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, 2012 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.
1,092,072,098 Common Shares outstanding as of December 31, 2012

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. 333-177401) under the Securities Act of 1933 as amended.

All dollar amounts in this Annual Report on Form 40-F are expressed in Canadian dollars. As of March 27, 2013, the noon buying rate for Canadian Dollars as expressed by the Federal Reserve Bank of New York was US$1.00 equals C$1.0224.

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, 2012.

B. Audited Annual Financial Statements

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2012 and 2011, including the auditor's report with respect thereto.

C. Management's Discussion and Analysis

Canadian Natural's Management's Discussion and Analysis for the year ended December 31, 2012.

Supplementary Oil & Gas Information

For Canadian Natural's Supplementary Oil & Gas Information for the year ended December 31, 2012, see Exhibit 1 to this Annual Report on Form 40-F.



ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2012

March 27, 2013

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DEFINITIONS AND ABBREVIATIONS

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

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
"Canadian Natural Resources Limited", "Canadian Natural", "Company", "Corporation"	Canadian Natural Resources Limited and includes, where applicable, reference to subsidiaries of and partnership interests held by Canadian Natural Resources Limited and its subsidiaries.
CBM	Coal Bed Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalents
Crude oil, NGLs and natural gas	The Company's light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), synthetic crude oil, natural gas and natural gas liquids reserves.
CSS	Cyclic Steam Simulation
development well	Well drilled inside the established limits of an oil or gas reservoir or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.
dry well	Well that proves to be incapable of producing either crude oil or natural gas in sufficient quantities to justify completion.
EOR	Enhanced oil recovery
exploratory well	Well that is not a development well, a service well or a stratigraphic test well.
extension well	Well that is drilled to test if a known reservoir extends beyond what had previously been believed to be the outer reservoir perimeter.
FPSO	Floating Production, Storage and Offloading vessel
GHG	Greenhouse gas
gross acres	Total number of acres in which the Company has a working interest.
gross wells	Total number of wells in which the Company has a working interest.
Horizon	Horizon Oil Sands
IFRS	International Financial Reporting Standards
Mbbl	thousand barrels
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MD&A	Management's Discussion and Analysis
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMcfe	millions of cubic feet equivalent

MM$	million Canadian dollars
NGLs	Natural gas liquids
net acres	Gross acres multiplied by the percentage working interest therein owned.
net asset value	Net present value of the future net revenue before income tax of the Company's total proved plus probable crude oil, NGLs and natural gas reserves prepared using forecast prices and costs discounted at 10%, plus the estimated market value of core unproved property, less net debt. Future development costs and associated material well abandonment costs have been applied against the future net revenue before income tax.
net wells	Gross wells multiplied by the percentage working interest therein owned by the Company.
NYSE	New York Stock Exchange
productive well	Exploratory, development or extension well that is not dry.
proved property	Property or part of a property to which reserves have been specifically attributed.
PRT	Petroleum Revenue Tax
SAGD	Steam-Assisted Gravity Drainage
SCO	Synthetic crude oil
SEC	United States Securities and Exchange Commission
service well	Well drilled or completed for the purpose of supporting production in an existing field and drilled for the specific purposes of gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.
stratigraphic test well	Drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition and ordinarily drilled without the intention of being completed for hydrocarbon production.
TSX	Toronto Stock Exchange
UK	United Kingdom
unproved property	Property or part of a property to which no reserves have been specifically attributed.
US	United States
working interest	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	West Texas Intermediate reference location at Cushing, Oklahoma

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", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses, and other guidance provided throughout this Annual Information Form ("AIF") 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 operations and future expansions, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, construction of the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast, the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia and the construction and future operations of the North West Redwater bitumen upgrader and refinery 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 as 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 and proved plus probable crude oil, NGLs, 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 disruptions or delays in the resumption of the mining, extracting or upgrading of 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 and in mining, extracting or upgrading the Company's bitumen products; 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, NGLs and natural gas 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 Factors” section of this AIF.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this AIF 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, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management’s estimates or opinions change.

Special Note Regarding Currency, Financial Information, Production and Reserves

In this document, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data are 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 conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6Mcf:1bbl conversion ratio may be misleading as an indication of value.

This AIF, the comparative Consolidated Financial Statements and the Company’s Management’s Discussion and Analysis for the most recently completed fiscal year ended December 31, 2012, herein incorporated by reference, have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board. Unless otherwise stated, 2010 comparative figures have been restated in accordance with IFRS.

For the year ended December 31, 2012, the Company retained Independent Qualified Reserves Evaluators (“Evaluators”), Sproule Associates Limited and Sproule International Limited (together as “Sproule”) and GLJ Petroleum Consultants Ltd. (“GLJ”), to evaluate and review all of the Company’s proved and proved plus probable reserves with an effective date of December 31, 2012 and a preparation date of February 11, 2013. Sproule evaluated the North America and International light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), natural gas and NGLs reserves. GLJ evaluated the Horizon SCO reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook (“COGE Handbook”) and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“NI 51-101”) requirements. In previous years, Canadian Natural had been granted an exemption order from the securities regulators in Canada that allowed substitution of SEC requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result, the 2010, 2011 and 2012 reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 “Extractive Activities - Oil and Gas” in the Company’s Form 40-F filed with the SEC in the “Supplementary Oil and Gas Information” section of the Company’s Annual Report on pages 92 to 99 which is incorporated herein by reference.

Special Note Regarding Non-GAAP Financial Measures

This AIF 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, cash production costs, and net asset value. These financial measures are not defined by IFRS 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 IFRS, 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 IFRS in the “Net Earnings and Cash Flow from Operations” section of the Company’s MD&A which is incorporated by reference into this document. The derivation of cash production costs is included in the “Operating Highlights – Oil Sands Mining and Upgrading” section of the Company’s MD&A which is incorporated by reference into this document.

CORPORATE STRUCTURE

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.

On January 1, 2012 Aspect Energy Ltd., Creo Energy Ltd., 1585024 Alberta Ltd. 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	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 wholly owned partnerships.

GENERAL DEVELOPMENT OF THE BUSINESS

2010

During the last half of 2010, the Company received regulatory approval for its Kirby South Phase 1 Project and the Board of Directors sanctioned Kirby South Phase 1 with construction commencing in the fourth quarter 2010. First steam is targeted for late 2013 and peak production is targeted to be 40,000 bbl/d in late 2014 with an overall cost target of $1.25 billion.

The Company completed a number of transactions in the normal course to acquire and dispose of interests in crude oil and natural gas properties for an aggregate net expenditure of $1.5 billion. 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.

2011

During 2011 the Company issued US$500 million of 1.45% unsecured notes due November 2014, and US$500 million of 3.45% unsecured notes due November 2021. Net proceeds were used to repay bank indebtedness.

The Company completed a number of transactions in the normal course to acquire and dispose of interests in crude oil and natural gas properties for an aggregate net expenditure of $1 billion. 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.

2012

During 2008, the Company entered into a 20 year transportation agreement to ship 120,000 bbl/d of heavy crude oil on the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast. The Company also entered into a 20 year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy crude oil to a major US refiner. The construction of the proposed Keystone XL Pipeline is dependent on a Presidential Permit.

During 2012, the Company entered into a 20 year transportation agreement to ship 75,000 bbl/d of crude oil on the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia. The regulatory approval process will begin in 2013 with a planned in-service date in 2017.

In 2011, the Company announced that it had entered into a partnership agreement with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of a bitumen upgrader and refinery ("the Project") near Redwater, Alberta. In addition, the partnership has entered into processing agreements that target to process bitumen for the Company of 12,500 bbl/d and bitumen for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, of 37,500 bbl/d under a 30 year fee-for-service tolling agreement under the Bitumen Royalty In Kind initiative. In 2012, the Project was sanctioned by the Board of Directors of each partner of the North West Redwater Partnership ("Redwater"), and the associated target toll amounts were accepted by Redwater, the Company and the APMC.

During 2012, the Company issued C$500 million of 3.05% medium-term notes due June 2019. Net proceeds from the sale were used to repay bank indebtedness and for general corporate purposes.

The Company completed a number of transactions in the normal course to acquire and dispose of interests in crude oil and natural gas properties for an aggregate net expenditure of $144 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.

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 UK sector of the North Sea and Offshore 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, NGLs 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, 2012, the Company had the following full time equivalent permanent employees:

North America, Exploration and Production	3,606
North America, Oil Sands Mining and Upgrading	1,956
North Sea	348
Offshore Africa	60
Total Company	5,970

Operational discipline, safe, effective and efficient operations as well as cost control are fundamental to the Company. By consistently managing costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Effective and efficient operations and cost control are attained by developing area knowledge and by maintaining high working interests and operator status in its properties. 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 and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), SCO and NGLs. The Company's large diversified project portfolio enables the effective allocation of capital to higher return opportunities, which together provide complementary infrastructure and balance throughout the business cycle. Natural gas is the largest single commodity sold accounting for 31% of 2012 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 and medium crude oil and NGLs, representing 16% of 2012 production, is located in the Company's North Sea and Offshore Africa properties, and in the provinces of Saskatchewan, British Columbia and Alberta. Primary heavy crude oil accounting for 19% of 2012 production, Pelican Lake heavy crude oil accounting for 6% of 2012 production, and our bitumen (thermal oil) accounting for 15% of 2012 production are in the provinces of Alberta and Saskatchewan. SCO from our oil sands mining operations in Northern Alberta accounted for approximately 13% of 2012 production. Midstream assets, primarily comprised two operated and one non operated pipeline systems and an electricity co-generation facility, provide cost effective infrastructure supporting the heavy crude oil and bitumen operations.

A. ENVIRONMENTAL MATTERS

The Company strives to carry out its activities in compliance with applicable regional, national and international regulations and industry standards. Environmental specialists in Canada and the UK track performance to numerous environmental performance indicators, 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'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 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 operations while meeting regulatory requirements, regional management frameworks, industry operating standards and guidelines, and internal corporate standards. The Company's proactive program 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 environmental impacts and to implement avoidance and mitigation programs; reporting for environmental liabilities; a program to optimize efficiencies at the Company's operated facilities; continued evaluation of new technologies to reduce environmental impacts and support for Canada's Oil Sands Innovation Alliance ("COSIA"); CO_2 reduction programs including the injection of CO_2 into tailings and for use in enhanced oil recovery; a program in place related to progressive reclamation and tailings management for the Horizon Oil Sands facility; and participation and support for the Joint Implementation Plan for Oil Sands Monitoring. 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. The Company has also adopted the Hydraulic Fracturing Operating Practices that were developed by the Canadian Association of Petroleum Producers ("CAPP"). In 2012, Canadian Natural continued its environmental liability reduction program with the abandonment of 622 inactive wells. In addition, reclamation was initiated at many of these sites with the eventual goal of reclamation certification. In 2012 the Company received 296 reclamation certificates representing 590 hectares of land. Further, decommissioning of inactive facilities and clean up of active facilities was conducted to address environmental liabilities at operating assets. Canadian Natural participates in both the Canadian federal and provincial regulated GHG emissions reporting programs and continues to quantify annual GHG emissions for internal reporting purposes. The Company has participated in the CAPP Responsible Canadian Energy Program since 2000. Canadian Natural continues to invest in people, proven and new technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently and in an environmentally sustainable manner.

The Company, through CAPP, is working with Canadian legislators and regulators as they develop and implement new GHG emissions laws and regulations. Internally, the Company is pursuing an integrated emissions reduction strategy, to ensure 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, such as COSIA and Carbon Management Canada ("CMC"), to ensure that new policies encourage technological innovation, energy efficiency, and 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, fuel and solution gas conservation programs. In 2012 the Company completed approximately 413 gas conservation projects in its primary heavy crude oil operations, resulting in a reduction of 2.1 million tonnes/year of CO_2e. Over the past five years the Company has spent over $53 million in its primary heavy crude oil and in situ oil sands operations to conserve the equivalent of over 10.7 million tonnes of CO_2e. The Company also monitors the performance of its compressor fleet as part of the Company's compressor optimization initiative to improve fuel gas 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 implemented a fuel gas import project to reduce diesel consumption in addition to continued focus on its flare reduction program in both the North Sea and Offshore Africa operations.

B. 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, and Manitoba. 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.

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 and are not subject to escalating rentals 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 their respective province. Government royalties are payable on crude oil, NGLs and natural gas production from leases owned by the province. The royalties are determined by regulation and are generally calculated as a percentage of production varied by a number of different factors including selling prices, production levels, recovery methods, transportation and processing costs, location and date of discovery.

The Alberta government implemented changes to the Alberta Royalty Framework ("ARF") effective January 1, 2009. The ARF includes a number of changes to royalty rates for natural gas, crude oil, and oil sands production. Under the ARF, royalties payable vary according to commodity prices and the productivity of wells. Initial changes to the Alberta royalty regime under the ARF included 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.

During 2010, the Government of Alberta modified the crude oil and natural gas royalty rates. These changes included:

- § Effective May 1, 2010, an extension of the period subject to the 5% maximum royalty rate for CBM and shale gas wells to the first 36 months after start of production, subject to volume limits of 750 MMcfe for CBM and no volume limits for shale gas.

- § Effective May 1, 2010, an extension of the period subject to the 5% maximum royalty rate for horizontal natural gas and crude oil wells. The period for horizontal natural gas wells is extended to the first 18 months after start of production, and volumes of 500 MMcfe. Limits on production months and volumes for crude oil will be set according to the measured depth of the wells.

- § Effective January 1, 2011, a reduction in the maximum royalty rate to 5% on new natural gas and crude oil wells for the first 12 months after the start of production, subject to volume limits of 500 MMcfe and 50,000 BOE respectively.

- § Effective January 1, 2011, a reduction in the maximum royalty rate for crude oil from 50% to 40% and a reduction in the maximum royalty rate for conventional and unconventional natural gas from 50% to 36%.

Modifications were also made to the natural gas deep drilling program, including changes to depth requirements. The Government of Alberta also announced changes to the price components of oil and gas royalty formulas to reduce the royalty rate at prices higher than $85.00 per bbl and $5.25 per GJ respectively.

During 2007, the Canadian federal government enacted income tax rate changes which decreased the federal corporate income tax rate over a five year period. The federal income tax rate in 2012 was 15%.

During 2011, the Canadian federal government enacted legislation to implement several taxation changes. These changes include a requirement that, beginning in 2012, partnership income must be included in the taxable income of each corporate partner based on the tax year of the partner, rather than the fiscal year of the partnership. The legislation includes a five year transition provision and has no impact on net earnings.

In addition to government royalties, the Company is subject to federal and provincial income taxes in Canada at a combined rate of approximately 25.1% after allowable deductions for 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.

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.

Crude oil and natural gas fields granted development approval before March 16, 1993 are subject to UK PRT of 50% charged on crude oil and natural gas profits. Approvals granted on or after March 16, 1993 are exempted from PRT. Profits for PRT purposes are calculated on a field-by-field basis by deducting field production 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.

During 2011, the UK government enacted legislation to increase the supplementary income tax rate charged on profits from UK North Sea crude oil and natural gas production, increasing the combined corporate and supplementary income tax rate from 50% to 62%.

During 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax relief on UK North Sea decommissioning expenditures to 50%.

In September 2012, the UK government announced the implementation of the Brownfield Allowance which allows for an agreed allowance related to property development for certain pre-approved qualifying field developments. This allowance partially mitigates the impact of previous tax increases.

Offshore 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.

C. COMPETITIVE FACTORS

The energy industry is highly competitive in all aspects of the business 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, the transportation and marketing of crude oil, NGLs, natural gas, and electricity and the attraction and retention of skilled personnel. The Company's competitors include both integrated and non integrated crude oil and natural gas companies as well as other petroleum products and energy sources.

D. 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 primarily 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 ability to secure adequate transportation for products, 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, Pelican Lake, the Kirby Thermal Oil Sands Project, and international projects, 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 40% of the Company's 2012 production on a BOE basis was primary heavy crude oil, Pelican Lake heavy crude oil, and bitumen (thermal oil). The market prices for these products 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 assessments of the carrying value of its assets in accordance with IFRS. 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.

Operational Risk

Exploring for, producing, mining, extracting, upgrading and transporting crude oil, NGLs and natural gas 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, interruption of operations and loss of

production, whether caused by human error or nature. In addition to the foregoing, the Horizon operations are also 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.

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.

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 level, 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, CO_2 capture and sequestration in oil sands tailings, CO_2 capture and storage in association with enhanced oil recovery, participation in an industry initiative to promote an integrated CO_2 capture and storage network and participation in organizations that are researching technologies to reduce GHG emissions specifically COSIA and CMC.

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 are being developed that adopt a structured process to emission 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 is also developing a comprehensive management system for air pollutants.

In Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Three of the Company's facilities, the Horizon Oil Sands facility, the Primrose/Wolf Lake in situ heavy crude oil facilities and the Hays sour natural gas plant are subject to compliance under the regulations. The Kirby South in situ heavy crude oil facility will be subject to compliance under regulations in 2016. The British Columbia carbon tax is currently being assessed at $30/tonne of CO_2e on fuel consumed and gas flared in the province. As part of its involvement with the Western Climate Initiative, British Columbia may require certain upstream oil and gas facilities to participate in a regional cap and trade system. If such a system is implemented, it is not expected to be in place before 2015. It is estimated that four facilities in British Columbia will be included under the cap and trade system based on a proposed requirement of 25 kilotonnes of CO_2e annually. Saskatchewan released draft GHG regulations that regulate facilities emitting more than 50 kilotonnes of CO_2e annually and will likely require the North Tangleflags in situ heavy oil facility to meet the reduction target for its GHG emissions once the governing legislation comes into force. In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 – 2007) of the UK National Allocation Plan, the Company operated below its CO_2 allocation. In Phase 2 (2008 – 2012) the Company's CO_2 allocation has been decreased below the Company's estimated current operations emissions. In Phase 3 (2013 - 2020) the Company's CO_2 allocation is expected to be further reduced, although details on Phase 3 have not yet been finalized. 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.

The US Environmental Protection Agency ("EPA") is proceeding to regulate GHGs under the Clean Air Act. This EPA action is subject to legal and political challenges, the outcome of which cannot be predicted. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. 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 regulations on the Company's operations will increase capital expenditures and production expense, including those related to Horizon and the Company's other existing and certain planned oil sands projects. Depending on the legislation enacted, this may have an adverse effect on the Company's financial condition.

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.

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.

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 production 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 of reserves that may be developed in the future are often based upon volumetric calculations and upon analogy to actual production history from similar reservoirs and wells. Subsequent evaluation of the same reserves based upon production history will result in variations in the previously estimated reserves.

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 and is impacted by our ability to maintain investment grade credit ratings and the condition of the capital and credit markets. In addition, changes in credit ratings may affect the Company's ability to, and the associated costs of, entering into ordinary course derivative or hedging transactions, as well as entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

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.

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.

Other Business Risks

Other business risks which may negatively impact the Company's financial condition include labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner, 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, risk of increases in government taxes and changes to the royalty regime and risk to the Company's reputation resulting from operational activities that may cause personal injury, property damage or environmental damage. The majority of the Company's assets are held in one or more corporate subsidiaries or partnerships. 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.

FORM 51-101F1 STATEMENT OF RESERVES DATA AND OTHER INFORMATION

For the year ended December 31, 2012 the Company retained Independent Qualified Reserves Evaluators ("Evaluators"), Sproule Associates Limited and Sproule International Limited (together as "Sproule") and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved and proved plus probable reserves with an effective date of December 31, 2012 and a preparation date of February 11, 2013. Sproule evaluated the North America and International light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), natural gas and NGLs reserves. GLJ evaluated the Horizon SCO reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements. In previous years, Canadian Natural had been granted an exemption order from the securities regulators in Canada that allowed substitution of U.S. Securities Exchange Commission ("SEC") requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result, the 2010, 2011 and 2012 reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's Independent Qualified Reserves Evaluators to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and related net present value of future net revenue of the remaining reserves.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 "Extractive Activities - Oil and Gas" in the Company's Form 40-F filed with the SEC in the "Supplementary Oil and Gas Information" section of the Company's Annual Report on pages 92 to 99 which is incorporated herein by reference.

The estimates of future net revenue presented in the tables below do not represent the fair market value of the reserves.

There is no assurance that the price and cost assumptions contained in the forecast case will be attained and variances could be material. The recovery and reserves estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater or less than the estimate provided herein.

Summary of Company Gross Reserves by Product
As of December 31, 2012
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	92	85	217	238	1,837	2,664	53	2,966
Developed Non-Producing	2	23	11	104	-	213	3	178
Undeveloped	19	96	39	724	418	1,108	38	1,519
Total Proved	113	204	267	1,066	2,255	3,985	94	4,663
Probable	51	80	105	1,056	1,096	1,589	44	2,697
Total Proved plus Probable	164	284	372	2,122	3,351	5,574	138	7,360
North Sea								
Proved								
Developed Producing	49					3		49
Developed Non-Producing	14					55		23
Undeveloped	164					24		168
Total Proved	227					82		240
Probable	105					20		109
Total Proved plus Probable	332					102		349
Offshore Africa								
Proved								
Developed Producing	65					56		75
Developed Non-Producing	-					-		-
Undeveloped	38					13		40
Total Proved	103					69		115
Probable	55					42		62
Total Proved plus Probable	158					111		177
Total Company								
Proved								
Developed Producing	206	85	217	238	1,837	2,723	53	3,090
Developed Non-Producing	16	23	11	104	-	268	3	201
Undeveloped	221	96	39	724	418	1,145	38	1,727
Total Proved	443	204	267	1,066	2,255	4,136	94	5,018
Probable	211	80	105	1,056	1,096	1,651	44	2,868
Total Proved plus Probable	654	284	372	2,122	3,351	5,787	138	7,886

Summary of Company Net Reserves by Product
As of December 31, 2012
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	81	71	170	179	1,516	2,394	37	2,453
Developed Non-Producing	1	19	10	83	-	178	2	145
Undeveloped	16	82	32	564	375	968	30	1,260
Total Proved	98	172	212	826	1,891	3,540	69	3,858
Probable	42	64	75	801	835	1,367	34	2,079
Total Proved plus Probable	140	236	287	1,627	2,726	4,907	103	5,937
North Sea								
Proved								
Developed Producing	49					3		49
Developed Non-Producing	14					55		23
Undeveloped	164					24		168
Total Proved	227					82		240
Probable	105					20		109
Total Proved plus Probable	332					102		349
Offshore Africa								
Proved								
Developed Producing	55					39		61
Developed Non-Producing	-					-		-
Undeveloped	30					9		32
Total Proved	85					48		93
Probable	42					28		47
Total Proved plus Probable	127					76		140
Total Company								
Proved								
Developed Producing	185	71	170	179	1,516	2,436	37	2,563
Developed Non-Producing	15	19	10	83	-	233	2	168
Undeveloped	210	82	32	564	375	1,001	30	1,460
Total Proved	410	172	212	826	1,891	3,670	69	4,191
Probable	189	64	75	801	835	1,415	34	2,235
Total Proved plus Probable	599	236	287	1,627	2,726	5,085	103	6,426

NOTES

1. "Company Gross reserves" are the Company's working interest share of reserves before deduction of royalties and without including any royalty interests of the Company.

2. "Company Net reserves" means the Company's gross reserves less all royalties payable to others plus royalties receivable from others.

3. "Reserves" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as at a given date, based on analysis of drilling, geological, geophysical, and engineering data, with the use of established technology and under specified economic conditions which are generally accepted as being reasonable.

   Reserves are classified according to the degree of certainty associated with the estimates:

   — "Proved reserves" are those reserves which can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

   — "Probable reserves" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

   Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

   — "Developed reserves" are reserves that are expected to be recovered from (i) existing wells and installed facilities or, if the facilities have not been installed, that would involve a low expenditure (compared to the cost of drilling a well) to put the reserves on production, and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. The developed category may be subdivided into producing and non-producing.

   — "Undeveloped reserves" are reserves that are expected to be recovered from known accumulations with 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.

4. The reserve evaluation involved data supplied by the Company with respect to geological and engineering data, adjustments for product quality, heating value and transportation, interests owned, royalties payable, production costs, capital costs and contractual commitments. This data was found by the Evaluators to be reasonable.

A report on reserves data by the Evaluators is provided in Schedule "A" to this Annual Information Form. A report by the Company's management and directors on crude oil, NGLs and natural gas reserves disclosure is provided in Schedule "B" to this Annual Information Form.

Summary of Net Present Values of Future Net Revenue Before Income Taxes
As of December 31, 2012
Forecast Prices and Costs

MM$	Discount @ 0%	Discount @ 5%	Discount @10%	Discount @ 15%	Discount @ 20%	Unit Value Discounted at 10%/year $/BOE (1)
North America						
Proved						
Developed Producing	82,986	40,532	27,494	21,477	17,944	11.21
Developed Non-Producing	5,248	4,050	3,258	2,695	2,274	22.47
Undeveloped	47,110	23,752	10,908	4,527	1,211	8.66
Total Proved	135,344	68,334	41,660	28,699	21,429	10.80
Probable	107,176	38,588	19,078	11,484	7,714	9.18
Total Proved plus Probable	242,520	106,922	60,738	40,183	29,143	10.23
North Sea						
Proved						
Developed Producing	1,534	1,325	1,168	1,045	948	23.84
Developed Non-Producing	980	737	569	450	362	24.74
Undeveloped	9,351	5,783	3,782	2,587	1,834	22.51
Total Proved	11,865	7,845	5,519	4,082	3,144	23.00
Probable	9,678	5,033	2,996	1,971	1,395	27.49
Total Proved plus Probable	21,543	12,878	8,515	6,053	4,539	24.40
Offshore Africa						
Proved						
Developed Producing	2,731	1,834	1,387	1,132	967	22.74
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	2,124	1,344	934	693	540	29.19
Total Proved	4,855	3,178	2,321	1,825	1,507	24.96
Probable	3,523	1,862	1,086	683	455	23.11
Total Proved plus Probable	8,378	5,040	3,407	2,508	1,962	24.34
Total Company						
Proved						
Developed Producing	87,251	43,691	30,049	23,654	19,859	11.72
Developed Non-Producing	6,228	4,787	3,827	3,145	2,636	22.78
Undeveloped	58,585	30,879	15,624	7,807	3,585	10.70
Total Proved	152,064	79,357	49,500	34,606	26,080	11.81
Probable	120,377	45,483	23,160	14,138	9,564	10.36
Total Proved plus Probable	272,441	124,840	72,660	48,744	35,644	11.31

(1) Unit values are based on Company net reserves.

Summary of Net Present Values of Future Net Revenue After Income Taxes (1)
As of December 31, 2012
Forecast Prices and Costs

MM$	Discount @ 0%	Discount @ 5%	Discount @10%	Discount @ 15%	Discount @ 20%
North America					
Proved					
Developed Producing	64,691	32,624	22,557	17,820	14,998
Developed Non-Producing	3,946	3,018	2,413	1,984	1,664
Undeveloped	35,231	16,953	7,057	2,166	(356)
Total Proved	103,868	52,595	32,027	21,970	16,306
Probable	80,066	28,688	14,063	8,375	5,556
Total Proved plus Probable	183,934	81,283	46,090	30,345	21,862
North Sea					
Proved					
Developed Producing	416	368	333	306	285
Developed Non-Producing	299	234	188	154	128
Undeveloped	2,521	1,567	1,032	712	508
Total Proved	3,236	2,169	1,553	1,172	921
Probable	2,589	1,385	848	572	414
Total Proved plus Probable	5,825	3,554	2,401	1,744	1,335
Offshore Africa					
Proved					
Developed Producing	2,083	1,392	1,051	859	736
Developed Non-Producing	-	-	-	-	-
Undeveloped	1,635	1,052	742	557	438
Total Proved	3,718	2,444	1,793	1,416	1,174
Probable	2,678	1,446	861	553	377
Total Proved plus Probable	6,396	3,890	2,654	1,969	1,551
Total Company					
Proved					
Developed Producing	67,190	34,384	23,941	18,985	16,019
Developed Non-Producing	4,245	3,252	2,601	2,138	1,792
Undeveloped	39,387	19,572	8,831	3,435	590
Total Proved	110,822	57,208	35,373	24,558	18,401
Probable	85,333	31,519	15,772	9,500	6,347
Total Proved plus Probable	196,155	88,727	51,145	34,058	24,748

(1) After tax net present values consider the Company's existing tax pool balances.

Additional Information Concerning Future Net Revenue

The following table summarizes the undiscounted future net revenue as at December 31, 2012 using forecast prices and costs.

Total Future Net Revenue (Undiscounted)

	North America		North Sea		Offshore Africa		Total	
MM$	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable
Revenue	438,869	732,256	27,419	41,274	8,968	13,633	475,256	787,163
Royalties	77,729	146,132	-	-	288	466	78,017	146,598
Operating Costs	173,295	268,167	10,359	13,791	2,507	2,590	186,161	284,548
Development Costs	51,824	74,444	5,107	5,840	1,314	2,134	58,245	82,418
Abandonment [1]	677	993	88	100	4	65	769	1,158
Future Net Revenue Before Income Taxes	135,344	242,520	11,865	21,543	4,855	8,378	152,064	272,441
Income Taxes	31,476	58,586	8,629	15,718	1,137	1,982	41,242	76,286
Future Net Revenue After Income Taxes [2]	103,868	183,934	3,236	5,825	3,718	6,396	110,822	196,155

(1) The evaluation of reserves includes only abandonment costs for future drilling locations that have been assigned reserves.
(2) Future net revenue is prior to provision for interest, general and administrative expenses and the impact of any risk management activities.

The following table summarizes the future net revenue by production group as at December 31, 2012 using forecast prices and costs.

Future Net Revenue By Production Group

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) (MM$)	Unit Value[1] ($/BOE)
Proved Reserves	**Light and Medium Crude Oil** (including solution gas and other by-products)	10,811	23.80
	Primary Heavy Crude Oil (including solution gas)	3,881	22.31
	Pelican Lake Heavy Crude Oil (including solution gas)	3,691	17.39
	Bitumen (Thermal Oil)	12,177	14.74
	Synthetic Crude Oil	13,636	7.21
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	5,304	8.37
	Total	**49,500**	**11.81**
Proved Plus Probable Reserves	**Light and Medium Crude Oil** (including solution gas and other by-products)	15,002	22.64
	Primary Heavy Crude Oil (including solution gas)	5,446	22.83
	Pelican Lake Heavy Crude Oil (including solution gas)	4,975	17.28
	Bitumen (Thermal Oil)	19,992	12.29
	Synthetic Crude Oil	20,180	7.40
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	7,065	7.99
	Total	**72,660**	**11.31**

(1) Unit values are based on Company net reserves.

Pricing Assumptions

The crude oil, NGLs and natural gas reference pricing and the inflation and exchange rates used in the preparation of reserves and related future net revenue estimates are as per the Sproule price forecast dated December 31, 2012. The following is a summary of the Sproule price forecast.

	2013	2014	2015	2016	2017	Average annual increase thereafter
Crude oil and NGLs						
WTI[1] (US$/bbl)	$ 89.63	$ 89.93	$ 88.29	$ 95.52	$ 96.96	1.5%
WCS[2] (C$/bbl)	$ 69.33	$ 74.57	$ 73.21	$ 80.17	$ 81.37	1.5%
Edmonton Par[3] (C$/bbl)	$ 84.55	$ 89.84	$ 88.21	$ 95.43	$ 96.87	1.5%
Edmonton C5+[4] (C$/bbl)	$ 90.53	$ 96.19	$ 94.44	$ 102.18	$ 103.71	1.5%
North Sea Brent[5] (US$/bbl)	$ 106.42	$ 101.65	$ 97.56	$ 105.07	$ 106.65	1.5%
Natural gas						
AECO[6] (C$/MMBtu)	$ 3.31	$ 3.72	$ 3.91	$ 4.70	$ 5.32	1.5%
BC Westcoast Station 2[7] (C$/MMBtu)	$ 3.25	$ 3.66	$ 3.85	$ 4.64	$ 5.26	1.5%
Henry Hub[8] (US$/MMBtu)	$ 3.65	$ 4.06	$ 4.24	$ 5.04	$ 5.66	1.5%

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

(2) "WCS" refers to Western Canadian Select, a blend of heavy crude oils and bitumen with sweet synthetic and condensate diluents at Hardisty, Alberta; reference price used in the preparation of primary heavy crude oil, Pelican Lake heavy crude oil and bitumen (thermal oil) reserves.

(3) "Edmonton Par" refers to the price of light gravity (40° API), low sulphur content crude oil at Edmonton, Alberta; reference price used in the preparation of light and medium crude oil and SCO reserves.

(4) "Edmonton C5+" refers to pentanes plus at Edmonton, Alberta; reference price used in the preparation of NGLs reserves; also used in determining the diluent costs associated with primary heavy crude oil and bitumen (thermal oil) reserves.

(5) "North Sea Brent" refers to the benchmark price for European, African and Middle Eastern crude oil; reference priced used in the preparation of North Sea and Offshore Africa light crude oil reserves.

(6) "AECO" refers to the Alberta natural gas trading price at the AECO-C hub in southeast Alberta; reference price used in the preparation of North America (excluding British Columbia) natural gas reserves.

(7) "BC Westcoast Station 2" refers to the natural gas delivery point on the Spectra Energy system at Chetwynd, British Columbia; reference price used in the preparation of British Columbia natural gas reserves.

(8) "Henry Hub" refers to a distribution hub on the natural gas pipeline system in Erath, Louisiana and is the pricing point for natural gas futures on the New York Mercantile Exchange.

The forecast prices and costs assume the continuance of current laws and regulations, and any increases in wellhead selling prices also take inflation into account. Sales prices are based on reference prices as detailed above and adjusted for quality and transportation on an individual property basis. A foreign exchange rate of 1.001 US$/Cdn$ was used in the 2012 evaluation. Capital and operating costs are escalated at Sproule's cost inflation rate of 1.5% per year for all products except SCO. For SCO, capital and operating costs are escalated at GLJ's cost inflation rates of 4.0% for 2014 to 2016, 3.0% for 2017, 2.0% for 2018 and 1.5% after 2018.

The Company's 2012 average pricing, excluding risk management activities, was $94.57/bbl for light and medium crude oil, $64.21/bbl for primary heavy crude oil, $65.43/bbl for Pelican Lake heavy crude oil, $64.03/bbl for bitumen (thermal oil), $88.91/bbl for SCO, $55.45/bbl for NGLs and $2.44/Mcf for natural gas.

Reconciliation of Company Gross Reserves by Product
As of December 31, 2012
Forecast Prices and Cost

PROVED

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2011	114	175	276	974	2,119	4,266	95	4,464
Discoveries	-	-	-	-	-	6	-	1
Extensions	4	24	1	68	-	52	2	107
Infill Drilling	5	20	-	10	-	16	1	39
Improved Recovery	-	-	5	-	-	-	-	5
Acquisitions	1	-	-	-	-	43	1	9
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	14	(38)	(1)	7
Technical Revisions	4	31	(1)	50	153	79	5	255
Production	(15)	(46)	(14)	(36)	(31)	(438)	(9)	(224)
December 31, 2012	**113**	**204**	**267**	**1,066**	**2,255**	**3,985**	**94**	**4,663**
North Sea								
December 31, 2011	228					98		244
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	4					1		4
Technical Revisions	2					(16)		(1)
Production	(7)					(1)		(7)
December 31, 2012	**227**					**82**		**240**
Offshore Africa								
December 31, 2011	109					83		123
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	1					-		1
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	-					(7)		(1)
Production	(7)					(7)		(8)
December 31, 2012	**103**					**69**		**115**
Total Company								
December 31, 2011	451	175	276	974	2,119	4,447	95	4,831
Discoveries	-	-	-	-	-	6	-	1
Extensions	4	24	1	68	-	52	2	107
Infill Drilling	6	20	-	10	-	16	1	40
Improved Recovery	-	-	5	-	-	-	-	5
Acquisitions	1	-	-	-	-	43	1	9
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	4	-	-	-	14	(37)	(1)	11
Technical Revisions	6	31	(1)	50	153	56	5	253
Production	(29)	(46)	(14)	(36)	(31)	(446)	(9)	(239)
December 31, 2012	**443**	**204**	**267**	**1,066**	**2,255**	**4,136**	**94**	**5,018**

PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2011	41	74	112	752	1,236	1,572	39	2,516
Discoveries	-	-	-	-	-	5	-	1
Extensions	4	10	-	277	-	38	3	301
Infill Drilling	6	8	-	5	-	10	-	20
Improved Recovery	-	-	3	-	-	-	-	3
Acquisitions	-	-	-	-	-	15	-	3
Dispositions	-	-	-	-	-	(2)	-	(1)
Economic Factors	-	-	-	-	(11)	(2)	-	(11)
Technical Revisions	-	(12)	(10)	22	(129)	(47)	2	(135)
Production	-	-	-	-	-	-	-	-
December 31, 2012	**51**	**80**	**105**	**1,056**	**1,096**	**1,589**	**44**	**2,697**

North Sea								
December 31, 2011	121					36		127
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	(4)					(1)		(4)
Technical Revisions	(12)					(15)		(14)
Production	-					-		-
December 31, 2012	**105**					**20**		**109**

Offshore Africa								
December 31, 2011	56					46		64
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	1					-		1
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(2)					(4)		(3)
Production	-					-		-
December 31, 2012	**55**					**42**		**62**

Total Company								
December 31, 2011	218	74	112	752	1,236	1,654	39	2,707
Discoveries	-	-	-	-	-	5	-	1
Extensions	4	10	-	277	-	38	3	301
Infill Drilling	7	8	-	5	-	10	-	21
Improved Recovery	-	-	3	-	-	-	-	3
Acquisitions	-	-	-	-	-	15	-	3
Dispositions	-	-	-	-	-	(2)	-	(1)
Economic Factors	(4)	-	-	-	(11)	(3)	-	(15)
Technical Revisions	(14)	(12)	(10)	22	(129)	(66)	2	(152)
Production	-	-	-	-	-	-	-	-
December 31, 2012	**211**	**80**	**105**	**1,056**	**1,096**	**1,651**	**44**	**2,868**

PROVED PLUS PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2011	155	249	388	1,726	3,355	5,838	134	6,980
Discoveries	-	-	-	-	-	11	-	2
Extensions	8	34	1	345	-	90	5	408
Infill Drilling	11	28	-	15	-	26	1	59
Improved Recovery	-	-	8	-	-	-	-	8
Acquisitions	1	-	-	-	-	58	1	12
Dispositions	-	-	-	-	-	(3)	-	(1)
Economic Factors	-	-	-	-	3	(40)	(1)	(4)
Technical Revisions	4	19	(11)	72	24	32	7	120
Production	(15)	(46)	(14)	(36)	(31)	(438)	(9)	(224)
December 31, 2012	**164**	**284**	**372**	**2,122**	**3,351**	**5,574**	**138**	**7,360**

North Sea								
December 31, 2011	349					134		371
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(10)					(31)		(15)
Production	(7)					(1)		(7)
December 31, 2012	**332**					**102**		**349**

Offshore Africa								
December 31, 2011	165					129		187
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	2					-		2
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(2)					(11)		(4)
Production	(7)					(7)		(8)
December 31, 2012	**158**					**111**		**177**

Total Company								
December 31, 2011	669	249	388	1,726	3,355	6,101	134	7,538
Discoveries	-	-	-	-	-	11	-	2
Extensions	8	34	1	345	-	90	5	408
Infill Drilling	13	28	-	15	-	26	1	61
Improved Recovery	-	-	8	-	-	-	-	8
Acquisitions	1	-	-	-	-	58	1	12
Dispositions	-	-	-	-	-	(3)	-	(1)
Economic Factors	-	-	-	-	3	(40)	(1)	(4)
Technical Revisions	(8)	19	(11)	72	24	(10)	7	101
Production	(29)	(46)	(14)	(36)	(31)	(446)	(9)	(239)
December 31, 2012	**654**	**284**	**372**	**2,122**	**3,351**	**5,787**	**138**	**7,886**

At December 31, 2012, the Company's gross proved crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 4,329 MMbbl, and gross proved plus probable crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 6,921 MMbbl. Proved reserve additions and revisions replaced 245% of 2012 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 143 MMbbl, and additions to proved plus probable reserves amounted to 460 MMbbl. Net positive revisions amounted to 261 MMbbl for proved reserves and 105 MMbbl for proved plus probable reserves, primarily due to technical revisions to prior estimates based on improved or better than expected reservoir performance.

At December 31, 2012, the Company's gross proved natural gas reserves totaled 4,136 Bcf, and gross proved plus probable natural gas reserves totaled 5,787 Bcf. Proved reserve additions and revisions replaced 30% of 2012 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 116 Bcf, and additions to proved plus probable reserves amounted to 182 Bcf. Net positive revisions amounted to 19 Bcf for proved reserves and net negative revisions amounted to 50 Bcf for proved plus probable reserves, primarily due to lower estimated future benchmark pricing.

Additional Information Relating To Reserves Data

Undeveloped Reserves

Undeveloped reserves are reserves expected to be recovered from known accumulations and require significant expenditure to develop and make capable of production. Proved and probable undeveloped reserves were estimated by the Evaluators in accordance with the procedures and standards contained in the COGE Handbook. The tables below do not include volumes of proved undeveloped and probable undeveloped reserves first attributed in 2009 and in aggregate before that time. This information was not evaluated prior to 2010 due to the Company having been granted an exemption order from securities regulators in Canada which allowed substitution of SEC requirements for certain NI 51-101 disclosures. This exemption expired on December 31, 2010.

Proved Undeveloped Reserves

Year	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
2010 First Attributed	3	34	3	156	-	209	7	238
2010 Total	195	66	85	687	128	1,082	17	1,358
2011 First Attributed	8	29	8	70	-	240	21	176
2011 Total	209	79	71	710	288	1,165	37	1,589
2012 First Attributed	6	20	-	77	-	32	1	109
2012 Total	221	96	39	724	418	1,145	38	1,727

Probable Undeveloped Reserves

Year	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
2010 First Attributed	3	16	2	224	-	103	3	265
2010 Total	146	27	43	777	862	470	6	1,939
2011 First Attributed	4	17	6	17	388	160	14	473
2011 Total	153	37	38	749	1,142	564	20	2,233
2012 First Attributed	8	13	-	283	-	40	3	314
2012 Total	144	47	22	1,046	988	599	24	2,371

Bitumen (thermal oil) accounts for approximately 42% of the Company's total proved undeveloped BOE reserves and 44% of the total probable undeveloped BOE reserves. These undeveloped reserves are scheduled to be developed in a staged approach to align with current operational capacities and efficient capital spending commitments over the next forty years. These plans are continuously reviewed and updated for internal and external factors affecting planned activity.

Undeveloped reserves, for products other than bitumen (thermal oil), are scheduled to be developed over the next ten years. The Company continually reviews the economic viability and ranking of these undeveloped reserves within the total portfolio of development projects. Development opportunities are then pursued based on capital availability and allocation.

Significant Factors or Uncertainties Affecting Reserves Data

The development plan for the Company's undeveloped reserves is based on forecast price and cost assumptions. Projects may be advanced or delayed based on actual prices that occur.

The evaluation of reserves is a process that can be significantly affected by a number of internal and external factors. Revisions are often necessary resulting in changes in technical data acquired, historical performance, fluctuations in production costs, development costs and product pricing, economic conditions, changes in royalty regimes and environmental regulations, and future technology improvements. See "Risk Factors" in this AIF for further information.

Future Development Costs

The following table summarizes the undiscounted future development costs, excluding abandonment costs, using forecast prices and costs as of December 31, 2012.

Future Development Costs (Undiscounted)

	North America		North Sea		Offshore Africa		Total	
Year	Proved (MM$)	Proved plus Probable (MM$)	Proved (MM$)	Proved plus Probable (MM$)	Proved (MM$)	Proved plus Probable (MM$)	Proved (MM$)	Proved plus Probable (MM$)
2013	4,226	4,740	331	331	159	197	4,716	5,268
2014	4,388	5,548	433	437	170	170	4,991	6,155
2015	4,554	5,700	456	460	71	216	5,081	6,376
2016	4,158	4,915	369	372	9	261	4,536	5,548
2017	4,197	4,637	458	438	7	83	4,662	5,158
Thereafter	30,301	48,904	3,060	3,802	898	1,207	34,259	53,913
Total	**51,824**	**74,444**	**5,107**	**5,840**	**1,314**	**2,134**	**58,245**	**82,418**

Management believes internally generated cash flows, existing credit facilities and access to capital debt markets are sufficient to fund future development costs. We do not anticipate the costs of funding would make the development of any property uneconomic.

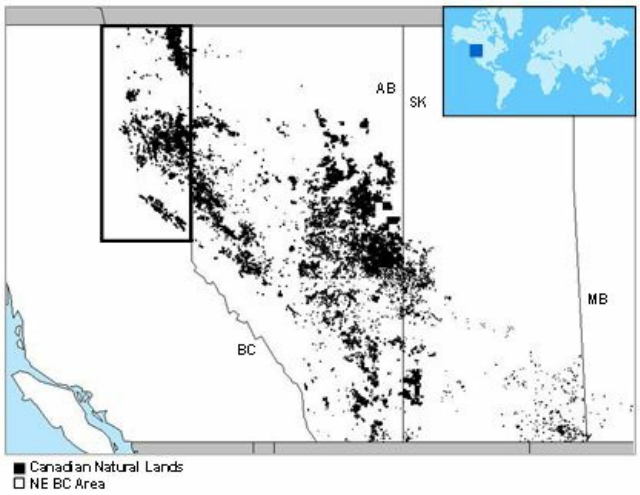
Other Oil and Gas Information

Daily Production

Set forth below is a summary of the production from crude oil, NGLs and natural gas properties for the fiscal years ended December 31, 2012 and 2011.

	2012 Average Daily Production Rates		2011 Average Daily Production Rates	
Region	**Crude oil & NGLs (Mbbl)**	**Natural gas (MMcf)**	Crude oil & NGLs (Mbbl)	Natural gas (MMcf)
North America				
Northeast British Columbia	**11**	**340**	8	345
Northwest Alberta	**24**	**481**	21	485
Northern Plains	**271**	**197**	248	240
Southern Plains	**12**	**177**	11	158
Southeast Saskatchewan	**8**	**3**	7	2
Oil Sands Mining & Upgrading	**86**	**-**	40	-
Non-core regions	**-**	**-**	1	1
North America Total	**412**	**1,198**	336	1,231
International				
North Sea UK Sector	**20**	**2**	30	7
Offshore Africa	**19**	**20**	23	19
International Total	**39**	**22**	53	26
Company Total	**451**	**1,220**	389	1,257

Northeast British Columbia

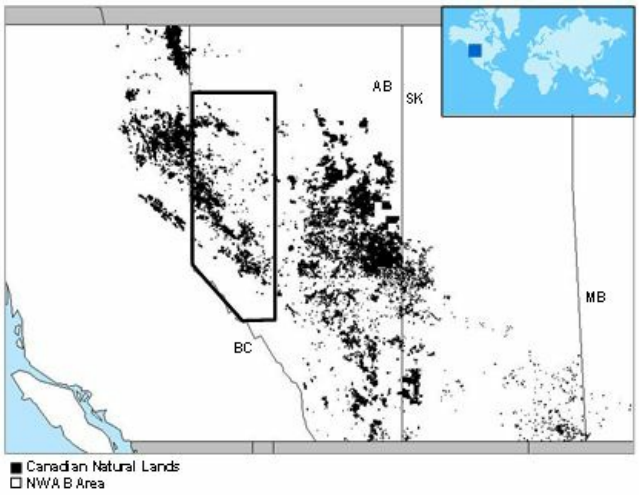


Significant geological variation extends throughout the productive reservoirs in this region located west of the British Columbia and Alberta border to Prince George, producing light and medium crude oil, NGLs and natural gas.

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

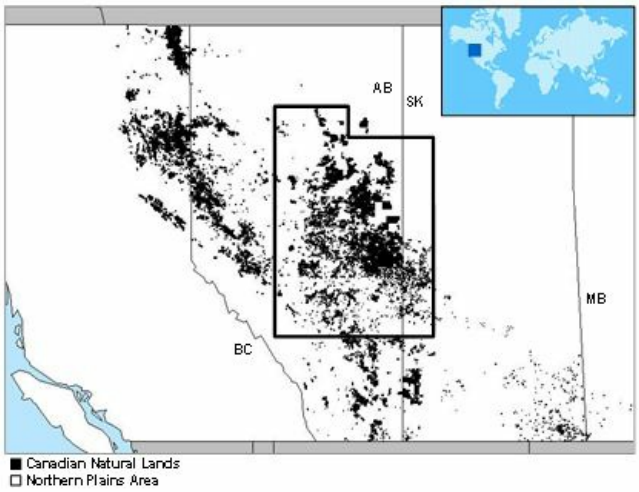
close to existing infrastructure. The region has a mix of low risk multi-zone targets, deep higher risk exploration plays and emerging unconventional shale gas plays. The 2006 acquisition of Anadarko Canada Corporation ("ACC") significantly increased the asset base in this area. In 2010, a natural gas processing plant with a design capacity of 50 MMcf/d was completed at our Septimus Montney gas play and in 2011 the Company completed a pipeline to a deep cut gas facility which increased liquids recoveries. 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 Rio Alto Exploration Ltd. and 2006 acquisition of ACC. The ACC acquisition added two very prospective properties to this region, Wild River and Peace River Arch. The Wild River assets provide a premium 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. In both 2011 and 2010, the Company purchased additional assets in the area which further complemented the asset base and operational efficiencies are expected as overlapping facilities are consolidated. 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 opportunities similar to the geology of the Company's Northern Plains core region. The Company is also pursuing development of shale gas plays 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.

Natural gas in this region is produced from shallow, low-risk, multi-zone prospects. The Company targets low-risk exploration and development opportunities and some shale gas exploration in this area.

Near Lloydminster, Alberta, reserves of primary 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. A key component to maintaining profitability in the production of heavy crude oil is to be an effective and efficient producer. The Company continues to control 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 production cost. 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.

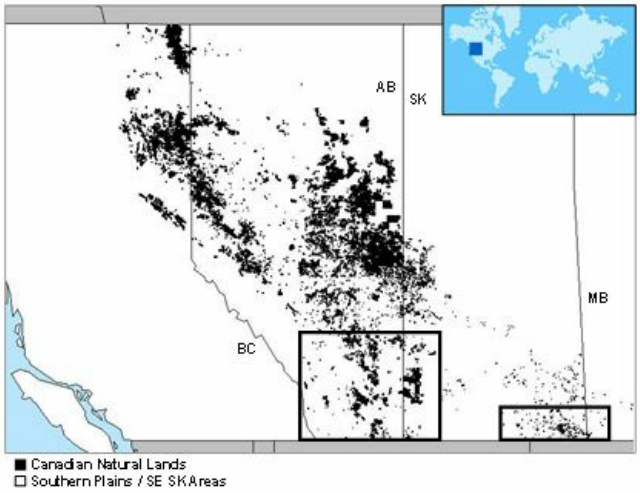
Included in the northern part of this region, approximately 200 miles north of Edmonton, are the Company's holdings at Pelican Lake. These assets produce Pelican Lake heavy crude oil from the Wabasca formation with gravities of 12°-17° API. Production costs are low due to the absence of sand production, 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 is using an EOR scheme through polymer flooding to increase the ultimate recoveries from the field. At the end of 2012, approximately 55% of the field had been converted to polymer injection. Completion of the new 20,000 bbl/d battery expansion is targeted to be on stream by the second quarter of 2013 and will support further production growth.

Production of bitumen (thermal oil) from the 100% owned Primrose Field located near Bonnyville, Alberta involves processes that utilize steam to increase the recovery of the bitumen (10°-11°API). The two processes employed by the Company are CSS and SAGD. Both recovery processes inject steam to heat the bitumen deposits, reducing the 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 bitumen recovery. The Company continues to develop its Primrose thermal project, as part of the phased expansion of its thermal in situ Oil Sands assets, and additional pad drilling was completed and drilled on budget, with these wells coming on production in 2013.

The regulatory application for the Kirby In Situ Oil Sands Project ("Kirby South Phase 1"), located approximately 85 km northeast of Lac la Biche, was approved in the third quarter 2010 and sanctioned by the Board of Directors, with construction commencing in the fourth quarter 2010. During 2012, drilling was completed on the fifth of seven pads. The project achieved 81% construction completion and target first steam in late 2013 and production is targeted to ramp up to 40,000 bbl/d in late 2014. In 2012, the Company acquired approximately 49 sections (12,630 hectares) of additional Oil Sands rights immediately adjacent to Canadian Natural's Kirby In Situ Oil Sands Expansion Project ("Kirby Project"). The Company is in the early stages of integrating the acquired lands into the development plan and is expecting to increase production capacity for future phases in Kirby North and Kirby South. On Kirby North Phase 1, engineering design specifications were completed and the transition to detailed engineering is in progress. Critical long lead items have been ordered and the central plant site has been cleared and first steam is targeted for 2016.

Southern Plains and Southeast Saskatchewan



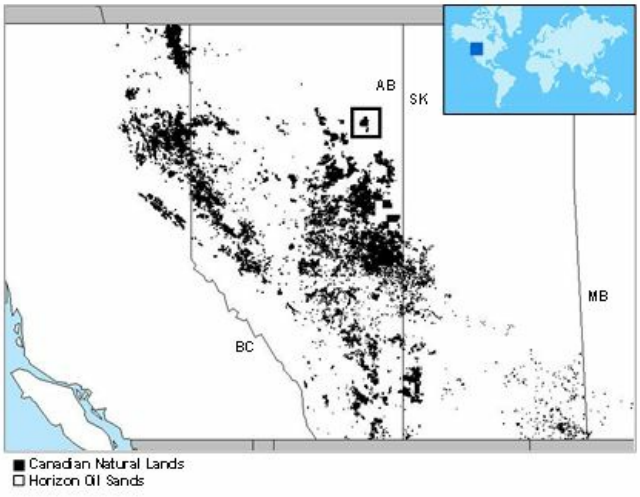
The Southern Plains area is principally located south of the Northern Plains area to the United States border and extending into western Saskatchewan.

Reserves of natural gas, NGLs and light and medium 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. The Company's extensive shallow gas assets in this region were augmented by the 2006 acquisition of ACC. The Company continues to acquire additional assets in the area which further complement the asset base.

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 Southeast Saskatchewan is located in the south eastern portion of the province 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 the main lease 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. The site is accessible by a private road and private airstrip. The oil sands resource is found in the cretaceous McMurray Formation which is further subdivided into three informal members: lower, middle and upper. Most of Horizon's oil sands resource is found within the lower and middle McMurray Formation at depths ranging from 50 to 100 meters below the surface.

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

Site clearing and pre-construction preparation activities commenced in 2004 following regulatory approvals 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 production averaged 86,077 bbl/day in 2012.

On January 6, 2011, the Company suspended SCO production at its Horizon Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. On August 16, the Company successfully and safely resumed production with first pipeline deliveries commencing on August 18, 2011.

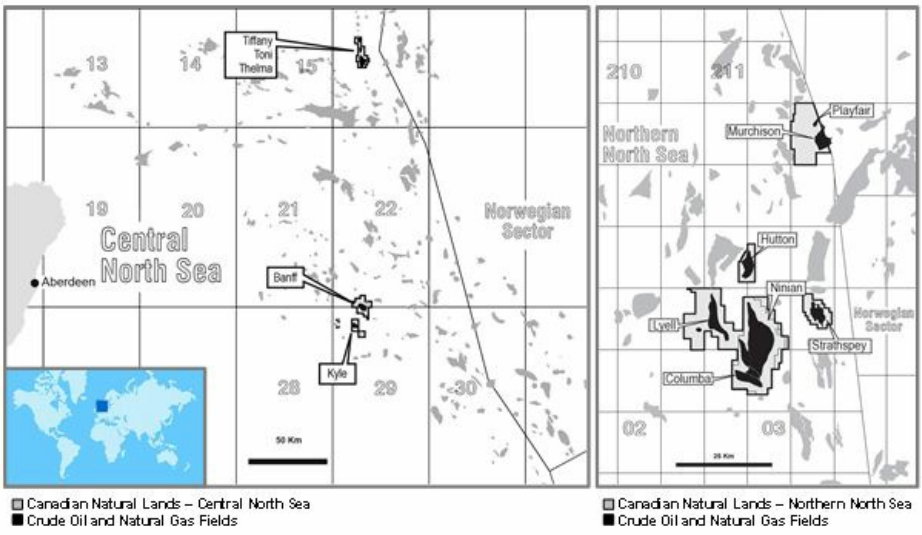
On February 5, 2012 the Company temporarily suspended SCO production to complete unplanned maintenance on the fractionating unit in the primary upgrading facility. In March 2012, the maintenance was completed and pipeline deliveries re-commenced.

In October 2012, the Company successfully completed proactive planned maintenance activities at Horizon. The planned outage, scheduled for twelve days in the month of October, was completed on schedule and on cost.

Phase 2/3 expansion activity during 2012 was focused on the field construction of the gas recovery unit, sulphur recovery unit, butane treatment unit, tank farms, coker expansion, hydrotransport, tailings, and extraction trains 3 and 4, along with engineering related to the hydrogen, utilities, hydrotreater, vacuum distillation and diluent recovery units, and permanent camp. Final commissioning of the third ore preparation plant and associated hydro-transport was completed in January 2012.

In the second quarter of 2013, Horizon will enter into a 24 day planned maintenance turnaround, resulting in a plant-wide shut down.

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 2012, the Company produced from 11 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 8 licences covering 11 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).

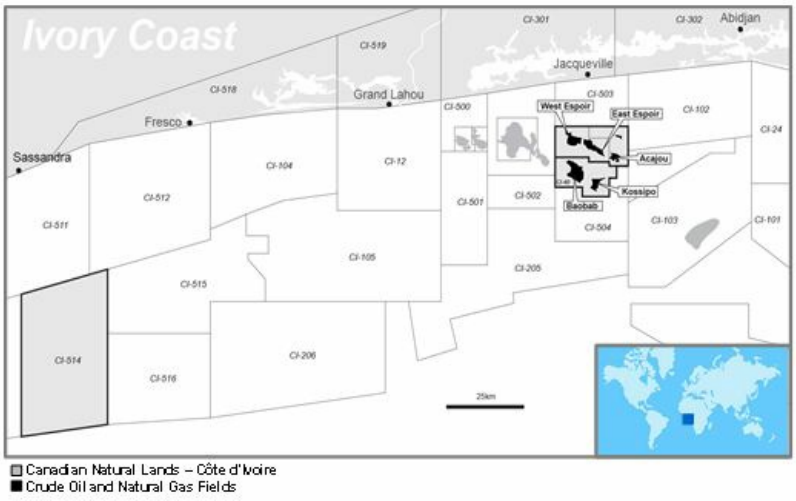
The Company receives tariff revenue from other field owners for the processing of crude oil and natural gas through some of the processing facilities. Opportunities for further long-reach well development on adjacent fields are provided by the existing processing facilities.

In December 2011 storm damage was sustained to the Banff FPSO and subsea infrastructure. Operations at Banff/Kyle were suspended. The FPSO and associated floating storage unit have subsequently been removed from the field and the FPSO is currently in dry dock for assessment of damages and repair timeframe. The extent of the property damage, including associated costs, is not expected to be significant.

During 2012, the Company continued drilling operations on Ninian, prior to commencing drilling operations towards the end of 2012 on the Tiffany field. There were ongoing facilities upgrade projects at Lyell and capital turnaround projects on all UK installations. The Company also continued planning for decommissioning of the Murchison field which is scheduled to commence in 2014 and estimates the decommissioning efforts will continue for approximately 5 years.

Offshore Africa

Côte d'Ivoire



The Company owns interests in three 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.

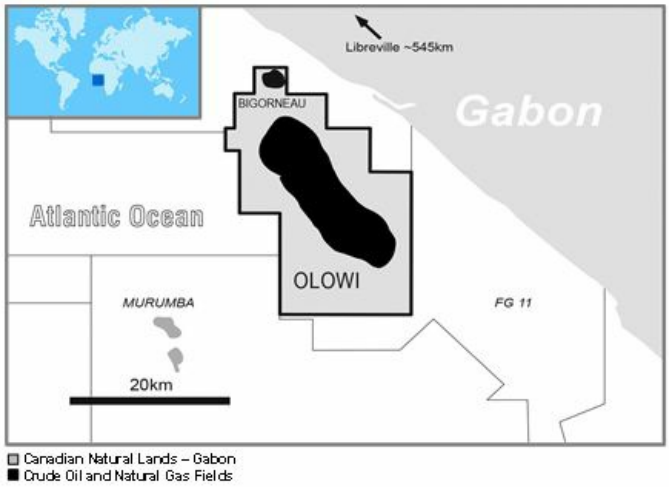
The Company's eight well infill drilling program at the Espoir Field is progressing. The drilling rig arrived in Côte d'Ivoire and preparations are ongoing to commence drilling with first oil targeted for 2013.

The Company also has a 57.6% interest in the Baobab Field, located in Block CI-40, which is eight kilometers south of the Espoir facilities. Production from the Baobab field commenced in 2005 and the Company carried out a drilling program in 2008 and 2009 to restore production from certain wells shut in due to control of sand and solids production issues.

In early 2012, the Company acquired a 36% interest in Block 514 in Côte d'Ivoire. This block's areal extent is approximately 1,250 square km and the Company believes this block is prospective for deepwater channel/fan plays similar to other discoveries in Ghana and elsewhere offshore Africa.

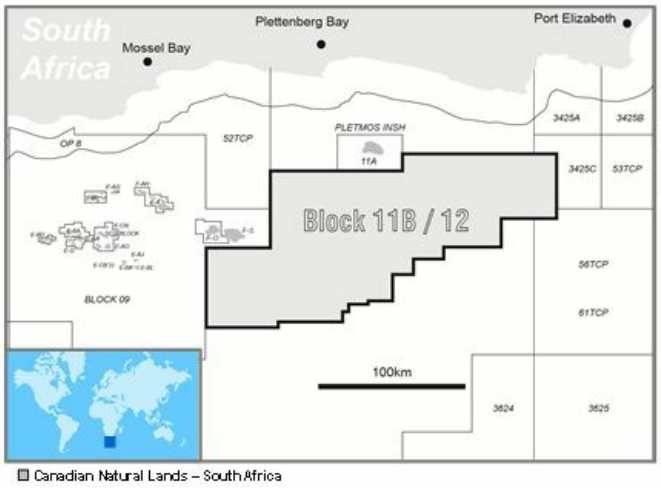
Following the formation of a new government in June 2011, Côte d'Ivoire has experienced a period of political stability.

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. First crude oil production was achieved during the second quarter of 2009 at Platform C and during 2010 on Platform A and B. In mid 2011, production was temporarily suspended as a result of a failure in the mid-water arch. Production was reinstated in mid August 2011. During 2012 a second failure of the mid-water arch occurred. Production resumed in the first quarter of 2013 and the Company is assessing the long-term operability of the mid-water arch.

South Africa



In May 2012 the Company completed the conversion of its 100% owned natural oil prospecting sub-lease in respect of Block 11B/12B off the south east coast of South Africa into an exploration right for petroleum in respect of this area. All regulatory requirements for drilling a well are complete and targeted drilling windows are from Q4 2013 to Q1 2014 and from Q4 2014 to Q1 2015.

Producing and Non Producing Crude Oil & Natural Gas Wells

Set forth below is a summary of the number of wells in which the Company has a working interest that were producing or mechanically capable of producing as of December 31, 2012.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	12,863.0	9,965.7	8,265.0	7,472.8	21,128.0	17,438.5
British Columbia	1,680.0	1,414.5	258.0	212.0	1,938.0	1,626.5
Saskatchewan	6,057.0	5,438.0	2,675.0	2,177.7	8,732.0	7,615.7
Manitoba	2.0	2.0	181.0	177.2	183.0	179.2
Total Canada	20,602.0	16,820.2	11,379.0	10,039.7	31,981.0	26,859.9
United States	2.0	0.2	2.0	0.3	4.0	0.5
North Sea UK Sector	1.0	0.1	87.0	73.1	88.0	73.2
Offshore Africa						
Gabon	-	-	13.0	12.0	13.0	12.0
Côte d'Ivoire	-	-	23.0	13.4	23.0	13.4
Total	20,605.0	16,820.5	11,504.0	10,138.5	32,109.0	26,959.0

Set forth below is a summary of the number of wells in which the Company has a working interest that were not producing or not mechanically capable of producing as of December 31, 2012.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Non Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	4,675.0	3,634.0	5,969.0	5,423.0	10,644.0	9,057.0
British Columbia	1,336.0	1,111.9	336.0	286.7	1,672.0	1,398.6
Saskatchewan	1,265.0	1,160.5	2,073.0	1,806.4	3,338.0	2,966.9
Manitoba	1.0	1.0	55.0	53.5	56.0	54.5
Northwest Territories	13.0	13.0	-	-	13.0	13.0
Total Canada	7,290.0	5,920.4	8,433.0	7,569.6	15,723.0	13,490.0
United States	-	-	3.0	0.5	3.0	0.5
North Sea UK Sector	-	-	33.0	25.7	33.0	25.7
Offshore Africa						
Gabon	-	-	-	-	-	-
Côte d'Ivoire	-	-	7.0	4.0	7.0	4.0
Total	7,290.0	5,920.4	8,476.0	7,599.8	15,766.0	13,520.2

Properties With Attributed and No Attributed Reserves

The following table summarizes the Company's landholdings as at December 31, 2012.

	Proved Properties		Unproved Properties		Total Acreage		Average Working Interest
Region (thousands of acres)	Gross	Net	Gross	Net	Gross	Net	%
North America							
Northeast British Columbia	1,013	844	3,775	2,954	4,788	3,798	79
Northwest Alberta	1,213	941	2,631	2,196	3,844	3,137	82
Northern Plains	2,197	1,882	7,303	6,603	9,500	8,485	89
Southern Plains	1,685	1,475	1,167	1,026	2,852	2,501	88
Southeast Saskatchewan	127	116	108	100	235	216	92
Thermal in situ Oil Sands	85	85	938	837	1,023	922	90
Oil Sands Mining & Upgrading	22	22	59	59	81	81	100
Non-core regions	12	3	1,026	249	1,038	252	24
North America Total	6,354	5,368	17,007	14,024	23,361	19,392	83
International							
North Sea UK Sector	68	57	158	128	226	185	82
Offshore Africa							
Côte d'Ivoire	10	6	403	165	413	171	41
Gabon	-	-	152	140	152	140	92
South Africa	-	-	4,002	4,002	4,002	4,002	100
International Total	78	63	4,715	4,435	4,793	4,498	94
Company Total	6,432	5,431	21,722	18,459	28,154	23,890	85

Where the Company holds interests in different formations under the same surface area pursuant to separate leases, the acreage for each lease is included in the gross and net amounts.

Canadian Natural has approximately 0.7 million net acres attributed to our North America properties which are currently expected to expire by December 31, 2013.

Significant Factors or Uncertainties Relevant To Properties With No Attributed Reserves

The Company's unproved property holdings are diverse and located in the North America and International regions. The land assets range from discovery areas where tenure to the property is held indefinitely by hydrocarbon test results or production to exploration areas in the early stages of evaluation. The Company continually reviews the economic viability and ranking of these unproved properties on the basis of product pricing, capital availability and allocation and level of infrastructure development in any specific area. From this process, some properties are scheduled for economic development activities while others are temporarily held inactive, sold, swapped or allowed to expire and relinquished back to the mineral rights owner.

Forward Contracts

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.

Additional Information Concerning Abandonment and Reclamation Costs

For 2012, the Company's capital expenditures included $204 million for abandonment expenditures and the Company expects approximately $471 million of abandonment expenditures to be incurred over the next 3 years. The Company's estimated undiscounted ARO at December 31, 2012 was $10,565 million and discounted at 10% is approximately $1,392 million. The Company expects to incur abandonment and reclamation costs on 43,985 net wells.

The abandonment and reclamation costs were not deducted in estimating the Company's future net revenue for December 31, 2012 as the reserve evaluation includes only abandonment costs for future drilling locations that have been assigned reserves.

The discounted ARO was based on estimates of future costs to abandon and restore wells, production facilities, mine site, upgrading facilities and tailings, and offshore production platforms. Factors that affect costs include number of wells drilled, well depth, facility size and the specific environmental legislation. The estimated future costs are based on engineering estimates of current costs in accordance with present legislation, industry operating practice and the expected timing of abandonment. The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates.

2012 Costs Incurred in Crude Oil, NGLs and Natural Gas Activities

MM$	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	144	-	-	144
Unproved	44	-	3	47
Exploration	251	-	11	262
Development	5,773	556	75	6,404
	6,212	556	89	6,857
Less non cash costs [(1)]	(476)	(302)	(25)	(803)
Costs Incurred	5,736	254	64	6,054

(1) Non cash costs are comprised primarily of increases in asset retirement obligations.

Exploration and Development Activities

Set forth below are summaries of crude oil, NGLs, and natural gas drilling activities completed by the Company for the fiscal year ended December 31, 2012 by geographic region along with a general discussion of 2013 activity.

		2012 Exploratory Wells					
		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	Total
North America							
Northeast British Columbia	Gross	-	1.0	-	-	-	1.0
	Net	-	1.0	-	-	-	1.0
Northwest Alberta	Gross	5.0	12.0	2.0	-	-	19.0
	Net	5.0	11.4	0.6	-	-	17.0
Northern Plains	Gross	13.0	-	5.0	-	-	18.0
	Net	11.7	-	5.0	-	-	16.7
Southern Plains	Gross	2.0	-	-	-	-	2.0
	Net	2.0	-	-	-	-	2.0
Southeast Saskatchewan	Gross	3.0	-	-	-	-	3.0
	Net	3.0	-	-	-	-	3.0
Oil Sands Mining and Upgrading	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Non-core Regions	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
North America Total	Gross	23.0	13.0	7.0	-	-	43.0
	Net	21.7	12.4	5.6	-	-	39.7
North Sea UK Sector	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Offshore Africa	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Company Total	Gross	23.0	13.0	7.0	-	-	43.0
	Net	21.7	12.4	5.6	-	-	39.7

		2012 Development Wells					
		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	Total
North America							
Northeast British Columbia	Gross	6.0	16.0	-	-	-	22.0
	Net	6.0	13.6	-	-	-	19.6
Northwest Alberta	Gross	30.0	12.0	1.0	-	-	43.0
	Net	25.5	8.4	1.0	-	-	34.9
Northern Plains	Gross	1,121.0	1.0	24.0	50.0	371.0	1,567.0
	Net	1,079.3	0.2	24.0	49.6	371.0	1,524.1
Southern Plains	Gross	41.0	-	1.0	-	-	42.0
	Net	40.8	-	1.0	-	-	41.8
Southeast Saskatchewan	Gross	34.0	-	1.0	3.0	-	38.0
	Net	30.1	-	1.0	2.9	-	34.0
Oil Sands Mining and Upgrading	Gross	-	-	-	-	303.0	303.0
	Net	-	-	-	-	303.0	303.0
Non-core Regions	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
North America Total	Gross	1,232.0	29.0	27.0	53.0	674.0	2,015.0
	Net	1,181.7	22.2	27.0	52.5	674.0	1,957.4
North Sea UK Sector	Gross	-	-	-	1.0	-	1.0
	Net	-	-	-	0.9	-	0.9
Offshore Africa	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Company Total	Gross	1,232.0	29.0	27.0	54.0	674.0	2,016.0
	Net	1,181.7	22.2	27.0	53.4	674.0	1,958.3

Total success rate, excluding service and stratigraphic test wells, for 2012 is 97%.

2013 North America Natural Gas Activity

The 2013 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)	2013 Guidance
Conventional natural gas	4
Deep natural gas	26
Total	30

2013 North America Crude Oil Activity

The 2013 North America crude oil drilling program is highlighted by continued development of the Primrose thermal projects, Pelican Lake, and a strong primary heavy crude oil program, as follows:

(Number of wells)	2013 Guidance
Primary heavy crude oil	889
Bitumen (thermal oil)	132
Light and Medium crude oil	114
Pelican Lake heavy crude oil	19
Total	1,154

2013 Oil Sands Mining and Upgrading Activity

The Company continues to execute its disciplined strategy of staged expansion and work remains on track. The budgeted project capital expenditures reflect the Board of Directors approval of approximately $2.1 billion in targeted strategic expansion.

2013 North Sea Activity

During 2013, capital expenditures will be incurred on drilling programs at Ninian and Tiffany in the North Sea. The Company is currently targeting to drill 3 net crude oil wells.

2013 Offshore Africa Activity

During 2013, capital expenditures will be incurred on drilling and completions at the Espoir field. The Company is currently targeting to drill 3 net crude oil wells.

Production Estimates

The following table illustrates the estimated 2013 gross daily proved and probable production reflected in the reserve reports as of December 31, 2012 using forecast prices and costs.

	Light And Medium Crude Oil (bbl/d)	Primary Heavy Crude Oil (bbl/d)	Pelican Lake Heavy Crude Oil (bbl/d)	Bitumen (Thermal Oil) (bbl/d)	Synthetic Crude Oil (bbl/d)	Natural Gas (MMcf/d)	Natural Gas Liquids (bbl/d)	Barrels of Oil Equivalent (BOE/d)
PROVED								
North America	38,899	125,544	48,247	105,358	100,800	1,038	22,278	614,126
North Sea	27,088					1		27,254
Offshore Africa	19,216					25		23,383
Total Proved	85,203	125,544	48,247	105,358	100,800	1,064	22,278	664,763
PROBABLE								
North America	3,506	9,572	1,000	737	5,450	51	1,282	30,047
North Sea	1,655					-		1,655
Offshore Africa	885					1		1,052
Total Probable	6,046	9,572	1,000	737	5,450	52	1,282	32,754

Production History

	2012				
	Q1	Q2	Q3	Q4	Year Ended
North America production and netbacks by product type [1]					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	41,149	39,387	39,672	41,729	40,485
Netbacks ($/bbl)					
Sales price [2]	$ 86.65	$ 76.77	$ 77.18	$ 76.64	$ 79.33
Royalties	16.66	14.20	13.33	12.73	14.23
Production expenses	21.80	19.30	20.92	19.12	20.28
Netback	**$ 48.19**	**$ 43.27**	**$ 42.93**	**$ 44.79**	**$ 44.82**
Primary Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	120,181	122,246	128,115	130,192	125,205
Netbacks ($/bbl)					
Sales price [2]	$ 72.84	$ 63.69	$ 61.54	$ 59.42	$ 64.21
Royalties	11.66	8.77	10.41	7.40	9.52
Production expenses	17.28	14.80	14.27	15.93	15.55
Netback	**$ 43.90**	**$ 40.12**	**$ 36.86**	**$ 36.09**	**$ 39.14**
Pelican Lake Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	38,709	37,330	40,544	36,383	38,243
Netbacks ($/bbl)					
Sales price [2]	$ 74.16	$ 63.07	$ 63.03	$ 61.32	$ 65.43
Royalties	10.90	2.40	11.78	5.26	7.72
Production expenses	12.95	11.12	10.69	12.91	11.89
Netback	**$ 50.31**	**$ 49.55**	**$ 40.56**	**$ 43.15**	**$ 45.82**
Bitumen (Thermal Oil)					
Average daily production (before royalties) (bbl/d)	79,626	94,724	100,858	121,499	99,478
Netbacks ($/bbl)					
Sales price [2]	$ 74.76	$ 64.65	$ 64.56	$ 56.14	$ 64.03
Royalties	15.28	8.54	13.82	7.61	10.95
Production expenses	12.56	10.47	8.84	7.95	9.69
Netback	**$ 46.92**	**$ 45.64**	**$ 41.90**	**$ 40.58**	**$ 43.39**
SCO					
Average daily production (before royalties) (bbl/d)	46,090	115,823	99,205	83,079	86,077
Netbacks ($/bbl)					
Sales price [2]	$ 97.09	$ 88.11	$ 87.40	$ 87.34	$ 88.91
Royalties [3]	5.16	5.20	3.45	3.80	4.34
Production expenses [4]	46.24	36.98	42.69	49.27	42.83
Netback	**$ 45.69**	**$ 45.93**	**$ 41.26**	**$ 34.27**	**$ 41.74**
Natural Gas					
Average daily production (before royalties) (MMcf/d)	1,281	1,230	1,169	1,113	1,198
Netbacks ($/Mcf)					
Sales price [2]	$ 2.36	$ 1.73	$ 2.15	$ 3.03	$ 2.31
Royalties	0.03	0.02	0.02	0.18	0.06
Production expenses	1.33	1.13	1.28	1.40	1.28
Netback	**$ 1.00**	**$ 0.58**	**$ 0.85**	**$ 1.45**	**$ 0.97**

Production History

	2012				
	Q1	Q2	Q3	Q4	Year Ended
Natural Gas Liquids					
Average daily production (before royalties) (bbl/d)	25,248	23,163	22,961	22,317	23,418
Netbacks ($/bbl)					
Sales price [2]	$ 59.54	$ 57.81	$ 50.31	$ 53.76	$ 55.45
Royalties	18.53	4.78	5.94	8.12	9.55
Production expenses	8.75	7.43	7.70	8.82	8.18
Netback	**$ 32.26**	**$ 45.60**	**$ 36.67**	**$ 36.82**	**$ 37.72**
North Sea production and netbacks by product type [1]					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	23,046	17,619	19,502	19,140	19,824
Netbacks ($/bbl)					
Sales price [2]	$ 117.03	$ 108.22	$ 106.68	$ 108.82	$ 110.75
Royalties	0.30	0.26	0.33	0.25	0.29
Production expenses	36.53	68.32	60.94	54.41	53.53
Netback	**$ 80.20**	**$ 39.64**	**$ 45.41**	**$ 54.16**	**$ 56.93**
Natural Gas					
Average daily production (before royalties) (MMcf/d)	3	2	2	1	2
Netbacks ($/Mcf)					
Sales price [2]	$ 4.11	$ 3.98	$ 3.65	$ 2.67	$ 3.70
Royalties	-	-	-	-	-
Production expenses	3.98	3.89	3.44	3.58	3.75
Netback	**$ 0.13**	**$ 0.09**	**$ 0.21**	**$ (0.91)**	**$ (0.05)**
Offshore Africa production and netbacks by product type [1]					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	20,712	20,598	17,566	15,762	18,648
Netbacks ($/bbl)					
Sales price [2]	$ 128.94	$ 106.30	$ 112.59	$ 97.97	$ 111.18
Royalties	20.01	28.63	37.84	33.59	29.46
Production expenses	12.17	22.94	38.34	22.14	23.11
Netback	**$ 96.76**	**$ 54.73**	**$ 36.41**	**$ 42.24**	**$ 58.61**
Natural Gas					
Average daily production (before royalties) (MMcf/d)	18	23	20	20	20
Netbacks ($/Mcf)					
Sales price [2]	$ 9.85	$ 10.54	$ 9.95	$ 10.25	$ 10.17
Royalties	1.53	1.86	1.89	1.74	1.77
Production expenses	1.76	1.78	2.37	3.19	2.27
Netback	**$ 6.56**	**$ 6.90**	**$ 5.69**	**$ 5.32**	**$ 6.13**

(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) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.
(4) Adjusted cash production costs on a per unit basis are based on sales volumes excluding the periods during suspension of production.

SELECTED FINANCIAL INFORMATION

(MM$, except per common share information)		Year Ended December 31 2012	2011
Product sales		**$ 16,195**	$ 15,507
Net earnings		**$ 1,892**	$ 2,643
Per common share	- basic	**$ 1.72**	$ 2.41
	- diluted	**$ 1.72**	$ 2.40
Adjusted net earnings from operations (1)		**$ 1,618**	$ 2,540
Per common share	- basic	**$ 1.48**	$ 2.32
	- diluted	**$ 1.47**	$ 2.30
Cash flow from operations (1)		**$ 6,013**	$ 6,547
Per common share	- basic	**$ 5.48**	$ 5.98
	- diluted	**$ 5.47**	$ 5.94
Dividends declared per common share		**$ 0.42**	$ 0.36
Total assets		**$ 48,980**	$ 47,278
Total long-term liabilities		**$ 20,721**	$ 20,346
Capital expenditures, net of dispositions		**$ 6,308**	$ 6,414

(1) These non-GAAP measures are reconciled to net earnings as determined in accordance with IFRS in the "Net Earnings and Cash Flow from Operations" section of the Company's MD&A which is incorporated by reference into this document.

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 and is restated for the two-for-one subdivision of the common shares which occurred in May 2010.

	2012	2011	2010
Cash dividends declared per common share	**$ 0.42**	$ 0.36	$ 0.30

In March 2013, the Company's Board of Directors increased the cash dividend on common shares for the thirteenth year in a row, approving a 19% increase in the quarterly dividend from $0.105 per common share in 2012 to $0.125 per common share effective with the April 1, 2013 payment.

DESCRIPTION OF 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 an unlimited number of Preferred Shares issuable in one or more series. The directors of the Company are authorized to fix, before the issue thereof, the number of shares in each series and to determine the designation, rights, privileges, restrictions and conditions attaching to the Preferred Shares of each series.

Credit Ratings

The following information relating to the Company's credit ratings is provided as it relates to the Company's financing costs, liquidity and operations. Specifically, credit ratings affect the Company's ability to obtain short-term and long-term financing and the cost of such financing. A reduction in the current rating on the Company's debt by its rating agencies (particularly a reduction below investment grade ratings), or a negative change to the Company's ratings outlook could adversely affect the Company's cost of financing and its access to sources of liquidity and capital. In addition, changes to credit ratings may affect the Company's ability to, and the associated costs of, entering into ordinary course derivative or hedging transactions and entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

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 on the current market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant, and if any such rating is so revised or withdrawn, the Company is under no obligation to update this Annual Information Form.

	Senior Unsecured Debt Securities	Commercial Paper [2]	Outlook/Trend
Moody's Investors Service Inc. ("Moody's")	Baa1	P-2	Stable
Standard & Poor's Rating Services ("S&P") [1]	BBB+	A-2	Stable
DBRS Limited ("DBRS")	BBB (high)	-	Stable

(1) S&P assigns a rating outlook to Canadian Natural and not to individual long-term debt instruments.
(2) Credit ratings pertaining to commercial paper were obtained in the first quarter of 2013.

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 Baa by Moody's is within the fourth highest of nine categories and is assigned to obligations that are judged to be medium-grade and are subject to moderate credit risk. Such securities may possess certain speculative characteristics. Moody's applies numerical modifiers 1, 2 and 3 to 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 rating direction over the medium term. Moody's credit ratings on commercial paper are on a short-term debt rating scale that ranges from P-1 to NP, representing the range of such securities rated from highest to lowest quality. A rating of P-2 by Moody's is the second highest of four categories and indicates a strong ability to repay short-term obligations.

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. S&P credit ratings on commercial paper are on a short-term debt rating scale that ranges from A-1 to D, representing the range of such securities rated from highest to lowest quality. A rating of A-2 by S&P is the second highest of nine categories and indicates that the obligor is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rating categories, but the obligor's capacity to meet its financial commitment on these obligations is satisfactory.

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. The capacity for the payment of financial obligations is considered acceptable, though may be vulnerable to future events. All rating categories other than AAA and D also contain subcategories "(high)" and "(low)" which indicate the relative standing within such rating category. The rating trend is DBRS' opinion regarding the outlook for the rating.

Canadian Natural has made payments to Moody's, S&P and DBRS in connection with the assignment of ratings to our long-term and short-term debt and will make payments to Moody's, S&P and DBRS in connection with the confirmation of such ratings for purposes of the offering of debt securities from time to time. Canadian Natural has made payments to an affiliate of Moody's in the last 2 years for subscription to use its online credit analytical tools.

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. Set forth below is the trading activity of the Company's common shares on the TSX in 2012.

2012 Monthly Historical Trading on TSX

Month		High	Low	Close	Volume Traded
January	$	40.69	37.18	39.72	58,555,081
February	$	41.12	36.09	36.73	71,184,039
March	$	37.47	32.10	33.06	79,997,452
April	$	34.37	30.73	34.32	56,058,020
May	$	34.88	29.06	29.66	55,877,925
June	$	30.30	25.97	27.31	74,027,721
July	$	29.05	25.58	27.35	67,702,723
August	$	32.68	26.73	29.99	53,496,017
September	$	33.97	29.04	30.33	54,283,789
October	$	31.52	29.29	30.10	44,429,002
November	$	30.50	26.88	28.59	58,328,531
December	$	29.11	27.40	28.64	55,758,076

During 2012, the Company purchased 11,012,700 common shares under a Normal Course Issuer Bid at a weighted average purchase price of $28.91 per common share for a total cost of $318 million.

DIRECTORS AND OFFICERS

The names, municipalities of residence, offices held with the Company and principal occupations of the Directors and Officers of the Company for the 5 preceding years, are set forth below. On April 2, 2012, the Board of Directors of the Company accepted the resignation of Mr. Allan P. Markin, Chairman of the Board. The Board appointed Mr. N. Murray Edwards, the Vice-Chairman, as Chairman of the Board of Directors of the Company effective April 2, 2012. Further detail on the Directors and Named Executive Officers are found in the Company's Information Circular dated March 13, 2013 incorporated herein by reference.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Catherine M. Best, FCA, ICD.D Calgary, Alberta Canada	Director [(1)(2)] (age 59)	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. Prior thereto, Executive Vice-President, Risk Management and Chief Financial Officer of the Calgary Health Region (fully integrated publicly funded health care system) from 2000 to 2008. She has served continuously as a director of the Company since November 2003 and is currently serving on the board of directors of Superior Plus Corporation and AltaGas Ltd. She is also a member of the Board of the Alberta Children's Hospital Foundation, The Calgary Foundation, The Wawanesa Mutual Insurance Company, The Wawanesa Life Insurance Company, Wawanesa General Insurance Company and serves as a volunteer member of the Audit Committee of the Calgary Stampede and of the Audit Committee of the University of Calgary.
N. Murray Edwards Calgary/Banff, Alberta Canada	Chairman and Director [(5)] (age 53)	President, Edco Financial Holdings Ltd. (private management and consulting company). He 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.
Timothy W. Faithfull Oxford, England	Director [(1)(3)] (age 68)	Independent businessman and corporate director. From 1999 until July 2003 when he retired, he was President and Chief Executive Officer of Shell Canada Limited. He has served continuously as a director of the Company since November 2010. He is a Trustee of the Starehe Endowment Fund in the UK and a Council Member of the Canada – UK Colloquia and is currently serving on the board of directors of TransAlta Corporation, ICE Futures Europe, AMEC plc, and Shell Pension Trust Limited, a private pension trust.
Honourable Gary A. Filmon, P.C., O.C., O.M. Winnipeg, Manitoba Canada	Director [(1)(4)] (age 70)	Corporate director. He has served continuously as a director of the Company since February 2006 and is currently serving on the board of directors of MTS Allstream Inc., Arctic Glacier Income Trust, and Exchange Income Corporation.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Christopher L. Fong Calgary, Alberta Canada	Director [3][5] (age 63)	Corporate director. Until his retirement in May 2009 he was Global Head, Corporate Banking, Energy with RBC Capital Markets. Prior thereto between 1974 and September 1980 he worked as a petroleum engineer and as corporate planning analyst in the oil and gas industry. In September 1980 he joined Royal Bank of Canada. He has served continuously as a director of the Company since November 2010. He was appointed Advisor to the Alberta's Department of Energy's Competitive Review process in 2009. He has served as Chair of EducationMatters and as a Governor of Honen's, an International Piano Competition. He is past Chair of UNICEF Canada and is currently serving on the board of directors of Anderson Energy Ltd., Computer Modelling Group Ltd. and sits on the Petroleum Advisory Committee of the Alberta Securities Commission.
Ambassador Gordon D. Giffin Atlanta, Georgia USA	Director [1][4] (age 63)	Senior Partner, McKenna Long & Aldridge LLP (law firm) since May 2001. He 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.
Wilfred A. Gobert Calgary, Alberta Canada	Director[2][4] (age 65)	Independent businessman. Until his retirement in 2006, he was Vice-Chair of Peters and Co. Limited a position he held since 2002 and was a member of its Board of Directors and its Executive Committee. He has served continuously as a director since November 2010. He is currently serving on the board of directors of Gluskin Sheff & Associates, Catapult Energy 2011 LP., Trilogy Energy Corp., and Manitok Energy Inc.
Steve W. Laut Calgary, Alberta Canada	President and Director[3] (age 55)	Officer of the Company. He has served continuously as a director of the Company since August 2006.
Keith A.J. MacPhail Calgary, Alberta Canada	Director [3][5] (age 56)	Executive Chairman of Bonavista Energy Corporation since November 2012 and prior thereto, Chairman and CEO of Bonavista since 1997. He is also Chairman of NuVista Energy Ltd. since July 2003. He has served continuously as a director of the Company since October 1993. He is currently serving on the board of directors of Bonavista Energy Corporation and NuVista Energy Ltd.
Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C. Cap Pelé, New Brunswick Canada	Director [2][4] (age 65)	Deputy Chair, TD Bank Group (financial services). Prior thereto, 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.

Name	Position Presently Held	Principal Occupation During Past 5 Years
James S. Palmer, C.M., A.O.E., Q.C. Calgary, Alberta Canada	Director [5] (age 84)	Chairman Emeritus and a Partner of Burnet, Duckworth & Palmer LLP (law firm). He has served continuously as a director of the Company since May 1997. Currently serving on the board of directors of Magellan Aerospace Corporation.
Dr. Eldon R. Smith, O.C., M.D. Calgary, Alberta Canada	Director [2][3] (age 73)	President of Eldon R. Smith & Associates Ltd., (a private health care consulting company) since 2001, and is Emeritus Professor of Medicine and Former Dean, Faculty of Medicine, University of Calgary. He has served continuously as a director of the Company since May 1997. Currently serving on the board of directors of Intellipharmaceutics International Inc., Resverlogix Corp., Alberta Health Services and Aston Hill Financial.
David A. Tuer Calgary, Alberta Canada	Director [1][5] (age 63)	Vice-Chairman and Chief Executive Officer of Teine Energy Ltd. (private oil and gas exploration company) and served as Vice-Chairman and Chief Executive Officer of Marble Point Energy Ltd. the predecessor to Teine Energy Ltd. also a private oil and gas exploration company from 2008 to 2010. Prior thereto he was Chairman, Calgary Health Region from 2001 to 2008 and Executive Vice-Chairman BA Energy Inc. from 2005 to 2008 when it was acquired by its parent company Value Creations Inc. through a Plan of Arrangement; and President, CEO and a director of Hawker Resources Inc. from January 2003 to March 2005. He has served continuously as a director of the Company since May 2002. Currently serving on the board of directors of Pace Oil and Gas Ltd. and Altalink Management LLP., a private limited partnership.
Jeffrey J. Bergeson Calgary, Alberta Canada	Vice-President, Exploitation West (age 56)	Officer of the Company.
Corey B. Bieber Calgary, Alberta Canada	Vice-President, Finance and Investor Relations (age 49)	Officer of the Company.
Bryan C. Bradley Calgary, Alberta Canada	Vice-President, Marketing (age 47)	Officer of the Company since November 2011; prior thereto Manager Crude Oil Marketing from November 2006 to November 2011.
Mary-Jo E. Case Calgary, Alberta Canada	Vice-President, Land (age 54)	Officer of the Company.
Michael A. Catley Calgary, Alberta Canada	Vice-President, Conventional and Thermal Field Operations (age 52)	Officer of the Company since January 29, 2013; prior thereto Manager, Eastern Operations from October 2006 to October 2010; Vice-President, Bitumen Production from October 2010 to April 2011; Director, Supply Management Operations from April 2011 to June 2012 and most recently Director, Field Operations Eastern and Thermal from June 2012 to January 2013.

Name	Position Presently Held	Principal Occupation During Past 5 Years
William R. Clapperton Calgary, Alberta Canada	Vice-President, Regulatory, Stakeholder and Environmental Affairs (age 50)	Officer of the Company.
James F. Corson Calgary, Alberta Canada	Vice-President, Human Resources, Horizon (age 62)	Officer of the Company.
Réal M. Cusson Calgary, Alberta Canada	Senior Vice-President, Marketing (age 62)	Officer of the Company.
Randall S. Davis Calgary, Alberta Canada	Vice-President, Finance & Accounting (age 46)	Officer of the Company.
Réal J. H. Doucet Calgary, Alberta Canada	Senior Vice-President, Horizon Projects (age 60)	Officer of the Company.
Darren M. Fichter Calgary, Alberta Canada	Vice-President, Exploitation, East (age 42)	Officer of the Company since January 2012; prior thereto Manager, Heavy Oil South April 2004 to June 2009 and most recently Vice-President, Exploitation of CNR International (U.K.) Limited, a wholly owned subsidiary of the Company, from June 2009 to January 2012.
Allan E. Frankiw Calgary, Alberta Canada	Vice-President, Production, East (age 56)	Officer of the Company.
Douglas A. Gardener Calgary, Alberta Canada	Vice-President, Exploration, Central (age 61)	Officer of the Company since January 2012; prior thereto Chief Geologist with the Company from December 2006 to January 2012.
Dean W. Halewich Calgary, Alberta Canada	Vice-President, Facilities and Pipelines (age 45)	Officer of the Company since September 2011; prior thereto Manager, Facilities Engineering from February 2002 to May 2011 and most recently Manager, Thermal Projects from May 2011 to September 2011.
Timothy J. Hamilton Calgary, Alberta Canada	Vice-President, Production, West (age 57)	Officer of the Company since February 2010; prior thereto Manager Production, British Columbia South from January 2007 to September 2009 and most recently Manager Production, British Columbia from September 2009 to February 2010.
Murray G. Harris Calgary, Alberta Canada	Vice-President, Financial Controller and Horizon Accounting (age 49)	Officer of the Company since March 2012; prior thereto Financial Controller from June 2005 to March 2012.

Name	Position Presently Held	Principal Occupation During Past 5 Years
David B. Holt Calgary, Alberta Canada	Vice-President, Production, Central (age 47)	Officer of the Company since September 2011; prior thereto Production Manager, Heavy Oil North from January 2003 to September 2011 and most recently Vice-President, Production West from September 2011 to January 2012.
John A. Howard Calgary, Alberta Canada	Vice-President, Thermal Production (age 54)	Officer of the Company since September 2011; prior thereto Project Manager, Bitumen Upgrading from May 2006 to May 2007; Manager, Deep Basin Production from May 2007 to October 2009 and most recently Manager, SAGD Production from October 2009 to September 2011.
Peter J. Janson Calgary, Alberta Canada	Senior Vice-President, Horizon Operations (age 55)	Officer of the Company.
Terry J. Jocksch Calgary, Alberta Canada	Senior Vice-President, Thermal and International (age 45)	Officer of the Company since June 2009; prior thereto Managing Director, International May 2007 to June 2009.
Pamela A. Jones Calgary, Alberta Canada	Vice-President, Safety and Asset Integrity (age 50)	Officer of the Company since May 2011; prior thereto Project Integration Manager from July 2007 to January 2011 and most recently Manager, Special Projects Assets from January 2011 to May 2011.
Philip A. Keele Calgary, Alberta Canada	Vice-President, Mining (age 53)	Officer of the Company.
Allen M. Knight Calgary, Alberta Canada	Senior Vice-President, International & Corporate Development (age 63)	Officer of the Company.
Kevin Kowbel Calgary, Alberta Canada	Vice-President, Drilling and Completions (age 42)	Officer of the Company since January 2012; prior thereto Drilling Manager from April 2006 to January 2012.
Ronald K. Laing Calgary, Alberta Canada	Vice-President, Commercial Operations (age 43)	Officer of the Company since March 2009; prior thereto Manager, Commercial Operations of the Company from April 2004 to March 2009.
John G. Langille Calgary, Alberta Canada	Vice-Chairman (age 67)	Officer of the Company.
Bruce E. McGrath Calgary, Alberta Canada	Corporate Secretary (age 63)	Officer of the Company.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Tim S. McKay Calgary, Alberta Canada	Chief Operating Officer (age 51)	Officer of the Company.
Casey D. McWhan Calgary, Alberta Canada	Vice-President, Horizon Bitumen Production (age 50)	Officer of the Company since November 2011; prior thereto President, Modec du Brasil from January 2006 to September 2008; Senior Vice-President, Prosafe Production from September 2008 to January 2010 and most recently Continuous Process Improvement Lead with the Company from April 2010 to November 2011.
Paul M. Mendes Calgary, Alberta Canada	Vice-President, Legal and General Counsel (age 47)	Officer of the Company since February 2010; prior thereto Director, Legal Services, Horizon from January 2007 to February 2010.
Leon Miura Calgary, Alberta Canada	Vice-President, Horizon Downstream Projects (age 58)	Officer of the Company.
S. John Parr Calgary, Alberta Canada	Vice-President, Thermal Projects (age 52)	Officer of the Company.
David A. Payne Calgary, Alberta Canada	Vice-President, Exploitation, Central (age 51)	Officer of the Company.
William R. Peterson Calgary, Alberta Canada	Senior Vice-President, Production, Drilling and Completions (age 46)	Officer of the Company.
Douglas A. Proll Calgary, Alberta Canada	Chief Financial Officer and Senior Vice-President, Finance (age 62)	Officer of the Company.
David W. Reed Calgary, Alberta Canada	Vice-President, Horizon Upgrading & Utilities (age 63)	Officer of the Company since August 2012; prior thereto Vice-President Tesoro Corporation from May 2007 to November 2011.
Timothy G. Reed Calgary, Alberta Canada	Vice-President, Human Resources (age 56)	Officer of the Company.
Joy P. Romero Calgary, Alberta Canada	Vice President, Technology Development (age 56)	Officer of the Company.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Sheldon L. Schroeder Fort McMurray, Alberta Canada	Vice-President, Horizon Upstream Projects (age 45)	Officer of the Company.
Kendall W. Stagg Calgary, Alberta Canada	Vice-President, Exploration, West (age 51)	Officer of the Company.
Scott G. Stauth Calgary, Alberta Canada	Senior Vice-President, North American Operations (age 47)	Officer of the Company.
Lyle G. Stevens Calgary, Alberta Canada	Senior Vice-President, Exploitation (age 58)	Officer of the Company.
Stephen C. Suche Calgary, Alberta Canada	Vice-President, Information and Corporate Services (age 53)	Officer of the Company.
Domenic Torriero Calgary, Alberta Canada	Vice-President, Exploration, East (age 48)	Officer of the Company.
Grant M. Williams Calgary, Alberta Canada	Vice-President, Thermal Exploration (age 55)	Officer of the Company.
Jeffrey W. Wilson Calgary, Alberta Canada	Senior Vice-President, Exploration (age 60)	Officer of the Company.
Daryl G. Youck Calgary, Alberta Canada	Vice-President, Thermal Exploitation (age 44)	Officer of the Company.
Lynn M. Zeidler Calgary, Alberta Canada	Vice-President, Horizon Technical, Business and Common Services (age 56)	Officer of the Company.

(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Health, Safety, and Environmental Committee.
(4) Member of the Nominating and Corporate Governance Committee.
(5) Member of the Reserves 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 and General Meeting of Shareholders held on May 3, 2012.

As at December 31, 2012, the directors and executive officers of the Company, as a group, beneficially owned or controlled or directed, directly or indirectly, in the aggregate, approximately 3% of the total outstanding common shares (approximately 4% after the exercise of options held by them pursuant to the Company's stock option plan).

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).

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

From time to time, Canadian Natural is the subject of litigation arising out of the Company's normal course of operations. Damages claimed under such litigation may be material 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.

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.

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 Investor Services LLC in the city of New York. The registers for transfers of the Company's common shares are maintained by Computershare Trust Company of Canada.

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 6, 2013 in respect of the Company's consolidated financial statements as at December 31, 2012, December 31, 2011, and for each of the three years in the period ended December 31, 2012 and the Company's internal control over financial reporting as at December 31, 2012. 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, Sproule International 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.

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, T.W. Faithfull, 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. All of the members of the Corporation's Audit Committee are financially literate. 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. Ms. C. M. Best who is chair of the Audit Committee qualifies as an "audit committee financial expert" under the rules issued by the SEC pursuant to the requirements of the Sarbanes Oxley Act of 2002.

Mr. T. W. Faithfull holds a Master of Arts degree in Economics and is an alumnus of the London Business School. As Chief Executive Officer of Shell Canada Limited and in his other capacities during his 36 years with the Royal Dutch/Shell group of companies, together with his experience as an audit committee member of other publicly traded companies, he has acquired significant financial experience and exposure to complex accounting and financial issues and an understanding of audit committee functions.

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.

Ambassador G. D. Giffin's education and experience relevant to the performance of his responsibilities as an audit committee member is derived from a law practice of over thirty years 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 2012 approved specified audit and non-audit services to be performed by PricewaterhouseCoopers LLP ("PwC"). The services provided include: (i) the annual audit of the Company's consolidated financial statements and internal controls over financial reporting, reviews of the Company's quarterly unaudited Consolidated Financial Statements, audits of certain of the Company's subsidiary companies' annual financial statements as well as other audit services provided in connection with statutory and regulatory filings; (ii) audit related services including pension assets and Crown Royalty Statements; (iii) tax services related to expatriate personal tax and compliance and 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 (000's)	2012	2011
Audit fees	**$ 2,723**	$ 2,696
Audit related fees	**183**	175
Tax fees	**481**	156
All other fees	**9**	9
	$ 3,396	$ 3,036

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

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 13, 2013 in connection with the Annual and Special Meeting of Shareholders of Canadian Natural to be held on May 2, 2013 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's Discussion and Analysis, comparative Consolidated Financial Statements and Supplementary Oil & Gas Information for the most recently completed fiscal year ended December 31, 2012 found on pages 18 to 54, 55 to 91 and 92 to 99 respectively, of the 2012 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 evaluated and reviewed the Corporation's reserves data as at December 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

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 and review.

   We carried out our evaluation and review 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).

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

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 and reviewed by us for the year ended December 31, 2012 and identifies the respective portions thereof that we have evaluated and reviewed and reported on to the Corporation's management and board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation/Review Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate) ($ millions)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	Sproule evaluated the P&NG Reserves February 11, 2013.	Canada and USA	$0	$39,438	$1,120	$40,558
Sproule International Limited	Sproule evaluated the P&NG Reserves February 11, 2013.	United Kingdom and Offshore Africa	$0	$11,922	$0	$11,922
GLJ Petroleum Consultants Ltd.	GLJ evaluated the oil sands mining properties February 11, 2013.	Canada	$0	$20,180	$0	$20,180
Totals			**$0**	**$71,540**	**$1,120**	**$72,660**

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, consistently applied. 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.

Executed as to our report(s) referred to above:

Sproule Associates Limited
Calgary, Alberta, Canada,
March 6, 2013

Original Signed By

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

Original Signed By

SIGNED “NORA T. STEWART”
Nora T. Stewart, P.Eng.
Manager, Engineering and Partner

Original Signed By

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

Sproule International Limited
Calgary, Alberta, Canada,
March 6, 2013

Original Signed By

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

Original Signed By

SIGNED “PHIL W. PANTELLA”
P.W. (Phil) Pantella, P.Eng.
Manager, Engineering and Partner

Original Signed By

SIGNED “GREG D. ROBINSON”
Greg D. Robinson, P.Eng.
Vice-President, International

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada,
March 6, 2013

Original Signed By

SIGNED “JAMES H. WILLMON”
James H. Willmon, P.Eng.
Vice-President, Corporate Evaluations

SCHEDULE "B"

FORM 51-101F3

**REPORT OF
MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE**

Report of Management and Directors on Reserves Data and Other Information

Management of Canadian Natural Resources Limited (the "Corporation") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated and reviewed 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 of the Board of Directors of the Corporation has:

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

(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

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

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

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(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.

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 Reserve Committee

Original Signed By:

SIGNED “CHRISTOPHER L. FONG”
Christopher L. Fong
Independent Director and Member of the Reserve Committee

Dated this 6th day of March, 2013

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 and review 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.

Table of Contents

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 International Financial Reporting Standards 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 and for the year ended December 31, 2012; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2012.

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"
Steve W. Laut
President

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

(signed) "Murray G. Harris"
Murray G. Harris, CA
Vice-President, Financial Controller
& Horizon Accounting

Calgary, Alberta, Canada
March 6, 2013

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 15d–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, 2012. 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, 2012, as stated in their Auditor's 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 6, 2013

Independent Auditor's Report

To the Shareholders of
Canadian Natural Resources Limited

We have completed integrated audits of Canadian Natural Resources Limited's 2012 and 2011 consolidated financial statements and its internal control over financial reporting as at December 31, 2012 and an audit of its 2010 consolidated financial statements. Our opinions, based on our audits are presented below.

Report on the consolidated financial statements
We have audited the accompanying consolidated financial statements of Canadian Natural Resources Limited, which comprise the consolidated balance sheets as at December 31, 2012 and December 31, 2011 and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2012, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits 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 the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards also require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Canadian Natural Resources Limited as at December 31, 2012 and December 31, 2011 and its financial performance and its cash flows for each of the three years in the period ended December 31, 2012 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on internal control over financial reporting
We have also audited Canadian Natural Resources Limited's internal control over financial reporting as at December 31, 2012, based on criteria established in Internal Control - Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Management's responsibility for internal control over financial reporting
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.

Auditor's responsibility
Our responsibility is to express an opinion on Canadian Natural Resources Limited'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 audit opinion on Canadian Natural Resources Limited's internal control over financial reporting.

Definition of internal control over financial reporting
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.

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.

Opinion
In our opinion, Canadian Natural Resources Limited maintained, in all material respects, effective internal control over financial reporting as at December 31, 2012, based on criteria established in Internal Control - Integrated Framework issued by COSO.

Chartered Accountants

Calgary, Alberta, Canada
March 6, 2013

Consolidated Balance Sheets

As at December 31 (millions of Canadian dollars)	Note	2012	2011
ASSETS			
Current assets			
Cash and cash equivalents		**$ 37**	$ 34
Accounts receivable		**1,197**	2,077
Inventory	4	**554**	550
Prepaids and other		**126**	120
		1,914	2,781
Exploration and evaluation assets	5	**2,611**	2,475
Property, plant and equipment	6	**44,028**	41,631
Other long-term assets	7	**427**	391
		$ 48,980	$ 47,278
LIABILITIES			
Current liabilities			
Accounts payable		**$ 465**	$ 526
Accrued liabilities		**2,273**	2,347
Current income tax liabilities		**285**	347
Current portion of long-term debt	8	**798**	359
Current portion of other long-term liabilities	9	**155**	455
		3,976	4,034
Long-term debt	8	**7,938**	8,212
Other long-term liabilities	9	**4,609**	3,913
Deferred income tax liabilities	11	**8,174**	8,221
		24,697	24,380
SHAREHOLDERS' EQUITY			
Share capital	12	**3,709**	3,507
Retained earnings		**20,516**	19,365
Accumulated other comprehensive income	13	**58**	26
		24,283	22,898
		$ 48,980	$ 47,278

Commitments and contingencies (note 18)

Approved by the Board of Directors on March 6, 2013

Catherine M. Best
Chair of the Audit Committee and Director

N. Murray Edwards
Chairman of the Board of Directors and Director

Consolidated Statements of Earnings

For the years ended December 31 (millions of Canadian dollars, except per common share amounts)	Note	2012	2011	2010
Product sales		**$ 16,195**	$ 15,507	$ 14,322
Less: royalties		**(1,606)**	(1,715)	(1,421)
Revenue		**14,589**	13,792	12,901
Expenses				
Production		**4,249**	3,671	3,449
Transportation and blending		**2,752**	2,327	1,783
Depletion, depreciation and amortization	6	**4,328**	3,604	4,120
Administration		**270**	235	211
Share-based compensation	9	**(214)**	(102)	203
Asset retirement obligation accretion	9	**151**	130	123
Interest and other financing costs	16	**364**	373	448
Risk management activities	17	**120**	(27)	(134)
Foreign exchange (gain) loss		**(49)**	1	(163)
Horizon asset impairment provision	10	**–**	396	–
Insurance recovery – property damage	10	**–**	(393)	–
Insurance recovery – business interruption	10	**–**	(333)	–
Equity loss from jointly controlled entity	7	**9**	–	–
		11,980	9,882	10,040
Earnings before taxes		**2,609**	3,910	2,861
Current income tax expense	11	**747**	860	789
Deferred income tax (recovery) expense	11	**(30)**	407	399
Net earnings		**$ 1,892**	$ 2,643	$ 1,673
Net earnings per common share				
Basic	15	**$ 1.72**	$ 2.41	$ 1.54
Diluted	15	**$ 1.72**	$ 2.40	$ 1.53

Consolidated Statements of Comprehensive Income

For the years ended December 31 (millions of Canadian dollars)	2012	2011	2010
Net earnings	**$ 1,892**	$ 2,643	$ 1,673
Net change in derivative financial instruments designated as cash flow hedges			
Unrealized income (loss), net of taxes of $4 million (2011 – $5 million, 2010 – $13 million)	**31**	(23)	(40)
Reclassification to net earnings, net of taxes of $nil (2011 – $17 million, 2010 – $1 million)	**(7)**	52	(4)
	24	29	(44)
Foreign currency translation adjustment			
Translation of net investment	**8**	(12)	(24)
Other comprehensive income (loss), net of taxes	**32**	17	(68)
Comprehensive income	**$ 1,924**	$ 2,660	$ 1,605

Consolidated Statements of Changes in Equity

For the years ended December 31 (millions of Canadian dollars)	Note	**2012**	2011	2010
Share capital	12			
Balance – beginning of year		**$ 3,507**	$ 3,147	$ 2,834
Issued upon exercise of stock options		**194**	255	170
Previously recognized liability on stock options exercised for common shares		**45**	115	149
Purchase of common shares under Normal Course Issuer Bid		**(37)**	(10)	(6)
Balance – end of year		**3,709**	3,507	3,147
Retained earnings				
Balance – beginning of year		**19,365**	17,212	15,927
Net earnings		**1,892**	2,643	1,673
Purchase of common shares under Normal Course Issuer Bid	12	**(281)**	(94)	(62)
Dividends on common shares	12	**(460)**	(396)	(326)
Balance – end of year		**20,516**	19,365	17,212
Accumulated other comprehensive income	13			
Balance – beginning of year		**26**	9	77
Other comprehensive income (loss), net of taxes		**32**	17	(68)
Balance – end of year		**58**	26	9
Shareholders' equity		**$ 24,283**	$ 22,898	$ 20,368

Consolidated Statements of Cash Flows

For the years ended December 31 (millions of Canadian dollars)	Note	2012	2011	2010
Operating activities				
Net earnings		**$ 1,892**	$ 2,643	$ 1,673
Non-cash items				
Depletion, depreciation and amortization		**4,328**	3,604	4,120
Share-based compensation		**(214)**	(102)	203
Asset retirement obligation accretion		**151**	130	123
Unrealized risk management gain		**(42)**	(128)	(24)
Unrealized foreign exchange loss (gain)		**129**	215	(161)
Realized foreign exchange gain on repayment of US dollar debt securities		**(210)**	(225)	–
Equity loss from jointly controlled entity		**9**	–	–
Deferred income tax (recovery) expense		**(30)**	407	399
Horizon asset impairment provision	6,10	**–**	396	–
Insurance recovery – property damage	10	**–**	(393)	–
Other		**(47)**	(55)	(8)
Abandonment expenditures		**(204)**	(213)	(179)
Net change in non-cash working capital	19	**447**	(36)	136
		6,209	6,243	6,282
Financing activities				
Issue (repayment) of bank credit facilities, net		**172**	(647)	(472)
Issue (repayment) of medium-term notes, net		**498**	–	(400)
(Repayment) issue of US dollar debt securities, net	8	**(344)**	621	–
Issue of common shares on exercise of stock options		**194**	255	170
Purchase of common shares under Normal Course Issuer Bid		**(318)**	(104)	(68)
Dividends on common shares		**(444)**	(378)	(302)
Net change in non-cash working capital	19	**(37)**	(15)	(12)
		(279)	(268)	(1,084)
Investing activities				
Expenditures on exploration and evaluation assets and property, plant and equipment	19	**(6,104)**	(6,201)	(5,335)
Investment in other long-term assets		**2**	(321)	–
Net change in non-cash working capital	19	**175**	559	146
		(5,927)	(5,963)	(5,189)
Increase in cash and cash equivalents		**3**	12	9
Cash and cash equivalents – beginning of year		**34**	22	13
Cash and cash equivalents – end of year		**$ 37**	$ 34	$ 22
Interest paid		**$ 464**	$ 456	$ 471
Income taxes paid		**$ 639**	$ 706	$ 213

Supplemental disclosure of cash flow information (note 19)

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. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire, Gabon, and South Africa in Offshore Africa.

The Horizon Oil Sands Mining and Upgrading segment ("Horizon") produces synthetic crude oil through bitumen mining and upgrading operations.

Within Western Canada, the Company maintains certain midstream activities that include pipeline operations, an electricity co-generation system and an investment in the North West Redwater Partnership ("Redwater").

The Company was incorporated in Alberta, Canada. The address of its registered office is 2500, 855-2 Street S.W., Calgary, Alberta, Canada.

The Company's consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The accounting policies adopted by the Company under IFRS are set out below. The Company has consistently applied the same accounting policies throughout all periods presented.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements have been prepared under the historical cost convention, unless otherwise required.

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and wholly owned partnerships.

Certain of the Company's activities are conducted through joint ventures. Where the Company has a direct ownership interest in jointly controlled assets, the assets, liabilities, revenue and expenses related to the jointly controlled assets are included in the consolidated financial statements in proportion to the Company's interest. Where the Company has an interest in jointly controlled entities, it uses the equity method of accounting. Under the equity method, the Company's initial and subsequent investments are recognized at cost and subsequently adjusted for the Company's share of the jointly controlled entity's income or loss, less dividends received.

(B) SEGMENTED INFORMATION

Operating segments have been determined based on the nature of the Company's activities and the geographic locations in which the Company operates, and are consistent with the level of information regularly provided to and reviewed by the Company's chief operating decision makers.

(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 in the consolidated balance sheets.

(D) INVENTORY

Inventory is primarily comprised of product inventory and materials and supplies. Product inventory includes crude oil held for sale, pipeline linefill and crude oil stored in floating production, storage and offloading vessels. Inventories are carried at the lower of cost and net realizable value. Cost consists of purchase costs, direct production costs, directly attributable overhead and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Net realizable value for product inventory is determined by reference to forward prices, and for materials and supplies is based on current market prices as at the date of the consolidated balance sheets.

(E) EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation ("E&E") assets consist of the Company's crude oil and natural gas exploration projects that are pending the determination of proved reserves.

E&E costs are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area. These costs are recognized in net earnings.

Once the technical feasibility and commercial viability of E&E assets are determined and a development decision is made by management, the E&E assets are tested for impairment upon reclassification to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made.

E&E assets are also tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of Cash Generating Units ("CGUs"), aggregated at the segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks.

(F) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Assets under construction are not depleted or depreciated until available for their intended use. The capitalized value of a finance lease is included in property, plant and equipment.

Exploration and Production

When significant components of an item of property, plant and equipment, including crude oil and natural gas interests, have different useful lives, they are accounted for separately.

The cost of an asset comprises its acquisition, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs. Property acquisition costs are comprised of the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Crude oil and natural gas properties are depleted using the unit-of-production method over proved reserves, except for major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop proved reserves.

Oil Sands Mining and Upgrading

Capitalized costs for the Oil Sands Mining and Upgrading segment are reported separately from the Company's North America Exploration and Production segment. Capitalized costs include property acquisition, construction and development costs, the estimate of any asset retirement costs, and applicable borrowing costs.

Mine-related costs are amortized on the unit-of-production method based on Horizon proved reserves. Costs of the upgrader and related infrastructure located on the Horizon site are amortized on the unit-of-production method based on productive capacity of the upgrader and related infrastructure. Other equipment is depreciated on a straight-line basis over its estimated useful life ranging from 2 to 15 years.

Midstream and Head Office

The Company capitalizes all costs that expand the capacity or extend the useful life of the assets. Midstream assets are depreciated on a straight-line basis over their estimated useful lives ranging from 5 to 30 years. Head office assets are amortized on a declining balance basis.

Useful lives

The expected useful lives of property, plant and equipment are reviewed on an annual basis, with changes in useful lives accounted for prospectively.

Derecognition

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is recognized in net earnings.

Major maintenance expenditures

Inspection costs associated with major maintenance turnarounds are capitalized and amortized over the period to the next major maintenance turnaround. All other maintenance costs are expensed as incurred.

Impairment

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low benchmark commodity prices for an extended period of time, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If any such indication of impairment exists, the Company performs an impairment test related to the assets. Individual assets are grouped for impairment assessment purposes into CGU's, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. A CGU's recoverable amount is the higher of its fair value less costs to sell and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount.

In subsequent periods, an assessment is made at each reporting date to determine whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is re-estimated and the net carrying amount of the asset is increased to its revised recoverable amount. The recoverable amount cannot exceed the carrying amount that would have been determined, net of depletion, had no impairment loss been recognized for the asset in prior periods. Such reversal is recognized in net earnings. After a reversal, the depletion charge is adjusted in future periods to allocate the asset's revised carrying amount over its remaining useful life.

(G) BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed in a business combination are recognized at their fair value at the date of the acquisition.

(H) OVERBURDEN REMOVAL COSTS

Overburden removal costs incurred during the initial development of a mine are capitalized to property, plant and equipment. Overburden removal costs incurred during the production of a mine are included in the cost of inventory, unless the overburden removal activity has resulted in a probable inflow of future economic benefits to the Company, 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.

(I) CAPITALIZED BORROWING COSTS

Borrowing costs attributable to the acquisition, construction or production of qualifying assets are capitalized to the cost of those assets until such time as the assets are substantially available for their intended use. Qualifying assets are comprised of those significant assets that require a period greater than one year to be available for their intended use. All other borrowing costs are recognized in net earnings.

(J) LEASES

Finance leases, which transfer substantially all of the risks and rewards incidental to ownership of the leased item to the Company, are capitalized at the commencement of the lease term at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term. Operating lease payments are recognized in net earnings over the lease term.

(K) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on all of its property, plant and equipment based on current legislation and industry operating practices. Provisions for asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred. Provisions are measured at the present value of management's best estimate of expenditures required to settle the obligation as at the date of the balance sheet. Subsequent to the initial measurement, the obligation is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes due to discount rates or the estimated future cash flows are capitalized to or derecognized from property, plant, and equipment. Actual costs incurred upon settlement of the asset retirement obligation are charged against the provision.

(L) FOREIGN CURRENCY TRANSLATION

(i) Functional and presentation currency

Items included in the financial statements of the Company's subsidiary companies and partnerships are measured using the currency of the primary economic environment in which the subsidiary operates (the "functional currency"). The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

The assets and liabilities of subsidiaries that have a functional currency different from that of the Company are translated into Canadian dollars at the closing rate at the date of the balance sheet, and revenue and expenses are translated at the average rate for the period. Cumulative foreign currency translation adjustments are recognized in other comprehensive income.

When the Company disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in other comprehensive income related to the foreign operation are recognized in net earnings.

(ii) Transactions and balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at balance sheet date exchange rates of monetary assets and liabilities denominated in currencies other than the functional currency of the Company or its subsidiaries are recognized in net earnings.

(M) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

Revenue from the sale 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 represents the Company's share net of 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.

(N) PRODUCTION SHARING CONTRACTS

Production generated from Offshore Africa is shared under the terms of various Production Sharing Contracts ("PSCs"). Product sales 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 respective PSCs.

(O) INCOME TAX

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases.

Deferred income tax assets and liabilities are calculated using the substantively enacted income tax rates that are expected to apply when the asset or liability is recovered. Deferred income tax assets or liabilities are not recognized when they arise on the initial recognition of an asset or liability in a transaction (other than in a business combination) that, at the time of the transaction, affects neither accounting nor taxable profit. Deferred income tax assets or liabilities are also not recognized on possible future distributions of retained earnings of subsidiaries where the timing of the distribution can be controlled by the Company and it is probable that a distribution will not be made in the foreseeable future, or when distributions can be made without incurring income taxes.

Deferred income tax assets for deductible temporary differences and tax loss carryforwards are recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized. The carrying amount of deferred income tax assets is reviewed at each reporting date, and is reduced if it is no longer probable that sufficient future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized.

Current income tax is calculated based on net earnings for the period, adjusted for items that are non-taxable or taxed in different periods, using income tax rates that are substantively enacted at each reporting date.

Income taxes are recognized in net earnings or other comprehensive income, consistent with the items to which they relate.

(P) SHARE-BASED COMPENSATION

The Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered. The liability for awards granted to employees is initially measured based on the grant date fair value of the awards and the number of awards expected to vest. The awards are re-measured each reporting period for subsequent changes in the fair value of the liability. Fair value is determined using the Black-Scholes valuation model. Expected volatility is estimated based on historic results. 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 the employee and any previously recognized liability associated with the stock options are recorded as share capital.

(Q) FINANCIAL INSTRUMENTS

The Company classifies its financial instruments into one of the following categories: fair value through profit or loss; held-to-maturity investments; loans and receivables; and financial liabilities measured at amortized cost. All financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Fair value through profit or loss financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash, cash equivalents, and 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 measured at amortized cost. Risk management assets and liabilities are classified as fair value through profit or loss.

Financial assets and liabilities are also 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 in respect of financial instruments at fair value through profit or loss are recognized in net earnings. Transaction costs in respect of other financial instruments are included in the initial measurement of the financial instrument.

Impairment of financial assets

At each reporting date, the Company assesses whether there is objective evidence that a financial asset is impaired. If such evidence exists, an impairment loss is recognized.

Impairment losses on financial assets carried at amortized cost including loans and receivables are calculated as the difference between the amortized cost of the loan or receivable and the present value of the estimated future cash flows, discounted using the instrument's original effective interest rate. Impairment losses on financial assets carried at amortized cost are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized.

(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 in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been 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. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The Company's own credit risk is not included in the carrying amount of a risk management liability.

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 and purchases of crude oil and natural gas in order to protect its cash flow for its 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 net earnings in the same period or periods in which the commodity is sold or purchased. The ineffective portion of changes in the fair value of these designated contracts is recognized in risk management activities in 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 net earnings.

The Company periodically 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 recognized in interest expense in net earnings. Changes in the fair value of non-designated interest rate swap contracts are recognized in risk management activities in 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 related to the notional principal amounts are recognized in foreign exchange gains and losses in 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 recognized in other comprehensive income and is reclassified to interest expense when realized, with the ineffective portion recognized in risk management activities in net earnings. Changes in the fair value of non-designated cross currency swap contracts are recognized in risk management activities in 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 net earnings in the period in which the underlying hedged items are 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 in net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in net earnings.

Upon termination of an interest rate swap designated as a fair value hedge, the interest rate swap is derecognized on the consolidated balance sheets and the related long-term debt hedged is no longer revalued for subsequent 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 long-term debt.

Foreign currency forward contracts are periodically used to manage foreign currency cash 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 gains and losses when realized. Changes in the fair value of non-designated foreign currency forward contracts are recognized in risk management activities in 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 arising from the net investment in foreign operations that do not have a Canadian dollar functional currency. Other comprehensive income is shown net of related income taxes.

(T) PER COMMON SHARE AMOUNTS

The Company calculates basic earnings per common share by dividing net earnings by the weighted average number of common shares outstanding during the period. As the Company's Option Plan allows for the settlement of stock options in either cash or shares at the option of the holder, diluted earnings per common share is calculated using the more dilutive of cash settlement or share settlement under the treasury stock method.

(U) SHARE CAPITAL

Common shares are classified as equity. Costs directly attributable to the issue of new shares or options are included in equity as a deduction from proceeds, net of tax. When the Company acquires its own common shares, share capital is reduced by the average carrying value of the shares purchased. The excess of the purchase price over the average carrying value is recognized as a reduction of retained earnings. Shares are cancelled upon purchase.

(V) DIVIDENDS

Dividends on common shares are recognized in the Company's financial statements in the period in which the dividends are approved by the Board of Directors.

2. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In May 2011, the IASB issued the following new accounting standards, which are required to be adopted effective January 1, 2013:

- IFRS 10 “Consolidated Financial Statements” replaces IAS 27 “Consolidated and Separate Financial Statements” (IAS 27 still contains guidance for Separate Financial Statements) and Standing Interpretations Committee (“SIC”) 12 “Consolidation – Special Purpose Entities”. IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on how to apply the control principle to determine whether an investor controls an investee.

- IFRS 11 “Joint Arrangements” replaces IAS 31 “Interests in Joint Ventures” and SIC 13 “Jointly Controlled Entities – Non-Monetary Contributions by Venturers”. The new standard defines two types of joint arrangements, joint operations and joint ventures. In a joint operation, the parties with joint control have rights to the assets and obligations for the liabilities of the joint arrangement and are required to recognize their proportionate interest in the assets, liabilities, revenues and expenses of the joint arrangement. In a joint venture, the parties have an interest in the net assets of the arrangement and are required to apply the equity method of accounting.

- IFRS 12 “Disclosure of Interests in Other Entities”. The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities. This standard does not impact the Company’s accounting for investments in other entities, but may impact the related disclosures.

- Adoption of the above standards is not expected to result in a significant accounting change to the Company’s consolidated financial statements, but may impact the related disclosures.

In May 2011, the IASB also issued IFRS 13 “Fair Value Measurement”, effective January 1, 2013, which provides guidance on how fair value should be applied where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value. The Company will be required to include its own credit risk in measuring the carrying amount of a risk management liability. In addition, the new standard may impact certain fair value disclosures.

The Company is required to adopt IFRS 9, “Financial Instruments”, effective January 1, 2015, with earlier adoption permitted. IFRS 9 replaces existing requirements included in IAS 39, “Financial Instruments - Recognition and Measurement”. The new standard replaces the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income. The Company is currently assessing the impact of this new standard on its consolidated financial statements.

In June 2011, the IASB issued amendments to IAS 1 “Presentation of Financial Statements” that require items of other comprehensive income that may be reclassified to net earnings to be grouped together. The amendments also require that items in other comprehensive income and net earnings be presented as either a single statement or two consecutive statements. The standard is effective for fiscal years beginning on or after July 1, 2012. Adoption of this amended standard is not expected to result in a significant change in the presentation of the Company’s consolidated financial statements.

In October 2011, the IASB issued IFRS Interpretation Committee (“IFRIC”) 20 “Stripping Costs in the Production Phase of a Surface Mine”. The IFRIC requires overburden removal costs during the production phase to be capitalized and depreciated if the Company can demonstrate that probable future economic benefits will be realized, the costs can be reliably measured, and the Company can identify the component of the ore body for which access has been improved. The IFRIC is effective for fiscal periods beginning on or after January 1, 2013. Adoption of this standard is not expected to result in a significant change to the Company’s consolidated financial statements.

3. CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

The Company has made estimates, assumptions and judgements regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements, primarily related to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts. The estimates, assumptions and judgements that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

(A) Crude Oil and Natural Gas Reserves

Purchase price allocations, depletion, depreciation and amortization, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserve estimates 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, interpretations and judgements. 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.

(B) Asset Retirement Obligations

The Company provides for asset retirement obligations on its property, plant and equipment based on current legislation and operating practices. Estimated future costs include assumptions on dates of future abandonment and technological advances and estimates of future inflation rates and discount rates. Actual costs may vary from the estimated provision due to changes in environmental legislation, the impact of inflation, changes in technology, changes in operating practices, and changes in the date of abandonment due to changes in reserve life, and may have a material impact on the estimated provision.

(C) Income Taxes

The Company is subject to income taxes in numerous legal jurisdictions. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes liabilities for potential tax audit issues based on assessments of whether additional taxes will likely be due.

(D) Fair Value of Derivatives and Other Financial Instruments

The fair value of financial instruments that are not traded in an active market is determined using valuation techniques. The Company uses its judgement to select a variety of methods and make assumptions that are primarily based on market conditions existing at the end of each reporting period. The Company uses directly and indirectly observable inputs in measuring the value of financial instruments that are not traded in active markets, including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates.

(E) Purchase Price Allocations

Purchase prices related to 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 estimates, assumptions and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties. 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 depletion, depreciation, and amortization expense and impairment tests.

(F) Share-Based Compensation

The Company has made various assumptions in estimating the fair values of the stock options granted under the Option Plan, including expected volatility, expected exercise timing and future forfeiture rates. At each period end, stock options outstanding are remeasured for changes in the fair value of the liability.

(G) Identification of CGUs

CGUs are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGUs requires significant judgement and interpretations with respect to the integration between assets, the existence of active markets, shared infrastructures, and the way in which management monitors the Company's operations.

(H) Impairment of Assets

The recoverable amount of a CGU or an individual asset has been determined as the higher of the CGU's or the asset's fair value less costs to sell and its value in use. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves, discount rates and income taxes as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGU's.

(I) Contingencies

Contingencies are subject to measurement uncertainty as the related financial impact will only be confirmed by the outcome of a future event. The assessment of contingencies requires the application of judgements and estimates including the determination of whether a present obligation exists and the reliable estimation of the timing and amount of cash flows required to settle the contingency.

4. INVENTORY

	2012	2011
Product inventory	**$ 315**	$ 328
Materials and supplies	**239**	222
	$ 554	$ 550

5. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			**Oil Sands Mining and Upgrading**	**Total**
	North America	**North Sea**	**Offshore Africa**		
Cost					
At December 31, 2010	$ 2,366	$ 5	$ 31	$ –	$ 2,402
Additions	309	1	2	–	312
Transfers to property, plant and equipment	(233)	(6)	–	–	(239)
At December 31, 2011	2,442	–	33	–	2,475
Additions	**295**	**–**	**14**	**–**	**309**
Transfers to property, plant and equipment	**(173)**	**–**	**–**	**–**	**(173)**
At December 31, 2012	**$ 2,564**	**$ –**	**$ 47**	**$ –**	**$ 2,611**

6. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2010	$ 40,861	$ 3,813	$ 2,928	$ 14,169	$ 291	$ 216	$ 62,278
Additions	5,026	235	76	1,545	7	18	6,907
Transfers from E&E assets	233	6	–	–	–	–	239
Disposals/derecognitions [1]	–	–	(29)	(503)	–	–	(532)
Foreign exchange adjustments and other	–	93	69	–	–	–	162
At December 31, 2011	46,120	4,147	3,044	15,211	298	234	69,054
Additions	**4,160**	**556**	**75**	**1,757**	**14**	**36**	**6,598**
Transfers from E&E assets	**173**	**–**	**–**	**–**	**–**	**–**	**173**
Disposals/derecognitions	**(129)**	**(39)**	**(8)**	**(5)**	**–**	**–**	**(181)**
Foreign exchange adjustments and other	**–**	**(90)**	**(66)**	**–**	**–**	**–**	**(156)**
At December 31, 2012	**$ 50,324**	**$ 4,574**	**$ 3,045**	**$ 16,963**	**$ 312**	**$ 270**	**$ 75,488**
Accumulated depletion and depreciation							
At December 31, 2010	$ 18,895	$ 2,205	$ 1,904	$ 607	$ 89	$ 149	$ 23,849
Expense	2,826	248	242	266	7	15	3,604
Impairment [1]	–	–	–	396	–	–	396
Disposals/derecognitions [1]	–	–	(29)	(503)	–	–	(532)
Foreign exchange adjustments and other	–	59	35	10	–	2	106
At December 31, 2011	21,721	2,512	2,152	776	96	166	27,423
Expense	**3,399**	**294**	**165**	**447**	**7**	**16**	**4,328**
Disposals/derecognitions	**(129)**	**(39)**	**(6)**	**(5)**	**–**	**–**	**(179)**
Foreign exchange adjustments and other	**–**	**(58)**	**(38)**	**(16)**	**–**	**–**	**(112)**
At December 31, 2012	**$ 24,991**	**$ 2,709**	**$ 2,273**	**$ 1,202**	**$ 103**	**$ 182**	**$ 31,460**
Net book value							
- at December 31, 2012	**$ 25,333**	**$ 1,865**	**$ 772**	**$ 15,761**	**$ 209**	**$ 88**	**$ 44,028**
- at December 31, 2011	$ 24,399	$ 1,635	$ 892	$ 14,435	$ 202	$ 68	$ 41,631

(1) During 2011, the Company derecognized certain property, plant and equipment related to the coker fire at Horizon in the amount of $411 million based on estimated replacement cost, net of accumulated depletion and depreciation of $15 million, resulting in an impairment charge of $396 million. For additional information, refer to note 10.

Horizon project costs not subject to depletion		
At December 31, 2012	**$**	**2,066**
At December 31, 2011	$	1,443

In addition, the Company has capitalized costs to date of $1,021 million (2011 – $528 million) related to the development of the Kirby Thermal Oil Sands Project which are not subject to depletion.

During 2012, the Company acquired a number of producing crude oil and natural gas assets in the North American Exploration and Production segment for total cash consideration of $144 million (2011 – $1,012 million; 2010 – $1,482 million), net of associated asset retirement obligations of $12 million (2011 – $79 million; 2010 – $22 million). Interests in jointly controlled assets were acquired with full tax basis. No working capital or debt obligations were assumed.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once construction is substantially complete and the asset is available for its intended use. During 2012, pre-tax interest of $98 million was capitalized to property, plant and equipment (2011 – $59 million; 2010 – $28 million) using a capitalization rate of 4.8% (2011 – 4.7%; 2010 – 4.9%).

7. OTHER LONG-TERM ASSETS

		2012		2011
Investment in North West Redwater Partnership	**$**	**310**	$	321
Other		**117**		70
	$	**427**	$	391

Other long-term assets include an investment in the 50% owned Redwater. The investment is accounted for using the equity method. Redwater has entered into an agreement to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission, an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement. During 2012, the Project received board sanction from Redwater and its partners.

The assets, liabilities, partners' equity and equity loss related to Redwater and the Company's 50% interest at December 31, 2012 were comprised as follows:

		Redwater 100% interest		**Company 50% interest**
Current assets	**$**	**40**	**$**	**20**
Non-current assets	**$**	**810**	**$**	**405**
Current liabilities	**$**	**68**	**$**	**34**
Non-current liabilities	**$**	**162**	**$**	**81**
Partners' equity	**$**	**620**	**$**	**310**
Equity loss	**$**	**18**	**$**	**9**

Non-current liabilities represent interim borrowings by Redwater under credit facilities totaling $600 million which mature no later than December 2017. These facilities are secured by a floating charge on the assets of Redwater with a mandatory repayment required from future financing proceeds. At maturity, under its processing agreement, the Company would be obligated to pay its 25% pro rata share of any shortfall.

Redwater has entered into various agreements related to the engineering and procurement of the Project. These contracts can be cancelled by Redwater upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

8. LONG-TERM DEBT

		2012		2011
Canadian dollar denominated debt				
Bank credit facilities	**$**	**971**	$	796
Medium-term notes				
4.50% unsecured debentures due January 23, 2013		**400**		400
4.95% unsecured debentures due June 1, 2015		**400**		400
3.05% unsecured debentures due June 19, 2019		**500**		–
		2,271		1,596
US dollar denominated debt				
US dollar debt securities				
5.45% due October 1, 2012 (2012 – US$ nil; 2011 – US$350 million)		**–**		356
5.15% due February 1, 2013 (US$400 million)		**398**		406
1.45% due November 14, 2014 (US$500 million)		**498**		509
4.90% due December 1, 2014 (US$350 million)		**348**		356
6.00% due August 15, 2016 (US$250 million)		**249**		255
5.70% due May 15, 2017 (US$1,100 million)		**1,094**		1,119
5.90% due February 1, 2018 (US$400 million)		**398**		406
3.45% due November 15, 2021 (US$500 million)		**498**		509
7.20% due January 15, 2032 (US$400 million)		**398**		406
6.45% due June 30, 2033 (US$350 million)		**348**		356
5.85% due February 1, 2035 (US$350 million)		**348**		356
6.50% due February 15, 2037 (US$450 million)		**448**		458
6.25% due March 15, 2038 (US$1,100 million)		**1,094**		1,119
6.75% due February 1, 2039 (US$400 million)		**398**		406
Less: original issue discount on US dollar debt securities [(1)]		**(20)**		(21)
		6,497		6,996
Fair value impact of interest rate swaps on US dollar debt securities [(2)]		**19**		31
		6,516		7,027
Long-term debt before transaction costs		**8,787**		8,623
Less: transaction costs [(1)] [(3)]		**(51)**		(52)
		8,736		8,571
Less: current portion [(1)] [(2)] [(4)]		**798**		359
	$	**7,938**	$	8,212

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

(2) The carrying amount of US$350 million of 4.90% unsecured notes due December 2014 was adjusted by $19 million to reflect the fair value impact of hedge accounting. At December 31, 2011, the carrying amounts of US$350 million of 5.45% unsecured notes due October 2012 and US$350 million of 4.90% unsecured notes due December 2014 were adjusted by $31 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.

(4) Subsequent to December 31, 2012, $400 million of 4.50% medium-term notes due January 2013 and US$400 million of 5.15% unsecured notes due February 2013 were repaid. This indebtedness was retired utilizing cash flow from operating activities generated in excess of capital expenditures and available bank credit facilities as necessary.

Bank Credit Facilities

As at December 31, 2012, the Company had in place unsecured bank credit facilities of $4,724 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $3,000 million maturing June 2015;
- a revolving syndicated credit facility of $1,500 million maturing June 2016; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During 2012, the $1,500 million revolving syndicated credit facility was extended to June 2016. Each of the $3,000 million and $1,500 million facilities is 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 may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.

The Company's weighted average interest rate on bank credit facilities outstanding as at December 31, 2012, was 2.2% (December 31, 2011 – 2.2%), and on long-term debt outstanding for the year ended December 31, 2012 was 4.8% (December 31, 2011 – 4.7%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $467 million, including an $87 million financial guarantee related to Horizon and $276 million of letters of credit related to North Sea operations, were outstanding at December 31, 2012. Subsequent to December 31, 2012, the letters of credit related to North Sea operations were increased to $347 million.

Medium-Term Notes

During 2012, the Company issued $500 million of 3.05% medium-term notes due June 2019. After issuing these securities, the Company has $2,500 million remaining on its outstanding $3,000 million base shelf prospectus that allows for the issue of medium-term notes in Canada, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance.

US Dollar Debt Securities

During 2012, the Company repaid US$350 million of 5.45% unsecured notes.

During 2011, the Company repaid US$400 million of 6.70% unsecured notes and issued US$1,000 million of unsecured notes under the US base shelf prospectus, comprised of US$500 million of 1.45% unsecured notes due November 2014 and US$500 million of 3.45% unsecured notes due November 2021. Concurrently, the Company entered into cross currency swaps to fix the Canadian dollar interest and principal repayment amounts on the US$500 million of 3.45% unsecured notes due November 2021 at 3.96% and C$511 million (note 17).

The Company has US$2,000 million remaining on its outstanding US$3,000 million base shelf prospectus that allows for the issue of US dollar debt securities in the United States, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance.

Scheduled Debt Repayments

Scheduled debt repayments are as follows:

Year		Repayment
2013	$	798
2014	$	846
2015	$	593
2016	$	1,027
2017	$	1,094
Thereafter	$	4,430

9. OTHER LONG-TERM LIABILITIES

		2012		2011
Asset retirement obligations	**$**	**4,266**	$	3,577
Share-based compensation		**154**		432
Risk management (note 17)		**257**		274
Other		**87**		85
		4,764		4,368
Less: current portion		**155**		455
	$	**4,609**	$	3,913

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.3% (2011 – 4.6%; 2010 – 5.1%). Reconciliations of the discounted asset retirement obligations were as follows:

		2012		2011		2010
Balance – beginning of year	**$**	**3,577**	$	2,624	$	2,214
Liabilities incurred		**51**		42		26
Liabilities acquired		**12**		79		22
Liabilities settled		**(204)**		(213)		(179)
Asset retirement obligation accretion		**151**		130		123
Revision of estimates		**384**		472		49
Change in discount rate		**315**		422		411
Foreign exchange adjustments		**(20)**		21		(42)
Balance – end of year	**$**	**4,266**	$	3,577	$	2,624

Segmented Asset Retirement Obligations

		2012		2011
Exploration and Production				
North America	**$**	**2,079**	$	1,862
North Sea		**1,030**		723
Offshore Africa		**218**		192
Oil Sands Mining and Upgrading		**937**		798
Midstream		**2**		2
	$	**4,266**	$	3,577

Share-Based Compensation

As the Company's Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered, a liability for potential cash settlements is recognized. The current portion represents the maximum amount of the liability payable within the next twelve month period if all vested stock options are surrendered for cash settlement.

	2012	2011	2010
Balance – beginning of year	**$ 432**	$ 663	$ 622
Share-based compensation (recovery) expense	**(214)**	(102)	203
Cash payment for stock options surrendered	**(7)**	(14)	(45)
Transferred to common shares	**(45)**	(115)	(149)
(Recovered from) capitalized to Oil Sands Mining and Upgrading	**(12)**	–	32
Balance – end of year	**154**	432	663
Less: current portion	**129**	384	623
	$ 25	$ 48	$ 40

The intrinsic value of vested stock options at December 31, 2012 was $36 million (2011 – $173 million; 2010 – $325 million).

The share-based compensation liability of $154 million at December 31, 2012 (2011 – $432 million; 2010 – $663 million) was estimated using the Black-Scholes valuation model with the following weighted average assumptions:

	2012	2011	2010
Fair value	**$ 4.60**	$ 10.84	$ 16.49
Share price	**$ 28.64**	$ 38.15	$ 44.35
Expected volatility	**32.6%**	36.9%	33.5%
Expected dividend yield	**1.5%**	0.9%	0.7%
Risk free interest rate	**1.3%**	1.1%	1.9%
Expected forfeiture rate	**4.2%**	4.7%	5.0%
Expected stock option life (1)	**4.5 years**	4.5 years	4.5 years

(1) At original time of grant.

10. HORIZON ASSET IMPAIRMENT PROVISION AND INSURANCE RECOVERY

In 2011, the Company recognized an asset impairment provision in the Oil Sands Mining and Upgrading segment of $396 million, net of accumulated depletion and amortization, related to the property damage resulting from a fire in the Horizon primary upgrading coking plant. The Company also recorded final property damage insurance recoveries of $393 million and business interruption insurance recoveries of $333 million in 2011. In 2012, upon final settlement of its insurance claims, all outstanding insurance proceeds were collected.

11. INCOME TAXES

The provision for income tax was as follows:

		2012		2011		2010
Current corporate income tax – North America	**$**	**366**	$	315	$	431
Current corporate income tax – North Sea		**115**		245		203
Current corporate income tax – Offshore Africa		**206**		140		64
Current PRT[(1)] expense – North Sea		**44**		135		68
Other taxes		**16**		25		23
Current income tax expense		**747**		860		789
Deferred corporate income tax expense		**–**		412		408
Deferred PRT[(1)] recovery – North Sea		**(30)**		(5)		(9)
Deferred income tax (recovery) expense		**(30)**		407		399
Income tax expense	**$**	**717**	$	1,267	$	1,188

(1) Petroleum Revenue Tax.

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:

		2012		2011		2010
Canadian statutory income tax rate		**25.1%**		26.6%		28.1%
Income tax provision at statutory rate	**$**	**655**	$	1,040	$	802
Effect on income taxes of:						
UK PRT and other taxes		**30**		155		82
Impact of deductible UK PRT and other taxes on corporate income tax		**(13)**		(77)		(30)
Foreign and domestic tax rate differentials		**63**		84		15
Non-taxable portion of foreign exchange (gain) loss		**(2)**		6		(17)
Stock options exercised for common shares		**(56)**		(31)		217
Income tax rate and other legislative changes		**58**		104		–
Non-deductible Offshore Africa impairment charge		**–**		–		130
Other		**(18)**		(14)		(11)
Income tax expense	**$**	**717**	$	1,267	$	1,188

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

		2012		2011
Deferred income tax liabilities				
Property, plant and equipment and exploration and evaluation assets	**$**	**8,834**	$	8,404
Timing of partnership items		**831**		1,065
Unrealized foreign exchange gain on long-term debt		**142**		149
Deferred PRT		**42**		74
		9,849		9,692
Deferred income tax assets				
Asset retirement obligations		**(1,362)**		(1,136)
Loss carryforwards		**(119)**		(119)
Unrealized risk management activities		**(36)**		(40)
Other		**(158)**		(176)
		(1,675)		(1,471)
Net deferred income tax liability	**$**	**8,174**	$	8,221

Movements in deferred tax assets and liabilities recognized in net earnings during the year were as follows:

		2012		2011		2010
Property, plant and equipment and exploration and evaluation assets	**$**	**465**	$	662	$	684
Timing of partnership items		**(234)**		77		(139)
Unrealized foreign exchange (gain) loss on long-term debt		**(7)**		(45)		42
Unrealized risk management activities		**–**		44		(8)
Asset retirement obligations		**(238)**		(321)		(127)
Share-based compensation		**–**		–		132
Loss carryforwards		**–**		25		(60)
Deferred PRT		**(30)**		(5)		(9)
Other		**14**		(30)		(116)
	$	**(30)**	$	407	$	399

The following table summarizes the movements of the net deferred income tax liability during the year:

		2012		2011		2010
Balance – beginning of year	**$**	**8,221**	$	7,788	$	7,462
Deferred income tax (recovery) expense		**(30)**		407		399
Deferred income tax expense (recovery) included in other comprehensive income		**4**		12		(14)
Foreign exchange adjustments		**(21)**		20		(59)
Other		–		(6)		–
Balance – end of year	**$**	**8,174**	$	8,221	$	7,788

Current income taxes recognized in each operating segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

During 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax relief on UK North Sea decommissioning expenditures to 50%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $58 million.

During 2011, the UK government enacted legislation to increase the supplementary income tax rate charged on profits from UK North Sea crude oil and natural gas production, increasing the combined corporate and supplementary income tax rate from 50% to 62%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $104 million. During 2011, the Canadian Federal government enacted legislation to implement several taxation changes. These changes include a requirement that, beginning in 2012, partnership income must be included in the taxable income of each corporate partner based on the tax year of the partner, rather than the fiscal year of the partnership. The legislation includes a five-year transition provision and has no impact on net earnings.

During 2010, deferred income tax expense included a charge of $132 million related to enacted changes in Canada to the taxation of stock options surrendered by employees for cash.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's results of operations, financial position or liquidity.

Deferred income tax assets are recognized for temporary differences to the extent that the realization of the related tax benefit through future taxable profits is probable. The Company did not recognize deferred income tax assets with respect to taxable capital loss carryforwards in excess of $1,000 million in North America, which can be carried forward indefinitely and only applied against future taxable capital gains.

Deferred income tax liabilities have not been recognized on the unremitted net earnings of wholly controlled subsidiaries. The Company is able to control the timing and amount of distributions and no taxes are payable on distributions from these subsidiaries provided that the distributions remain within certain limits.

12. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued

	2012		2011	
Common shares	**Number of shares** (thousands)	**Amount**	Number of shares (thousands)	Amount
Balance – beginning of year	**1,096,460**	**$ 3,507**	1,090,848	$ 3,147
Issued upon exercise of stock options	**6,625**	**194**	8,683	255
Previously recognized liability on stock options exercised for common shares	–	**45**	–	115
Purchase of common shares under Normal Course Issuer Bid	**(11,013)**	**(37)**	(3,071)	(10)
Balance – end of year	**1,092,072**	**$ 3,709**	1,096,460	$ 3,507

Preferred Shares

During 2012, the Company amended its Articles by special resolution of the shareholders, changing the designation of its Class 1 preferred shares to "Preferred Shares" which may be issuable in series. If issued, the number of shares in each series, and the designation, rights, privileges, restrictions and conditions attached to the shares will be determined by the Board of Directors of the Company.

Dividend Policy

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

On March 6, 2013, the Board of Directors set the regular quarterly dividend at $0.125 per common share (2012 – $0.105 per common share; 2011 – $0.09 per common share).

Normal Course Issuer Bid

In 2012, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the twelve month period commencing April 2012 and ending April 2013, up to 55,027,447 common shares. The Company's Normal Course Issuer Bid announced in 2011 expired April 2012.

During 2012, the Company purchased for cancellation 11,012,700 common shares (2011 – 3,071,100 common shares; 2010 – 2,000,000 common shares) at a weighted average price of $28.91 per common share (2011 – $33.68 per common share; 2010 – $33.77 per common share), for a total cost o $318 million (2011 – $104 million; 2010 – $68 million). Retained earnings were reduced by $281 million (2011 – $94 million; 2010 – $62 million), representing the excess of the purchase price of the common shares over their average carrying value.

Share Split

The Company's shareholders passed a Special Resolution subdividing the common shares of the Company on a two-for-one basis at the Company's Annual and Special Meeting held on May 6, 2010 with such subdivision taking effect on May 21, 2010. All common share, per common share, and stock option amounts were restated to reflect the common share split.

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 o 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 stock option.

The Option Plan is a "rolling 9%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 9% of the common shares outstanding from time to time.

The following table summarizes information relating to stock options outstanding at December 31, 2012 and 2011:

	2012		2011	
	Stock options (thousands)	**Weighted average exercise price**	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	**73,486**	**$ 34.85**	66,844	$ 33.31
Granted [1]	**14,779**	**$ 29.27**	19,516	$ 37.54
Surrendered for cash settlement	**(998)**	**$ 29.82**	(1,124)	$ 29.84
Exercised for common shares	**(6,625)**	**$ 29.19**	(8,683)	$ 29.34
Forfeited [1]	**(6,895)**	**$ 36.68**	(3,067)	$ 35.87
Outstanding – end of year	**73,747**	**$ 34.13**	73,486	$ 34.85
Exercisable – end of year	**29,366**	**$ 33.73**	26,486	$ 32.13

(1) Subsequent to December 31, 2012, 3,479,000 stock options at a weighted average exercise price of $28.74 were granted and 8,228,000 stock options at a weighted average exercise price of $35.27 were forfeited.

The range of exercise prices of stock options outstanding and exercisable at December 31, 2012 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**
$22.98 - $24.99	8,690	1.18	$ 23.17	6,478	$ 23.15
$25.00 - $29.99	9,993	5.17	$ 28.02	98	$ 29.09
$30.00 - $34.99	17,019	3.22	$ 33.45	6,289	$ 34.07
$35.00 - $39.99	25,583	2.70	$ 36.48	11,926	$ 35.80
$40.00 - $44.99	10,432	3.16	$ 42.23	3,757	$ 42.24
$45.00 - $46.25	2,030	2.79	$ 45.68	818	$ 46.22
	73,747	3.04	$ 34.13	29,366	$ 33.73

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

		2012		2011
Derivative financial instruments designated as cash flow hedges	**$**	**86**	$	62
Foreign currency translation adjustment		**(28)**		(36)
	$	**58**	$	26

14. 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 at each reporting date.

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 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's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2012, the ratio was within the target range at 26%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS and this financial measure may not be comparable to similar measures presented by other companies. Further, there are 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 in the future.

		2012		2011
Long-term debt [(1)]	**$**	**8,736**	$	8,571
Total shareholders' equity	**$**	**24,283**	$	22,898
Debt to book capitalization		**26%**		27%

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

15. NET EARNINGS PER COMMON SHARE

	2012	2011	2010
Weighted average common shares outstanding – basic (thousands of shares)	**1,097,084**	1,095,582	1,088,096
Effect of dilutive stock options (thousands of shares)	**2,435**	7,000	7,552
Weighted average common shares outstanding – diluted (thousands of shares)	**1,099,519**	1,102,582	1,095,648
Net earnings	**$ 1,892**	$ 2,643	$ 1,673
Net earnings per common share – basic	**$ 1.72**	$ 2.41	$ 1.54
– diluted	**$ 1.72**	$ 2.40	$ 1.53

In 2012, the Company excluded 62,400,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share.

16. INTEREST AND OTHER FINANCING COSTS

	2012	2011	2010
Interest expense:			
Long-term debt	**$ 464**	$ 450	$ 485
Other financing costs	**(1)**	(4)	(6)
	463	446	479
Less: amounts capitalized on qualifying assets	**98**	59	28
Total interest and other financing costs	**365**	387	451
Total interest income	**(1)**	(14)	(3)
Net interest and other financing costs	**$ 364**	$ 373	$ 448

17. FINANCIAL INSTRUMENTS

The carrying amounts of the Company's financial instruments by category were as follows:

	2012				
Asset (liability)	**Loans and receivables at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 1,197**	**$ –**	**$ –**	**$ –**	**$ 1,197**
Accounts payable	**–**	**–**	**–**	**(465)**	**(465)**
Accrued liabilities	**–**	**–**	**–**	**(2,273)**	**(2,273)**
Other long-term liabilities	**–**	**4**	**(261)**	**(79)**	**(336)**
Long-term debt [1]	**–**	**–**	**–**	**(8,736)**	**(8,736)**
	$ 1,197	**$ 4**	**$ (261)**	**$ (11,553)**	**$ (10,613)**

	2011				
Asset (liability)	Loans and receivables at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 2,077	$ –	$ –	$ –	$ 2,077
Accounts payable	–	–	–	(526)	(526)
Accrued liabilities	–	–	–	(2,347)	(2,347)
Other long-term liabilities	–	(38)	(236)	(75)	(349)
Long-term debt [1]	–	–	–	(8,571)	(8,571)
	$ 2,077	$ (38)	$ (236)	$ (11,519)	$ (9,716)

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

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

	2012		
	Carrying amount	**Fair value**	
Asset (liability) [1]		**Level 1**	**Level 2**
Other long-term liabilities	**$ (257)**	**$ –**	**$ (257)**
Fixed rate long-term debt [2] [3] [4]	**(7,765)**	**(9,118)**	**–**
	$ (8,022)	**$ (9,118)**	**$ (257)**

	2011		
	Carrying amount	Fair value	
Asset (liability) [1]		Level 1	Level 2
Other long-term liabilities	$ (274)	$ –	$ (274)
Fixed rate long-term debt [2] [3] [4]	(7,775)	(9,120)	–
	$ (8,049)	$ (9,120)	$ (274)

(1) Excludes financial assets and liabilities where the carrying amount 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 amount of US$350 million of 4.90% unsecured notes due December 2014 was adjusted by $19 million to reflect the fair value impact of hedge accounting. At December 31, 2011, the carrying amounts of US$350 million of 5.45% unsecured notes due October 2012 and US$350 million of 4.90% unsecured notes due December 2014 were adjusted by $31 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.

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

The following provides a summary of the carrying amounts of derivative contracts held and a reconciliation to the Company's consolidated balance sheets.

Asset (liability)	**2012**	2011
Derivatives held for trading		
Crude oil price collars	**$ (16)**	$ (13)
Foreign currency forward contracts	**20**	(25)
Cash flow hedges		
Cross currency swaps	**(261)**	(236)
	$ (257)	$ (274)
Included within:		
Current portion of other long-term liabilities	**$ (4)**	$ (43)
Other long-term liabilities	**(253)**	(231)
	$ (257)	$ (274)

During 2012, the Company recognized a gain of $1 million (2011 – loss of $2 million; 2010 – loss of $1 million) related to ineffectiveness arising from cash flow hedges.

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)		**2012**		2011
Balance – beginning of year	**$**	**(274)**	$	(485)
Net change in fair value of outstanding derivative financial instruments attributable to:				
Risk management activities		**42**		128
Foreign exchange		**(53)**		42
Other comprehensive income		**28**		41
Balance – end of year		**(257)**		(274)
Less: current portion		**(4)**		(43)
	$	**(253)**	$	(231)

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

		2012		2011		2010
Net realized risk management loss (gain)	**$**	**162**	$	101	$	(110)
Net unrealized risk management gain		**(42)**		(128)		(24)
	$	**120**	$	(27)	$	(134)

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 periodically 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 and with natural gas purchases. At December 31, 2012, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Price collars [(1)]	Jan 2013	–	Jun 2013	50,000 bbl/d	US$80.00	–	US$145.07	Brent
	Jan 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$135.59	Brent
	Jan 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$97.73	WTI
	Jan 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$110.34	WTI

(1) Subsequent to December 31, 2012, the Company entered into an additional 50,000 bbl/d of US$80 – US$111.05 WTI collars for the period April to December 2013 and an additional 50,000 bbl/d of US$80 – US$132.18 Brent collars for the period July to December 2013.

During 2012, US$65 million of put option costs were settled.

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.

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 periodically 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, 2012, the Company had no interest rate swap contracts outstanding.

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 and in the carrying value of its 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, 2012, the Company had the following cross currency swap contracts outstanding:

	Remaining term	Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency					
Swaps	Jan 2013 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2013 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2013 – Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2013 – Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments designated as hedges at December 31, 2012 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2012, the Company had US$2,821 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 2012 net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2012, 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 cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

Increase (decrease)	Impact on net earnings	Impact on other comprehensive income
Commodity price risk		
Increase Brent US$1.00/bbl	**$ (3)**	**$ –**
Decrease Brent US$1.00/bbl	**$ 3**	**$ –**
Increase WTI US$1.00/bbl	**$ (13)**	**$ –**
Decrease WTI US$1.00/bbl	**$ 13**	**$ –**
Interest rate risk		
Increase interest rate 1%	**$ (5)**	**$ 17**
Decrease interest rate 1%	**$ 5**	**$ (43)**
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	**$ (8)**	**$ –**
Decrease exchange rate by US$0.01	**$ 8**	**$ –**

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, 2012, substantially all of the Company's accounts receivable 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, 2012, the Company had net risk management assets of $18 million with specific counterparties related to derivative financial instruments (December 31, 2011 – $nil).

The carrying amount of financial assets approximates the maximum credit exposure.

c) 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	$ 465	$ –	$ –	$ –
Accrued liabilities	$ 2,273	$ –	$ –	$ –
Risk management	$ 4	$ 53	$ 123	$ 77
Other long-term liabilities	$ 22	$ 24	$ 33	$ –
Long-term debt [1]	$ 798	$ 846	$ 2,714	$ 4,430

(1) Long-term debt represents principal repayments only and does not reflect fair value adjustments, interest, original issue discounts or transaction costs.

18. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2013	2014	2015	2016	2017	Thereafter
Product transportation and pipeline	$ 231	$ 218	$ 204	$ 135	$ 117	$ 788
Offshore equipment operating leases and offshore drilling	$ 156	$ 135	$ 104	$ 76	$ 57	$ 65
Office leases	$ 33	$ 34	$ 32	$ 33	$ 35	$ 262
Other	$ 173	$ 95	$ 43	$ 10	$ 2	$ 7

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases of Horizon. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. 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.

19. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

		2012		2011		2010
Changes in non-cash working capital						
Accounts receivable	**$**	**869**	$	(198)	$	(321)
Inventory		**(9)**		(72)		(35)
Prepaids and other		**(8)**		(17)		18
Accounts payable		**(64)**		251		36
Accrued liabilities		**(138)**		627		232
Current income tax liabilities		**(65)**		(83)		340
Net changes in non-cash working capital	**$**	**585**	$	508	$	270
Relating to:						
Operating activities	**$**	**447**	$	(36)	$	136
Financing activities		**(37)**		(15)		(12)
Investing activities		**175**		559		146
	$	**585**	$	508	$	270

		2012		2011		2010
Expenditures on exploration and evaluation assets	**$**	**309**	$	312	$	572
Expenditures on property, plant and equipment		**5,804**		5,895		4,771
Net proceeds on sale of property, plant and equipment		**(9)**		(6)		(8)
Net expenditures on exploration and evaluation assets and property, plant and equipment	**$**	**6,104**	$	6,201	$	5,335

20. SEGMENTED INFORMATION

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

The Company's Oil Sands Mining and Upgrading activities are reported in a separate segment from exploration and production activities. The bitumen in the segment is recovered through mining operations.

	Exploration and Production								
	North America			North Sea			Offshore Africa		
	2012	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Segmented product sales	**$ 11,607**	$ 11,806	$ 9,713	**$ 928**	$ 1,224	$ 1,058	**$ 773**	$ 946	$ 884
Less: royalties	**(1,268)**	(1,538)	(1,267)	**(2)**	(3)	(2)	**(199)**	(114)	(62)
Segmented revenue	**10,339**	10,268	8,446	**926**	1,221	1,056	**574**	832	822
Segmented expenses									
Production	**2,165**	1,933	1,675	**402**	412	387	**163**	186	167
Transportation and blending	**2,735**	2,301	1,761	**10**	13	8	**1**	1	1
Depletion, depreciation and amortization [1]	**3,413**	2,840	2,484	**296**	249	297	**165**	242	935
Asset retirement obligation accretion	**85**	70	52	**27**	33	36	**7**	7	7
Realized risk management activities	**162**	101	(110)	**–**	–	–	**–**	–	–
Horizon asset impairment provision	**–**	–	–	**–**	–	–	**–**	–	–
Insurance recovery – property damage (note 10)	**–**	–	–	**–**	–	–	**–**	–	–
Insurance recovery – business interruption (note 10)	**–**	–	–	**–**	–	–	**–**	–	–
Equity loss from jointly controlled entity	**–**	–	–	**–**	–	–	**–**	–	–
Total segmented expenses	**8,560**	7,245	5,862	**735**	707	728	**336**	436	1,110
Segmented earnings (loss) before the following	**$ 1,779**	$ 3,023	$ 2,584	**$ 191**	$ 514	$ 328	**$ 238**	$ 396	$ (288)
Non–segmented expenses									
Administration									
Share-based compensation									
Interest and other financing costs									
Unrealized risk management activities									
Foreign exchange (gain) loss									
Total non–segmented expenses									
Earnings before taxes									
Current income tax expense									
Deferred income tax (recovery) expense									
Net earnings									

(1) During 2010, the Company recognized a $637 million impairment relating to the Gabon CGU, in Offshore Africa, which was included in depletion, depreciation and amortization expense.

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

Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. Segment revenue and segment results include transactions between business segments. These transactions and any unrealized profits and losses are eliminated on consolidation, unless unrealized losses provide evidence of an impairment of the asset transferred. Sales to external customers are based on the location of the seller.

Operating segments are reported in a manner consistent with the internal reporting provided to senior management.

Oil Sands Mining and Upgrading			Midstream			Inter–segment elimination and other			Total		
2012	2011	2010	**2012**	2011	2010	**2012**	2011	2010	**2012**	2011	2010
$ 2,871	$ 1,521	$ 2,649	**$ 93**	$ 88	$ 79	**$ (77)**	$ (78)	$ (61)	**$ 16,195**	$ 15,507	$ 14,322
(137)	(60)	(90)	**–**	–	–	**–**	–	–	**(1,606)**	(1,715)	(1,421)
2,734	1,461	2,559	**93**	88	79	**(77)**	(78)	(61)	**14,589**	13,792	12,901
1,504	1,127	1,208	**29**	26	22	**(14)**	(13)	(10)	**4,249**	3,671	3,449
61	62	61	**–**	–	–	**(55)**	(50)	(48)	**2,752**	2,327	1,783
447	266	396	**7**	7	8	**–**	–	–	**4,328**	3,604	4,120
32	20	28	**–**	–	–	**–**	–	–	**151**	130	123
–	–	–	**–**	–	–	**–**	–	–	**162**	101	(110)
–	396	–	**–**	–	–	**–**	–	–	**–**	396	–
–	(393)	–	**–**	–	–	**–**	–	–	**–**	(393)	–
–	(333)	–	**–**	–	–	**–**	–	–	**–**	(333)	–
–	–	–	**9**	–	–	**–**	–	–	**9**	–	–
2,044	1,145	1,693	**45**	33	30	**(69)**	(63)	(58)	**11,651**	9,503	9,365
$ 690	$ 316	$ 866	**$ 48**	$ 55	$ 49	**$ (8)**	$ (15)	$ (3)	**2,938**	4,289	3,536
									270	235	211
									(214)	(102)	203
									364	373	448
									(42)	(128)	(24)
									(49)	1	(163)
									329	379	675
									2,609	3,910	2,861
									747	860	789
									(30)	407	399
									$ 1,892	$ 2,643	$ 1,673

Capital Expenditures [1]

	2012			2011		
	Net expenditures	**Non cash and fair value changes**[2]	**Capitalized costs**	Net expenditures	Non cash and fair value changes[2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America	**$ 295**	**$ (173)**	**$ 122**	$ 309	$ (233)	$ 76
North Sea	**–**	**–**	**–**	1	(6)	(5)
Offshore Africa	**14**	**–**	**14**	2	–	2
	$ 309	**$ (173)**	**$ 136**	$ 312	$ (239)	$ 73
Property, plant and equipment						
Exploration and Production						
North America	**$ 3,831**	**$ 373**	**$ 4,204**	$ 4,427	$ 832	$ 5,259
North Sea	**254**	**263**	**517**	226	15	241
Offshore Africa	**50**	**17**	**67**	31	16	47
	4,135	**653**	**4,788**	4,684	863	5,547
Oil Sands Mining and Upgrading [3] [4]	**1,610**	**142**	**1,752**	1,182	(140)	1,042
Midstream	**14**	**–**	**14**	5	2	7
Head office	**36**	**–**	**36**	18	–	18
	$ 5,795	**$ 795**	**$ 6,590**	$ 5,889	$ 725	$ 6,614

(1) This table provides a reconciliation of capitalized costs including derecognitions and does not include the impact of foreign exchange adjustments.

(2) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, and other fair value adjustments.

(3) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest and share-based compensation.

(4) During 2011, the Company derecognized certain property, plant and equipment related to the coker fire at Horizon in the amount of $411 million. This amount was included in non cash and fair value changes.

Segmented Assets

	2012	2011
Exploration and Production		
North America	**$ 29,012**	$ 28,233
North Sea	**1,993**	1,809
Offshore Africa	**924**	1,070
Other	**36**	23
Oil Sands Mining and Upgrading	**16,291**	15,433
Midstream	**636**	642
Head office	**88**	68
	$ 48,980	$ 47,278

21. REMUNERATION OF DIRECTORS AND SENIOR MANAGEMENT

Remuneration of Non-Management Directors

	2012	2011	2010
Fees earned	$ 2	$ 2	$ 2

Remuneration of Senior Management [1]

	2012	2011	2010
Salary	$ 2	$ 2	$ 2
Common stock option based awards	12	18	30
Annual incentive plans	3	2	3
Long-term incentive plans	9	8	16
Other compensation	–	–	2
	$ 26	$ 30	$ 53

(1) Senior management identified above are consistent with the disclosure on Named Executive Officers provided in the Company's Information Circular to shareholders for the respective years.

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", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses 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 operations and future expansions, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, construction of the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast, the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia, and the construction and future operations of the North West Redwater bitumen upgrader and refinery 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 as 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 and proved plus probable crude oil, natural gas and natural gas liquids ("NGLs") 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 disruptions or delays in the resumption of the mining, extracting or upgrading of 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 and in mining, extracting or upgrading the Company's bitumen products; 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, natural gas and NGLs 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, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management's estimates or opinions change.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

This MD&A 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 costs and net asset value. These financial measures are not defined by International Financial Reporting Standards ("IFRS") 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 IFRS, 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 IFRS, in the "Net Earnings and Cash Flow from Operations" 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

This MD&A 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, 2012.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. Common share data and per common share amounts have been restated to reflect the two-for-one common share split in May 2010. The Company's consolidated financial statements and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB"). Unless otherwise stated, 2010 comparative figures have been restated in accordance with IFRS.

A Barrel of Oil Equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

Production volumes and per unit 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 2012 financial results compared to 2011 and 2010, unless otherwise indicated. In addition, this MD&A details the Company's capital program and outlook for 2013. Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2012, its Annual Information Form for the year ended December 31, 2012, and its audited consolidated financial statements for the year ended December 31, 2012 is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. This MD&A is dated March 6, 2013.

ABBREVIATIONS

AECO	Alberta natural gas reference location
AIF	Annual Information Form
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
Bcf/d	billion cubic feet per day
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
Bitumen	Solid or semi-solid viscous mixture consisting mainly of pentanes and heavier hydrocarbons with viscosity greater than 10,000 centipoise
Brent	Dated Brent
C$	Canadian dollars
CAGR	Compound annual growth rate
CAPEX	Capital expenditures
CICA	Canadian Institute of Chartered Accountants
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalents
Canadian GAAP	Generally accepted accounting principles in Canada prior to adoption of IFRS on January 1, 2011
Crude Oil	Includes light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and synthetic crude oil
CSS	Cyclic Steam Stimulation
EOR	Enhanced oil recovery
E&P	Exploration and Production
FPSO	Floating Production, Storage and Offloading Vessel
GHG	Greenhouse gas
GJ	gigajoules
GJ/d	gigajoules per day
Horizon	Horizon Oil Sands
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
Mbbl	thousand barrels
Mbbl/d	thousand barrels per day
MBOE	thousand barrels of oil equivalent
MBOE/d	thousand barrels of oil equivalent per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
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
SAGD	Steam-Assisted Gravity Drainage
SCO	Synthetic crude oil
SEC	United States Securities and Exchange Commission
Tcf	trillion cubic feet
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
WCS Heavy Differential	WCS Heavy Differential from WTI
WTI	West Texas Intermediate reference location at Cushing, Oklahoma

OBJECTIVES 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 and medium crude oil and NGLs, Pelican Lake heavy crude oil [(2)], primary heavy crude oil, bitumen (thermal 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 unproved land, less net debt.
(2) Pelican Lake heavy 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, safe, effective and efficient operations as well as cost control are fundamental to the Company. By consistently managing costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Effective and efficient operations and cost control are attained by developing area knowledge, 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 hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure 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 areas.

Highlights for the year ended December 31, 2012 include the following:

- § Achieved net earnings of $1.9 billion, adjusted net earnings from operations of $1.6 billion, and cash flow from operations of $6.0 billion;
- § Achieved record yearly crude oil and NGLs production of 326,829 bbl/d in the North America – Exploration and Production segment;
- § The Company largely maintained its natural gas production levels while strategically reducing its related natural gas capital expenditure program;
- § Drilled a record 886 net primary heavy crude oil wells;
- § The Company focuses on efficient and effective operations at Horizon and continues to place emphasis on safe, steady, reliable operations;
- § Purchased 11,012,700 common shares for a total cost of $318 million under the Normal Course Issuer Bid; and
- § Increased annual per share dividend payment to $0.42 from $0.36, the 12 th consecutive year of dividend increases.

NET EARNINGS AND CASH FLOW FROM OPERATIONS

Financial Highlights

($ millions, except per common share amounts)			**2012**		2011		2010
Product sales		**$**	**16,195**	$	15,507	$	14,322
Net earnings		**$**	**1,892**	$	2,643	$	1,673
Per common share	– basic	**$**	**1.72**	$	2.41	$	1.54
	– diluted	**$**	**1.72**	$	2.40	$	1.53
Adjusted net earnings from operations (1)		**$**	**1,618**	$	2,540	$	2,444
Per common share	– basic	**$**	**1.48**	$	2.32	$	2.25
	– diluted	**$**	**1.47**	$	2.30	$	2.23
Cash flow from operations (2)		**$**	**6,013**	$	6,547	$	6,333
Per common share	– basic	**$**	**5.48**	$	5.98	$	5.82
	– diluted	**$**	**5.47**	$	5.94	$	5.78
Dividends declared per common share		**$**	**0.42**	$	0.36	$	0.30
Total assets		**$**	**48,980**	$	47,278	$	42,954
Total long-term liabilities		**$**	**20,721**	$	20,346	$	18,880
Capital expenditures, net of dispositions		**$**	**6,308**	$	6,414	$	5,514

(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" presents 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" presents 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)		***2012***		*2011*		*2010*
Net earnings as reported	***$***	***1,892***	*$*	*2,643*	*$*	*1,673*
Share-based compensation (recovery) expense, net of tax (1)		***(214)***		*(102)*		*203*
Unrealized risk management gain, net of tax (2)		***(37)***		*(95)*		*(16)*
Unrealized foreign exchange loss (gain), net of tax (3)		***129***		*215*		*(142)*
Gabon, Offshore Africa impairment		***–***		*–*		*594*
Realized foreign exchange gain on repayment of US dollar debt securities, net of tax (4)		***(210)***		*(225)*		*–*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (5)		***58***		*104*		*132*
Adjusted net earnings from operations	***$***	***1,618***	*$*	*2,540*	*$*	*2,444*

(1) The Company's employee stock option plan provides for a cash payment option. Accordingly, the fair value of the outstanding vested options is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings or are capitalized to Oil Sands Mining and Upgrading construction costs.

(2) Derivative financial instruments are recorded at fair value on the balance sheets, with changes in the 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 and foreign exchange.

(3) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, partially offset by the impact of cross currency swaps, and are recognized in net earnings.

(4) During 2012, the Company repaid US$350 million of 5.45% unsecured notes. During 2011, the Company repaid US$400 million of 6.70% unsecured notes.

(5) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's balance sheets in determining deferred 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. During 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax rate relief on UK North Sea decommissioning expenditures to 50%, resulting in an increase in the Company's deferred income tax liability of $58 million. During 2011, the UK government enacted legislation to increase the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%, resulting in an increase in the Company's deferred income tax liability of $104 million. During 2010, changes in Canada to the taxation of stock options surrendered by employees for cash payments resulted in a $132 million charge to deferred income tax expense.

Cash Flow from Operations

($ millions)	***2012***	*2011*	*2010*
Net earnings	***$ 1,892***	*$ 2,643*	*$ 1,673*
Non-cash items:			
Depletion, depreciation and amortization	***4,328***	*3,604*	*4,120*
Share-based compensation	***(214)***	*(102)*	*203*
Asset retirement obligation accretion	***151***	*130*	*123*
Unrealized risk management gain	***(42)***	*(128)*	*(24)*
Unrealized foreign exchange loss (gain)	***129***	*215*	*(161)*
Realized foreign exchange gain on repayment of US dollar debt securities	***(210)***	*(225)*	*–*
Equity loss from jointly controlled entity	***9***	*–*	*–*
Deferred income tax (recovery) expense	***(30)***	*407*	*399*
Horizon asset impairment provision	***–***	*396*	*–*
Insurance recovery – property damage	***–***	*(393)*	*–*
Cash flow from operations	***$ 6,013***	*$ 6,547*	*$ 6,333*

For 2012, the Company reported net earnings of $1,892 million compared with net earnings of $2,643 million for 2011 (2010 – $1,673 million). Net earnings for 2012 included net after-tax income of $274 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of a realized foreign exchange gain on repayment of long-term debt, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities (2011 – $103 million after-tax income; 2010 – $771 million after-tax expenses). Excluding these items, adjusted net earnings from operations for 2012 decreased to $1,618 million from $2,540 million for 2011 (2010 – $2,444 million).

The decrease in adjusted net earnings for 2012 from 2011 was primarily due to:
§ lower crude oil and NGLs and natural gas netbacks;
§ lower realized SCO prices;
§ higher depletion, depreciation and amortization expense; and
§ higher realized risk management losses;

partially offset by:
§ higher crude oil and SCO sales volumes in the North America and Oil Sands Mining and Upgrading segments.

The impacts of share-based compensation, risk management activities 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 2012 decreased to $6,013 million ($5.48 per common share) from $6,547 million ($5.98 per common share) for 2011 (2010 – $6,333 million; $5.82 per common share). The decrease in cash flow from operations for 2012 from 2011 was primarily due to the factors noted above relating to the decrease in adjusted net earnings, excluding depletion, depreciation and amortization expense, as well as due to the impact of cash taxes.

In the Company's Exploration and Production activities, the 2012 average sales price per bbl of crude oil and NGLs decreased 9% to average $70.24 per bbl from $77.46 per bbl in 2011 (2010 – $65.81 per bbl), and the average natural gas price decreased 35% to average $2.44 per Mcf from $3.73 per Mcf in 2011 (2010 – $4.08 per Mcf). The Company's average sales price of SCO decreased 11% to average $88.91 per bbl from $99.74 per bbl in 2011 (2010 – $77.89 per bbl).

Total production of crude oil and NGLs before royalties increased 16% to 451,378 bbl/d from 389,053 bbl/d in 2011 (2010 – 424,985 bbl/d). The increase in crude oil and NGLs production from 2011 was primarily related to additional Horizon production volumes and the impact of a strong heavy crude oil drilling program.

Total natural gas production before royalties decreased 3% to average 1,220 MMcf/d from 1,257 MMcf/d in 2011 (2010 – 1,243 MMcf/d). The decrease in natural gas production was primarily a result of a strategic reduction of natural gas drilling as the Company allocated capital to higher return crude oil projects, as well as expected production declines.

Total crude oil and NGLs and natural gas production volumes before royalties increased 9% to average 654,665 BOE/d from 598,526 BOE/d in 2011 (2010 – 632,191 BOE/d).

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)

2012	**Total**	**Dec 31**	**Sep 30**	**Jun 30**	**Mar 31**
Product sales	**$ 16,195**	**$ 4,059**	**$ 3,978**	**$ 4,187**	**$ 3,971**
Net earnings	**$ 1,892**	**$ 352**	**$ 360**	**$ 753**	**$ 427**
Net earnings per common share					
– basic	**$ 1.72**	**$ 0.32**	**$ 0.33**	**$ 0.68**	**$ 0.39**
– diluted	**$ 1.72**	**$ 0.32**	**$ 0.33**	**$ 0.68**	**$ 0.39**

2011	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales	$ 15,507	$ 4,788	$ 3,690	$ 3,727	$ 3,302
Net earnings	$ 2,643	$ 832	$ 836	$ 929	$ 46
Net earnings per common share					
– basic	$ 2.41	$ 0.76	$ 0.76	$ 0.85	$ 0.04
– diluted	$ 2.40	$ 0.76	$ 0.76	$ 0.84	$ 0.04

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

§ Crude oil pricing – The impact of fluctuating demand, inventory storage levels and geopolitical uncertainties on worldwide benchmark pricing, the impact of the WCS Heavy Differential from WTI in North America and the impact of the differential between WTI and Dated Brent benchmark pricing in the North Sea and Offshore Africa.

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

§ Crude oil and NGLs sales volumes – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, the record heavy crude oil drilling program, and the impact of the suspension and recommencement of production at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore Africa, and payout of the Baobab field in May 2011.

§ Natural gas sales volumes – Fluctuations in production 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, shut-in natural gas production due to pricing and the impact and timing of acquisitions.

§ Production expense – Fluctuations primarily due to the impact of the demand for services, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, production and cost optimizations in North America, acquisitions of natural gas producing properties in 2011 that had higher operating costs per Mcf than the Company's existing properties, and the suspension and recommencement of production at Horizon.

§ Depletion, depreciation and amortization – Fluctuations due to changes in sales volumes, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, and the impact of the suspension and recommencement of production at Horizon.

§ Share-based compensation – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company's share-based compensation liability.

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

§ Foreign exchange rates – Changes in the Canadian dollar relative to the US dollar that 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. Fluctuations in realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.

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

BUSINESS ENVIRONMENT

(Yearly average)		**2012**		2011		2010
WTI benchmark price (US$/bbl)	**$**	**94.19**	$	95.14	$	79.55
Dated Brent benchmark price (US$/bbl)	**$**	**111.56**	$	111.29	$	79.50
WCS blend differential from WTI (US$/bbl)	**$**	**21.05**	$	17.10	$	14.26
WCS blend differential from WTI (%)		**22%**		18%		18%
SCO price (US$/bbl)	**$**	**92.59**	$	103.63	$	78.56
Condensate benchmark price (US$/bbl)	**$**	**100.92**	$	105.38	$	81.81
NYMEX benchmark price (US$/MMBtu)	**$**	**2.80**	$	4.07	$	4.42
AECO benchmark price (C$/GJ)	**$**	**2.28**	$	3.48	$	3.91
US / Canadian dollar average exchange rate (US$)	**$**	**1.0004**	$	1.0111	$	0.9709
US / Canadian dollar year end exchange rate (US$)	**$**	**1.0051**	$	0.9833	$	1.0054

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 prices are 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 2012, with a high of approximately US$1.03 in September 2012 and a low of approximately US$0.96 in June 2012.

WTI pricing in 2012 was reflective of the political instability in the Middle East, the declining optimism in the United States economy related to the fiscal cliff, the European debt crisis, and lower than expected growth in Asian demand. For 2012, WTI averaged US$94.19 per bbl and was comparable with 2011 (2010 – US$79.55 per bbl).

Brent averaged US$111.56 per bbl for 2012 and was comparable with 2011 (2010 – US$79.50 per bbl). Crude oil sales contracts for the North Sea and Offshore Africa are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. The higher Brent pricing relative to WTI in 2012 was due to logistical constraints and high inventory levels of crude oil at Cushing.

The WCS Heavy Differential averaged 22% for 2012 compared with 18% for 2011 and 2010. The WCS Heavy Differential widened from the comparable periods as a result of planned and unplanned pipeline outages to key Canadian crude oil markets. The impact of higher WCS Heavy Differentials in January and February 2013 of 35% and 39% respectively were partially offset by higher overall WTI benchmark pricing. The WCS Heavy Differential narrowed in March 2013 to average approximately 29%.

The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During 2012 and the comparable periods, condensate prices traded at a premium to WTI and reflected normal seasonal pricing adjustments.

The Company anticipates continued volatility in crude oil pricing benchmarks due to supply and demand factors, geopolitical events, and the timing and extent of the economic recovery. The WCS Heavy Differential is expected to continue to reflect seasonal demand fluctuations, changes in transportation logistics, and refinery utilization and shutdowns.

NYMEX natural gas prices averaged US$2.80 per MMBtu for 2012, a decrease of 31% from US$4.07 per MMBtu for 2011 (2010 – US$4.42 per MMBtu). AECO natural gas pricing averaged $2.28 per GJ for 2012, a decrease of 34% from US$3.48 per GJ for 2011 (2010 – $3.91 per GJ). While Canadian production has declined in response to low prices, US production has held steady during 2012. Natural gas pricing continues to be volatile as the market still requires a shift to higher utilization of gas fired electric generation to offset the strong North America supply position.

Operating and Capital Costs

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

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.

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

($ millions)	2010	Changes due to Volumes	Changes due to Prices	Other	2011	**Changes due to Volumes**	**Changes due to Prices**	**Changes due to Other**	**2012**
North America									
Crude oil and NGLs	$ 7,805	$ 708	$ 1,448	$ 90	$ 10,051	**$ 1,055**	**$ (583)**	**$ (43)**	**$ 10,480**
Natural gas	1,908	21	(174)	–	1,755	**(42)**	**(586)**	**–**	**1,127**
	9,713	729	1,274	90	11,806	**1,013**	**(1,169)**	**(43)**	**11,607**
North Sea									
Crude oil and NGLs	1,043	(139)	292	19	1,215	**(380)**	**16**	**73**	**924**
Natural gas	15	(5)	(1)	–	9	**(6)**	**1**	**–**	**4**
	1,058	(144)	291	19	1,224	**(386)**	**17**	**73**	**928**
Offshore Africa									
Crude oil and NGLs	846	(191)	220	3	878	**(207)**	**36**	**(8)**	**699**
Natural gas	38	9	21	–	68	**2**	**4**	**–**	**74**
	884	(182)	241	3	946	**(205)**	**40**	**(8)**	**773**
Subtotal									
Crude oil and NGLs	9,694	378	1,960	112	12,144	**468**	**(531)**	**22**	**12,103**
Natural gas	1,961	25	(154)	–	1,832	**(46)**	**(581)**	**–**	**1,205**
	11,655	403	1,806	112	13,976	**422**	**(1,112)**	**22**	**13,308**
Oil Sands Mining and Upgrading	2,649	(1,458)	322	8	1,521	**1,688**	**(338)**	**–**	**2,871**
Midstream	79	–	–	9	88	**–**	**–**	**5**	**93**
Intersegment eliminations and other [1]	(61)	–	–	(17)	(78)	**–**	**–**	**1**	**(77)**
Total	$ 14,322	$ (1,055)	$ 2,128	$ 112	$ 15,507	**$ 2,110**	**$ (1,450)**	**$ 28**	**$ 16,195**

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

Revenue increased 4% to $16,195 million for 2012 from $15,507 million for 2011 (2010 – $14,322 million). The increase was primarily due to higher crude oil and SCO volumes in North America and Oil Sands Mining and Upgrading segments, partially offset by a decrease in realized North America crude oil and NGLs and natural gas prices, Oil Sands Mining and Upgrading SCO prices, and lower International production.

For 2012, 11% of the Company's crude oil and natural gas revenue was generated outside of North America (2011 – 14%; 2010 – 13%). North Sea accounted for 6% of crude oil and natural gas revenue for 2012 (2011 – 8%; 2010 – 7%), and Offshore Africa accounted for 5% of crude oil and natural gas revenue for 2012 (2011 – 6%; 2010 – 6%).

ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2012	2011	2010
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**326,829**	295,618	270,562
North America – Oil Sands Mining and Upgrading	**86,077**	40,434	90,867
North Sea	**19,824**	29,992	33,292
Offshore Africa	**18,648**	23,009	30,264
	451,378	389,053	424,985
Natural gas (MMcf/d)			
North America	**1,198**	1,231	1,217
North Sea	**2**	7	10
Offshore Africa	**20**	19	16
	1,220	1,257	1,243
Total barrels of oil equivalent (BOE/d)	**654,665**	598,526	632,191
Product mix			
Light and medium crude oil and NGLs	**16%**	18%	18%
Pelican Lake heavy crude oil	**6%**	6%	6%
Primary heavy crude oil	**19%**	18%	15%
Bitumen (thermal oil)	**15%**	16%	14%
Synthetic crude oil	**13%**	7%	14%
Natural gas	**31%**	35%	33%
Percentage of gross revenue [(1)]			
(excluding midstream revenue)			
Crude oil and NGLs	**91%**	86%	85%
Natural gas	**9%**	14%	15%

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

ANALYSIS OF DAILY PRODUCTION, NET OF ROYALTIES

	2012	2011	2010
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**273,374**	240,006	219,736
North America – Oil Sands Mining and Upgrading	**82,171**	38,721	87,763
North Sea	**19,772**	29,919	33,227
Offshore Africa	**13,628**	20,532	28,288
	388,945	329,178	369,014
Natural gas (MMcf/d)			
North America	**1,171**	1,186	1,168
North Sea	**2**	7	10
Offshore Africa	**17**	16	15
	1,190	1,209	1,193
Total barrels of oil equivalent (BOE/d)	**587,246**	530,576	567,743

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 and medium crude oil and NGLs, Pelican Lake heavy crude oil, primary heavy crude oil, bitumen (thermal oil), and SCO.

Total 2012 production averaged 654,665 BOE/d, a 9% increase from 598,526 BOE/d in 2011 (2010 – 632,191 BOE/d).

Total production of crude oil and NGLs before royalties increased 16% to 451,378 bbl/d for 2012 from 389,053 bbl/d in 2011 (2010 – 424,985 bbl/d). The increase in crude oil and NGLs production from 2011 was primarily related to additional Horizon production volumes and the impact of a strong heavy crude oil drilling program. Crude oil and NGLs production for 2012 was slightly below the Company's previously issued guidance of 452,000 to 460,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering, accounting for 31% of the Company's total production in 2012 on a BOE basis. Total natural gas production before royalties decreased 3% to 1,220 MMcf/d for 2012 from 1,257 MMcf/d for 2011 (2010 – 1,243 MMcf/d). The decrease in natural gas production from 2011 was primarily a result of a strategic reduction of natural gas drilling as the Company allocated capital to higher return crude oil projects, as well as expected production declines. Natural gas production for 2012 was slightly below the Company's previously issued guidance of 1,222 to 1,229 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production for 2012 increased 11% to average 326,829 bbl/d from 295,618 bbl/d for 2011 (2010 – 270,562 bbl/d). The increase in production from 2011 was primarily due to the impact of a strong heavy crude oil drilling program.

North America natural gas production for 2012 decreased 3% to average 1,198 MMcf/d from 1,231 MMcf/d in 2011 (2010 – 1,217 MMcf/d). The decrease in natural gas production from 2011 was primarily a result of a strategic reduction of natural gas drilling as the Company allocated capital to higher return crude oil projects, as well as expected production declines.

North America – Oil Sands Mining and Upgrading

Production averaged 86,077 bbl/d for 2012 compared with 40,434 bbl/d for 2011 (2010 – 90,867 bbl/d). Production in 2012 reflected the impact of unplanned maintenance on the fractionator in the Horizon primary upgrading facility.

North Sea

North Sea crude oil production for 2012 was 19,824 bbl/d, a decrease of 34% from 29,992 bbl/d for 2011 (2010 – 33,292 bbl/d). The decrease in production volumes from 2011 was primarily due to temporary shut ins of the third-party operated pipeline to Sullom Voe, which caused all Ninian and associated fields to be shut in for a portion of the third and fourth quarters of 2012, the suspension of production at Banff/Kyle, and natural field declines.

In December 2011, the Banff FPSO and subsea infrastructure suffered storm damage. Operations at Banff/Kyle, with combined net production of approximately 3,500 bbl/d, were suspended. The FPSO and associated floating storage unit have subsequently been removed from the field and the FPSO is currently in dry dock for assessment of damages and repair timeframe. The extent of the property damage, including associated costs, is not expected to be significant.

Offshore Africa

Offshore Africa crude oil production for 2012 decreased 19% to 18,648 bbl/d from 23,009 bbl/d for 2011 (2010 – 30,264 bbl/d) due to natural field declines, planned turnaround activity, and the shut in of approximately 1,500 bbl/d of production at the Olowi field, Gabon. The Company currently has a vessel on-site in Gabon assessing the operability of the midwater arch.

Guidance

The Company targets production levels in 2013 to average between 482,000 bbl/d and 513,000 bbl/d of crude oil and NGLs and between 1,085 MMcf/d and 1,145 MMcf/d of natural gas.

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 FPSOs, as follows:

(bbl)	**2012**	2011	2010
North America – Exploration and Production	**643,758**	557,475	761,351
North America – Oil Sands Mining and Upgrading (SCO)	**993,627**	1,021,236	1,172,200
North Sea	**77,018**	286,633	264,995
Offshore Africa	**1,036,509**	527,312	404,197
	2,750,912	2,392,656	2,602,743

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

		2012		2011		2010
Crude oil and NGLs ($/bbl) [1]						
Sales price [2]	**$**	**70.24**	$	77.46	$	65.81
Royalties		**10.67**		12.30		10.09
Production expense		**16.11**		15.75		14.16
Netback	**$**	**43.46**	$	49.41	$	41.56
Natural gas ($/Mcf) [1]						
Sales price [2]	**$**	**2.44**	$	3.73	$	4.08
Royalties		**0.09**		0.18		0.20
Production expense		**1.31**		1.15		1.09
Netback	**$**	**1.04**	$	2.40	$	2.79
Barrels of oil equivalent ($/BOE) [1]						
Sales price [2]	**$**	**50.81**	$	57.16	$	49.90
Royalties		**7.07**		8.12		6.72
Production expense		**13.14**		12.42		11.25
Netback	**$**	**30.60**	$	36.62	$	31.93

(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.

ANALYSIS OF PRODUCT PRICES – EXPLORATION AND PRODUCTION

		2012		2011		2010
Crude oil and NGLs ($/bbl) [1] [2]						
North America	**$**	**65.54**	$	72.17	$	62.28
North Sea	**$**	**110.75**	$	108.56	$	82.49
Offshore Africa	**$**	**111.18**	$	105.53	$	78.93
Company average	**$**	**70.24**	$	77.46	$	65.81
Natural gas ($/Mcf) [1] [2]						
North America	**$**	**2.31**	$	3.64	$	4.05
North Sea	**$**	**3.70**	$	4.07	$	3.83
Offshore Africa	**$**	**10.17**	$	9.56	$	6.63
Company average	**$**	**2.44**	$	3.73	$	4.08
Company average ($/BOE) [1] [2]	**$**	**50.81**	$	57.16	$	49.90

(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.

Realized crude oil and NGLs prices decreased 9% to average $70.24 per bbl for 2012 from $77.46 per bbl for 2011 (2010 – $65.81 per bbl). The decrease in 2012 was primarily a result of the lower WTI benchmark pricing and the widening of the WCS Heavy Differential, partially offset by the impact of a weaker Canadian dollar relative to the US dollar.

The Company's realized natural gas price decreased 35% to average $2.44 per Mcf for 2012 from $3.73 per Mcf for 2011 (2010 – $4.08 per Mcf). The decrease in 2012 was primarily due to lower NYMEX and AECO benchmark pricing related to the impact of strong supply from US shale projects.

North America

North America realized crude oil prices decreased 9% to average $65.54 per bbl for 2012 from $72.17 per bbl for 2011 (2010 – $62.28 per bbl). The decrease in 2012 was primarily a result of the lower WTI benchmark pricing and the widening of the WCS Heavy Differential, partially offset by the impact of a weaker Canadian dollar relative to the US dollar.

North America realized natural gas prices decreased 37% to average $2.31 per Mcf for 2012 from $3.64 per Mcf for 2011 (2010 – $4.05 per Mcf), primarily due to lower NYMEX and AECO benchmark pricing related to the impact of strong supply from US shale projects.

The Company continues to focus on its crude oil marketing strategy including 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 2012, the Company contributed approximately 157,000 bbl/d of heavy crude oil blends to the WCS stream. The Company has entered into a 20 year transportation agreement to ship 120,000 bbl/d of heavy crude oil on the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast. The Company also entered into a 20 year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy crude oil to a major US refiner. The construction of the Keystone XL Pipeline is dependent on a Presidential Permit. During 2012, the Company entered into a 20 year transportation agreement to ship 75,000 bbl/d of crude oil on the proposed Kinder Morgan Trans Mountain Expansion from Edmonton, Alberta to Vancouver, British Columbia. The regulatory approval process will begin in 2013 with a planned in-service date in 2017.

Comparisons of the prices received in North America Exploration and Production by product type were as follows:

(Yearly average)		**2012**		2011		2010
Wellhead Price (1) (2)						
Light and medium crude oil and NGLs (C$/bbl)	**$**	**70.58**	$	82.01	$	68.02
Pelican Lake heavy crude oil (C$/bbl)	**$**	**65.43**	$	71.45	$	61.69
Primary heavy crude oil (C$/bbl)	**$**	**64.21**	$	70.51	$	62.04
Bitumen (thermal oil) (C$/bbl)	**$**	**64.03**	$	68.55	$	59.55
Natural gas (C$/Mcf)	**$**	**2.31**	$	3.64	$	4.05

(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.

North Sea

North Sea realized crude oil prices increased 2% to average $110.75 per bbl for 2012 from $108.56 per bbl for 2011 (2010 – $82.49 per bbl). Realized crude oil prices per bbl in any particular period are dependent 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 slight increase in realized crude oil prices in the North Sea from 2011 was primarily due to higher Brent benchmark pricing, the impact of the weaker Canadian dollar, and the timing of liftings.

Offshore Africa

Offshore Africa realized crude oil prices increased 5% to average $111.18 per bbl for 2012 from $105.53 per bbl for 2011 (2010 – $78.93 per bbl). Realized crude oil prices per bbl in any particular year are dependent 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 increase in realized crude oil prices in Offshore Africa from 2011 was primarily due to the higher Brent benchmark pricing, the impact of the weaker Canadian dollar, and the timing of liftings.

ROYALTIES – EXPLORATION AND PRODUCTION

	2012	2011	2010
Crude oil and NGLs ($/bbl) [1]			
North America	**$ 10.33**	$ 13.51	$ 11.85
North Sea	**$ 0.29**	$ 0.26	$ 0.16
Offshore Africa	**$ 29.46**	$ 12.47	$ 5.54
Company average	**$ 10.67**	$ 12.30	$ 10.09
Natural gas ($/Mcf) [1]			
North America	**$ 0.06**	$ 0.16	$ 0.20
Offshore Africa	**$ 1.77**	$ 1.59	$ 0.53
Company average	**$ 0.09**	$ 0.18	$ 0.20
Company average ($/BOE) [1]	**$ 7.07**	$ 8.12	$ 6.72

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

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").

Crude oil and NGLs royalties averaged approximately 16% of product sales in 2012 compared with 19% in 2011 (2010 – 19%) primarily due to lower WTI benchmark pricing and changes in the WCS Heavy Differential. North America crude oil and NGLs royalties per bbl are anticipated to average 16% to 18% of product sales for 2013.

Natural gas royalties averaged approximately 3% of product sales for 2012 compared with 4% in 2011 (2010 – 5%) primarily due to lower realized natural gas prices. North America natural gas royalties per Mcf are anticipated to average 4% to 6% of product sales for 2013.

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 Africa

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital and operating costs, the status of payouts, and the timing of liftings from each field.

Royalty rates as a percentage of product sales averaged approximately 26% for 2012 compared to 17% for 2011 (2010 – 7%) primarily due to higher crude oil prices, adjustments to royalties on liftings, and the payout of the Baobab field in May 2011. Offshore Africa royalty rates are anticipated to average 9% to 11% of product sales for 2013.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	2012	2011	2010
Crude oil and NGLs ($/bbl) [1]			
North America	**$ 13.40**	$ 13.21	$ 12.14
North Sea	**$ 53.53**	$ 37.06	$ 29.73
Offshore Africa	**$ 23.11**	$ 20.72	$ 14.64
Company average	**$ 16.11**	$ 15.75	$ 14.16
Natural gas ($/Mcf) [1]			
North America	**$ 1.28**	$ 1.12	$ 1.06
North Sea	**$ 3.75**	$ 2.83	$ 2.91
Offshore Africa	**$ 2.27**	$ 2.03	$ 1.76
Company average	**$ 1.31**	$ 1.15	$ 1.09
Company average ($/BOE) [1]	**$ 13.14**	$ 12.42	$ 11.25

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

North America

North America crude oil and NGLs production expense for 2012 averaged $13.40 per bbl and was comparable with 2011 (2010 – $12.14 per bbl). North America crude oil and NGLs production expense is anticipated to average $12.00 to $14.00 per bbl for 2013.

North America natural gas production expense for 2012 increased 14% to $1.28 per Mcf from $1.12 per Mcf for 2011 (2010 – $1.06 per Mcf). Natural gas production expense increased from 2011 due to the impact of lower production volumes related to the shut in of production and the curtailment of capital expenditures related to natural gas activity. North America natural gas production expense is anticipated to average $1.30 to $1.40 per Mcf for 2013 due to natural declines.

North Sea

North Sea crude oil production expense for 2012 increased 44% to $53.53 per bbl from $37.06 per bbl for 2011 (2010 – $29.73 per bbl). Production expense increased on a per bbl basis due to the impact of production declines on relatively fixed costs, temporary shut ins of the third-party operated pipeline to Sullom Voe, and higher maintenance costs related to turnaround activity in 2012. North Sea crude oil production expense is anticipated to average $62.00 to $66.00 per bbl for 2013 due to natural declines on a relatively fixed cost structure.

Offshore Africa

Offshore Africa crude oil production expense for 2012 increased 12% to $23.11 per bbl from $20.72 per bbl for 2011 (2010 – $14.64 per bbl). Production expense increased due to the timing of liftings from various fields, which have different cost structures. Offshore Africa crude oil production expense is anticipated to average $33.50 to $37.50 per bbl for 2013 due to timing of liftings from various fields.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts) (1)		**2012**		2011		2010
North America	**$**	**3,413**	$	2,840	$	2,484
North Sea		**296**		249		297
Offshore Africa		**165**		242		935
Expense	**$**	**3,874**	$	3,331	$	3,716
$/BOE	**$**	**18.65**	$	16.35	$	18.76

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

Depletion, depreciation and amortization expense for 2012 increased to $3,874 million from $3,331 million for 2011 (2010 – $3,716 million) primarily due to higher sales volumes in North America associated with heavy crude oil drilling, higher overall future development costs and the impact of property, plant and equipment amortized on a straight line basis.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts) (1)		**2012**		2011		2010
North America	**$**	**85**	$	70	$	52
North Sea		**27**		33		36
Offshore Africa		**7**		7		7
Expense	**$**	**119**	$	110	$	95
$/BOE	**$**	**0.57**	$	0.54	$	0.47

(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.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

During 2012, the Company continued to focus on efficient and effective operations at Horizon and place emphasis on safe, steady, reliable operations. Production in 2012 reflected the impact of unplanned maintenance on the fractionator in the Horizon primary upgrading facility.

In the second quarter of 2013, Horizon will enter into a 24 day planned maintenance turnaround, resulting in a plant-wide shut down. The impact of the turnaround has been reflected in the Company's 2013 production, cash production cost and capital expenditure guidance.

PRODUCT PRICES AND ROYALTIES – OIL SANDS MINING AND UPGRADING

($/bbl) [1]		2012		2011		2010
SCO sales price [2]	**$**	**88.91**	$	99.74	$	77.89
Bitumen value for royalty purposes [3]	**$**	**59.93**	$	61.86	$	56.14
Bitumen royalties [4]	**$**	**4.34**	$	3.99	$	2.72

(1) Amounts expressed on a per unit basis in 2012 and 2011 are based on sales volumes excluding the period during suspension of production.
(2) Net of transportation and excluding risk management activities.
(3) Calculated as the simple quarterly average of the bitumen valuation methodology price.
(4) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Realized SCO sales prices decreased 11% to average $88.91 per bbl for 2012 from $99.74 per bbl for 2011 (2010 – $77.89 per bbl), reflecting benchmark pricing and prevailing differentials.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 20 to the Company's consolidated financial statements.

($ millions)		2012		2011		2010
Cash production costs	**$**	**1,504**	$	1,127	$	1,208
Less: costs incurred during the period of suspension of production		**(154)**		(581)		–
Adjusted cash production costs	**$**	**1,350**	$	546	$	1,208
Adjusted cash production costs, excluding natural gas costs	**$**	**1,254**	$	502	$	1,082
Adjusted natural gas costs		**96**		44		126
Adjusted cash production costs	**$**	**1,350**	$	546	$	1,208

($/bbl) [1]		2012		2011		2010
Adjusted cash production costs, excluding natural gas costs	**$**	**39.79**	$	33.68	$	32.58
Adjusted natural gas costs		**3.04**		2.96		3.78
Adjusted cash production costs	**$**	**42.83**	$	36.64	$	36.36
Sales (bbl/d) [2]		**86,153**		40,847		91,010

(1) Adjusted cash production costs on a per unit basis in 2012 and 2011 were based on sales volumes excluding the periods during suspension of production.
(2) Sales on a per unit basis reflect sales volumes including the periods during suspension of production.

Adjusted cash production costs averaged $42.83 per bbl for 2012, an increase of 17% compared with $36.64 per bbl for 2011 (2010 – $36.36 per bbl). The increase in 2012 adjusted cash production costs per bbl was primarily due to higher overall production costs. Cash production costs are anticipated to average $38.00 to $41.00 per bbl for 2013.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions)		2012		2011		2010
Depletion, depreciation and amortization	**$**	**447**	$	266	$	396
Less: depreciation incurred during the period of suspension of production		**(6)**		(64)		–
Adjusted depletion, depreciation and amortization	**$**	**441**	$	202	$	396
$/bbl [1]	**$**	**13.99**	$	13.54	$	11.91

(1) Amounts expressed on a per unit basis in 2012 and 2011 are based on sales volumes excluding the period during suspension of production.

Depletion, depreciation and amortization expense for 2012 increased to $447 million from $266 million for 2011 (2010 – $396 million) primarily due to higher sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

		2012		2011		2010
Expense ($ millions)	**$**	**32**	$	20	$	28
$/bbl [(1)]	**$**	**1.01**	$	1.33	$	0.88

(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.

MIDSTREAM

($ millions)		2012		2011		2010
Revenue	**$**	**93**	$	88	$	79
Production expense		**29**		26		22
Midstream cash flow		**64**		62		57
Depreciation		**7**		7		8
Equity loss from jointly controlled entity		**9**		–		–
Segment earnings before taxes	**$**	**48**	$	55	$	49

The Company's midstream assets include 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 a portion 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.

In 2011, the Company announced that it had entered into a partnership agreement with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of a bitumen upgrader and refinery ("the Project") near Redwater, Alberta. In addition, the partnership entered into processing agreements that target to process bitumen for the Company and the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement under the Bitumen Royalty In Kind initiative. In 2012, the Project was sanctioned by the Board of Directors of each partner of the North West Redwater Partnership ("Redwater"), and the associated target toll amounts were accepted by Redwater, the Company and the APMC.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)		2012		2011		2010
Expense	**$**	**270**	$	235	$	211
$/BOE [(1)]	**$**	**1.13**	$	1.07	$	0.92

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

Administration expense for 2012 increased from 2011 primarily due to higher staffing related costs and general corporate costs.

SHARE-BASED COMPENSATION

($ millions)		2012		2011		2010
(Recovery) expense	**$**	**(214)**	$	(102)	$	203

The Company's stock option plan provides current employees with the right to receive common shares or a direct cash payment in exchange for stock options surrendered.

The share-based compensation liability at December 31, 2012 reflected the Company's liability for awards granted to employees at fair value estimated using the Black-Scholes valuation model. In periods when substantial share price changes occur, the Company's net earnings are subject to significant volatility. The Company utilizes its share-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

The Company recorded a $214 million share-based compensation recovery for the year ended December 31, 2012, primarily as a result of remeasurement of the fair value of outstanding stock options at the end of the year related to a decrease in the Company's share price, partially offset by normal course graded vesting of stock options granted in prior periods and the impact of vested stock options exercised or surrendered during the year. For the year ended December 31, 2012, a $12 million recovery was recognized in respect of capitalized share-based compensation to Oil Sands Mining and Upgrading (2011 – $nil; 2010 – $32 million expense capitalized).

During 2012, the Company paid $7 million for stock options surrendered for cash payments (2011 – $14 million; 2010 – $45 million).

INTEREST AND OTHER FINANCING COSTS

($ millions, except per BOE amounts and interest rates)		**2012**		2011		2010
Expense, gross	**$**	**462**	$	432	$	476
Less: capitalized interest		**98**		59		28
Expense, net	**$**	**364**	$	373	$	448
$/BOE [(1)]	**$**	**1.52**	$	1.71	$	1.94
Average effective interest rate		**4.8%**		4.7%		4.9%

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

Gross interest and other financing costs for 2012 increased from 2011 due to higher variable interest rates and the impact of a weaker Canadian dollar, partially offset by lower average debt levels. Capitalized interest of $98 million for 2012 was related to the Horizon Phase 2/3 expansion and the Kirby Thermal Oil Sands Project ("Kirby Project").

RISK MANAGEMENT ACTIVITIES

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

($ millions)		**2012**		2011		2010
Crude oil and NGLs financial instruments	**$**	**65**	$	117	$	84
Natural gas financial instruments		**–**		–		(234)
Foreign currency contracts and interest rate swaps		**97**		(16)		40
Realized loss (gain)	**$**	**162**	$	101	$	(110)
Crude oil and NGLs financial instruments	**$**	**3**	$	(134)	$	(108)
Natural gas financial instruments		**–**		–		72
Foreign currency contracts and interest rate swaps		**(45)**		6		12
Unrealized gain	**$**	**(42)**	$	(128)	$	(24)
Net loss (gain)	**$**	**120**	$	(27)	$	(134)

During 2012, realized risk management losses primarily related to the settlement of crude oil and foreign currency contracts. The Company recorded a net unrealized gain of $42 million ($37 million after-tax) on its risk management activities (2011 – $128 million unrealized gain, $95 million after-tax; 2010 – $24 million unrealized gain, $16 million after-tax), related to changes in the fair value of these contracts.

The cash settlement amount of commodity derivative financial instruments may vary materially depending upon the underlying crude oil prices at the time of final settlement, as compared to their fair value at December 31, 2012.

Complete details related to outstanding derivative financial instruments at December 31, 2012 are disclosed in note 17 to the Company's consolidated financial statements.

FOREIGN EXCHANGE

($ millions)		**2012**		2011		2010
Net realized gain	**$**	**(178)**	$	(214)	$	(2)
Net unrealized loss (gain) [(1)]		**129**		215		(161)
Net (gain) loss	**$**	**(49)**	$	1	$	(163)

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

The Company's operating results are affected by the fluctuations in the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. Predominantly all 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 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 realized foreign exchange gain for 2012 was primarily due to the repayment of US$350 million of 5.45% unsecured notes, together with the impact of foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange loss in 2012 was primarily related to the reversal of the life-to-date unrealized foreign exchange gain on the repayment of US$350 million of 5.45% unsecured notes; partially offset by the impact of the strengthening of the Canadian dollar at December 31, 2012 with respect to remaining US dollar debt. Included in the net unrealized loss for 2012 was an unrealized loss of $53 million (2011 – $42 million unrealized gain, 2010 – $101 million unrealized loss) related to the impact of cross currency swaps. The US/Canadian dollar exchange rate ended the year at US$1.0051 compared with US$0.9833 at December 31, 2011 (December 31, 2010 – US$1.0054).

INCOME TAXES

($ millions, except income tax rates)	**2012**	2011	2010
North America [1]	**$ 366**	$ 315	$ 431
North Sea	**115**	245	203
Offshore Africa	**206**	140	64
PRT expense – North Sea	**44**	135	68
Other taxes	**16**	25	23
Current income tax	**747**	860	789
Deferred income tax expense	**–**	412	408
Deferred PRT recovery – North Sea	**(30)**	(5)	(9)
Deferred income tax (recovery) expense	**(30)**	407	399
	717	1,267	1,188
Income tax rate and other legislative changes	**(58)**	(104)	(132)
	$ 659	$ 1,163	$ 1,056
Effective income tax rate on adjusted net earnings from operations [2]	**27.8%**	27.7%	28.9%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.
(2) Excludes the impact of current and deferred PRT expense and other current income tax expense.

Current income taxes recognized in each operating segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

During 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax relief on UK North Sea decommissioning expenditures to 50%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $58 million.

During 2011, the UK government enacted legislation to increase the supplementary income tax rate charged on profits from UK North Sea crude oil and natural gas production, increasing the combined corporate and supplementary income tax rate from 50% to 62%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $104 million.

During 2011, the Canadian federal government enacted legislation to implement several taxation changes. These changes include a requirement that, beginning in 2012, partnership income must be included in the taxable income of each corporate partner based on the tax year of the partner, rather than the fiscal year of the partnership. The legislation includes a five-year transition provision and has no impact on net earnings.

During 2010, deferred income tax expense included a charge of $132 million related to enacted changes in Canada to the taxation of stock options surrendered by employees for cash.The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's results of operations, financial position or liquidity.

During 2012, the Company filed Scientific Research and Experimental Development claims of approximately $300 million (2011 – $210 million, 2010 – $190 million) relating to qualifying research and development, capital and operating expenditures for Canadian income tax purposes.

For 2013, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $550 million to $650 million in Canada and $10 million to $100 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES (1)

($ millions)	2012	2011	2010
Exploration and Evaluation			
Net expenditures	**$ 309**	$ 312	$ 572
Property, Plant and Equipment			
Net property acquisitions	**144**	1,012	1,482
Well drilling, completion and equipping	**1,902**	1,878	1,499
Production and related facilities	**1,978**	1,690	1,122
Capitalized interest and other (2)	**111**	104	92
Net expenditures	**4,135**	4,684	4,195
Total Exploration and Production	**4,444**	4,996	4,767
Oil Sands Mining and Upgrading			
Horizon Phases 2/3 construction costs	**1,315**	481	319
Sustaining capital	**223**	170	128
Turnaround costs	**21**	79	–
Capitalized interest and other (2)	**51**	48	96
Total Oil Sands Mining and Upgrading	**1,610**	778	543
Horizon coker rebuild and collateral damage costs (3)	**–**	404	–
Midstream	**14**	5	7
Abandonments (4)	**204**	213	179
Head office	**36**	18	18
Total net capital expenditures	**$ 6,308**	$ 6,414	$ 5,514
By segment			
North America	**$ 4,126**	$ 4,736	$ 4,369
North Sea	**254**	227	149
Offshore Africa	**64**	33	249
Oil Sands Mining and Upgrading	**1,610**	1,182	543
Midstream	**14**	5	7
Abandonments (4)	**204**	213	179
Head office	**36**	18	18
Total	**$ 6,308**	$ 6,414	$ 5,514

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.
(2) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.
(3) During 2011, the Company recognized $393 million of property damage insurance recoveries (see note 10 to the Company's consolidated financial statements), offsetting the costs incurred related to the coker rebuild and collateral damage costs.
(4) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

The Company's 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 areas. 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 owning associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for 2012 were $6,308 million compared with $6,414 million for 2011 (2010 – $5,514 million). The increase in 2012 capital expenditures in the Exploration and Production and Oil Sands Mining and Upgrading segments from 2011 was primarily due to an increase in production and related facilities spending, partially offset by lower net property acquisition costs, and the ramp up of Horizon site construction activity.

Drilling Activity (number of wells)	**2012**	2011	2010
Net successful natural gas wells	**35**	83	92
Net successful crude oil wells (1)	**1,203**	1,103	934
Dry wells	**33**	48	33
Stratigraphic test / service wells	**727**	657	491
Total	**1,998**	1,891	1,550
Success rate (excluding stratigraphic test / service wells)	**97%**	96%	97%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 69% of the total capital expenditures for 2012 compared to approximately 77% for 2011 (2010 – 83%).

During 2012, the Company targeted 35 net natural gas wells, including 15 wells in Northeast British Columbia and 20 wells in Northwest Alberta. The Company also targeted 1,236 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 886 primary heavy crude oil wells, 65 Pelican Lake heavy crude oil wells, 8 light crude oil wells and 161 bitumen (thermal oil) wells were drilled. Another 116 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 and low natural gas prices, 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 thermal in situ Oil Sands assets, the Company is continuing to develop its Primrose thermal projects. During 2012, the Company drilled 135 bitumen (thermal oil) wells, and 105 stratigraphic test wells and observation wells. Overall Primrose thermal production for 2012 averaged approximately 99,000 bbl/d, compared with approximately 98,000 bbl/d in 2011 (2010 – 90,000 bbl/d). Production volumes were in line with expectations due to the cyclic nature of thermal production at Primrose. Additional pad drilling was completed and drilled on budget, with these wells coming on production in 2013.

The next planned phase of the Company's thermal in situ Oil Sands assets expansion is the Kirby South Phase 1 Project. As at December 31, 2012, the overall project was 81% complete, drilling was completed on the fifth of seven pads, and first steam is targeted for late 2013. In 2012, the Company acquired approximately 49 sections (12,630 hectares) of additional Oil Sands rights immediately adjacent to the Kirby Project.

The Company continued to develop the tertiary recovery conversion projects at Pelican Lake throughout 2012. Pelican Lake production averaged approximately 38,000 bbl/d in 2012 (2011 – 38,000 bbl/d; 2010 – 38,000 bbl/d). The completion of the new 20,000 bbl/d battery expansion is targeted to be on stream in the second quarter of 2013. With this incremental capacity, both Woodenhouse and Pelican production volumes will no longer be restricted.

For 2013, the Company's overall drilling activity in North America is expected to be 1,022 net crude oil wells, 132 net bitumen wells and 30 net natural gas wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity during 2012 was focused on the field construction of the gas recovery unit, sulphur recovery unit, butane treatment unit, tank farms, coker expansion, hydrotransport, tailings, and extraction trains 3 and 4, along with engineering related to the hydrogen, utilities, hydrotreater, vacuum distillation and diluent recovery units, and permanent camp. Final commissioning of the third ore preparation plant and associated hydro-transport was completed in January 2012.

North Sea

In December 2011, the Banff FPSO and subsea infrastructure suffered storm damage. Operations at Banff/Kyle, with combined net production of approximately 3,500 bbl/d, were suspended. The FPSO and associated floating storage unit have subsequently been removed from the field and the FPSO is currently in dry dock for assessment of the damage and repair timeframe. The extent of the property damage, including associated costs, is not expected to be significant.

In 2012, the UK government announced the implementation of the Brownfield Allowance, which allows for an agreed allowance related to property development for certain pre-approved qualifying field developments. This allowance partially mitigates the impact of previous tax increases. The Company is currently assessing the impact of this initiative on its future capital programs.

The Company currently plans to decommission the Murchison platform in the North Sea commencing in 2014 and estimates the decommissioning efforts will continue for approximately 5 years.

Offshore Africa

During 2011, the Company sanctioned an 8 well drilling program at the Espoir field in Côte d'Ivoire. Preparations are ongoing and a drilling rig is on-site in preparation for the commencement of the drilling program in 2013. At the Olowi field in Gabon, approximately 1,500 bbl/d of production was shut in. The Company currently has a vessel on-site in Gabon assessing the operability of the midwater arch.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**2012**		2011		2010
Working capital (deficit) [1]	**$**	**(1,264)**	$	(894)	$	(1,200)
Long-term debt [2] [3]	**$**	**8,736**	$	8,571	$	8,485
Shareholders' equity						
Share capital	**$**	**3,709**	$	3,507	$	3,147
Retained earnings		**20,516**		19,365		17,212
Accumulated other comprehensive income		**58**		26		9
Total	**$**	**24,283**	$	22,898	$	20,368
Debt to book capitalization [3] [4]		**26%**		27%		29%
Debt to market capitalization [3] [5]		**22%**		17%		15%
After-tax return on average common shareholders' equity [6]		**8%**		12%		8%
After-tax return on average capital employed [3] [7]		**7%**		10%		7%

(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 (2012 – $798 million; 2011 – $359 million; 2010 – $397 million).
(3) Long-term debt 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 twelve month trailing period; as a percentage of average common shareholders' equity for the year.
(7) Calculated as net earnings plus after-tax interest and other financing costs for the twelve month trailing period; as a percentage of average capital employed for the year.

At December 31, 2012, 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 and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of this MD&A. In addition, the Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon 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 ongoing 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. At December 31, 2012, the Company had $3,661 million of available credit under its bank credit facilities.

During 2012, the Company's $1,500 million revolving syndicated credit facility was extended to June 2016. Additionally, the Company issued $500 million of 3.05% medium-term notes due June 2019. Proceeds from the securities issued were used to repay bank indebtedness and for general corporate purposes. After issuing these securities, the Company has $2,500 million remaining on its outstanding $3,000 million base shelf prospectus that allows for the issue of medium-term notes in Canada, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance.

During 2012, the Company repaid US$350 million of 5.45% unsecured notes. The Company has US$2,000 million remaining on its outstanding US$3,000 million base shelf prospectus that allows for the issue of US dollar debt securities in the United States, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance.

Subsequent to December 31, 2012, $400 million of 4.50% medium-term notes and US$400 million of 5.15% unsecured notes were repaid. This indebtedness was retired utilizing cash flow from operations generated in excess of capital expenditures and available bank credit facilities as necessary, while maintaining the ongoing dividend program. On a pro forma basis, reflecting the retirement of this indebtedness at December 31, 2012, the available credit under its bank credit facilities would amount to $2,863 million.

Long-term debt was $8,736 million at December 31, 2012, resulting in a debt to book capitalization ratio of 26% (December 31, 2011 – 27%; December 31, 2010 – 29%). This ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operations is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. The Company has hedged a portion of its crude oil production for 2013 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs. Further details related to the Company's long-term debt at December 31, 2012 are discussed in note 8 to the Company's consolidated financial statements.

The Company's commodity hedge policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs. This policy 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 policy, the purchase of put options is in addition to the above parameters. As at March 6, 2013, approximately 48% of currently forecasted 2013 crude oil volumes were hedged using price collars. Further details related to the Company's commodity related derivative financial instruments outstanding at December 31, 2012 are discussed in note 17 to the Company's consolidated financial statements.

Share Capital

As at December 31, 2012, there were 1,092,072,000 common shares outstanding and 73,747,000 stock options outstanding. As at March 5, 2013, the Company had 1,092,589,000 common shares outstanding and 68,482,000 stock options outstanding.

During 2012, the Company amended its Articles by special resolution of the shareholders, changing the designation of its Class 1 preferred shares to "Preferred Shares" which may be issuable in series. If issued, the number of shares in each series, and the designation, rights, privileges, restrictions and conditions attached to the shares will be determined by the Board of Directors of the Company.

On March 6, 2013, the Company's Board of Directors approved an increase in the annual dividend to be paid by the Company to $0.50 per common share for 2013. The increase represents an approximately 19% increase from 2012, recognizing the stability of the Company's cash flow and providing a return to shareholders. The dividend policy undergoes periodic review by the Board of Directors and is subject to change. In March 2012, an increase in the annual dividend paid by the Company to $0.42 per common share was approved for 2012. The increase represented a 17% increase from 2011.

In 2012, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the TSX and the NYSE, during the twelve month period commencing April 2012 and ending April 2013, up to 55,027,447 common shares. The Company's Normal Course Issuer Bid announced in 2011 expired April 2012.

During 2012, the Company purchased for cancellation 11,012,700 common shares at a weighted average price of $28.91 per common share for a total cost of $318 million.

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. As at December 31, 2012, no entities were consolidated under the Standing Interpretations Committee ("SIC") 12, "Consolidation – Special Purpose Entities". The following table summarizes the Company's commitments as at December 31, 2012:

($ millions)	2013	2014	2015	2016	2017	Thereafter
Product transportation and pipeline	$ 231	$ 218	$ 204	$ 135	$ 117	$ 788
Offshore equipment operating leases and offshore drilling	$ 156	$ 135	$ 104	$ 76	$ 57	$ 65
Long-term debt [(1)]	$ 798	$ 846	$ 593	$ 1,027	$ 1,094	$ 4,430
Interest and other financing costs [(2)]	$ 414	$ 395	$ 359	$ 338	$ 283	$ 3,782
Office leases	$ 33	$ 34	$ 32	$ 33	$ 35	$ 262
Other	$ 173	$ 95	$ 43	$ 10	$ 2	$ 7

(1) Long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs.
(2) Interest and other financing cost amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at December 31, 2012.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases of Horizon. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is a defendant and plaintiff in a number of legal actions arising in the normal course of business. 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 years ended December 31, 2012, 2011 and 2010, the Company retained Independent Qualified Reserves Evaluators to evaluate and review all of the Company's proved and proved plus probable crude oil, NGLs and natural gas reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements. In previous years, the Company was granted an exemption from certain provisions of NI 51-101 allowing the Company to substitute SEC requirements under Regulations S-K and S-X for certain disclosures required under NI 51-101. Such exemption expired on December 31, 2010.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States FASB Topic 932 "Extractive Activities - Oil and Gas" in the Company's annual Form 40-F filed with the SEC and in the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

The following tables summarize the company gross proved and proved plus probable reserves using forecast prices and costs as at December 31, 2012, prepared in accordance with NI 51-101 reserves disclosures:

Proved Reserves	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2011	451	175	276	974	2,119	4,447	95	4,831
Discoveries	–	–	–	–	–	6	–	1
Extensions	4	24	1	68	–	52	2	107
Infill Drilling	6	20	–	10	–	16	1	40
Improved Recovery	–	–	5	–	–	–	–	5
Acquisitions	1	–	–	–	–	43	1	9
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	4	–	–	–	14	(37)	(1)	11
Technical Revisions	6	31	(1)	50	153	56	5	253
Production	(29)	(46)	(14)	(36)	(31)	(446)	(9)	(239)
December 31, 2012	**443**	**204**	**267**	**1,066**	**2,255**	**4,136**	**94**	**5,018**

Proved plus Probable Reserves	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2011	669	249	388	1,726	3,355	6,101	134	7,538
Discoveries	–	–	–	–	–	11	–	2
Extensions	8	34	1	345	–	90	5	408
Infill Drilling	13	28	–	15	–	26	1	61
Improved Recovery	–	–	8	–	–	–	–	8
Acquisitions	1	–	–	–	–	58	1	12
Dispositions	–	–	–	–	–	(3)	–	(1)
Economic Factors	–	–	–	–	3	(40)	(1)	(4)
Technical Revisions	(8)	19	(11)	72	24	(10)	7	101
Production	(29)	(46)	(14)	(36)	(31)	(446)	(9)	(239)
December 31, 2012	**654**	**284**	**372**	**2,122**	**3,351**	**5,787**	**138**	**7,886**

At December 31, 2012, the company gross proved crude oil, bitumen, SCO and NGLs reserves totaled 4,329 MMbbl, and gross proved plus probable crude oil, bitumen, SCO and NGLs reserves totaled 6,921 MMbbl. Proved reserve additions and revisions replaced 245% of 2012 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 143 MMbbl, and additions to proved plus probable reserves amounted to 460 MMbbl. Net positive revisions amounted to 261 MMbbl for proved reserves and 105 MMbbl for proved plus probable reserves, primarily due to technical revisions to prior estimates based on improved or better than expected reservoir performance.

At December 31, 2012, the company gross proved natural gas reserves totaled 4,136 Bcf, and gross proved plus probable natural gas reserves totaled 5,787 Bcf. Proved reserve additions and revisions replaced 30% of 2012 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 116 Bcf, and additions to proved plus probable reserves amounted to 182 Bcf. Net positive revisions amounted to 19 Bcf for proved reserves and net negative revisions amounted to 50 Bcf for proved plus probable reserves, primarily due to lower estimated future benchmark pricing.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's Independent Qualified Reserves Evaluators to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and related net present value of future net revenue of the remaining reserves.

Additional reserves disclosure is annually disclosed in the AIF and the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

RISKS AND UNCERTAINTIES

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

- The ability to find, produce and replace reserves, whether sourced from exploration, improved recovery or acquisitions, 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;
- Reservoir quality and uncertainty of reserve estimates;
- Volatility in the 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 properties and/or companies;
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including derivative financial instruments and physical sales contracts as part of a hedging program;
- 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 predominantly all sales are based on US dollar denominated benchmarks;
- Environmental impact risk associated with exploration and development activities, including GHG;
- Geopolitical risks associated with changing governments or governmental policies, social instability and other political, economic or diplomatic developments in the regions where the Company has its operations;
- Future legislative and regulatory developments related to environmental regulation;
- Potential actions of governments, regulatory authorities and other stakeholders that may result in costs or restrictions in the jurisdictions where the Company has operations;
- Changing royalty regimes;
- Business interruptions because of unexpected events such as fires or explosions whether caused by human error or nature, severe storms and other calamitous acts of nature, blowouts, freeze-ups, mechanical or equipment failures of facilities and infrastructure and other similar events affecting the Company or other parties whose operations or assets directly or indirectly impact the Company and that may or may not be financially recoverable;
- The access to markets for the Company's products; 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 price, foreign currency and interest rate exposures. 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 AIF.

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 operated facilities;
— Continued evaluation of new technologies to reduce environmental impacts and support for Canada's Oil Sands Innovation Alliance ("COSIA");
— CO_2 reduction programs including the injection of CO_2 into tailings and for use in enhanced oil recovery;
— A program in place related to progressive reclamation and tailings management for the Horizon Oil Sands facility; and
— Participation and support for the Joint Oil Sands Monitoring Program.

For 2012, the Company's capital expenditures included $204 million for abandonment expenditures (2011 – $213 million; 2010 – $179 million). The Company's estimated discounted ARO at December 31, 2012 was as follows:

($ millions)		**2012**		2011
Exploration and Production				
North America	**$**	**2,079**	$	1,862
North Sea		**1,030**		723
Offshore Africa		**218**		192
Oil Sands Mining and Upgrading		**937**		798
Midstream		**2**		2
	$	**4,266**	$	3,577

The discounted ARO was based on estimates of future costs to abandon and restore wells, production facilities, mine site, upgrading facilities and tailings, and offshore production platforms. Factors that affect costs include number of wells drilled, well depth, facility size and the specific environmental legislation. The estimated future costs are based on engineering estimates of current costs in accordance with present legislation, industry operating practice and the expected timing of abandonment. The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates.

GREENHOUSE GAS AND OTHER AIR EMISSIONS

The Company, through the Canadian Association of Petroleum Producers ("CAPP"), is working with Canadian 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, and 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 is also developing a comprehensive management system for air pollutants.

In the province of Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Three of the Company's facilities, the Horizon facility, the Primrose/Wolf Lake in situ heavy crude oil facilities and the Hays sour natural gas plant are subject to compliance under the regulations. The Kirby South in situ heavy crude oil facility will be subject to compliance under the regulations in 2016. In the province of British Columbia, carbon tax is currently being assessed at $30/tonne of CO_2e on fuel consumed and gas flared in the province. As part of its involvement with the Western Climate Initiative, British Columbia may require certain upstream oil and gas facilities to participate in a regional cap and trade system. If such a system is implemented, it is not expected to be in place before 2015. It is estimated that four facilities in British Columbia will be included under the cap and trade system, based on a proposed requirement of 25 kilotonne CO_2e annually. The province of Saskatchewan released draft GHG regulations that regulate facilities emitting more than 50 kilotonnes of CO_2e annually and will likely require the North Tangleflags in situ heavy oil facility to meet the reduction target for its GHG emissions once the governing legislation comes into force. In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 – 2007) of the UK National Allocation Plan, the Company operated below its CO_2 allocation. In Phase 2 (2008 – 2012) the Company's CO_2 allocation has been decreased below the Company's estimated current operations emissions. In Phase 3 (2013 – 2020) the Company's CO_2 allocation is expected to be further reduced, although details on Phase 3 have not yet been finalized. 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.

The United States Environmental Protection Agency ("EPA") is proceeding to regulate GHGs under the Clean Air Act. This EPA action has been subject to legal and political challenges, the outcome of which cannot be predicted. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. 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 common facility emission level, 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, CO_2 capture and sequestration in oil sands tailings, CO_2 capture and storage in association with enhanced oil recovery, participation in an industry initiative to promote an integrated CO_2 capture and storage network, and participation in organizations that are researching technologies to reduce GHG emissions (specifically COSIA and Carbon Management Canada (CMC)).

The additional requirements of enacted or proposed GHG regulations on the Company's operations will increase capital expenditures and operating expenses, including those related to Horizon and the Company's other existing and certain planned oil sands projects. This may have an adverse effect on the Company's future 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 are being developed that adopt a structured process to emission reductions that is commensurate with technological development and operational requirements.

CRITICAL ACCOUNTING ESTIMATES AND CHANGE IN ACCOUNTING POLICIES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, 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.

Depletion, Depreciation and Amortization and Impairment

Exploration and evaluation ("E&E") asset costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. The judgements associated with the estimation of proved reserves are described below in "Crude Oil and Natural Gas Reserves".

An alternative acceptable accounting method for E&E assets under IFRS 6 "Exploration for and Evaluation of Mineral Resources" is to charge exploratory dry holes and geological and geophysical exploration costs incurred after having obtained the legal rights to explore an area against net earnings in the period incurred rather than capitalizing to E&E assets.

E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of Cash Generating Units ("CGUs"), aggregated at the segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. The determination of the fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and production costs. Changes in any of these assumptions, such as a downward revision in probable reserves volumes, decrease in commodity prices or increase in costs, could impact the fair value.

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Crude oil and natural gas properties in the Exploration and Production segments are depleted using the unit-of-production method over proved reserves, except for major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production rate takes into account expenditures incurred to date, together with future estimated development expenditures required to develop proved reserves. Estimates of proved reserves have a significant impact on net earnings, as they are a key input to the calculation of depletion expense.

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low commodity prices for an extended period, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If any such indication of impairment exists, the Company performs an impairment test related to the specific assets. Individual assets are grouped for impairment assessment purposes into CGU's, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. The determination of fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices, discount rates and income taxes as well as development and production costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

Crude Oil and Natural Gas Reserves

Reserve estimates 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, interpretations, and judgements. 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. 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 depletion, depreciation and amortization charge to net earnings. Downward revisions to reserve estimates may also result in an impairment of property, plant and equipment and E&E carrying amounts.

Asset Retirement Obligations

The Company is required to recognize a liability for ARO 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 present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for 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 4.3%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes in discount rates or the estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. 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.

Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred 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 as at the date of the balance sheet. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes liabilities for potential tax audit issues based on assessments of whether additional taxes will likely be due.

Risk Management Activities

The Company uses 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 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. In determining these assumptions, the Company uses directly and indirectly observable inputs in measuring the value of financial instruments that are not traded in active markets, 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.

Purchase Price Allocations

Purchase prices related to 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 estimates, assumptions and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties. 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 depletion, depreciation and amortization 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 judgements 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 judgements 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.

Share-Based Compensation

The Company has made various assumptions in estimating the fair values of stock options granted including expected volatility, expected exercise behavior and future forfeiture rates. At each period end, stock options outstanding are remeasured for subsequent changes in the fair value of the liability.

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, 2012, 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, 2012, 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 2012 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal control 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.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In 2010, the CICA Handbook was revised to incorporate IFRS and require publicly accountable enterprises to apply IFRS effective for years beginning on or after January 1, 2011. The 2011 fiscal year was the first year in which the Company prepared its consolidated financial statements and the related notes in accordance with IFRS as issued by the IASB.

The accounting policies adopted by the Company under IFRS are set out in note 1 to the Company's consolidated financial statements.

Unless otherwise stated, comparative figures for 2010 have been restated from Canadian GAAP to comply with IFRS.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In May 2011, the IASB issued the following new accounting standards, which are required to be adopted effective January 1, 2013:

- IFRS 10 "Consolidated Financial Statements" replaces IAS 27 "Consolidated and Separate Financial Statements" (IAS 27 still contains guidance for Separate Financial Statements) and SIC 12 "Consolidation – Special Purpose Entities". IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on how to apply the control principle to determine whether an investor controls an investee.

- IFRS 11 "Joint Arrangements" replaces IAS 31 "Interests in Joint Ventures" and SIC 13 "Jointly Controlled Entities – Non-Monetary Contributions by Venturers". The new standard defines two types of joint arrangements, joint operations and joint ventures. In a joint operation, the parties with joint control have rights to the assets and obligations for the liabilities of the joint arrangement and are required to recognize their proportionate interest in the assets, liabilities, revenues and expenses of the joint arrangement. In a joint venture, the parties have an interest in the net assets of the arrangement and are required to apply the equity method of accounting.

- IFRS 12 "Disclosure of Interests in Other Entities". The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities. This standard does not impact the Company's accounting for investments in other entities, but may impact the related disclosures.

- Adoption of the above standards is not expected to result in a significant accounting change to the Company's consolidated financial statements, but may impact the related disclosures.

In May 2011, the IASB also issued IFRS 13 "Fair Value Measurement", effective January 1, 2013, which provides guidance on how fair value should be applied where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value. The Company will be required to include its own credit risk in measuring the carrying amount of a risk management liability. In addition, the new standard may impact certain fair value disclosures.

The Company is required to adopt IFRS 9, “Financial Instruments”, effective January 1, 2015, with earlier adoption permitted. IFRS 9 replaces existing requirements included in IAS 39, “Financial Instruments - Recognition and Measurement”. The new standard replaces the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income. The Company is currently assessing the impact of this new standard on its consolidated financial statements.

In June 2011, the IASB issued amendments to IAS 1 “Presentation of Financial Statements” that require items of other comprehensive income that may be reclassified to net earnings to be grouped together. The amendments also require that items in other comprehensive income and net earnings be presented as either a single statement or two consecutive statements. The standard is effective for fiscal years beginning on or after July 1, 2012. Adoption of this amended standard is not expected to result in a significant change in the presentation of the Company’s consolidated financial statements.

In October 2011, the IASB issued IFRS Interpretation Committee (“IFRIC”) 20 “Stripping Costs in the Production Phase of a Surface Mine”. The IFRIC requires overburden removal costs during the production phase to be capitalized and depreciated if the Company can demonstrate that probable future economic benefits will be realized, the costs can be reliably measured, and the Company can identify the component of the ore body for which access has been improved. The IFRIC is effective for fiscal periods beginning on or after January 1, 2013. Adoption of this standard is not expected to result in a significant change to the Company’s consolidated financial statements.

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 targets production levels in 2013 to average between 482,000 bbl/d and 513,000 bbl/d of crude oil and NGLs and between 1,085 MMcf/d and 1,145 MMcf/d of natural gas.

Capital expenditures in 2013 are currently targeted to be as follows:

($ millions)	2013 Guidance
Exploration and Production	
North America natural gas	$ 445
North America crude oil	1,965
International crude oil	605
Thermal In Situ Oil Sands	
Primrose and Future	770
Kirby South Phase 1	315
Kirby North Phase 1	205
Property acquisitions, dispositions and other	85
Total Exploration and Production	$ 4,390
Oil Sands Mining and Upgrading	
Project capital	
Reliability – Tranche 2	100
Directive 74 and Technology	60
Phase 2A	180
Phase 2B	940
Phase 3	535
Phase 4	20
Owner's Costs and Other	245
Total Capital Projects	$ 2,080
Sustaining capital	180
Turnarounds and reclamation	105
Capitalized interest and other	190
Total Oil Sands Mining and Upgrading	$ 2,555
Total	$ 6,945

The above capital expenditure budget incorporates the following levels of drilling activity:

(Number of wells)	2013 Guidance
Targeting natural gas	30
Targeting crude oil	1,160
Stratigraphic test / service wells – Exploration and Production	218
Stratigraphic test / service wells – Oil Sands Mining and Upgrading	353
Total	1,761

North America

The 2013 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)	2013 Guidance
Conventional natural gas	4
Deep natural gas	26
Total	30

The 2013 North America crude oil drilling program is highlighted by continued development of the Primrose thermal projects, Pelican Lake, and a strong primary heavy crude oil program, as follows:

(Number of wells)	2013 Guidance
Primary heavy crude oil	889
Bitumen (thermal oil)	132
Light and medium crude oil	114
Pelican Lake heavy crude oil	19
Total	1,154

Oil Sands Mining and Upgrading

The Company continues to execute its disciplined strategy of staged expansion and work remains on track. The budgeted project capital expenditures reflect the Board of Directors approval of approximately $2.1 billion in targeted strategic expansion.

North Sea

During 2013, capital expenditures will be incurred on drilling programs at Ninian and Tiffany in the North Sea. The Company is currently targeting to drill 3 net crude oil wells.

Offshore Africa

During 2013, capital expenditures will be incurred on drilling and completions at the Espoir field. The Company is currently targeting to drill 3 net crude oil wells.

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 2012, excluding mark-to-market gains (losses) on risk management activities 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	$ 110	$ 0.10	$ 110	$ 0.10
Including financial derivatives	$ 110	$ 0.10	$ 110	$ 0.10
Natural gas – AECO C$0.10/Mcf [(1)]	$ 24	$ 0.02	$ 24	$ 0.02
Volume changes				
Crude oil – 10,000 bbl/d	$ 131	$ 0.12	$ 86	$ 0.08
Natural gas – 10 MMcf/d	$ 4	$ –	$ –	$ –
Foreign currency rate change				
$0.01 change in US$ [(1)]				
Including financial derivatives	$ 78 – 79	$ 0.07	$ 37 – 38	$ 0.03
Interest rate change – 1%	$ 7	$ 0.01	$ 7	$ 0.01

(1) For details of financial instruments in place, refer to note 17 to the Company's consolidated financial statements as at December 31, 2012.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2012	2011	2010
Crude oil and NGLs (bbl/d)							
North America –							
Exploration and Production	**305,613**	**316,483**	**332,895**	**351,983**	**326,829**	295,618	270,562
North America –							
Oil Sands Mining and Upgrading	**46,090**	**115,823**	**99,205**	**83,079**	**86,077**	40,434	90,867
North Sea	**23,046**	**17,619**	**19,502**	**19,140**	**19,824**	29,992	33,292
Offshore Africa	**20,712**	**20,598**	**17,566**	**15,762**	**18,648**	23,009	30,264
Total	**395,461**	**470,523**	**469,168**	**469,964**	**451,378**	389,053	424,985
Natural gas (MMcf/d)							
North America	**1,281**	**1,230**	**1,169**	**1,113**	**1,198**	1,231	1,217
North Sea	**3**	**2**	**2**	**1**	**2**	7	10
Offshore Africa	**18**	**23**	**20**	**20**	**20**	19	16
Total	**1,302**	**1,255**	**1,191**	**1,134**	**1,220**	1,257	1,243
Barrels of oil equivalent (BOE/d)							
North America –							
Exploration and Production	**519,046**	**521,472**	**527,743**	**537,449**	**526,460**	500,778	473,447
North America –							
Oil Sands Mining and Upgrading	**46,090**	**115,823**	**99,205**	**83,079**	**86,077**	40,434	90,867
North Sea	**23,509**	**17,885**	**19,835**	**19,386**	**20,151**	31,082	34,973
Offshore Africa	**23,634**	**24,427**	**20,833**	**19,059**	**21,977**	26,232	32,904
Total	**612,279**	**679,607**	**667,616**	**658,973**	**654,665**	598,526	632,191

PER UNIT RESULTS – EXPLORATION AND PRODUCTION (1)

	Q1	Q2	Q3	Q4	2012	2011	2010
Crude oil and NGLs ($/bbl)							
Sales price (2)	**$ 80.08**	**$ 69.99**	**$ 67.59**	**$ 64.23**	**$ 70.24**	$ 77.46	$ 65.81
Royalties	**13.08**	**9.18**	**12.08**	**8.59**	**10.67**	12.30	10.09
Production expense	**16.78**	**16.66**	**15.79**	**15.32**	**16.11**	15.75	14.16
Netback	**$ 50.22**	**$ 44.15**	**$ 39.72**	**$ 40.32**	**$ 43.46**	$ 49.41	$ 41.56
Natural gas ($/Mcf)							
Sales price (2)	**$ 2.47**	**$ 1.90**	**$ 2.28**	**$ 3.16**	**$ 2.44**	$ 3.73	$ 4.08
Royalties	**0.05**	**0.05**	**0.05**	**0.21**	**0.09**	0.18	0.20
Production expense	**1.34**	**1.15**	**1.30**	**1.43**	**1.31**	1.15	1.09
Netback	**$ 1.08**	**$ 0.70**	**$ 0.93**	**$ 1.52**	**$ 1.04**	$ 2.40	$ 2.79
Barrels of oil equivalent ($/BOE)							
Sales price (2)	**$ 55.21**	**$ 49.17**	**$ 49.08**	**$ 49.83**	**$ 50.81**	$ 57.16	$ 49.90
Royalties	**8.23**	**5.93**	**7.94**	**6.22**	**7.07**	8.12	6.72
Production expense	**13.43**	**13.06**	**12.97**	**13.11**	**13.14**	12.42	11.25
Netback	**$ 33.55**	**$ 30.18**	**$ 28.17**	**$ 30.50**	**$ 30.60**	$ 36.62	$ 31.93

(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.

PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING (1)

	Q1	Q2	Q3	Q4	2012	2011	2010
Crude oil and NGLs ($/bbl)							
SCO sales price (2)	**$ 97.09**	**$ 88.11**	**$ 87.40**	**$ 87.34**	**$ 88.91**	$ 99.74	$ 77.89
Bitumen royalties (3)	**5.16**	**5.20**	**3.45**	**3.80**	**4.34**	3.99	2.72
Adjusted cash production costs (4)	**46.24**	**36.98**	**42.69**	**49.27**	**42.83**	36.64	36.36
Netback	**$ 45.69**	**$ 45.93**	**$ 41.26**	**$ 34.27**	**$ 41.74**	$ 59.11	$ 38.81

(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.
(4) Amounts expressed on a per unit basis in 2012 and 2011 are based on sales volumes excluding the period during suspension of production.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2012	2011
TSX – C$						
Trading volume (thousands)	**209,737**	**185,964**	**175,483**	**158,516**	**729,700**	800,044
Share Price ($/share)						
High	**$ 41.12**	**$ 34.88**	**$ 33.97**	**$ 31.52**	**$ 41.12**	$ 50.50
Low	**$ 32.10**	**$ 25.97**	**$ 25.58**	**$ 26.88**	**$ 25.58**	$ 27.25
Close	**$ 33.06**	**$ 27.31**	**$ 30.33**	**$ 28.64**	**$ 28.64**	$ 38.15
Market capitalization as at December 31 ($ millions)					**$ 31,277**	$ 41,830
Shares outstanding (thousands)					**1,092,072**	1,096,460
NYSE – US$						
Trading volume (thousands)	**214,928**	**221,660**	**208,889**	**199,170**	**844,647**	937,481
Share Price ($/share)						
High	**$ 41.38**	**$ 35.40**	**$ 35.12**	**$ 32.07**	**$ 41.38**	$ 52.04
Low	**$ 32.09**	**$ 25.13**	**$ 25.01**	**$ 26.83**	**$ 25.01**	$ 25.69
Close	**$ 33.18**	**$ 26.85**	**$ 30.79**	**$ 28.87**	**$ 28.87**	$ 37.37
Market capitalization as at December 31 ($ millions)					**$ 31,528**	$ 40,975
Shares outstanding (thousands)					**1,092,072**	1,096,460

ADDITIONAL DISCLOSURE

Certifications

The required disclosure is included in Exhibits 2, 3, 4 and 5 to this Annual Report on Form 40-F.

Disclosure Controls and Procedures

As of the end of the registrant's fiscal year ended December 31, 2012, 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 Canadian Natural 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 Canadian Natural'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 Annual Report on 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, 2012, 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, 2012, 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, 2012, 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 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, principal financial officer, principal accounting officer or controller and persons performing similar functions, 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 have not been any waivers, including implicit waivers, from any provisions of the Code of Ethics and there have been no substantive amendments.

The Code of Ethics is available through the System for Electronic Document and Analysis and Retrieval (SEDAR) at www.sedar.com, Canadian Natural hereby undertakes to provide to any person, without charge and upon request, a copy of its Code of Ethics. 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 ended December 31, 2012 and December 31, 2011, 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 $2,723,000 for 2012 and were $2,696,000 for 2011.

Audit-Related Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ended December 31, 2012 and December 31, 2011, for audit-related services by PwC including pension assets and Crown Royalty Statements, were $183,000 for 2012 and were $175,000 for 2011. 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, ended December 31, 2012 and December 31, 2011, for professional services rendered by PwC for tax services related to expatriate personal tax compliance and other corporate tax return matters were $481,000 for 2012 and were $156,000 for 2011. 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, ended December 31, 2012 and December 31, 2011 for other services were $9,000 for 2012 and were $9,000 for 2011. The fees for other services paid in 2012 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 2012.

OFF BALANCE SHEET ARRANGEMENTS

The Company does not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Tabular Disclosure of Contractual Obligations

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at December 31, 2012:

($ millions)	2013	2014	2015	2016	2017	Thereafter
Product transportation and pipeline	$ 231	$ 218	$ 204	$ 135	$ 117	$ 788
Offshore equipment operating leases	$ 156	$ 135	$ 104	$ 76	$ 57	$ 65
Long-term debt (1)	$ 798	$ 846	$ 593	$ 1,027	$ 1,094	$ 4,430
Interest and other financing costs (2)	$ 414	$ 395	$ 359	$ 338	$ 283	$ 3,782
Office leases	$ 33	$ 34	$ 32	$ 33	$ 35	$ 262
Other	$ 173	$ 95	$ 43	$ 10	$ 2	$ 7

(1) Long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs.

(2) Interest and other financing cost amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at December 31, 2012.

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 Ms. C.M. Best, who chairs the Audit Committee and Messrs. T. W. Faithfull, G. A. Filmon, G. D. Giffin, D. A. Tuer.

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 registrant.

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 27th day of March, 2013.

CANADIAN NATURAL RESOURCES LIMITED

By: SIGNED "STEVE W. LAUT"
Name: Steve W. Laut
Title: President

Documents filed as part of this report:

EXHIBIT INDEX

Exhibit No.	Description
1.	Supplementary Oil & Gas Information for the fiscal year ended December 31, 2012.
2.	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
3.	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) 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 Sproule International Limited, Independent Petroleum Engineering Consultants.
9.	Consent of GLJ Petroleum Consultants Ltd., Independent Petroleum Engineering Consultants.

EXHIBIT 1

Supplementary Oil & Gas Information for the Fiscal Year Ended December 31, 2012

SUPPLEMENTARY OIL & GAS INFORMATION (unaudited)

This supplementary crude oil and natural gas information is provided in accordance with the United States Financial Accounting Standards Board ("FASB") Topic 932 – "Extractive Activities – Oil and Gas" and where applicable, financial information is prepared in accordance with International Financial Reporting Standards ("IFRS"). In addition, comparative financial information for 2010 has been restated from generally accepted accounting principles in the United States to reflect the adoption of IFRS.

For the years ended December 31, 2012, 2011 and 2010, the Company filed its reserves information under National Instrument 51-101 – "Standards of Disclosure of 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. For years prior to 2010, the Company was granted an exemption from certain provisions of NI 51-101 allowing the Company to substitute SEC requirements under Regulations S-K and S-X for certain disclosures required under NI 51-101. Such exemption expired on December 31, 2010.

There are significant differences to the type of volumes disclosed and the basis from which the volumes are economically determined under the SEC requirements and NI 51-101. The SEC requires disclosure of net reserves, after royalties, using 12-month average prices and current costs; whereas NI 51-101 requires gross reserves, before royalties, using forecast pricing and costs. Therefore the difference between the reported numbers under the two disclosure standards can be material.

For the purposes of determining proved crude oil and natural gas reserves for SEC requirements as at December 31, 2012, 2011, and 2010 the Company used the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The Company has used the following 12-month average benchmark prices to determine its 2012 reserves for SEC requirements.

Crude Oil and NGLs				**Natural Gas**			
WTI Cushing Oklahoma (US$/bbl)	WCS (C$/bbl)	Edmonton Par (C$/bbl)	North Sea Brent (US$/bbl)	Edmonton C5+ (C$/bbl)	Henry Hub Louisiana (US$/MMbtu)	AECO (C$/MMbtu)	BC Westcoast Station 2 (C$/MMbtu)
94.71	73.63	87.07	111.13	101.31	2.77	2.35	2.27

A foreign exchange rate of US$1.00/C$1.00 was used in the 2012 evaluation, determined on the same basis as the 12-month average price.

NET PROVED CRUDE OIL AND NATURAL GAS RESERVES

The Company retains Independent Qualified Reserves Evaluators to evaluate the Company's proved crude oil, bitumen, synthetic crude oil ("SCO"), natural gas liquids ("NGLs") and natural gas reserves.

- For the years ended December 31, 2012, 2011, 2010, and 2009, the reports by GLJ Petroleum Consultants Ltd. covered 100% of the Company's SCO reserves. With the inclusion of non-traditional resources within the definition of "oil and gas producing activities" in the SEC's modernization of oil and gas reporting rules ("Final Rule"), effective January 1, 2010 these reserves volumes are included within the Company's crude oil and natural gas reserves totals.

- For the years ended December 31, 2012, 2011, 2010, and 2009, the reports by Sproule Associates Limited and Sproule International Limited covered 100% of the Company's bitumen, crude oil and NGLs and natural gas reserves.

Proved crude oil and natural gas reserves, as defined within the SEC's Regulation S-X under the Final Rule, are the estimated quantities of oil and gas that geoscience and engineering data demonstrate with reasonable certainty to be economically producible, from a given date forward, from known reservoirs under existing economic conditions, operating methods and government regulations. Proved developed reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared 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.

Estimates of crude oil and natural gas reserves are subject to uncertainty and will change as additional information regarding producing fields and technology becomes available and as future economic and operating conditions change.

The following table summarizes the Company's proved and proved developed crude oil and natural gas reserves, net of royalties, as at December 31, 2012, 2011, 2010, and 2009:

	North America						
Crude Oil and NGLs (MMbbl)	**Synthetic Crude Oil[1]**	**Bitumen[2]**	**Crude Oil & NGLs**	**North America Total**	**North Sea**	**Offshore Africa**	**Total**
Net Proved Reserves							
Reserves, December 31, 2009	1,650	695	319	2,664	240	123	3,027
Extensions and discoveries	–	55	9	64	–	–	64
Improved recovery	–	22	6	28	–	–	28
Purchases of reserves in place	–	92	15	107	–	–	107
Sales of reserves in place	–	–	–	–	–	–	–
Production	(32)	(54)	(26)	(112)	(12)	(10)	(134)
Economic revisions due to prices	(41)	(25)	–	(66)	28	–	(38)
Revisions of prior estimates	86	93	5	184	1	(11)	174
Reserves, December 31, 2010	1,663	878	328	2,869	257	102	3,228
Extensions and discoveries	–	78	28	106	–	–	106
Improved recovery	–	10	8	18	–	2	20
Purchases of reserves in place	–	–	6	6	–	–	6
Sales of reserves in place	–	–	–	–	–	–	–
Production	(14)	(60)	(28)	(102)	(11)	(8)	(121)
Economic revisions due to prices	18	(32)	1	(13)	26	–	13
Revisions of prior estimates	169	(5)	23	187	(28)	(8)	151
Reserves, December 31, 2011	1,836	869	366	3,071	244	88	3,403
Extensions and discoveries	**–**	**90**	**5**	**95**	**–**	**–**	**95**
Improved recovery	**–**	**25**	**9**	**34**	**–**	**1**	**35**
Purchases of reserves in place	**–**	**–**	**2**	**2**	**–**	**–**	**2**
Sales of reserves in place	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Production	**(30)**	**(70)**	**(31)**	**(131)**	**(7)**	**(5)**	**(143)**
Economic revisions due to prices	**34**	**6**	**(20)**	**20**	**4**	**–**	**24**
Revisions of prior estimates	**134**	**79**	**39**	**252**	**(6)**	**1**	**247**
Reserves, December 31, 2012	**1,974**	**999**	**370**	**3,343**	**235**	**85**	**3,663**
Net proved developed reserves							
December 31, 2009	1,589	268	204	2,061	94	106	2,261
December 31, 2010	1,546	262	240	2,048	94	83	2,225
December 31, 2011	1,588	269	269	2,126	78	61	2,265
December 31, 2012	**1,612**	**348**	**295**	**2,255**	**66**	**55**	**2,376**

(1) Pursuant to the SEC's Final Rule in effect January 1, 2010, SCO is now included in the Company's crude oil and natural gas reserves 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 classified as bitumen.

Natural Gas (Bcf)	North America	North Sea	Offshore Africa	Total
Net Proved Reserves				
Reserves, December 31, 2009	3,027	67	85	3,179
Extensions and discoveries	249	–	–	249
Improved recovery	19	–	–	19
Purchases of reserves in place	364	–	–	364
Sales of reserves in place	–	–	–	–
Production	(426)	(4)	(5)	(435)
Economic revisions due to prices	105	6	–	111
Revisions of prior estimates	83	9	(4)	88
Reserves, December 31, 2010	3,421	78	76	3,575
Extensions and discoveries	154	–	–	154
Improved recovery	48	–	–	48
Purchases of reserves in place	375	–	–	375
Sales of reserves in place	(1)	–	–	(1)
Production	(433)	(2)	(6)	(441)
Economic revisions due to prices	(104)	3	–	(101)
Revisions of prior estimates	39	18	(16)	41
Reserves, December 31, 2011	3,499	97	54	3,650
Extensions and discoveries	**50**	**–**	**–**	**50**
Improved recovery	**11**	**–**	**–**	**11**
Purchases of reserves in place	**34**	**–**	**–**	**34**
Sales of reserves in place	**(1)**	**–**	**–**	**(1)**
Production	**(429)**	**(1)**	**(6)**	**(436)**
Economic revisions due to prices	**(596)**	**1**	**–**	**(595)**
Revisions of prior estimates	**79**	**(14)**	**–**	**65**
Reserves, December 31, 2012	**2,647**	**83**	**48**	**2,778**
Net proved developed reserves				
December 31, 2009	2,333	45	81	2,459
December 31, 2010	2,557	49	72	2,678
December 31, 2011	2,637	60	47	2,744
December 31, 2012	**2,060**	**58**	**39**	**2,157**

CAPITALIZED COSTS RELATED TO CRUDE OIL AND NATURAL GAS ACTIVITIES

	2012			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Proved properties	**$ 67,287**	**$ 4,574**	**$ 3,045**	**$ 74,906**
Unproved properties	**2,564**	**–**	**47**	**2,611**
	69,851	**4,574**	**3,092**	**77,517**
Less: accumulated depletion and depreciation	**(26,193)**	**(2,709)**	**(2,273)**	**(31,175)**
Net capitalized costs	**$ 43,658**	**$ 1,865**	**$ 819**	**$ 46,342**

	2011			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	$ 61,331	$ 4,147	$ 3,044	$ 68,522
Unproved properties	2,442	–	33	2,475
	63,773	4,147	3,077	70,997
Less: accumulated depletion and depreciation	(22,497)	(2,512)	(2,152)	(27,161)
Net capitalized costs	$ 41,276	$ 1,635	$ 925	$ 43,836

	2010[1]			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	$ 55,030	$ 3,813	$ 2,928	$ 61,771
Unproved properties	2,366	5	31	2,402
	57,396	3,818	2,959	64,173
Less: accumulated depletion and depreciation	(19,502)	(2,205)	(1,904)	(23,611)
Net capitalized costs	$ 37,894	$ 1,613	$ 1,055	$ 40,562

(1) Comparative amounts for 2010 have been restated to reflect the adoption of IFRS.

COSTS INCURRED IN CRUDE OIL AND NATURAL GAS ACTIVITIES

(millions of Canadian dollars)	2012 North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	**$ 144**	**$ –**	**$ –**	**$ 144**
Unproved	**44**	**–**	**3**	**47**
Exploration	**251**	**–**	**11**	**262**
Development	**5,773**	**556**	**75**	**6,404**
Costs incurred	**$ 6,212**	**$ 556**	**$ 89**	**$ 6,857**

(millions of Canadian dollars)	2011 North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 1,012	$ –	$ –	$ 1,012
Unproved	59	–	–	59
Exploration	250	1	2	253
Development	5,559	235	76	5,870
Costs incurred	$ 6,880	$ 236	$ 78	$ 7,194

(millions of Canadian dollars)	2010[(1)] North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 1,482	$ –	$ –	$ 1,482
Unproved	522	–	–	522
Exploration	41	6	3	50
Development	3,332	190	254	3,776
Costs incurred	$ 5,377	$ 196	$ 257	$ 5,830

(1) Comparative amounts for 2010 have been restated to reflect the adoption of IFRS.

RESULTS OF OPERATIONS FROM CRUDE OIL AND NATURAL GAS PRODUCING ACTIVITIES

The Company's results of operations from crude oil and natural gas producing activities for the years ended December 31, 2012, 2011 and 2010 are summarized in the following tables:

	2012			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Crude oil and natural gas revenue, net of royalties and blending costs	**$ 10,609**	**$ 837**	**$ 574**	**$ 12,020**
Production	**(3,669)**	**(402)**	**(163)**	**(4,234)**
Transportation	**(479)**	**(10)**	**(1)**	**(490)**
Depletion, depreciation and amortization	**(3,860)**	**(296)**	**(165)**	**(4,321)**
Asset retirement obligation accretion	**(117)**	**(27)**	**(7)**	**(151)**
Petroleum revenue tax	**–**	**(14)**	**–**	**(14)**
Income tax	**(623)**	**(55)**	**(55)**	**(733)**
Results of operations	**$ 1,861**	**$ 33**	**$ 183**	**$ 2,077**

	2011			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 9,600	$ 1,206	$ 828	$ 11,634
Production	(3,060)	(412)	(186)	(3,658)
Transportation	(374)	(13)	(1)	(388)
Depletion, depreciation and amortization	(3,488)	(248)	(242)	(3,978)
Asset retirement obligation accretion	(90)	(33)	(7)	(130)
Petroleum revenue tax	–	(130)	–	(130)
Income tax	(688)	(218)	(89)	(995)
Results of operations	$ 1,900	$ 152	$ 303	$ 2,355

	2010[2]			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 9,687	$ 1,059	$ 821	$ 11,567
Production	(2,883)	(387)	(167)	(3,437)
Transportation	(365)	(8)	(1)	(374)
Depletion, depreciation and amortization[1]	(2,869)	(295)	(935)	(4,099)
Asset retirement obligation accretion	(80)	(36)	(7)	(123)
Petroleum revenue tax	–	(59)	–	(59)
Income tax	(980)	(137)	146	(971)
Results of operations	$ 2,510	$ 137	$ (143)	$ 2,504

(1) Includes the impact of an impairment relating to Gabon, Offshore Africa at December 31, 2010 of $637 million.
(2) Comparative amounts for 2010 have been restated to reflect the adoption of IFRS.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS FROM PROVED CRUDE OIL AND NATURAL GAS RESERVES AND CHANGES THEREIN

The following standardized measure of discounted future net cash flows from proved crude oil and natural gas reserves has been computed using the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, costs as at the balance sheet date and year-end statutory income tax rates. A discount factor of 10% has been applied in determining the standardized measure of discounted future net cash flows. The Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair value of the crude oil and natural gas properties. Actual net cash flows will differ from the presented estimated future net cash flows due to several factors including:

- Future production will include production not only from proved properties, but may also include production from probable and possible reserves;
- Future production of crude oil and natural gas from proved properties will differ from reserves estimated;
- Future production rates will vary from those estimated;
- Future prices and costs rather than 12-month average prices and costs as at the balance sheet date will apply;
- Economic factors such as interest rates, income tax rates, regulatory and fiscal environments and operating conditions will change;
- Future estimated income taxes do not take into account the effects of future exploration and evaluation expenditures; and
- Future development and asset retirement obligations will differ from those estimated.

Future net revenues, development, production and asset retirement obligation costs have been based upon the estimates referred to above. The following tables summarize the Company's future net cash flows relating to proved crude oil and natural gas reserves based on the standardized measure as prescribed in FASB Topic 932 – "Extractive Activities – Oil and Gas":

	2012			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Future cash inflows	**$ 273,167**	**$ 26,922**	**$ 7,985**	**$ 308,074**
Future production costs	**(114,825)**	**(9,369)**	**(2,428)**	**(126,622)**
Future development costs and asset retirement obligations	**(49,226)**	**(7,032)**	**(1,640)**	**(57,898)**
Future income taxes	**(16,688)**	**(7,662)**	**(949)**	**(25,299)**
Future net cash flows	**92,428**	**2,859**	**2,968**	**98,255**
10% annual discount for timing of future cash flows	**(61,878)**	**(1,330)**	**(1,313)**	**(64,521)**
Standardized measure of future net cash flows	**$ 30,550**	**$ 1,529**	**$ 1,655**	**$ 33,734**

	2011			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Future cash inflows	$ 280,809	$ 26,887	$ 8,257	$ 315,953
Future production costs	(109,586)	(8,908)	(2,058)	(120,552)
Future development costs and asset retirement obligations	(37,486)	(6,821)	(1,669)	(45,976)
Future income taxes	(23,100)	(8,095)	(1,070)	(32,265)
Future net cash flows	110,637	3,063	3,460	117,160
10% annual discount for timing of future cash flows	(75,438)	(1,376)	(1,623)	(78,437)
Standardized measure of future net cash flows	$ 35,199	$ 1,687	$ 1,837	$ 38,723

	2010			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Future cash inflows	$ 221,337	$ 21,117	$ 8,268	$ 250,722
Future production costs	(96,899)	(8,596)	(1,884)	(107,379)
Future development costs and asset retirement obligations	(35,424)	(5,448)	(688)	(41,560)
Future income taxes	(17,249)	(5,572)	(1,760)	(24,581)
Future net cash flows	71,765	1,501	3,936	77,202
10% annual discount for timing of future cash flows	(47,687)	(722)	(1,906)	(50,315)
Standardized measure of future net cash flows	$ 24,078	$ 779	$ 2,030	$ 26,887

The principal sources of change in the standardized measure of discounted future net cash flows are summarized in the following table:

(millions of Canadian dollars)	**2012**	2011	2010
Sales of crude oil and natural gas produced, net of production costs	**$ (7,895)**	$ (7,727)	$ (7,641)
Net changes in sales prices and production costs	**(7,994)**	15,802	14,748
Extensions, discoveries and improved recovery	**1,834**	1,328	1,636
Changes in estimated future development costs	**(3,492)**	(2,022)	(5,208)
Purchases of proved reserves in place	**83**	803	1,894
Sales of proved reserves in place	**(1)**	–	–
Revisions of previous reserve estimates	**4,266**	4,154	2,567
Accretion of discount	**5,110**	3,648	2,757
Changes in production timing and other	**946**	(1,141)	(895)
Net change in income taxes	**2,154**	(3,009)	(4,016)
Net change	**(4,989)**	11,836	5,842
Balance – beginning of year	**38,723**	26,887	21,045
Balance – end of year	**$ 33,734**	$ 38,723	$ 26,887

EXHIBIT 2

Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a)
of the Securities Exchange Act of 1934

CERTIFICATION

I, Steve W. Laut, certify that:

1. I have reviewed this annual report on Form 40-F of Canadian Natural Resources Limited;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13(a)-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated this 27th day of March, 2013.

SIGNED " STEVE W. LAUT"
Steve W. Laut
President (Principal Executive Officer),
Canadian Natural Resources Limited

EXHIBIT 3

Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a)
of the Securities Exchange Act of 1934

CERTIFICATION

I, Douglas A. Proll, certify that:

1. I have reviewed this annual report on Form 40-F of Canadian Natural Resources Limited;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13(a)-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusion about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated this 27th day of March, 2013.

SIGNED "DOUGLAS A. PROLL"
Douglas A. Proll
Chief Financial Officer and Senior Vice-President, Finance (Principal Financial Officer),
Canadian Natural Resources Limited

EXHIBIT 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)

In connection with the Annual Report of Canadian Natural Resources Limited (the "Company") on Form 40-F for the fiscal year ending December 31, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Steve W. Laut, certify pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

DATED this 27th day of March, 2013.

SIGNED "STEVE W. LAUT"
Steve W. Laut
President (Principal Executive Officer),
Canadian Natural Resources Limited

EXHIBIT 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)

In connection with the Annual Report of Canadian Natural Resources Limited (the "Company") on Form 40-F for the fiscal year ending December 31, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Douglas A. Proll, certify pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

DATED this 27th day of March, 2013.

SIGNED "DOUGLAS A. PROLL"
Douglas A. Proll
Chief Financial Officer and Senior Vice-President, Finance (Principal Financial Officer),
Canadian Natural Resources Limited

EXHIBIT 6

Consent of Independent Auditor

We hereby consent to the inclusion in this Annual Report on Form 40-F for the year ended December 31, 2012 of Canadian Natural Resources Limited of our report dated March 6, 2013, relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appear in this Annual Report.

We also consent to the incorporation by reference in the Registration Statement on Form F-9 (File No. 333-177401) of Canadian Natural Resources Limited of our report dated March 6, 2013 referred to above.

SIGNED
"PRICEWATERHOUSECOOPERS LLP"

Chartered Accountants
Calgary, Alberta
March 27, 2013

Over 60 Years of Excellence

R.K. MacLeod*, B.S., P.Eng., *President*
H.J. Helwerda*, B.Sc., P.Eng., FEC, *Executive VP*
D.J. Carsted*, CD, B.Sc., P.Geol., *VP, Geoscience*
G.D. Robinson*, B.Sc., P.Eng., *VP, International*
D.W.C. Ho*, B.A.Sc., P.Eng., *VP, Unconventional*
C.P. Six, B.Sc., P.Eng., *VP, Engineering, Canada*
B.F. Jose, M.Sc., P.Geoph., *VP, Geoscience, International*
K.P. McDonald, B.Comm, CA, *CFO*
M.R. Van de Veen, QC, J.D., M.B.A., L.L.M., *General Counsel, Corporate Secretary*

**Directors*

Ref: 1808

March 27, 2013

Canadian Natural Resources Limited
2500, 855 Second Street SW
Calgary, AB T2P 4J8

Re: Consent of Independent Petroleum Consultants

To Whom It May Concern:

We consent to the use of our report with respect to the reserves data of Canadian Natural Resources Limited included and incorporated by reference in its

(i) Annual Report on Form 40-F for the year ended December 31, 2012; and,

(ii) Registration Statement on Form F-9 (File No. 333-177401), filed with the Securities and Exchange Commission.

Sincerely,

SPROULE ASSOCIATES LIMITED

Original Signed by Nora T. Stewart, P.Eng.

Nora T. Stewart, P.Eng.
Manager, Engineering and Partner

Calgary, Alberta, Canada

EXHIBIT 8



R.K. MacLeod*, B.S., P.Eng., *President*
H.J. Helwerda*, B.Sc., P.Eng., FEC, *Executive VP*
D.J. Carsted*, CD, B.Sc., P.Geol., *VP, Geoscience*
G.D. Robinson*, B.Sc., P.Eng., *VP, International*
D.W.C. Ho*, B.A.Sc., P.Eng., *VP, Unconventional*
C.P. Six, B.Sc., P.Eng., *VP, Engineering, Canada*
B.F. Jose, M.Sc., P.Geoph., *VP, Geoscience, International*
K.P. McDonald, B.Comm, CA, *CFO*
M.R. Van de Veen, QC, J.D., M.B.A., L.L.M., *General Counsel, Corporate Secretary*

**Directors*

Ref: 1808

March 27, 2013

Canadian Natural Resources Limited
2500, 855 Second Street SW
Calgary, AB T2P 4J8

Re: Consent of Independent Petroleum Consultants

To Whom It May Concern:

We consent to the use of our report with respect to the reserves data of Canadian Natural Resources Limited included and incorporated by reference in its

(i) Annual Report on Form 40-F for the year ended December 31, 2012; and,

(ii) Registration Statement on Form F-9 (File No. 333-177401), filed with the Securities and Exchange Commission.

Sincerely,

SPROULE INTERNATIONAL LIMITED

Original Signed by P.W. (Phil) Pantella, P.Eng.

P. W. (Phil) Pantella, P.Eng.
Manager, Engineering and Partner

Calgary, Alberta, Canada

EXHIBIT 9

GLJ Petroleum Consultants

Principal Officers:
Keith M. Braaten, P. Eng.
President & CEO
Jodi L. Anhorn, P. Eng.
Executive Vice President & COO

Officers / Vice Presidents:
Terry L. Aarsby, P. Eng.
Caralyn P. Bennett, P. Eng.
Leonard L. Herchen, P. Eng.
Myron J. Hladyshevsky, P. Eng.
Bryan M. Joa, P. Eng.
Mark Jobin, P. Geol.
John E. Keith, P. Eng.
John H. Stilling, P. Eng.
Douglas R. Sutton, P. Eng.
James H. Willmon, P. Eng.

Canadian Natural Resources Limited
2500, 855 – 2nd Street SW
Calgary, Alberta T2P 4J8

Re: Consent of Independent Petroleum Consultants

To Whom It May Concern:

We consent to the use of our report with respect to the reserves data of Canadian Natural Resources Limited included and incorporated by reference in its

(i) Annual Report on Form 40-F for the year ended December 31, 2012; and,

(ii) Registration Statement on Form F-9 (File No. 333-177401), filed with the Securities and Exchange Commission.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

"ORIGINALLY SIGNED BY"

Tim R. Freeborn, P. Eng.
Manager, Engineering

March 27, 2013
Calgary, Alberta, Canada