CANADIAN NATURAL RESOURCES LTD
Form 40-F
March 28, 2013

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

TABLE OF CONTENTS

Table of Contents

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
CO2	Carbon dioxide
CO2e	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

Table of Contents

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

Table of Contents

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the “Company”) in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as “forward-looking statements”) within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words “believe”, “anticipate”, “expect”, “plan”, “estimate”, “target”, “continue”, “could”, “int “potential”, “predict”, “should”, “will”, “objective”, “project”, “forecast”, “goal”, “guidance”, “outlook”, “effort”, “seeks”, “ 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

Table of Contents

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.

Table of Contents

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:

Subsidiary	Jurisdiction of Incorporation	% Ownership
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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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 CO2e. 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 CO2e. 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 CO2 capture and the sequestration of CO2 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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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, CO2 capture and sequestration in oil sands tailings, CO2 capture and storage in association with enhanced oil recovery, participation in an industry initiative to promote an integrated CO2 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 CO2e 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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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	-					-		