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 risks and uncertainties 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 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. The Company's operations have been, and 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. For additional information refer to the "Risks and Uncertainties" section of this MD&A. Readers are cautioned that the foregoing list of 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 NON-GAAP FINANCIAL MEASURES
Management's Discussion and Analysis includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, cash production cost and net asset value. These financial measures are not defined by generally accepted accounting principles in Canada ("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 of this MD&A. The derivation of cash production costs is included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis of the financial condition and results of operations of the Company should be read in conjunction with the Company's audited consolidated financial statements and related notes for the year ended December 31, 2009. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in Canada ("Canadian GAAP"). A reconciliation of Canadian GAAP to generally accepted accounting principles in the United States ("US GAAP") is included in note 17 to the consolidated financial statements. All dollar amounts are referenced in millions of Canadian dollars, except where otherwise noted. The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of crude oil to estimate relative energy content. This conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the wellhead. Production volumes and per barrel statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of transportation and blending costs and exclude the effect of risk management activities. Production on an "after royalty" or "net" basis is also presented for information purposes only. The following discussion and analysis refers primarily to the Company's 2009 financial results compared to 2008 and 2007, unless otherwise indicated. In addition, this MD&A details the Company's capital program and outlook for 2010. Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2009, its Annual Information Form for the year ended December 31, 2009, and its audited consolidated financial statements for the year ended December 31, 2009 is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. This MD&A is dated March 3, 2010.

ABBREVIATIONS

AECO	Alberta natural gas reference location
API	Specific gravity measured in degrees on the American Petroleum Institute scale
ARO	Asset retirement obligations
bbl	barrels

bbl/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Brent	Dated Brent
C$	Canadian dollars
CICA	Canadian Institute of Chartered Accountants
CO2	Carbon dioxide
CO2e	Carbon dioxide equivalents
Canadian GAAP	Generally accepted accounting principles in Canada
FPSO	Floating Production, Storage and Offtake Vessel
GHG	Greenhouse gas
GJ	gigajoules
GJ/d	gigajoules per day
Heavy Differential	Heavy crude oil differential from WTI

Horizon	Horizon Oil Sands
LIBOR	London Interbank Offered Rate
mcf	thousand cubic feet
mmbbl	million barrels
mmbtu	million British thermal units
mmcf/d	million cubic feet per day
mmcfe	millions of cubic feet equivalent
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
PRT	Petroleum Revenue Tax
SCO	Synthetic light crude oil
SEC	United States Securities and Exchange Commission
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US GAAP	Generally accepted accounting principles in the United States
US$	United States dollars
WCS	Western Canadian Select
WTI	West Texas Intermediate

OBJECTIVE AND STRATEGY

The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value (1) 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 strives to meet these objectives by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a balanced approach to growth and investments and focuses on creating long-term shareholder value. The Company allocates its capital by maintaining:

- Balance among its products, namely natural gas, light/medium crude oil and NGLs, Pelican Lake crude oil (2), primary heavy crude oil and thermal heavy crude oil and SCO;
- Balance among near-, mid- and long-term projects;
- Balance among acquisitions, exploitation and exploration; and
- Balance between sources and terms of debt financing and maintenance of a strong balance sheet.

(1) Discounted value of crude oil and natural gas reserves plus value of undeveloped land, less net debt.
(2) Pelican Lake crude oil is 14–17º API oil, which receives medium quality crude netbacks due to lower production costs and lower royalty rates.

The Company's three-phase crude oil marketing strategy includes:

- Blending various crude oil streams with diluents to create more attractive feedstock;
- Supporting and participating in pipeline expansions and/or new additions; and
- Supporting and participating in projects that will increase the downstream conversion capacity for heavy crude oil.

Operational discipline and cost control are fundamental to the Company. By consistently controlling costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Cost control is attained by developing area knowledge, by dominating core areas and by maintaining high working interests and operator status in its properties.

The Company is committed to maintaining a strong balance sheet and flexible capital structure. The Company believes it has built the necessary financial capacity to complete all of its growth projects. Additionally, the Company's risk management hedge program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs.

Strategic accretive acquisitions are a key component of the Company's strategy. The Company has used a combination of internally generated cash flows and debt financing to selectively acquire properties generating future cash flows in its core regions.

Highlights for the year ended December 31, 2009 include the following:

- Achieved net earnings of $1.6 billion, adjusted net earnings from operations of $2.7 billion, and cash flow from operations of $6.1 billion;
- Completed the construction of Phase 1 of Horizon and commenced operations;
- Achieved annual crude oil and natural gas production guidance;
- Achieved first crude oil production from Platform C in the Olowi Field in Offshore Gabon;
- Reduced long-term debt by $3.4 billion to $9.7 billion in 2009 from $13.0 billion in 2008; and
- Increased annual dividend payout to $0.42 from $0.40, our 10th consecutive year of dividend increases.

4

NET EARNINGS AND CASH FLOW FROM OPERATIONS

Financial Highlights

($ millions, except per common share amounts)	2009	2008	2007
Revenue, before royalties	$11,078	$16,173	$12,543
Net earnings	$1,580	$4,985	$2,608
Per common share– basic and diluted	$2.92	$9.22	$4.84
Adjusted net earnings from operations (1)	$2,689	$3,492	$2,406
Per common share– basic and diluted	$4.96	$6.46	$4.46
Cash flow from operations (2)	$6,090	$6,969	$6,198
Per common share– basic and diluted	$11.24	$12.89	$11.49
Dividends declared per common share	$0.42	$0.40	$0.34
Total assets	$41,024	$42,650	$36,114
Total long-term liabilities	$19,193	$20,856	$19,230
Capital expenditures, net of dispositions	$2,997	$7,451	$6,425

(1) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings from Operations" presented below lists the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.
(2) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Cash Flow from Operations" presented below lists the effects of certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations

($ millions)	2009	2008	2007
Net earnings as reported	$1,580	$4,985	$2,608
Stock-based compensation expense (recovery), net of tax (a)	261	(38)	134
Unrealized risk management loss (gain), net of tax (b)	1,437	(2,112)	977
Unrealized foreign exchange (gain) loss, net of tax (c)	(570)	698	(449)
Effect of statutory tax rate and other legislative changes on future income tax liabilities (d)	(19)	(41)	(864)
Adjusted net earnings from operations	$2,689	$3,492	$2,406

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the intrinsic value of outstanding vested options is recorded as a liability on the Company's balance sheet and periodic changes in the intrinsic value are recognized in net earnings or are capitalized to Oil Sands Mining and Upgrading construction costs.
(b) Derivative financial instruments are recorded at fair value on the balance sheet, with changes in fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.
(c) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, offset by the impact of cross currency swap hedges, and are recognized in net earnings.

(d) All substantively enacted or enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's consolidated balance sheet in determining future income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted or enacted. Income tax rate changes during 2009 resulted in a reduction of future income tax liabilities of approximately $19 million in North America. Income tax rate changes during 2008 resulted in a reduction of future income tax liabilities of approximately $19 million in North America and $22 million in Côte d'Ivoire, Offshore West Africa. Income tax rate and other legislative changes during 2007 resulted in a reduction of future income tax liabilities of approximately $864 million in North America.

5

Cash Flow from Operations

($ millions)	2009	2008	2007
Net earnings	$1,580	$4,985	$2,608
Non-cash items:			
Depletion, depreciation and amortization	2,819	2,683	2,863
Asset retirement obligation accretion	90	71	70
Stock-based compensation expense (recovery)	355	(52)	193
Unrealized risk management loss (gain)	1,991	(3,090)	1,400
Unrealized foreign exchange (gain) loss	(661)	832	(524)
Deferred petroleum revenue tax expense (recovery)	15	(67)	44
Future income tax (recovery) expense	(99)	1,607	(456)
Cash flow from operations	$6,090	$6,969	$6,198

For 2009, the Company reported net earnings of $1,580 million compared to net earnings of $4,985 million for 2008 (2007 – $2,608 million). The 2009 operating results of the Company were significantly impacted by lower benchmark crude oil and natural gas pricing, partially offset by the impact of the commencement of production from Horizon. Net earnings for the year ended December 31, 2009 included net unrealized after-tax expenses of $1,109 million related to the effects of risk management activities, fluctuations in foreign exchange rates and stock-based compensation, and the impact of statutory tax rate and other legislative changes on future income tax liabilities (2008 – $1,493 million after-tax income; 2007 – $202 million after-tax income). Excluding these items, adjusted net earnings from operations for the year ended December 31, 2009 decreased to $2,689 million from $3,492 million for 2008 (2007 – $2,406 million) primarily due to the impact of lower realized pricing, lower natural gas sales volumes, higher production expenses, higher depletion, depreciation and amortization expense, including the impact of a ceiling test impairment in Gabon, Offshore West Africa, higher accretion expense, higher interest expense, and the impact of realized foreign exchange loss, partially offset by the impact of higher crude oil sales volumes, lower royalty expense, realized risk management activities and the weaker Canadian dollar relative to the US dollar during 2009.

The impacts of unrealized risk management activities, stock-based compensation and changes in foreign exchange rates are expected to continue to contribute to significant volatility in consolidated net earnings and are discussed in detail in the relevant sections of this MD&A.

Cash flow from operations for the year ended December 31, 2009 decreased to $6,090 million ($11.24 per common share) from $6,969 million ($12.89 per common share) for 2008 (2007 – $6,198 million; $11.49 per common share). The decrease was primarily due to the impact of lower realized pricing, lower natural gas sales volumes, higher production expense, higher interest expense and the impact of realized foreign exchange losses, partially offset by the impact of higher crude oil sales volumes, lower royalty expense, lower current income tax and PRT and the impact of realized risk management gains and the weaker Canadian dollar relative to the US dollar during 2009.

The Company’s 2009 average sales price per bbl of conventional crude oil and NGLs decreased 30% to average $57.68 per bbl from $82.41 per bbl in 2008 (2007 – $55.45 per bbl). The Company’s average natural gas price decreased 46% to average $4.53 per mcf from $8.39 per mcf for 2008 (2007 – $6.85 per mcf).

Total production of crude oil and NGLs before royalties increased 13% to 355,463 bbl/d from 315,667 bbl/d for 2008 (2007 – 331,232 bbl/d). The increase in crude oil and NGLs production was primarily due to new production from Horizon and the Olowi Field in Offshore Gabon, partially offset by the impact of planned maintenance shutdowns in the North Sea, and in North America due to the cyclic nature of the Company’s thermal production and shut in of Primrose East for part of the year.

Total natural gas production before royalties decreased 12% to average 1,315 mmcf/d from 1,495 mmcf/d for 2008 (2007 – 1,668 mmcf/d). The decrease in natural gas production primarily reflected natural production declines and the Company's strategic reduction in natural gas drilling activity in North America.

Total crude oil and NGLs and natural gas production volumes before royalties increased 2% to average 574,730 boe/d from 564,845 boe/d for 2008 (2007 – 609,206 boe/d). Total production for 2009 was within the Company's previously issued revised guidance.

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

($ millions, except per common share amounts)					
2009	Total	Dec 31	Sep 30	Jun 30	Mar 31
Revenue, before royalties	$11,078	$3,319	$2,823	$2,750	$2,186
Net earnings	$1,580	$455	$658	$162	$305
Net earnings per common share					
– basic and diluted	$2.92	$0.85	$1.21	$0.30	$0.56
2008	Total	Dec 31	Sep 30	Jun 30	Mar 31
Revenue, before royalties	$16,173	$2,511	$4,583	$5,112	$3,967
Net earnings (loss)	$4,985	$1,770	$2,835	$(347)	$727
Net earnings (loss) per common share					
– basic and diluted	$9.22	$3.27	$5.25	$(0.65)	$1.35

Volatility in quarterly net earnings over the eight most recently completed quarters was primarily due to:

§ Crude oil pricing – The impact of fluctuating demand, geopolitical uncertainties on worldwide benchmark pricing, and the fluctuations in the Heavy Crude Oil Differential from WTI ("Heavy Differential") in North America.

§ Natural gas pricing – The impact of seasonal fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US, as well as fluctuations in imports of liquefied natural gas into the US.

§ Crude oil and NGLs sales volumes – Fluctuations in production from the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, and the commencement of operations at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore West Africa and the impact of the shut in, and subsequent restoration of some of the production in the Baobab Field.

§ Natural gas sales volumes – Production declines due to the Company's strategic decision to reduce natural gas drilling activity in North America and the allocation of capital to higher return crude oil projects, as well as natural decline rates.

§ Production expense – Fluctuations primarily due to the impact of the demand for services, industry-wide inflationary cost pressures experienced in prior quarters, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, and the commencement of operations at Horizon and the Olowi Field in Offshore Gabon.

§ Depletion, depreciation and amortization – Fluctuations due to changes in sales volumes, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, the commencement of operations at Horizon and the Olowi Field in Offshore Gabon, and the impact of a ceiling test impairment at the Olowi Field at December 31, 2009.

§ Stock-based compensation – Fluctuations due to the mark-to-market movements of the Company's stock-based compensation liability. Stock-based compensation expense (recovery) reflected fluctuations in the Company's share price.

§ Risk management – Fluctuations due to the recognition of realized and unrealized gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.

§ Foreign exchange rates – Fluctuations in the Canadian dollar relative to the US dollar impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately on US dollar denominated benchmarks. Similarly, unrealized foreign exchange gains and losses were recorded with respect to US dollar denominated debt and the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars, partially offset by the impact of cross currency swap hedges.

§ Income tax expense (recovery) – Fluctuations in income tax expense (recovery) include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.

BUSINESS ENVIRONMENT

(Yearly average)	2009	2008	2007
WTI benchmark price (US$/bbl)	$61.93	$99.65	$72.40
Dated Brent benchmark price (US$/bbl)	$61.61	$96.99	$72.59
WCS blend differential from WTI (US$/bbl) (1)	$9.64	$20.03	$23.25
WCS blend differential from WTI (%) (1)	16 %	20 %	32 %
SCO price (US$/bbl)	$61.51	$102.48	$70.11
Condensate benchmark price (US$/bbl)	$60.60	$100.10	$72.88
NYMEX benchmark price (US$/mmbtu)	$4.03	$8.95	$6.92
AECO benchmark price (C$/GJ)	$3.91	$7.71	$6.26
US / Canadian dollar average exchange rate	$0.8760	$0.9381	$0.9304
US / Canadian dollar year end exchange rate	$0.9555	$0.8166	$1.0120

(1) Beginning in 2008, the Company has quantified the Heavy Differential using the WCS blend as the heavy crude oil marker. Prior period amounts have been reclassified.

Commodity Prices

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized price is also highly sensitive to fluctuations in foreign exchange rates. The average value of the Canadian dollar in relation to the US dollar fluctuated significantly throughout 2009, with a high of approximately $0.97 in December 2009 and a low of approximately $0.77 in March 2009.

The overall decrease in WTI pricing in 2009 reflected a decrease in demand as a result of worldwide financial and economic events during the year, and ongoing geopolitical uncertainty resulting in increased market volatility, partially offset by strong Asian demand in the second half of the year. For 2009, WTI averaged US$61.93 per bbl, a decrease of 38% compared to US$99.65 per bbl for 2008 (2007 – US$72.40 per bbl).

Brent averaged US$61.61 per bbl for 2009, a decrease of 36% compared to US$96.99 per bbl for 2008 (2007 – US$72.59 per bbl). Crude oil sales contracts for the North Sea and Offshore West Africa are typically based on Brent pricing, which is more reflective of international markets and the overall supply and demand balance.

The Heavy Differential averaged 16% of WTI for 2009 compared to 20% for 2008 (2007 – 32%), reflecting relatively weak refinery margins.

The Company anticipates continued volatility in the crude oil pricing benchmarks due to the unpredictable nature of supply and demand factors, geopolitical events and the timing and extent of recovery of the global economy. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and refinery margins.

NYMEX natural gas prices averaged US$4.03 per mmbtu for 2009, a decrease of 55% from US$8.95 per mmbtu for 2008 (2007 – US$6.92 per mmbtu). Alberta based AECO natural gas pricing for 2009 decreased 49% to average $3.91 per GJ from $7.71 per GJ in 2008 (2007 – $6.26 per GJ). During 2009, natural gas pricing decreased due to a significant increase in production from shale gas reservoirs in the US, a significant decline in industrial demand caused by the onset of worldwide financial and economic events, and record storage levels in North America.

Operating, Royalty and Capital Costs

Strong commodity prices in recent years have resulted in increased demand for oilfield services worldwide. This has led to inflationary operating and capital cost pressures throughout the crude oil and natural gas industry, particularly related to drilling activities and oil sands developments.

In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in the near term to address industrial GHG emissions, as part of the national GHG reduction target. 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 of the Company's facilities, the Primrose/Wolf Lake in-situ heavy crude oil facilities and the Hays sour natural gas plant, fall under the regulations. The British Columbia carbon tax is currently being assessed at $15/tonne of CO2e on fuel consumed and gas flared in the province. This rate is scheduled to increase to $20/tonne on July 1, 2010, and to $30/tonne by July 1, 2012. As part of its involvement with the Western Climate Initiative, British Columbia has also announced that certain upstream oil and gas facilities will be included in a regional cap and trade system beginning in 2012. It is estimated that six facilities in British Columbia will be included under the cap and trade system, based on a proposed 25 kt CO2e threshold. Saskatchewan is expected to release GHG regulations in 2010 that would require the North Tangleflags in-situ heavy oil facility to meet a reduction target for its GHG emissions intensity. In the UK, GHG 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 Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Legislation to regulate GHGs in the United States through a cap and trade system is currently before the US Congress, although there is no certainty as to the form or stringency of the final legislation. In the absence of legislation, the US Environmental Protection Agency ("EPA") is authorized under the Clean Air Act to regulate GHGs, although EPA action would be subject to legal and political challenges. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the US. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oil with higher emissions intensity.

Continued cost pressures and the final outcome of changes to environmental regulations may adversely impact the Company's future net earnings, cash flow and capital projects. For additional details, refer to the "Greenhouse Gas and Other Air Emissions" section of this MD&A.

The Alberta Government implemented changes to the Alberta Royalty Framework ("ARF") effective January 1, 2009. The ARF includes a number of changes to royalty rates for natural gas, conventional crude oil, and oil sands production. Under the ARF, royalties payable vary according to commodity prices and the productivity of wells. Changes to the Alberta royalty regime under the ARF include 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. For additional details, refer to the "Royalties" section of this MD&A.

ANALYSIS OF CHANGES IN REVENUE, BEFORE ROYALTIES AND RISK MANAGEMENT ACTIVITIES

($ millions)	2007	Volumes	Changes due to Prices	Other	2008	Volumes	Changes due to Prices	Other	2009
North America									
Crude oil and NGLs	$ 5,847	$ (49)	$ 3,013	$ –	$ 8,811	$ (424)	$ (2,649)	$ –	$ 5,738
Natural Gas	4,302	(531)	914	–	4,685	(598)	(1,852)	–	2,235
	10,149	(580)	3,927	–	13,496	(1,022)	(4,501)	–	7,973
North Sea									
Crude oil and NGLs	1,575	(334)	512	–	1,753	(344)	(465)	–	944
Natural gas	22	(5)	(1)	–	16	–	1	–	17
	1,597	(339)	511	–	1,769	(344)	(464)	–	961
Offshore West Africa									
Crude oil and NGLs	751	(136)	280	–	895	413	(436)	–	872
Natural gas	25	5	19	–	49	18	(26)	–	41
	776	(131)	299	–	944	431	(462)	–	913
Subtotal									
Crude oil and NGLs	8,173	(519)	3,805	–	11,459	(355)	(3,550)	–	7,554
Natural gas	4,349	(531)	932	–	4,750	(580)	(1,877)	–	2,293
	12,522	(1,050)	4,737	–	16,209	(935)	(5,427)	–	9,847
Oil Sands Mining and Upgrading	–	–	–	–	–	1,253	–	–	1,253
Midstream	74	–	–	3	77	–	–	(5)	72
Intersegment eliminations and other (1)	(53)	–	–	(60)	(113)	–	–	19	(94)
Total	$ 12,543	$ (1,050)	$ 4,737	$ (57)	$ 16,173	$ 318	$ (5,427)	$ 14	$ 11,078

(1) Eliminates primarily internal transportation, electricity charges, and natural gas sales.

Revenue decreased 32% to $11,078 million for 2009 from $16,173 million for 2008 (2007 – $12,543 million). The decrease was primarily due to decreased realized crude oil and NGLs and natural gas prices company-wide.

For 2009, 17% of the Company’s crude oil and natural gas revenue was generated outside of North America (2008 – 17%; 2007 – 19%). North Sea accounted for 9% of crude oil and natural gas revenue for 2009 (2008 – 11%; 2007 – 13%), and Offshore West Africa accounted for 8% of crude oil and natural gas revenue for 2009 (2008 – 6%; 2007 – 6%).

ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2009	2008	2007
Crude oil and NGLs (bbl/d)			
North America – Conventional	234,523	243,826	246,779
North America – Oil Sands Mining and Upgrading	50,250	–	–
North Sea	37,761	45,274	55,933
Offshore West Africa	32,929	26,567	28,520
	355,463	315,667	331,232
Natural gas (mmcf/d)			
North America	1,287	1,472	1,643
North Sea	10	10	13
Offshore West Africa	18	13	12
	1,315	1,495	1,668
Total barrels of oil equivalent (boe/d)	574,730	564,845	609,206
Product mix			
Light/medium crude oil and NGLs	21%	22%	23%
Pelican Lake crude oil	6%	6%	6%
Primary heavy crude oil	15%	16%	15%
Thermal heavy crude oil	11%	12%	11%
Synthetic crude oil	9%	–	–
Natural gas	38%	44%	45%
Percentage of gross revenue (1)			
(excluding midstream revenue)			
Crude oil and NGLs	75%	68%	62%
Natural gas	25%	32%	38%

(1) Net of transportation and blending costs and excluding risk management activities.

ANALYSIS OF DAILY PRODUCTION, NET OF ROYALTIES

	2009	2008	2007
Crude oil and NGLs (bbl/d)			
North America – Conventional	201,873	207,933	210,769
North America – Oil Sands Mining and Upgrading	48,833	–	–
North Sea	37,683	45,182	55,825
Offshore West Africa	29,922	22,641	26,012
	318,311	275,756	292,606
Natural gas (mmcf/d)			
North America	1,214	1,225	1,378
North Sea	10	10	13
Offshore West Africa	17	11	11
	1,241	1,246	1,402
Total barrels of oil equivalent (boe/d)	525,103	483,541	526,193

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, primary heavy crude oil, thermal heavy crude oil, and SCO.

Total production averaged 574,730 boe/d for 2009, a 2% increase from 564,845 boe/d for 2008 (2007 – 609,206 boe/d).

Total production of crude oil and NGLs before royalties increased 13% to 355,463 bbl/d for 2009 from 315,667 bbl/d for 2008 (2007 – 331,232 bbl/d). The increase in crude oil and NGLs production from 2008 was primarily due to the commencement of production from Horizon and the Olowi Field in Offshore Gabon and the restoration of some of the production in the Baobab Field in Offshore Côte d'Ivoire. Crude oil and NGLs production for 2009 was within the Company's previously issued guidance of 352,000 to 363,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering, accounting for 38% of the Company's total production in 2009. Total natural gas production before royalties decreased 12% to 1,315 mmcf/d for 2009 from 1,495 mmcf/d for 2008 (2007 – 1,668 mmcf/d). The decrease in natural gas production from 2008 primarily reflected natural production declines due to the Company's strategic decision to reduce natural gas drilling activity to focus on higher return crude oil projects. Natural gas production for 2009 exceeded the Company's previously issued guidance of 1,305 to 1,314 mmcf/d.

For 2010, annual production is forecasted to average between 400,000 and 445,000 bbl/d of crude oil and NGLs and between 1,117 and 1,185 mmcf/d of natural gas.

North America - Conventional
North America crude oil and NGLs production for 2009 decreased 4% to average 234,523 bbl/d from 243,826 bbl/d for 2008 (2007 – 246,779 bbl/d). The decrease in production from 2008 was primarily due to the cyclic nature of the Company's thermal production and was in line with expectations.

North America natural gas production for 2009 decreased 13% to average 1,287 mmcf/d from 1,472 mmcf/d for 2008 (2007 –1,643 mmcf/d). The decrease in natural gas production from 2008 reflected production declines due to the Company's strategic decision to reduce natural gas drilling activity to focus on higher return crude oil projects.

North America – Oil Sands Mining and Upgrading
Horizon Phase 1 achieved first production of synthetic crude oil during 2009. Production averaged 50,250 bbl/d for 2009. Production volumes fluctuated throughout the year as the Company continued to stabilize and ramp up production.

North Sea
North Sea crude oil production for 2009 was 37,761 bbl/d, a decrease of 17% from 45,274 bbl/d for 2008 (2007 – 55,933 bbl/d) due to expected production decline.

Offshore West Africa
Offshore West Africa crude oil production for 2009 increased 24% to 32,929 bbl/d from 26,567 bbl/d for 2008 (2007 – 28,520 bbl/d). Production increased in 2009 due to additional volumes from the Baobab drilling program, which was completed in the second quarter, and new production from the Olowi Field in Offshore Gabon, offset by expected declines at Espoir.

Production volumes from the first platform at the Olowi Field continue to be below expectations and, as a result, the Company recognized a ceiling test impairment of $115 million at December 31, 2009. Drilling results and production data is being reviewed in order to develop appropriate remediation strategies and determine the impact on future production from the Field, the impact on recoverable reserves and the scope of the overall development plan. The Company continues drilling at the next scheduled platform with production targeted for the second quarter of 2010.

CRUDE OIL INVENTORY VOLUMES

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. Revenue has not been recognized on crude oil volumes that were stored in various tanks, pipelines, or floating production, storage and offtake vessels as follows:

(bbl)	2009	2008	2007
North America – Conventional	1,131,372	761,351	1,097,526
North America – Oil Sands Mining and Upgrading (SCO)	1,224,481	–	–
North Sea	713,112	558,904	1,032,723
Offshore West Africa(1)	51,103	1,113,156	342,987
	3,120,068	2,433,411	2,473,236

(1) Prior period inventory volumes include one-time adjustments to sales volumes for MD&A reporting purposes only.

OPERATING HIGHLIGHTS – CONVENTIONAL

	2009	2008	2007
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	$57.68	$82.41	$55.45
Royalties	6.73	10.48	5.94
Production expense	15.92	16.26	13.34
Netback	$35.03	$55.67	$36.17
Natural gas ($/mcf) (1)			
Sales price (2)	$4.53	$8.39	$6.85
Royalties (3)	0.32	1.46	1.11
Production expense	1.08	1.02	0.91
Netback	$3.13	$5.91	$4.83
Barrels of oil equivalent ($/boe) (1)			
Sales price (2)	$44.87	$68.62	$49.05
Royalties	4.72	9.78	6.26
Production expense	11.98	11.79	9.75
Netback	$28.17	$47.05	$33.04

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.
(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

ANALYSIS OF PRODUCT PRICES – CONVENTIONAL

	2009	2008	2007
Crude oil and NGLs ($/bbl) (1) (2)			
North America	$54.70	$77.42	$49.16
North Sea	$68.84	$100.31	$74.99
Offshore West Africa	$65.27	$97.96	$71.68
Company average	$57.68	$82.41	$55.45
Natural gas ($/mcf) (1) (2)			
North America	$4.51	$8.41	$6.87
North Sea	$4.66	$4.09	$4.26
Offshore West Africa	$6.11	$10.03	$5.68
Company average	$4.53	$8.39	$6.85
Company average ($/boe) (1) (2)	$44.87	$68.62	$49.05

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

Realized crude oil and NGLs prices decreased 30% to average $57.68 per bbl for 2009 from $82.41 per bbl for 2008 (2007 – $55.45 per bbl). The decrease in 2009 was primarily a result of lower WTI and Brent benchmark crude oil prices during most of the year, partially offset by the impact of the narrowing of the Heavy Differential and the weaker Canadian dollar relative to the US dollar during 2009.

The Company's realized natural gas price decreased 46% to average $4.53 per mcf for 2009 from $8.39 per mcf for 2008 (2007 – $6.85 per mcf). The decrease in 2009 was primarily due to lower benchmark prices resulting from lower demand, as well as higher storage levels due to increased shale gas production in the US.

13

North America

North America realized crude oil prices decreased 29% to average $54.70 per bbl for 2009 from $77.42 per bbl for 2008 (2007 – $49.16 per bbl). The decrease in 2009 was due to decreased WTI benchmark pricing, partially offset by the impact of a narrower Heavy Differential, and a weaker Canadian dollar.

The Company continues to focus on its crude oil marketing strategy, including the development of a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil conversion capacity. During 2009, the Company contributed approximately 140,000 bbl/d of heavy crude oil blends to the WCS stream. The Company has entered into a 20 year transportation agreement to commit to ship 120,000 bbl/d of heavy sour crude oil on the proposed 500,000 bbl/d Keystone Pipeline US Gulf Coast expansion from Hardisty, Alberta to the US Gulf Coast. Contemporaneously, the Company also entered into a 20 year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy sour crude oil to a major US refiner. Deliveries under the agreements are expected to commence in 2012 upon completion of the pipeline expansion and are subject to Keystone's receipt of regulatory approval of the pipeline expansion.

In the first quarter of 2010, the Company announced, together with North West Upgrading Inc., the submission of a joint proposal to the Alberta Government to construct and operate a bitumen refinery near Redwater, Alberta. This proposal was submitted in response to a request for proposal under the Alberta Royalty Framework's Bitumen Royalty In Kind (BRIK) program.

North America realized natural gas prices decreased 46% to average $4.51 per mcf for 2009 from $8.41 per mcf for 2008 (2007 – $6.87 per mcf), primarily related to lower benchmark prices due to the impact of weather and storage levels.

Comparisons of the prices received for the Company's North America conventional production by product type were as follows:

(Yearly average)	2009	2008	2007
Wellhead Price (1) (2)			
Light/medium crude oil and NGLs (C$/bbl)	$57.02	$89.04	$66.24
Pelican Lake crude oil (C$/bbl)	$55.52	$76.91	$46.29
Primary heavy crude oil (C$/bbl)	$55.66	$74.91	$43.77
Thermal heavy crude oil (C$/bbl)	$51.18	$71.89	$43.49
Natural gas (C$/mcf)	$4.51	$8.41	$6.87

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

North Sea

North Sea realized crude oil prices decreased 31% to average $68.84 per bbl for 2009 from $100.31 per bbl for 2008 (2007 – $74.99 per bbl). Realized crude oil prices per bbl in any particular period are dependant on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices at the time of lifting. The decrease in realized crude oil prices in the North Sea from 2008 reflected weaker Brent benchmark pricing, partially offset by the impact of the weaker Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices decreased 33% to average $65.27 per bbl for 2009 from $97.96 per bbl for 2008 (2007 – $71.68 per bbl). Realized crude oil prices per bbl in any particular period are dependant on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices at the time of lifting. The decrease in realized crude oil prices in Offshore West Africa from 2008 reflected weaker Brent benchmark pricing, partially offset by the impact of the weaker Canadian dollar.

ROYALTIES – CONVENTIONAL

	2009	2008	2007
Crude oil and NGLs ($/bbl) (1)			
North America	$7.93	$11.99	$7.19
North Sea	$0.14	$0.21	$0.14
Offshore West Africa	$5.79	$14.81	$6.40
Company average	$6.73	$10.48	$5.94
Natural gas ($/mcf) (1)			
North America (2)	$0.32	$1.47	$1.12
Offshore West Africa	$0.53	$1.52	$0.51
Company average	$0.32	$1.46	$1.11
Company average ($/boe) (1)	$4.72	$9.78	$6.26
Percentage of revenue (3)			
Crude oil and NGLs	12 %	13 %	11 %
Natural gas (2)	7 %	17 %	16 %
Boe	11 %	14 %	13 %

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.
(3) Net of transportation and blending costs and excluding risk management activities.

North America

Government royalties on a significant portion of North America crude oil and NGLs 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 investments in the applicable project were fully recovered, at which time the royalty increased to 25% of net profit. Effective January 1, 2009, changes to the Alberta royalty regime under the ARF include 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, effective January 1, 2009, new royalty formulas under the ARF for conventional crude oil and natural gas operate on sliding scales ranging up to 50%, determined by commodity prices and well productivity.

In March 2009, the Government of Alberta announced new incentive programs to stimulate activity in Alberta. These programs provide for:

- A royalty credit of $200 per meter on new conventional crude oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, to a maximum of 10% of conventional Crown royalties paid in Alberta.
- Reduced royalty rates that set the maximum royalty at 5% for the first 12 months of production, up to a maximum of 50,000 boe or 500 mmcfe, for new conventional crude oil and natural gas wells that commence production between April 1, 2009 and March 31, 2010.

In June 2009, the Government of Alberta extended the two incentive programs described above by one year, to March 31, 2011.

Effective September 1, 2009, the Province of British Columbia announced an oil and gas stimulus package that includes:

•

A one-year, 2% royalty rate for all natural gas wells drilled between September 1, 2009 and June 30, 2010. Qualifying wells must commence production before December 31, 2010.

- A permanent increase of 15% in the existing royalty holiday credits for the Deep Royalty Program.
- Permanent qualification of horizontal wells drilled to a vertical depth between 1,900 and 2,300 meters into the Deep Royalty Program.
- An additional $50 million allocation for the Infrastructure Royalty Credit Program to stimulate investment in oil and gas roads and pipelines.

Crude oil and NGLs royalties for 2009 compared to 2008 reflected weaker realized crude oil prices and the impact of the ARF and averaged approximately 14% of gross revenues for 2009 compared to 15% for 2008 (2007 – 15%). North America crude oil and NGLs royalties per bbl are anticipated to average 17% to 19% of gross revenue for 2010.

Natural gas royalties averaged approximately 7% of gross revenues for 2009 compared to 18% for 2008 (2007 – 16%), primarily due to lower benchmark natural gas prices and the impact of the ARF. North America natural gas royalties per mcf are anticipated to average 11% to 13% of gross revenue for 2010.

North Sea

North Sea government royalties on crude oil were eliminated effective January 1, 2003. The remaining royalty is a gross overriding royalty on the Ninian Field.

Offshore West Africa

Under the terms of Production Sharing Contracts ("PSCs"), royalty rates fluctuate based on realized commodity pricing, capital costs, and the timing of liftings from each field. Royalty rates as a percentage of revenue averaged approximately 9% for 2009 compared to 15% for 2008 (2007 – 9%). Offshore West Africa royalty rates are anticipated to average 7% to 9% of gross revenue for 2010.

PRODUCTION EXPENSE – CONVENTIONAL

	2009	2008	2007
Crude oil and NGLs ($/bbl) (1)			
North America	$14.63	$14.96	$12.26
North Sea	$26.98	$26.29	$20.78
Offshore West Africa	$12.83	$10.29	$8.32
Company average	$15.92	$16.26	$13.34
Natural gas ($/mcf) (1)			
North America	$1.07	$1.00	$0.90
North Sea	$2.16	$2.51	$2.17
Offshore West Africa	$1.23	$1.61	$1.48
Company average	$1.08	$1.02	$0.91
Company average ($/boe) (1)	$11.98	$11.79	$9.75

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and NGLs production expense for 2009 decreased 2% to $14.63 per bbl from $14.96 per bbl for 2008 (2007 – $12.26 per bbl). The decrease in production expense per bbl from 2008 was primarily a result of the Company's focus on optimizing service costs, together with lower power prices and cost of natural gas for fuel for the Company's thermal operations partially offset by the impact of increased property tax.

North America natural gas production expense for 2009 increased 7% to $1.07 per mcf from $1.00 per mcf for 2008 (2007 – $0.90 per mcf). The increase in production expense per mcf from 2008 was primarily a result of the impact of lower production volumes on fixed costs, offset by reductions due to the Company's focus on optimizing service costs and lower power prices.

North Sea

North Sea crude oil production expense increased on a per barrel basis from 2008 primarily due to lower production volumes on a relatively fixed operating cost base and the weakening of the Canadian dollar against the UK pound sterling.

Offshore West Africa

Offshore West Africa crude oil production expense increased on a per barrel basis from 2008. Production expense was impacted by the timing of liftings of each field and higher operating costs per barrel in Gabon.

DEPLETION, DEPRECIATION AND AMORTIZATION – CONVENTIONAL

($ millions, except per boe amounts) (1)	2009	2008	2007
North America	$2,060	$2,236	$2,350
North Sea	261	317	340
Offshore West Africa	335	132	165
Expense	$2,656	$2,685	$2,855
$/boe	$13.82	$12.97	$12.84

(1) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, Depreciation and Amortization ("DD&A") expense for 2009 decreased slightly to $2,656 million from $2,685 million for 2008 (2007 – $2,855 million), primarily due to the impact of lower sales volumes offset by the impact of a ceiling test impairment related to Gabon, Offshore West Africa.

ASSET RETIREMENT OBLIGATION ACCRETION – CONVENTIONAL

($ millions, except per boe amounts) (1)	2009	2008	2007
North America	$41	$42	$38
North Sea	24	27	30
Offshore West Africa	4	2	2
Expense	$69	$71	$70
$/boe	$0.36	$0.34	$0.32

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Accretion expense in 2009 was comparable to 2008.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

FINANCIAL METRICS

($/bbl) (1)	2009	2008	2007
SCO sales price (2)	$70.83	$–	$–
Bitumen value for royalty purposes	$56.57	$–	$–
Bitumen royalties (3)	$2.15	$–	$–

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and excluding risk management activities.
(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

PRODUCTION COSTS

The following tables provide reconciliations of Oil Sands Mining and Upgrading production costs to the Segmented Information disclosed in note 16 to the Company’s consolidated financial statements.

($ millions)	2009	2008	2007
Cash costs, excluding natural gas costs	$599	$–	$–
Natural gas costs	84	–	–
Total cash production costs	$683	$–	$–

($/bbl) (1)	2009	2008	2007
Cash costs, excluding natural gas costs	$34.97	$–	$–
Natural gas costs	4.92	–	–
Total cash production costs	$39.89	$–	$–
Sales (bbl/d)	46,896	–	–

(1) Amounts expressed on a per unit basis are based on sales volumes.

First sales from Horizon occurred in the second quarter of 2009.

Production expense in 2009 reflected the effects of the commencement of operations. Total cash production costs averaged $39.89 per bbl in 2009. Cash production costs in 2009 reflected the impact of maintenance costs related to premature equipment failures and overall plant reliability. Cash production costs are targeted to average $31.00 to $37.00 per barrel in 2010.

($ millions)	2009	2008	2007
Depreciation, depletion and amortization	$187	$–	$–
Asset retirement obligation accretion	21	–	–
Total	$208	$–	$–

($/bbl) (1)	2009	2008	2007
Depreciation, depletion and amortization	$10.95	$–	$–
Asset retirement obligation accretion	1.22	–	–
Total	$12.17	$–	$–

(1) Amounts expressed on a per unit basis are based on sales volumes.

During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs has ceased, and depletion, depreciation and amortization of these assets has commenced. Depletion, depreciation and amortization included the disposal of a portion of the tailings line pipe related to premature wear.

MIDSTREAM

($ millions)	2009	2008	2007
Revenue	$72	$77	$74
Production expense	19	25	22
Midstream cash flow	53	52	52
Depreciation	9	8	8
Segment earnings before taxes	$44	$44	$44

The Company's midstream assets consist of three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 80% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The midstream pipeline assets allow the Company to control the transport of its own production volumes as well as earn third party revenue. This transportation control enhances the Company's ability to manage the full range of costs associated with the development and marketing of its heavier crude oil.

ADMINISTRATION EXPENSE

($ millions, except per boe amounts) (1)	2009	2008	2007
Expense	$181	$180	$208
$/boe	$0.87	$0.87	$0.93

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense for 2009 was comparable to 2008. Administration expense on a boe basis in 2009 includes sales volumes associated with the commencement of Horizon.

STOCK-BASED COMPENSATION

($ millions)	2009	2008	2007
Expense (recovery)	$355	$(52)	$193

The Company's Stock Option Plan (the "Option Plan") provides current employees (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. The design of the Option Plan balances the need for a long-term compensation program to retain employees with the benefits of reducing the impact of dilution on current Shareholders and the reporting of the obligations associated with stock options. Transparency of the cost of the Option Plan is increased as changes in the intrinsic value of outstanding stock options are recognized each period. The cash payment feature provides option holders with substantially the same benefits and allows them to realize the value of their options through a simplified administration process.

The Company recorded a $355 million ($261 million after-tax) stock-based compensation expense during 2009 primarily as a result of normal course graded vesting of options granted in prior periods, the impact of vested options exercised or surrendered during the year, and the 56% increase in the Company's share price for the year ended December 31, 2009 (December 31, 2009 – $76.00; December 31, 2008 – $48.75; December 31, 2007 – $72.58; December 31, 2006 – $62.15). As required by Canadian GAAP, the Company records a liability for potential cash payments to settle its outstanding employee stock options each reporting period based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. For the year ended December 31, 2009, the Company capitalized $2 million in stock-based compensation to Oil Sands Mining and Upgrading (2008 – $23 million recovery; 2007 – $58 million capitalized).

The stock-based compensation liability reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on December 31, 2009. In periods when substantial stock price changes occur, the Company's earnings are subject to significant volatility. The Company utilizes its stock-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

For the year ended December 31, 2009, the Company paid $94 million for stock options surrendered for cash settlement (2008 – $207 million; 2007 – $375 million).

INTEREST EXPENSE

($ millions, except per boe amounts and interest rates) (1)	2009	2008	2007
Expense, gross	$516	$609	$632
Less: capitalized interest, Oil Sands Mining and Upgrading	106	481	356
Expense, net	$410	$128	$276
$/boe	$1.96	$0.62	$1.24

Average effective interest rate	4.3 %	5.1 %	5.5 %

(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest expense decreased from 2008 primarily due to lower debt levels and lower variable interest rates and reflected the impact of fluctuations in foreign exchange rates on US dollar denominated debt. The Company's average effective interest rate decreased from the comparable period in 2008 primarily due to lower variable interest rates.

During 2009, interest capitalization ceased on Horizon Phase 1 as the Phase 1 assets were completed and available for their intended use, increasing net interest expense accordingly.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, currency and interest rate exposures. These derivative financial instruments are not intended for trading or speculative purposes.

($ millions)	2009	2008	2007
Crude oil and NGLs financial instruments	$(1,330)	$2,020	$505
Natural gas financial instruments	(33)	(21)	(343)
Foreign currency contracts	110	(139)	-
Realized (gain) loss	$(1,253)	$1,860	$162
Crude oil and NGLs financial instruments	$2,039	$(3,104)	$1,244
Natural gas financial instruments	(58)	16	156
Foreign currency contracts	10	(2)	-
Unrealized loss (gain)	$1,991	$(3,090)	$1,400
Net loss (gain)	$738	$(1,230)	$1,562

Complete details related to outstanding derivative financial instruments at December 31, 2009 are disclosed in note 13 to the Company's consolidated financial statements.

The commodity derivative financial instruments currently outstanding have not been designated as hedges for accounting purposes (the "non-designated hedges"). The fair value of these non-designated hedges is based on prevailing forward commodity prices in effect at the end of each reporting period and is reflected in risk management activities in consolidated net earnings. The cash settlement amount of the commodity derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement, as compared to their mark-to-market value at December 31, 2009.

Due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized loss of $1,991 million ($1,437 million after-tax) on its risk management activities for the year ended December 31, 2009 (2008 – $3,090 million unrealized gain, $2,112 million after-tax; 2007 – $1,400 million unrealized loss, $977 million after-tax).

FOREIGN EXCHANGE

($ millions)	2009	2008	2007
Net realized loss (gain)	$30	$(114)	$53
Net unrealized (gain) loss (1)	(661)	832	(524)
Net (gain) loss	$(631)	$718	$(471)

(1) Amounts are reported net of the hedging effect of cross currency swap hedges.

As a result of foreign currency translation, the Company's operating results are affected by the fluctuations in the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. A majority of the Company's revenue is based on reference to US dollar benchmark prices. An increase in the value of the Canadian dollar in relation to the US dollar results in decreased revenue from the sale of the Company's production. Conversely a decrease in the value of the Canadian dollar in relation to the US dollar results in increased revenue from the sale of the Company's production. Production expenses and future income tax liabilities in the North Sea are subject to foreign currency fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar. The value of the Company's US dollar denominated debt is also impacted by the value of the Canadian dollar in relation to the US dollar.

The net unrealized foreign exchange gain in 2009 was primarily related to the strengthening Canadian dollar in relation to the US dollar with respect to the US dollar denominated debt, partially offset by the impact of the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars. Included in the net unrealized gain for the year ended December 31, 2009 was an unrealized loss of $338 million (2008 – $449 million unrealized gain, 2007 – $351 million unrealized loss) related to the impact of cross currency swap hedges. The net realized foreign exchange loss for 2009 was primarily due to the result of foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US dollar denominated debt. The Canadian dollar ended the year at US$0.9555 compared to US$0.8166 at December 31, 2008 (December 31, 2007 – US$1.0120).

TAXES

($ millions, except income tax rates)	2009	2008	2007
Current	$91	$245	$121
Deferred	15	(67)	44
Taxes other than income tax	$106	$178	$165
North America (1)	$28	$33	$96
North Sea	278	340	210
Offshore West Africa	82	128	74
Current income tax	388	501	380
Future income tax	(99)	1,607	(456)
	289	2,108	(76)
Income tax rate and other legislative changes (2) (3) (4)	19	41	864
	$308	$2,149	$788
Effective income tax rate before income tax rate and other legislative changes	24.3%	27.8%	32.2%

(1) Includes North America Conventional Crude Oil and Natural Gas, Midstream, and Oil Sands Mining and Upgrading segments.
(2) Includes the effects of one time recoveries of $19 million due to British Columbia corporate income tax rate reductions substantively enacted or enacted during 2009.
(3) Includes the effects of one time recoveries of $19 million due to British Columbia corporate income tax rate reductions and $22 million due to Côte d'Ivoire corporate income tax rate reductions substantively enacted or enacted during 2008.
(4) Includes the effect of one time recoveries of $864 million due to Canadian Federal income tax rate reductions and other legislative changes substantively enacted or enacted during 2007.

Taxes other than income tax primarily includes current and deferred PRT, which is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including related capital and abandonment expenditures.

Taxable income from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. North America current income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each business segment will vary depending on available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities ultimately arising from these reassessments will be material.

For 2010, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense in Canada of $450 million to $550 million and in the North Sea and Offshore West Africa of $220 million to $260 million.

NET CAPITAL EXPENDITURES (1)

($ millions)	2009	2008	2007
Expenditures on property, plant and equipment			
Net property acquisitions (dispositions)	$6	$336	$(39)
Land acquisition and retention	77	86	95
Seismic evaluations	73	107	124
Well drilling, completion and equipping	1,244	1,664	1,642
Production and related facilities	977	1,282	1,205
Total net reserve replacement expenditures	2,377	3,475	3,027
Oil Sands Mining and Upgrading:			
Horizon Phase 1 construction costs	69	2,732	2,740
Horizon Phase 1 commissioning costs and other	202	364	–
Horizon Phases 2/3 construction costs	104	336	124
Capitalized interest, stock-based compensation and other	98	480	437
Sustaining capital	80	–	–
Total Oil Sands Mining and Upgrading (2)	553	3,912	3,301
Midstream	6	9	6
Abandonments (3)	48	38	71
Head office	13	17	20
Total net capital expenditures	$2,997	$7,451	$6,425
By segment			
North America	$1,663	$2,344	$2,428
North Sea	168	319	439
Offshore West Africa	544	811	159
Other	2	1	1
Oil Sands Mining and Upgrading	553	3,912	3,301
Midstream	6	9	6
Abandonments (3)	48	38	71
Head office	13	17	20
Total	$2,997	$7,451	$6,425

(1) Net capital expenditures exclude adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Net expenditures for Oil Sands Mining and Upgrading assets also include the impact of intersegment eliminations.

(3) Abandonments represent expenditures to settle ARO and have been reflected as capital expenditures in this table.

The Company's operating strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core regions where it can dominate the land base and infrastructure. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for 2009 were $2,997 million compared to $7,451 million for 2008 (2007 – $6,425 million). The decrease in capital expenditures from the prior year reflects the completion of Horizon Phase 1 construction. Capital expenditures were also impacted by the effects of an overall strategic reduction in the North America natural gas drilling program.

Drilling Activity (number of wells)

	2009	2008	2007
Net successful natural gas wells	109	269	383
Net successful crude oil wells	644	682	592
Dry wells	46	39	93
Stratigraphic test / service wells	329	131	254
Total	1,128	1,121	1,322
Success rate (excluding stratigraphic test / service wells)	94%	96%	91%

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 58% of the total capital expenditures for the year ended December 31, 2009 compared to approximately 32% for 2008 (2007 – 39%).

During 2009, the Company targeted 117 net natural gas wells, including 21 wells in Northeast British Columbia, 39 wells in the Northern Plains region, 47 wells in Northwest Alberta, and 10 wells in the Southern Plains region. The Company also targeted 676 net crude oil wells during the year. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 496 primary heavy crude oil wells, 60 Pelican Lake crude oil wells, 82 thermal crude oil wells and 2 light crude oil wells were drilled. Another 36 wells targeting light crude oil were drilled outside the Northern Plains region.

The Company continued to access its large crude oil drilling inventory to maximize value in both the short and long term. Due to the Company's focus on drilling crude oil wells in recent years, a low natural gas price, and as a result of royalty changes under the ARF, natural gas drilling activities have been reduced. Deferred natural gas well locations have been retained in the Company's prospect inventory.

As part of the phased expansion of its In-Situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. During 2009, the Company drilled 82 thermal oil wells, and 36 stratigraphic test wells and observation wells. Overall Primrose thermal production for 2009 was approximately 64,000 bbl/d (2008 – 65,000 bbl/d; 2007 – 64,000 bbl/d). The Primrose East Expansion, a new facility located 15 kilometers from the existing Primrose South steam plant and 25 kilometers from the Wolf Lake central processing facility, was completed and first steaming commenced in September 2008, with first production achieved in the fourth quarter of 2008. During the first quarter of 2009, operational issues on one of the pads caused steaming to cease on all well pads in the Primrose East project area. During 2009, upon receipt of regulatory approval, the Company began diagnostic steaming and is continuing to work on resolving the issue.

The next planned phase of the Company's In-Situ Oil Sands Assets expansion is the Kirby project located 120 kilometers north of the existing Primrose facilities. During 2007, the Company filed a combined application and Environmental Impact Assessment for this project with Alberta Environment and the Alberta Energy and Utilities Board. Final corporate sanction and project scope is targeted for late 2010. Currently, the Company is proceeding with the detailed engineering and design work.

Development of new pads and tertiary recovery conversion projects at Pelican Lake continued as expected throughout 2009. Drilling consisted of 60 horizontal crude oil wells, with plans to drill 147 additional horizontal crude oil wells in 2010. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 37,000 bbl/d in 2009 (2008 – 37,000 bbl/d; 2007 – 34,000 bbl/d).

For 2010, the Company's overall drilling activity in North America is expected to comprise approximately 93 natural gas wells and 956 crude oil wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

With construction completed, Horizon Phase 1 assets are now available for their intended use. Accordingly, capitalization of all associated development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs ceased, and depletion, depreciation and amortization of these assets commenced.

Production was lower than anticipated due to a number of challenges encountered in the third and fourth quarter. The challenges primarily relate to:

- Premature equipment failures in the Ore Preparation Plant, Primary Upgrading, the Naphtha Recovery Unit and the Sulphur Plant;
- Ore processing challenges arising in September resulting from a higher percentage of clays in the second mine bench and the lack of available blending materials from other mine benches associated with early mine operations; and
- Equipment failure in the hydrogen plant requiring a shutdown for an extended period to time, and issues with one of the coker furnaces.

Engineering and procurement is underway for Tranche 2 of the Phase 2/3 expansion with a focus on increasing reliability and uptime. Tranches 3 and 4 of Phase 2/3 continue to be re-profiled. The Company continues to work on completing its lessons learned from the construction of Phase 1 and implementing these into the development of future expansions.

North Sea

During 2009, the Company drilled 0.9 net oil wells and 0.3 net exploration wells at Deep Banff, which did not find commercial reserves. Focus continued on lowering costs and high grading infill drilling opportunities ahead of the planned restart of platform drilling operations in the second quarter of 2010.

The Company also completed planned maintenance turnarounds at four of its five Platform installations on time and on budget.

Offshore West Africa

The Company drilled 6.1 net wells during 2009.

The Company completed the Baobab drilling program in the first quarter of 2009, adding approximately 10,000 bbl/d net to the Company.

Progress on the Facility Upgrade Project at Espoir to increase processing capacity of the Floating Production Storage and Offtake Vessel ("FPSO") has reverted to the original schedule to accommodate effective utilization of the installation vessel at Olowi.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	2009	2008	2007
Working capital (deficit) (1)	$(514)	$392	$(1,382)
Long-term debt (2) (3)	$9,658	$13,016	$10,940
Shareholders' equity			
Share capital	$2,834	$2,768	$2,674
Retained earnings	16,696	15,344	10,575
Accumulated other comprehensive (loss) income	(104)	262	72
Total	$19,426	$18,374	$13,321
Debt to book capitalization (3) (4)	33%	41%	45%
Debt to market capitalization (3) (5)	19%	33%	22%
After tax return on average common shareholders' equity (6)	8%	33%	22%
After tax return on average capital employed (3) (7)	6%	19%	12%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.
(2) Includes the current portion of long-term debt (2009 – $nil; 2008 – $420 million; 2007 – $nil).
(3) Long-term debt at December 31, 2009 and 2008 is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs.
(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.
(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus current and long-term debt.
(6) Calculated as net earnings for the year; as a percentage of average common shareholders' equity for the year.
(7) Calculated as net earnings plus after-tax interest expense for the year; as a percentage of average capital employed. Average capital employed is the average shareholders' equity and current and long-term debt for the year, including $12,855 million in average capital employed related to the Horizon Oil Sands (2008 – $10,678 million; 2007 –

$7,001 million).

At December 31, 2009, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations is dependent on factors discussed in the "Risks and Uncertainties" section of this MD&A. The Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon these factors, as well as maintaining an investment grade debt rating and the condition of capital and credit markets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its on-going hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms, will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

During 2009, the Company repaid $2,350 million remaining on the non-revolving syndicated credit facility related to the acquisition of Anadarko Canada Corporation and cancelled the facility. At December 31, 2009, the Company had $2,004 million of available credit under its bank credit facilities. The Company's current debt ratings are BBB (high) with a stable trend by DBRS Limited, Baa2 with a stable outlook by Moody's Investors Service and BBB with a stable outlook by Standard & Poor's.

Further details related to the Company's long-term debt at December 31, 2009 are discussed below and in note 5 to the Company's audited annual consolidated financial statements.

Long-term debt was $9,658 million at December 31, 2009, resulting in a debt to book capitalization level of 33% as at December 31, 2009 (December 31, 2008 – 41%; December 31, 2007 – 45%). This ratio is below the 35% to 45% range targeted by management. The Company remains committed to maintaining a strong balance sheet and flexible capital structure. The Company has hedged a portion of its crude oil and natural gas production for 2010 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs.

During 2009, the Company filed new base shelf prospectuses that allow for the issue of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

The Company's commodity hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs. This program currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. As at December 31, 2009, in accordance with the policy, approximately 39% of budgeted crude oil and approximately 17% of budgeted natural gas volumes were hedged using collars for 2010.

Further details related to the Company's commodity related derivative financial instruments outstanding at December 31, 2009, are discussed in note 13 to the Company's audited annual consolidated financial statements.

Share Capital

As at December 31, 2009, there were 542,327,000 common shares outstanding and 32,106,000 stock options outstanding. As at March 3, 2010, the Company had 542,655,000 common shares outstanding and 30,702,000 stock options outstanding.

The Company did not renew its Normal Course Issuer Bid during 2009. During 2008 and 2009, the Company did not purchase any common shares for cancellation under the programs then in place.

On March 3, 2010, the Company's Board of Directors approved an increase in the annual dividend declared by the Company to $0.60 per common share for 2010. The increase represents a 43% increase from the prior year. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change. In March 2009, an increase in the annual dividend paid by the Company to $0.42 per common share was approved for 2009. The increase represented a 5% increase from 2008.

On March 3, 2010 the Board of Directors approved a resolution to file with the Toronto Stock Exchange a Notice of Intention to purchase by way of normal course issuer bid up to 2.5% of the Company's issued and outstanding common shares. Subject to acceptance by the Toronto Stock Exchange of the Notice of Intention, the purchases would be made through the facilities of the Toronto Stock Exchange and the New York Stock Exchange.

Share Split

On March 3, 2010, the Company’s Board of Directors approved a resolution to subdivide the Company’s common shares on a two for one basis, subject to shareholder approval. The proposal will be voted on at the Company’s Annual and Special Meeting of Shareholders to be held on May 6, 2010.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. These commitments primarily relate to firm commitments for gathering, processing and transmission services; operating leases relating to offshore FPSOs, drilling rigs and office space; expenditures relating to ARO; as well as long-term debt and interest payments. As at December 31, 2009, no entities were consolidated under CICA Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2009:

($ millions)	2010	2011	2012	2013	2014	Thereafter
Product transportation and pipeline	$207	$162	$136	$125	$126	$1,051
Offshore equipment operating lease	$155	$124	$103	$102	$101	$261
Offshore drilling	$49	$–	$–	$–	$–	$–
Asset retirement obligations (1)	$16	$20	$21	$31	$39	$6,479
Long-term debt (2)	$400	$419	$366	$819	$366	$5,424
Interest expense (3)	$473	$451	$415	$370	$350	$4,779
Office leases	$25	$19	$3	$2	$2	$–
Other	$271	$67	$23	$15	$12	$34

(1) Amounts represent management's estimate of the future undiscounted payments to settle ARO related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2010 – 2014 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(2) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,897 million of revolving bank credit facilities due to the extendable nature of the facilities.

(3) Interest expense amounts represent the scheduled fixed rate and variable rate cash payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates as of December 31, 2009.

LEGAL PROCEEDINGS

The Company is defendant and plaintiff in a number of legal actions. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

RESERVES

For the year ended December 31, 2009, the Company retained qualified independent reserves evaluators, Sproule Associates Limited ("Sproule"), and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved, as well as probable crude oil, synthetic crude oil, bitumen, natural gas, coal bed methane, and NGLs reserves and prepare Evaluation Reports on these reserves. Sproule evaluated and reviewed all of the Company's crude oil, bitumen, natural gas, coal bed methane and NGLs reserves. GLJ evaluated all of the synthetic crude oil reserves related to the Company's oil sands mine. The Company has been granted an exemption from certain 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, under Regulations S-K and S-X, for certain disclosures required under NI 51-101. On December 31, 2008, the SEC released its final rules for the modernization of oil and gas reporting (“Final Rule”). The material changes include the ability to include oil sands mining as an oil and gas activity, ability to use reliable technology to establish undeveloped reserves, the optional ability to report probable reserves, the requirement to track undeveloped locations, and the directive to use 12–month average price and current costs. These resulting changes are more in line with NI 51-101; however, there are material differences to the type of volumes disclosed and the basis from which the volumes are determined. NI 51-101 requires gross reserves and future net revenue under forecast pricing and costs, however, the SEC, as discussed, requires disclosure of net reserves, after royalties, using 12–month average prices and current costs. Therefore the difference between the reported numbers, under the two disclosure standards can be material.

The Company annually discloses proved reserves and the standardized measure of discounted future net cash flows using 12–month average prices and current costs as mandated by the SEC in the supplementary oil and gas information section of the Company’s Annual Report and in its annual Form 40-F filing with the SEC.

The following tables summarize the Company's proved crude oil and natural gas reserves, net of royalties, as at December 31, 2009 and 2008:

Crude oil and NGLs (mmbbl)	Synthetic Crude Oil (1)	Bitumen (2)	Other Oil & NGLs	North America Total	North Sea	Offshore West Africa	Total
Net proved reserves							
Reserves, December 31, 2008	–	690	258	948	256	142	1,346
Extensions and discoveries	–	24	6	30	–	–	30
Improved recovery	–	8	75	83	–	–	83
SEC Reliable Technology (3)	–	7	–	7	–	–	7
SEC Rule Transition (4)	1,650	–	–	1,650	–	–	1,650
Purchases of reserves in place	–	–	1	1	–	–	1
Sales of reserves in place	–	–	–	–	–	–	–
Production	–	(49)	(24)	(73)	(14)	(11)	(98)
Economic revisions due to prices	–	(64)	(8)	(72)	57	(4)	(19)
Revisions of prior estimates	–	79	11	90	(59)	(4)	27
Reserves, December 31, 2009	1,650	695	319	2,664	240	123	3,027

(1) Prior to December 31, 2009, the Company's Horizon SCO reserves were reported separately in accordance with SEC's Industry Guide 7. With SEC's Final Rule in effect January 1, 2010, this synthetic crude oil is now included in the Company's crude oil and natural gas reserve totals.

(2) Bitumen as defined by the SEC, under the Final Rule, "is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis." Under this definition, all the Company's thermal and primary heavy crude oil reserves have been included. Prior to December 31, 2009, these numbers would have been included within the Company's conventional crude oil and NGL totals.

(3) SEC reliable technology accounts for reserve volumes added due to the reserve rule changes.

(4) For continuity purposes, with respect to the transition from Industry Guide 7 into SEC's Final Rule, the following SCO table has been provided to illustrate the changes in the Company's Horizon SCO reserves for the 2009 year.

Horizon SCO reserves (mmbbl)	Net Proved (mmbl)
Reserves, December 31, 2008	1,946
Production	(18)
Economic revisions due to prices	(307)
Revisions of prior estimates	29
Reserves, December 31, 2009	1,650

Natural gas (bcf)	North America	North Sea	Offshore West Africa	Total
Net proved reserves				

Reserves, December 31, 2008	3,523	67	94	3,684
Extensions and discoveries	92	–	–	92
Improved recovery	11	–	–	11
SEC Reliable Technology	–	–	–	–
Purchases of reserves in place	15	–	–	15
Sales of reserves in place	(6)	–	–	(6)
Production	(443)	(4)	(6)	(453)
Economic revisions due to prices	(335)	12	(4)	(327)
Revisions of prior estimates	170	(8)	1	163
Reserves, December 31, 2009	3,027	67	85	3,179

The Company's net proved crude oil and NGLs reserves at December 31, 2009, excluding synthetic crude oil, totaled 1,377 mmbbl. Approximately 132% of the production was replaced by reserve additions and revisions during 2009. Additions resulting from exploration and development and acquisition activities amounted to 121 mmbbl, while net positive revisions amounted to 8 mmbbl.

The Company's net proved natural gas reserves, net of royalties, at December 31, 2009 totaled 3,179 bcf. Additions related to exploration, development, acquisition and dispostion activities amounted to 112 bcf, while net negative revisions amounted to 164 bcf. This net loss is largely due to the change in price from year end 2008 to year end 2009.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of Sproule and 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 synthetic crude oil, crude oil, NGLs and natural gas reserves.

Additional reserves disclosure is annually disclosed in the supplementary oil and gas information of the Company's Annual Report.

RISKS AND UNCERTAINTIES

The Company is exposed to various operational risks inherent in exploring, developing, producing and marketing crude oil and natural gas and the mining and upgrading of bitumen into SCO. These inherent risks include, but are not limited to, the following items:

- Economic risk of finding, producing and replacing reserves at a reasonable cost, including the risk of reserve revisions due to economic and technical factors. Reserve revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
- Prevailing prices of crude oil and NGLs, and natural gas;
- Regulatory risk related to approval for exploration and development activities, which can add to costs or cause delays in projects;
- Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
- Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas;
- Success of exploration and development activities;
- 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;
- Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;
- Foreign exchange risk due to fluctuating exchange rates on the Company's US dollar denominated debt and as the majority of sales are based in US dollars;
- Environmental impact risk associated with exploration and development activities, including GHG;
- Risk of catastrophic loss due to fire, explosion or acts of nature;
- Geopolitical risks associated with changing governmental policies, social instability and other political, economic or diplomatic developments in the Company's operations;
- Future legislative and regulatory developments related to environmental regulation;
- Reservoir quality;
- The ability to replace reserves of oil and gas, whether sourced from exploration, improved recovery or acquisition;
- Potential actions of governments, regulatory authorities and other stakeholders that may impose operating costs or restrictions in the jurisdations where the Company has operations;
- Changing royalty regimes;
- Business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting the Company or other parties whose operations or assets directly or indirectly affect the Company and that may or may not be financially recoverable; and
- Other circumstances affecting revenue and expenses.

The Company uses a variety of means to help mitigate and/or minimize these risks. The Company maintains a comprehensive property loss and business interruption insurance program to reduce risk to an acceptable level. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. Substantially all of the Company's accounts receivables are due within normal trade terms. Derivative financial instruments are utilized to help ensure targets are met and to manage commodity prices, foreign currency rates and interest rate exposure. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with substantially all investment grade financial institutions and other entities. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

For additional detail regarding the Company's risks and uncertainties, refer to the Company's Annual Information Form.

ENVIRONMENT

The Company continues to invest in people, technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently and in an environmentally sustainable manner.

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 require the Company to address and mitigate the effect of its activities on the environment. Increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings and cash flow from operations.

The Company's associated environmental risk management strategies focus on working with legislators and regulators to ensure that any new or revised policies, legislation or regulations properly reflect a balanced approach to sustainable development. Specific measures in response to existing or new legislation include a focus on the Company's energy efficiency, air emissions management, released water quality, reduced fresh water use and the minimization of the impact on the landscape. Training and due diligence for operators and contractors are key to the effectiveness of the Company's environmental management programs and the prevention of incidents. The Company's environmental risk management strategies employ an Environmental Management Plan (the "Plan"). Details of the Plan, along with performance results, are presented to, and reviewed by, the Board of Directors quarterly.

The Company's Plan and operating guidelines focus on minimizing the impact of operations while meeting regulatory requirements, regional management frameworks, industry operating standards and guidelines, and internal corporate standards. The Company, as part of this Plan, has implemented a proactive program that includes:

- An internal environmental compliance audit and inspection program of the Company's 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 and reclaiming spill sites;
- A solution gas conservation program;
- A program to replace the majority of fresh water for steaming with brackish water;
- Water programs to improve efficiency of use, recycle rates and water storage;
- Environmental planning for all projects to assess impacts and to implement avoidance and mitigation programs;
- Reporting for environmental liabilities;
- A program to optimize efficiencies at the Company's operating facilities;
- Continued evaluation of new technologies to reduce environmental impacts;
- Development and implementation of a tailings management plan; and
- CO_2 reduction programs including the injection of CO_2 into tailings and for use in enhanced oil recovery.

For 2009, the Company's capital expenditures included $48 million for abandonment expenditures (2008 – $38 million; 2007 – $71 million).

The Company's estimated undiscounted ARO at December 31, 2009 was as follows:

Estimated ARO, undiscounted ($ millions)	2009	2008
North America, Conventional	$3,346	$3,072
North America, Oil Sands Mining and Upgrading (1)	1,485	93
North Sea	1,522	1,216
Offshore West Africa	253	93
	6,606	4,474
North Sea PRT recovery	(568)	(529)
	$6,038	$3,945

(1) Prior period amounts have been reclassified to conform to the presentation adopted in 2009.

The estimate of ARO is based on estimates of future costs to abandon and restore 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 $568 million (2008 – $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 $6,038 million (2008 – $3,945 million).

GREENHOUSE GAS AND OTHER AIR EMISSIONS

The Company, through the Canadian Association of Petroleum Producers ("CAPP"), is working with legislators and regulators as they develop and implement new GHG emission laws and regulations. Internally, the Company is pursuing an integrated emissions reduction strategy, to ensure that it is able to comply with existing and future emissions reduction requirements, for both GHGs and air pollutants (such as sulphur dioxide and oxides of nitrogen). 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 technological innovation, energy efficiency, targeted research and development while not impacting competitiveness.

In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in the near term to address industrial GHG emissions, as part of the national GHG reduction target. The Federal Government has also outlined national and sectoral reduction targets for several categories of air pollutants.

In Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO2e annually. Two of the Company's facilities, the Primrose/Wolf Lake in-situ heavy crude oil facilities and the Hays sour natural gas plant, fall under the regulations. The British Columbia carbon tax is currently being assessed at $15/tonne of CO2e on fuel consumed and gas flared in the province. This rate is scheduled to increase to $20/tonne on July 1, 2010, and to $30/tonne by July 1, 2012. As part of its involvement with the Western Climate Initiative, British Columbia has also announced that certain upstream oil and gas facilities will be included in a regional cap and trade system beginning in 2012. It is estimated that six facilities in British Columbia will be included under the cap and trade system, based on a proposed 25 kt CO2e threshold. Saskatchewan is expected to release GHG regulations in 2010 that may require the North Tangleflags in-situ heavy oil facility to meet a reduction target for its GHG emissions intensity. In the UK, GHG 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 CO_2 allocation has been decreased below the Company's estimated current operations emissions. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Legislation to regulate GHGs in the United States through a cap and trade system is currently before the US Congress, although there is no certainty as to the form or stringency of the final legislation. In the absence of legislation, the US Environmental Protection Agency (EPA) is authorized under the Clean Air Act to regulate GHGs, although EPA action would be subject to legal and political challenges. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the US. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oil with higher emissions intensity.

There are a number of unresolved issues in relation to Canadian Federal and Provincial GHG regulatory requirements. Key among them is the form of regulation, an appropriate facility emission threshold, availability and duration of compliance mechanisms, and resolution of federal/provincial harmonization agreements. The Company continues to pursue GHG emission reduction initiatives including solution gas conservation, compressor optimization to improve fuel gas efficiency, 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.

The additional requirements of enacted or proposed GHG regulations 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.

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 Company and industry participation with stakeholders, guidelines have been developed that adopt a structured process to emission reductions that is commensurate with technological development and operational requirements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make judgments, assumptions and estimates in the application of Canadian GAAP that have a significant impact on the financial results of the Company. Actual results may differ from those estimates, and those differences may be material. Critical accounting estimates are reviewed by the Company's Audit Committee annually. The Company believes the following are the most critical accounting estimates in preparing its consolidated financial statements.

Property, Plant and Equipment / Depletion, Depreciation and Amortization

Under Canadian GAAP, the Company follows the CICA's guideline on the full cost method of accounting for its conventional crude oil and natural gas properties and equipment. Accordingly, all costs relating to the exploration for and development of conventional crude oil and natural gas reserves, whether successful or not, are capitalized and accumulated in country-by-country cost centres. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of a gain or loss except where such dispositions result in a change in the depletion rate of the specific cost centre of 20% or more. Under Canadian GAAP, substantially all of the capitalized costs and estimated future capital costs related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of that country using estimated future prices and costs, rather than constant prices and costs as required by the SEC for US GAAP purposes.

Under Canadian GAAP, the carrying amount of crude oil and natural gas properties in each cost centre may not exceed their recoverable amount ("the ceiling test"). The recoverable amount is calculated as the undiscounted cash flow using proved reserves and estimated future prices and costs. If the carrying amount of a cost centre exceeds its recoverable amount, an impairment loss equal to the amount by which the carrying amount of the properties exceeds their estimated fair value is charged against net earnings. Fair value is calculated as the cash flow from those properties using proved and probable reserves and estimated future prices and costs, discounted at a risk-free interest rate. At December 31, 2009, a ceiling test impairment of $115 million was recognized under Canadian GAAP related to the Olowi Field in Offshore Gabon. Further, net revenues exceed capitalized costs for all other cost centres; therefore, no other impairments were required under Canadian GAAP. Under US GAAP, the ceiling test differs from

Canadian GAAP in that future net revenues from proved reserves are based on prices and costs using the average first-day-of-the-month price during the previous twelve-month period and costs as at the balance sheet date and are discounted at 10%. Capitalized costs and future net revenues are determined on a net of tax basis. These differences in applying the ceiling test in the current year resulted in the recognition of an after-tax ceiling test impairment of $815 million under US GAAP.

The alternate acceptable method of accounting for crude oil and natural gas properties and equipment is the successful efforts method. A major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs would be charged against net earnings in the year incurred rather than being capitalized to property, plant and equipment. In addition, under this method, cost centres are defined based on reserve pools rather than by country. The use of the full cost method usually results in higher capitalized costs and increased DD&A rates compared to the successful efforts method.

Crude Oil and Natural Gas Reserves

The estimation of reserves involves the exercise of judgment. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserve estimates would result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates may also result in an impairment of crude oil and natural gas property, plant and equipment carrying amounts under the ceiling test.

Asset Retirement Obligations

Under CICA Handbook Section 3110, "Asset Retirement Obligations", the Company is required to recognize a liability for the future retirement obligations associated with its property, plant and equipment. An ARO liability associated with the retirement of a tangible long-lived asset is recognized to the extent of a legal obligation resulting from an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total ARO amount. These individual assumptions can be subject to change.

The estimated fair values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. Retirement costs equal to the estimated fair value of the ARO are capitalized as part of the cost of associated capital assets and are amortized to expense through depletion over the life of the asset. The fair value of the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's average credit-adjusted risk-free interest rate, which is currently 6.9%. In subsequent periods, the ARO is adjusted for the passage of time and for any changes in the amount or timing of the underlying future cash flows. The estimates described impact earnings by way of depletion on the retirement cost and accretion on the asset retirement liability. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

An ARO is not recognized for assets with an indeterminate useful life (e.g. pipeline assets and the Horizon upgrader and related infrastructure) because an amount cannot be reasonably determined. An ARO for these assets will be recorded in the first period in which the lives of these assets are determinable.

Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences between the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted or enacted as of the consolidated balance sheet date. Accounting for income taxes is a complex process that requires management to interpret frequently changing laws and regulations (e.g. changing income tax rates) and make certain judgments with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. These interpretations and judgments impact the current and future income tax provisions, future income tax assets and liabilities, and net earnings.

Risk Management Activities

The Company utilizes various derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company has relied primarily on external readily observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction and these differences may be material.

Purchase Price Allocations

The purchase prices of business combinations and asset acquisitions are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future DD&A expense and impairment tests.

The Company has made various assumptions in determining the fair values of the acquired assets and liabilities. The most significant assumptions and judgments relate to the estimation of the fair value of the crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates (a) crude oil and natural gas reserves, and (b) future prices of crude oil and natural gas. Reserve estimates are based on the work performed by the Company's internal engineers and outside consultants. The judgments associated with these estimated reserves are described above in "Crude Oil and Natural Gas Reserves". Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

CONTROL ENVIRONMENT

The Company's management, including the President and the Chief Financial Officer and Senior Vice-President, Finance, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2009, and concluded that disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings and other reports filed with securities regulatory authorities in Canada and the United States is recorded, processed, summarized and reported within the time periods specified and such information is accumulated and communicated to the Company's management to allow timely decisions regarding required disclosures.

The Company's management also performed an assessment of internal control over financial reporting as at December 31, 2009, and concluded that internal control over financial reporting is effective. Further, there were no changes in the Company's internal control over financial reporting during 2009 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal controls over financial reporting provide a reasonable level of assurance they are effective, they recognize that all control systems have inherent limitations. Because of its inherent limitations, the Company's control systems may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

NEW ACCOUNTING STANDARDS

During 2009, the Company adopted the following new accounting standards issued by the CICA:

Goodwill and Intangible Assets

- Effective January 1, 2009 Section 3064 – "Goodwill and Intangible Assets" replaced Section 3062 – "Goodwill and Other Intangible Assets" and Section 3450 – "Research and Development Costs". In addition, EIC-27 – "Revenue and Expenditures during the Pre-Operating Period" was withdrawn. The new standard addresses when an internally generated intangible asset meets the definition of an asset. The adoption of this standard, which was adopted retroactively, did not have an impact on the Company's results of operations or financial position.

Credit Risk and the Fair Value of Financial Assets and Liabilities

- On January 20, 2009 the Emerging Issues Committee ("EIC") issued a new abstract EIC–173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". This abstract concludes that an entity's own credit risk and the credit risk of the counterparty should be taken into account when determining the fair value of financial assets and financial liabilities, including derivative financial instruments. This abstract applies to all financial assets and liabilities measured at fair value in interim and annual financial statements for periods ending on or after January 20, 2009. The adoption of this abstract did not have a material impact on the Company's results of operations or financial position.

The Company also adopted the following amendments to accounting standards issued by the CICA:

Financial Instruments

- Effective July 1, 2009 Section 3855 – "Financial Instruments – Recognition and Measurement" was amended to add guidance on the assessment of embedded derivatives upon reclassification of a financial asset from the held-for-trading category. This amendment did not have any impact on the Company's results of operations or financial position.

Financial Instruments – Disclosures

- Effective October 1, 2009 Section 3862 – "Financial Instruments – Disclosures" was amended to include additional disclosure requirements for fair value measurements of financial instruments and to enhance liquidity risk disclosure requirements. The amendment requires the classification and disclosure of fair value measurements using a three-level hierarchy that reflects the significance of the inputs used in making the fair value measurements. This amendment affected disclosure only and did not impact the Company's accounting for financial instruments.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the International

Accounting Standards Board ("IASB") in place of Canadian GAAP effective January 1, 2011.

The Company has established a formal IFRS project governance structure. The structure includes a Steering Committee, which consists of senior levels of management from finance and accounting, operations and information technology ("IT"). The Steering Committee provides regular updates to the Company's Management and the Audit Committee of the Board of Directors.

The Company's IFRS conversion project has been broken down into the following phases:

- Phase 1 Diagnostic – identification of potential accounting and reporting differences between Canadian GAAP and IFRS.
- Phase 2 Planning – establishment of project governance, processes, resources, budget and timeline.
- Phase 3 Policy Delivery and Documentation – establishment of accounting policies under IFRS.
- Phase 4 Policy Implementation – establishment of processes for accounting and reporting, IT change requirements, and education.
- Phase 5 Sustainment – ongoing compliance with IFRS after implementation.

The Company has completed the Diagnostic and Planning phases (Phases 1 and 2). Significant differences were identified in accounting for Property, Plant & Equipment ("PP&E"), including exploration costs, depletion and depreciation, capitalized interest, impairment testing, and asset retirement obligations. Other significant differences were noted in accounting for stock-based compensation, risk management activities, and income taxes. The Company is continuing to perform the necessary research to develop and document IFRS policies to address the major differences noted (Phase 3). A summary of the significant differences identified is included below. At this time, the impact on the Company's future financial position and results of operations is not reasonably determinable. In addition, certain IFRS standards are expected to change prior to adoption in 2011, and the impact of these potential changes is not known.

The Company has identified, developed and tested process and system changes required to capture data required for IFRS accounting and reporting (Phase 4), including requirements to capture both Canadian GAAP and IFRS data in 2010. IT system changes are substantially complete and implemented as at December 31, 2009.

Summary of Identified IFRS Accounting Policy Differences

Property, Plant & Equipment

Adoption of IFRS will significantly impact the Company's accounting policies for PP&E. For Canadian GAAP purposes, the Company follows the full cost method of accounting for its conventional crude oil and natural gas properties and equipment as prescribed by Accounting Guideline 16. Application of the full cost method of accounting is discussed in the "Critical Accounting Estimates" section of this MD&A. Significant differences in accounting for PP&E under IFRS include:

- Pre-exploration costs must be expensed. Under full cost accounting, these costs are currently included in the country cost centre.

- Exploration and evaluation costs will be initially capitalized as exploration and evaluation assets. Once technical feasibility and commercial viability of reserves is established for an area, the costs will be transferred to PP&E. If technically feasible and commercially viable reserves are not established for a new area, the costs must be expensed. Under full cost accounting, exploration and evaluation costs are currently disclosed as PP&E but withheld from depletion. Costs are transferred to the depletable assets when proved reserves are assigned or when it is determined that the costs are impaired.

- PP&E for producing properties will be depreciated at an asset level. Under full cost accounting, PP&E is depleted on a country cost centre basis.

- Interest directly attributable to the acquisition or construction of a qualifying asset must be capitalized to the cost of the asset. Under Canadian GAAP, capitalization of interest is discretionary.

- Impairment of PP&E will be tested at a cash generating unit level (the lowest level at which cash inflows can be identified). Under full cost accounting, impairment is tested at the country cost centre level.

IFRS 1 “First-time Adoption of International Financial Reporting Standards” issued by the IASB includes a transition exemption for oil and gas companies following full cost accounting under their previous GAAP. The transition exemption allows full cost companies to allocate their existing full cost PP&E balances using reserve values or volumes to IFRS compliant units of account without requiring retroactive adjustment, subject to an initial impairment test. The Company intends to adopt this transition exemption.

Asset Retirement Obligations

Canadian GAAP accounting requirements for ARO are discussed in the “Critical Accounting Estimates” section of this MD&A. A significant difference in accounting for ARO under IFRS is that the liability must be re-measured at each balance sheet date using the current discount rates, whereas under Canadian GAAP the discount rates do not change once the liability is recorded. On transition to IFRS, the change in ARO liability on PP&E for which the full cost exemption above is applied must be recorded in retained earnings. For the change in ARO liability on other non-full cost PP&E, the change will be adjusted to PP&E in accordance with the general exemption for decommissioning liabilities included in IFRS 1. In future periods, the impact of changes in discount rates on the ARO liability for all PP&E is adjusted to PP&E.

Stock-based Compensation

Under Canadian GAAP, the Company’s stock option plan liability is valued using the intrinsic value method, calculated as the amount by which the market price of the Company’s shares exceeds the exercise price of the option for vested options. Under IFRS, the stock option plan liability must be measured using a fair value option pricing model such as the Black-Scholes-Merton model. The Company intends to utilize the exemption in IFRS 1 under which options that were settled prior to January 1, 2010 will not have to be retrospectively restated.

Income Taxes

Both Canadian GAAP and IFRS follow the liability method of accounting for income taxes, where tax liabilities and assets are recognized on temporary differences. However, there are certain exceptions to the treatment of temporary differences under IFRS that may result in an adjustment to the Company's future tax liability under IFRS. In addition, the Company's future tax liability will be impacted by the tax effects of any changes noted in the above areas.

Other IFRS 1 Exemptions

The Company also intends to adopt the following IFRS 1 transition exemptions:

- The Company intends to elect to reset the foreign currency translation adjustment to zero by transferring the Canadian GAAP balance to retained earnings on January 1, 2010, rather than retrospectively restating the balance.
- The Company intends to adopt the IFRS 1 election to not restate business combinations entered into prior to January 1, 2010.

OUTLOOK

The Company continues to implement its strategy of maintaining a large portfolio of varied projects, which the Company believes will enable it, over an extended period of time, to provide consistent growth in production and create shareholder value. Annual budgets are developed, scrutinized throughout the year and revised if necessary in the context of targeted financial ratios, project returns, product pricing expectations, and balance in project risk and time horizons. The Company maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of capital expenditures in each of its project areas. The Company expects production levels in 2010 to average between 400,000 bbl/d and 445,000 bbl/d of crude oil and NGLs and between 1,117 mmcf/d and 1,185 mmcf/d of natural gas.

The forecasted capital expenditures in 2010 are currently expected to be as follows:

($ millions)	2010 Forecast
Conventional crude oil and natural gas	
North America natural gas	$674
North America crude oil and NGLs	1,900
North Sea	199
Offshore West Africa	264
Property acquisitions, dispositions and midstream	100
	$3,137
Oil Sands Mining and Upgrading	
Horizon Phase 2/3 – Tranche 2	$479
Horizon Phase 2/3 – Engineering	95
Sustaining capital	164
Capitalized interest and other costs	47
	$785
Total	$3,922

The above capital expenditure budget incorporates the following levels of drilling activity:

(Number of wells)	2010 Forecast
Targeting natural gas	93
Targeting crude oil	966
Stratigraphic test / service wells – conventional	227
Stratigraphic test wells – mining	166
Total	1,452

North America Natural Gas

The 2010 North America natural gas drilling program is highlighted by the continued high-grading of the Company's natural gas asset base as follows:

(Number of wells)	2010 Forecast
Coal bed methane and shallow natural gas	8
Conventional natural gas	36
Cardium natural gas	1
Deep natural gas	47
Foothills natural gas	1
Total	93

North America Crude Oil and NGLs

The 2010 North America crude oil drilling program is highlighted by continued development of the Primrose thermal projects, Pelican Lake, and a strong conventional primary heavy program, as follows:

(Number of wells)	2010 Forecast
Conventional primary heavy crude oil	610
Thermal heavy crude oil	28
Light crude oil	117
Pelican Lake crude oil	201
Total	956

Oil Sands Mining and Upgrading

In 2010, Horizon Phase 2/3 Tranche 2 expenditures are targeted to increase reliability of the plant while also affording some debottlenecking opportunities.

Engineering and procurement is underway for Tranche 2 of the Phase 2/3 expansion, and Tranches 3 and 4 of Phase 2/3 continue to be re-profiled. The Company continues to work on completing its lessons learned from the construction of Phase 1 and implementing these into the development of future expansions.

North Sea

During 2010, the Company will recommence platform drilling activities in the Northern North Sea with a program of infill wells and workovers.

Offshore West Africa

During 2010, the Company will complete the project to increase capacity on the Espoir FPSO. At Olowi, the Company will complete commissioning of the remaining platforms and continue the drilling program from these locations.

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flow from operations and net earnings from changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2009, excluding mark-to-market gains (losses) on risk management activities and capitalized interest, and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flow from operations ($ millions)	Cash flow from operations (per common share, basic)	Net earnings ($ millions)	Net earnings (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl (1)				
Excluding financial derivatives	$109	$0.20	$90	$0.17
Including financial derivatives	$91	$0.17	$76	$0.14
Natural gas – AECO C$0.10/mcf (1)				
Excluding financial derivatives	$33	$0.06	$24	$0.04
Including financial derivatives	$18	$0.03	$14	$0.03
Volume changes				
Crude oil – 10,000 bbl/d	$161	$0.30	$105	$0.19
Natural gas – 10 mmcf/d	$12	$0.02	$4	$0.01
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$95 – 97	$0.17 – 0.18	$31 – 32	$0.06
Interest rate change – 1%	$13	$0.02	$13	$0.02

(1) For details of financial instruments in place, refer to note 13 to the Company’s audited annual consolidated financial statements as at December 31, 2009.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2009	2008	2007
Crude oil and NGLs (bbl/d)							
North America – Conventional	253,833	232,139	223,307	229,206	234,523	243,826	246,779
North America – Oil Sands Mining and Upgrading	3,384	59,599	66,907	70,194	50,250	–	–
North Sea	42,369	40,362	34,034	34,408	37,761	45,274	55,933
Offshore West Africa	30,431	33,572	35,021	32,643	32,929	26,567	28,520
Total	330,017	365,672	359,269	366,451	355,463	315,667	331,232
Natural gas (mmcf/d)							
North America	1,347	1,322	1,264	1,218	1,287	1,472	1,643
North Sea	10	10	8	12	10	10	13
Offshore West Africa	12	20	21	20	18	13	12
Total	1,369	1,352	1,293	1,250	1,315	1,495	1,668
Barrels of oil equivalent (boe/d)							
North America – Conventional	478,301	452,494	433,928	432,167	449,054	489,081	520,564
North America – Oil Sands Mining and Upgrading	3,384	59,599	66,907	70,194	50,250	–	–
North Sea	44,039	42,045	35,380	36,440	39,444	46,956	58,099
Offshore West Africa	32,418	36,846	38,540	36,056	35,982	28,808	30,543
Total	558,142	590,984	574,755	574,857	574,730	564,845	609,206

PER UNIT RESULTS – CONVENTIONAL (1)

	Q1	Q2	Q3	Q4	2009	2008	2007
Crude oil and NGLs ($/bbl)							
Sales price (2)	$41.25	$59.56	$62.90	$68.00	$57.68	$82.41	$55.45
Royalties	3.98	7.27	7.89	7.96	6.73	10.48	5.94
Production expense	15.02	16.59	16.71	15.45	15.92	16.26	13.34
Netback	$22.25	$35.70	$38.30	$44.59	$35.03	$55.67	$36.17
Natural gas ($/mcf)							
Sales price (2)	$5.46	$4.11	$3.80	$4.75	$4.53	$8.39	$6.85
Royalties (3)	0.72	0.06	0.13	0.35	0.32	1.46	1.11
Production expense	1.18	1.05	1.05	1.03	1.08	1.02	0.91
Netback	$3.56	$3.00	$2.62	$3.37	$3.13	$5.91	$4.83
Barrels of oil equivalent ($/boe)							
Sales price (2)	$37.87	$44.52	$45.52	$51.95	$44.87	$68.62	$49.05
Royalties	4.14	4.34	4.85	5.60	4.72	9.78	6.26
Production expense	11.77	12.21	12.26	11.72	11.98	11.79	9.75
Netback	$21.96	$27.97	$28.41	$34.63	$28.17	$47.05	$33.04

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.
(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2009	2008
TSX – C$						
Trading volume (thousands)					520,160	679,738
Share Price ($/share)						
High	$57.20	$68.69	$76.91	$79.00	$79.00	$111.30
Low	$35.85	$47.70	$52.71	$65.97	$35.85	$34.19
Close	$48.91	$61.19	$72.30	$76.00	$76.00	$48.75
Market capitalization as at December 31 ($ millions)					$41,217	$26,373
Shares outstanding (thousands)					542,327	540,991
NYSE – US$						
Trading volume (thousands)					757,307	967,228
Share Price ($/share)						
High	$48.54	$63.46	$71.93	$76.51	$76.51	$109.32
Low	$27.69	$37.73	$45.03	$62.05	$27.69	$26.43
Close	$38.56	$52.49	$67.19	$71.95	$71.95	$39.98
Market capitalization as at December 31 ($ millions)					$39,020	$21,629
Shares outstanding (thousands)					542,327	540,991

ADDITIONAL DISCLOSURE

Certifications

The required disclosure is included in Exhibits 2, 3, 4 and 5 of the Annual Report on Form 40-F

Disclosure Controls and Procedures

As of the end of the registrant's fiscal year ended December 31, 2009, an evaluation of the effectiveness of Canadian Natural's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") was carried out by Canadian Natural's management with the participation of Canadian Natural's principal executive officer and principal financial officer. Based upon the evaluation, Canadian Natural's principal executive officer and principal financial officer have concluded that as of the end of the fiscal year, Canadian Natural's disclosure controls and procedures are effective to ensure that information required to be disclosed by the registrant in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and (ii) accumulated and communicated to the registrant's management, including its principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

It should be noted that while Canadian Natural's principal executive officer and principal financial officer believe that Canadian Natural's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect Canadian Natural's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Management's Assessment of Internal Control Over Financial Reporting

The required disclosure is included in the "Management's Assessment of Internal Control Over Financial Reporting" that accompanies Canadian Natural's audited consolidated financial statements for the fiscal year ended December 31, 2009, filed as part of this Annual Report on Form 40-F.

Attestation Report of the Registered Public Accounting Firm

The required disclosure is included in the "Independent Auditors' Report" that accompanies Canadian Natural's audited consolidated financial statements for the fiscal year ended December 31, 2009, filed as part of this Annual Report on Form 40-F.

Changes in Internal Control Over Financial Reporting

During the fiscal year ended December 31, 2009, there were no changes in Canadian Natural's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, Canadian Natural's internal control over financial reporting.

Notices Pursuant to Regulation BTR

None.

Audit Committee Financial Expert

The Board of Directors of Canadian Natural has determined that Ms. C.M. Best qualifies as an "audit committee financial expert" (as defined in paragraph 8(b) of General Instruction B to the Form 40-F) serving on its Audit Committee. Ms. C.M. Best is, as are all members of the Audit Committee of the Board of Directors of Canadian Natural, "independent" as such term is defined in the rules of the New York Stock Exchange.

Code of Ethics

Canadian Natural has a long-standing Code of Integrity, Business Ethics and Conduct (the "Code of Ethics"), which covers such topics as employment standards, conflict of interest, the treatment of confidential information and trading in Canadian Natural's shares and is designed to ensure that Canadian Natural's business is consistently conducted in a legal and ethical manner. Each director and all employees, including each member of senior management and more specifically the principal executive officer, the principal financial officer and the principal accounting officer, are required to abide by the Code of Ethics. The Nominating and Corporate Governance Committee periodically reviews the Code of Ethics to ensure it addresses appropriate topics and complies with regulatory requirements and recommends any appropriate changes to the Board for approval.

Any waivers of or amendments to the Code of Ethics must be approved by the Board of Directors and will be appropriately disclosed. In the past fiscal year, there has not been any amendments to the Code of Ethics or waivers, including implicit waivers, from any provisions of the Code of Ethics.

The Code of Ethics is available through the System for Electronic Document and Analysis and Retrieval (SEDAR) at www.sedar.com. Requests for copies can also be made by contacting: Bruce E. McGrath, Corporate Secretary, Canadian Natural Resources Limited, 2500-855 2nd Street, S.W., Calgary, Alberta, Canada T2P 4J8.

Principal Accountant Fees and Services

PricewaterhouseCoopers LLP ("PwC") has been the auditor of Canadian Natural since Canadian Natural's inception. The aggregate amounts billed by PwC for each of the last two fiscal years for audit fees, audit-related fees, tax fees and all other fees, excluding expenses, are set forth below.

Audit Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural ending December 31, 2009 and December 31, 2008, for professional services rendered by PwC for the audit of its internal controls and annual consolidated financial statements in connection with statutory and regulatory filings or engagements for those fiscal years, unaudited reviews of the first, second and third quarters of its interim consolidated financial statements and audits of certain of Canadian Natural's subsidiary companies' annual financial statements were $2,710,110 for 2009 and were $2,685,800 for 2008.

Audit-Related Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2009 and December 31, 2008, for audit-related services by PwC including debt covenant compliance and Crown Royalty Statements, were $154,302 for 2009 and were $156,300 for 2008. Canadian Natural's Audit Committee approved all of these audit-related services.

Tax Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2009 and December 31, 2008, for professional services rendered by PwC for tax-related services related to expatriate personal tax compliance as well as other corporate tax return matters provided in 2009 were $131,653 for 2009 and were $91,500 for 2008. Canadian Natural's Audit Committee approved all of these tax-related services.

All Other Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2009 and December 31, 2008 for other services were $9,500 for 2009 and were $9,500 for 2008. The fees for other services paid in 2009 related to accessing resource materials through PwC's accounting literature library. Canadian Natural's Audit Committee approved all of the noted services.

Audit Committee Pre-Approval Policies and Procedures

The Audit Committee's duties and responsibilities include the review and approval of fees to be paid to the independent auditors, scope and timing of the audit and other related services rendered by the independent auditors. The Audit Committee also reviews and approves the independent auditor's annual audit plan, including scope, staffing, locations and reliance upon management and internal audit department prior to the commencement of the audit and reviews and approves proposed non-audit services to be provided by the independent auditors, except those non-audit services prohibited by legislation. Canadian Natural did not rely on the de minimis exemption provided by paragraph (c)(7)(i)(c) of Rule 2.01 of Regulation S-X in 2009.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. These commitments primarily relate to firm commitments for gathering, processing and transmission services; operating leases relating to offshore FPSOs, drilling rigs and office space; expenditures relating to ARO; as well as long-term debt and interest payments. As at December 31, 2009, no entities were consolidated under CICA Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2009:

($ millions)		2010		2011		2012		2013		2014		Thereafter
Product transportation and pipeline	$	207	$	162	$	136	$	125	$	126	$	1,051
Offshore equipment operating lease	$	155	$	124	$	103	$	102	$	101	$	261
Offshore drilling	$	49	$	–	$	–	$	–	$	–	$	–
Asset retirement obligations (1)	$	16	$	20	$	21	$	31	$	39	$	6,479
Long-term debt (2)	$	400	$	419	$	366	$	819	$	366	$	5,424
Interest expense (3)	$	473	$	451	$	415	$	370	$	350	$	4,779
Office leases	$	25	$	19	$	3	$	2	$	2	$	–
Other	$	271	$	67	$	23	$	15	$	12	$	34

(1) Amounts represent management's estimate of the future undiscounted payments to settle ARO related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2010 – 2014 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(2) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,897 million of revolving bank credit facilities due to the extendable nature of the facilities.

(3) Interest expense amounts represent the scheduled fixed rate and variable rate cash payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates as of December 31, 2009.

Identification of the Audit Committee

Canadian Natural has a separately designated standing audit committee established in accordance with section 3(a)(58)(A) of the Exchange Act. The members of the Audit Committee are Messrs. G. A. Filmon, G. D. Giffin, D. A. Tuer and Ms. C.M. Best, who chairs the Audit Committee.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

Undertaking

Canadian Natural undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

Consent to Service of Process

Canadian Natural has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

Any change to the name or address of the agent for service of process of Canadian Natural shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the relevant registration statement.

SIGNATURES

Pursuant to the requirements of the Exchange Act, Canadian Natural certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report to be signed on its behalf by the undersigned, thereto duly authorized.

Dated this 25th day of March, 2010.

CANADIAN NATURAL RESOURCES LIMITED

By:	/s/ Steve W. Laut
Name:	Steve W. Laut
Title:	President (Principal Executive Officer)

Documents filed as part of this report:

EXHIBIT INDEX

Exhibit No.	Description
1.	Supplementary Oil & Gas Information for the fiscal year ended December 31, 2009.
2.	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934.
3.	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934.
4.	Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
5.	Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
6.	Consent of PricewaterhouseCoopers LLP, independent chartered accountants.
7.	Consent of Sproule Associates Limited, independent petroleum engineering consultants.
8.	Consent of GLJ Petroleum Consultants Ltd., independent petroleum engineering consultants.