Canadian Natural

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2015

March 24, 2016

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	barrel
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, natural gas and NGLs	The Company's light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, synthetic crude oil, bitumen (thermal oil), natural gas and natural gas liquids
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
fee title interest	Absolute ownership of legal title to mineral lands, subject to conditional interests that may have been granted from the title, such as petroleum and natural gas leases
FPSO	Floating Production, Storage and Offloading vessel
GHG	Greenhouse gas
gross acres	Total number of acres in which the Company has a working interest or fee title 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

MM$	million Canadian dollars
NGLs	Natural gas liquids
net acres	Gross acres multiplied by the percentage working interest or fee title interest therein owned
net asset value	Calculated as net present value, discounted at 10%, of the future net revenue (before income tax and excluding the ARO for development existing as at December 31, 2015) of the Company's total proved plus probable crude oil, natural gas and NGLs reserves prepared using forecast prices and costs, plus the estimated market value of core unproved property, less net debt. Net debt is long term debt plus/minus the working capital deficit/surplus. Future development costs and abandonment and reclamation costs attributable to future development activity have been applied against the future net revenue
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, the construction and future operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or SCO that the Company may be reliant upon to transport its products to market and reference to the 2016 activity provided 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 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 its 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 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 (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.

The comparative Consolidated Financial Statements and the Company's MD&A for the most recently completed fiscal year ended December 31, 2015, herein incorporated by reference, and certain information included in this AIF, have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board.

For the year ended December 31, 2015, the Company retained Independent Qualified Reserves Evaluators ("IQRE"), 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, 2015 and a preparation date of February 1, 2016. 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.

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 annual report on 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 adjusted net earnings from operations, cash flow from operations, adjusted 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 (loss), as determined in accordance with IFRS in the "Net Earnings (Loss) and Cash Flow from Operations" section of the Company's MD&A which is incorporated by reference into this document. The derivation of adjusted 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 2100, 855 - 2nd Street S.W., T2P 4J8.

The Company has amalgamated pursuant to the *Business Corporations Act* (Alberta) under the name Canadian Natural Resources Limited with the following:

October 1, 2000 - Ranger Oil Limited ("Ranger")

January 1, 2003 - Rio Alto Exploration Ltd. ("RAX")

January 1, 2004 - CanNat Resources Inc.

January 1, 2007 - ACC-CNR Resources Corporation

January 1, 2008 - Ranger Oil (International) Ltd.; 764968 Alberta Inc.; CNR International (Norway) Limited; Renata Resources Inc.

January 1, 2012 - Aspect Energy Ltd.; Creo Energy Ltd.; 1585024 Alberta Ltd.

January 1, 2014 - Barrick Energy Inc.

January 1, 2015 - EOG Resources Canada Inc.

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		
Canadian Natural Upgrading Limited	Alberta	100
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
CNR International (South Africa) Limited	Alberta	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, a general 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

2013

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 Partnership"), and the associated target toll amounts were accepted by Redwater Partnership, the Company and the APMC. In December 2013, Redwater Partnership, the Company and APMC agreed in principle to amend certain terms of the processing agreements. In conjunction with these amendments, the Company, along with APMC, each committed to provide additional funding up to $350 million to attain Project completion based on the revised Project cost estimate of approximately $8,500 million. The additional funding is in the form of subordinated debt bearing interest at prime plus 6%, which is anticipated to form part of the equity toll. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion. Under its processing agreement, beginning on the earlier of the commercial operations date of the refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the Redwater Partnership's syndicated credit facility and bonds, over the tolling period of 30 years.

During 2013, the Company discovered bitumen emulsion at surface in areas of the Primrose field. The Company continues to work with the regulator on the causation review of the bitumen emulsion seepage. The Company's near-term steaming plan at Primrose has been modified, with steaming being reduced in certain areas.

During 2013, the Company acquired all the issued and outstanding shares of Barrick Energy Inc. and 1729580 Alberta Ltd., subsidiaries of Barrick Gold Corporation for approximately $173 million.

During 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for a net cash consideration of US$255 million. In the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US$450 million for a commercial crude oil discovery and US$120 million for a commercial natural gas discovery.

During 2013, the Company entered into a 20 year transportation agreement to ship 80,000 bbl/d of crude oil on the proposed Energy East pipeline originating at Hardisty, Alberta with delivery points in Quebec City, Quebec and Saint John, New Brunswick. This pipeline is subject to regulatory approval.

During 2013, the Company issued $500 million of 2.89% medium-term notes due August 2020. Net proceeds from the sale were used to repay bank indebtedness and for general corporate purposes.

2014

In 2014, the Company completed the acquisition of certain Canadian crude oil and natural gas properties for cash consideration of approximately $3,110 million, subject to final closing adjustments. In connection with the agreement, the Company negotiated an additional $1,000 million unsecured bank credit facility with a two-year maturity and with terms similar to the Company's current syndicated credit facilities. The acquired lands and production base are all located in Western Canada in areas adjacent to or near the Company's current conventional operations, primarily in Northeast British Columbia, Northwest Alberta and Northern Plains areas.

In March 2014, the Company issued US$500 million floating rate unsecured notes due March 30, 2016 at a rate of 3 month LIBOR plus 0.375%, and US$500 million principal amount of 3.80% unsecured notes due April 15, 2024. Net proceeds from the sale were used to repay bank indebtedness and for general corporate purposes.

In May 2014, the Company issued $500 million of 2.60% unsecured notes due December 3, 2019 and $500 million of 3.55% unsecured notes due June 3, 2024. Net proceeds from the sale were used to repay bank indebtedness and for general corporate purposes.

In November 2014, the Company issued US$600 million of 1.75% unsecured notes due January 15, 2018 and US$600 million of 3.90% unsecured notes due February 1, 2025. Net proceeds from the sale were used to repay bank indebtedness and for general corporate purposes.

2015

In response to declining commodity prices, the Company's capital expenditures for 2015 reflected reductions in its capital program by approximately $3,400 million, as well as changes to its capital allocation strategy, including the decrease in drilling activity in North America, partially offset by the planned drilling activities in Offshore Africa.

In 2015, the Company's existing $1,000 million non-revolving term credit facility was extended, maturing January 2017. The Company also entered into a new $1,500 million non-revolving term credit facility maturing April 2018. Both facilities were fully drawn at December 31, 2015. In addition, the Company's $1,500 million revolving syndicated credit facility was increased to $2,425 million and the maturity date was extended to June 2019 from June 2016. The $3,000 million revolving syndicated credit facility was reduced to $2,425 million and the maturity date was extended to June 2020 from June 2017.

In 2015, the Company issued $500 million of series 2 medium-term notes due August 2020 through the reopening of its previously issued 2.89% notes. Net proceeds from the sale were used to repay bank indebtedness and for general corporate purposes. The Company also repaid $400 million of 4.95% medium-term notes.

In 2014, the Company commenced a review of its royalty lands and royalty revenue portfolio. The review included a detailed examination of the Company's freehold and royalty land position, production volumes, product mix, associated cash flow and collection of payments. In the fourth quarter of 2015, the Company disposed of its North America royalty income assets for total consideration of $1,658 million. Total consideration on the disposition was comprised of $673 million in cash, together with $985 million of non-cash consideration, comprised of approximately 44.4 million common shares of PrairieSky with a value of $22.16 per common share determined at the closing date. Subject to certain conditions, including applicable regulatory and/or shareholder approvals, the Company has agreed with PrairieSky that, by no later than December 31, 2016, it will distribute sufficient common shares of PrairieSky to the Company's shareholders so that the Company, after such distribution, will hold less than 10% of the issued and outstanding common shares of PrairieSky.

2016

In the first quarter of 2016, the Company prepaid $250 million of the borrowings outstanding under the $1,000 million non-revolving term credit facility and extended the facility to February 2019 from January 2017. The Company also entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn.

On March 21, 2016, the Court of Queen's Bench of Alberta (the "Court") granted an interim order under subsection 193(4) of the Business Corporations Act (Alberta), containing declarations and directions with respect to a Plan of Arrangement (the "Plan") which, if approved by the Company's shareholders at a subsequent meeting, will allow for the a return of capital to shareholders of the Company through the distribution of a minimum of 0.02 of a PrairieSky share in respect of each common share of the Company outstanding as of the effective time in accordance with the terms of the Plan. In the event that shareholder approval is obtained, the Company intends to apply to the Court for a final order approving the Plan, at which time the Company will have the discretion to proceed with the Plan as it stands or amend, alter or cancel the Plan.

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, natural gas and NGLs. 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 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, 2015, the Company had the following full time equivalent permanent employees:

North America, Exploration and Production	4,513
North America, Oil Sands Mining and Upgrading	2,651
North Sea	372
Offshore Africa	32
Total Company	7,568

Operational discipline, safe, effective and efficient operations as well as cost control are fundamental to the Company. By consistently managing costs throughout all industry cycles, 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 enter new core regions or increase 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 and NGLs, light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, SCO from our oil sands mining operations and bitumen (thermal oil). 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 34% of 2015 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 US. Light and medium crude oil and NGLs, representing 16% of 2015 production, is located in the Company's North Sea and Offshore Africa properties, and in the provinces of Alberta, British Columbia and Saskatchewan. Primary heavy crude oil accounting for 15% of 2015 production, Pelican Lake heavy crude oil accounting for 6% of 2015 production, and our bitumen (thermal oil) accounting for 15% of 2015 production are in the provinces of Alberta and Saskatchewan. SCO from our oil sands mining operations in Northern Alberta accounted for approximately 14% of 2015 production. Midstream assets, primarily comprised of two operated and one non operated pipeline systems, and an electricity cogeneration facility, provide cost effective infrastructure supporting the heavy crude oil and bitumen operations. The Company's Midstream assets also include a 50% interest in the Redwater Partnership.

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, Asset Integrity 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 EOR; a program in place related to progressive reclamation and tailings management for the Horizon facility through the operation of thickeners to reduce fluid tailings and the implementation of low fines mining to reduce fines from ore entering the bitumen extraction process and participation and support for the Joint Oil Sands Monitoring Program. 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 2015, Canadian Natural continued its environmental liability reduction program with the abandonment of 519 inactive wells. In addition, reclamation was initiated at many of these sites with the eventual goal of reclamation certification. In 2015 the Company received 170 reclamation certificates representing 477 hectares of land. Further, decommissioning of inactive facilities and cleanup of active facilities was conducted to address environmental liabilities at operating assets. The Company 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. The Company 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 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. The Company 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 2015, the Company completed approximately 593 gas conservation projects in its primary heavy crude oil operations, resulting in a reduction of 3.3 million tonnes/year of CO_2e. Over the past five years the Company has spent over $102 million in its primary heavy crude oil and in situ oil sands operations to conserve the equivalent of over 18.5 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. The Company implemented a fuel gas import project in its North Sea operations 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, natural gas and NGLs 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.

Alberta Oil Sands royalties are based on a sliding scale ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout, depending on benchmark crude oil pricing.

In January 2016, the Alberta government released its Royalty Review Panel Report (the "Panel Report") recommending modernization of conventional crude oil and natural gas royalties effective for new wells drilled beginning in 2017 and also recommending no material change to the oil sands royalty framework. The Alberta government accepted the recommendations, subject to the terms being finalized, in the Panel Report and is expected to adopt the recommendations in 2016. Until the royalty terms to be implemented have been finalized, it is difficult to comment on the impact to industry of these changes.

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 June 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. The Company is subject to federal and provincial income taxes in Canada at a combined rate of approximately 26% in 2015 and 27% thereafter, after allowable deductions.

In Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Five of the Company's facilities, the Horizon facility, the Primrose/Wolf Lake in situ heavy crude oil facilities, the Kirby South in situ heavy crude oil facility, the Hays sour natural gas plant and the Wapiti gas plant are subject to compliance under the regulations. In British Columbia, carbon tax is currently being assessed at $30/tonne of CO_2e on fuel consumed and gas flared in the province. The Saskatchewan Government released draft GHG regulations that would 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 Canada, the federal government has indicated its intent to develop regulations 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, and has released draft regulations pertaining to certain boilers, heaters and compressor engines operated by the Company. In Alberta, the provincial government has implemented increases in both the carbon price and stringency of the existing large-emitter regulatory system for 2016 and 2017. The Alberta Government has also announced additional changes to this system after 2017, as well as a program to reduce methane emissions from the upstream oil and gas sector, and a carbon price on combustion emissions from the upstream oil and gas sector beginning in 2023. In British Columbia, the provincial government is reviewing its climate change strategy with announcements on future changes expected in 2016.

United Kingdom

Under existing law, the UK government has broad authority to regulate the petroleum industry, including exploration, development, conservation and rates of production.

Crude oil and natural gas fields granted development approval before March 16, 1993 are subject to UK 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.

In 2013, the UK government introduced a Decommissioning Relief Deed ("DRD") which is a contractual mechanism whereby the UK government guarantees its participation in future field abandonments through a recovery of PRT and corporate income tax.

In March 2015, the UK government enacted legislation that reduced the supplementary charge on oil and gas profits from 32% to 20% effective January 1, 2015. In addition, the legislation reduced the PRT rate from 50% to 35% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to prior taxation years for PRT purposes are still recoverable at the previous tax rate of 50%. The legislation also replaced the existing Brownfield Allowance with a new Investment Allowance on qualifying capital expenditures, effective April 1, 2015. The new Investment Allowance is deductible for supplementary charge purposes, subject to certain restrictions.

The overall tax rate applicable to taxable income from oil and gas activities, including PRT and corporate and supplementary income tax charges, is 50% for non-PRT paying fields and for PRT paying fields is 75% in 2015 and 67.5% thereafter.

In March 2016, the UK government further reduced the PRT rate from 35% to 0%, effective January 1, 2016. The impact of the reduction to the Company is currently being determined. A proposed reduction to the supplementary charge from 20% to 10% was also introduced which remains subject to legislative approval.

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 was decreased below the Company's operations emissions. In Phase 3 (2013 - 2020) the Company's CO_2 allocation was further reduced. 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.

Offshore Africa

Terms of licences, including royalties and taxes payable on production or profit sharing arrangements, as appropriate, 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.

In South Africa, for oil and gas companies, royalty rates range from 0.5% to 5% and the corporate income tax rate is 28%.

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, natural gas and NGLs, 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 which could be affected by pipeline constraints, the construction by third parties of new or expansion of existing pipeline capacity and other factors, and 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, and prices of alternate sources of energy. Any substantial or extended decline in the prices of crude oil or natural gas could result in a delay or cancellation of existing or future drilling, development or construction programs, including but not limited to Horizon, Primrose, Pelican Lake, the Kirby Thermal Oil Sands Project, the North West Redwater bitumen upgrader and refinery 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 36% of the Company's 2015 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 may differ from the established market indices for light and medium grades of crude oil due principally to quality differences. As a result, the price received for these products may differ from the benchmark they are priced against. Future quality differentials are uncertain and a significant increase in differential 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 related 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, natural gas and NGLs 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.

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, African 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. In November 2015, the Government of Alberta announced a Climate Leadership Plan, including measures to reduce methane emissions, implement an emissions limit for oil sands, introduce a broad-based carbon price (with phase-in for the upstream industry), and modify the existing regulatory system for large emitting facilities. 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 EOR and participation in COSIA.

The US 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 and judicial decisions made within the United States. Various states in the United States have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oils with higher emissions intensity. In March 2016 the US and Canadian governments issued a joint statement regarding a commitment to lowering methane emissions from the oil and gas sector by 2025. This reduction is expected to be implemented through a combination of federal and provincial actions, such as those announced by the Alberta government in November 2015.

The additional requirements of enacted or proposed GHG regulations on the Company's operations may increase capital expenditures and production expense, 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 financial condition.

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 February 2009, the Energy Resources Conservation Board (ERCB), now the Alberta Energy Regulator or AER, released Directive 74 - *Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes*. In March 2015, Alberta Environment and Parks released the Tailings Management Framework (TMF) policy and the AER suspended Directive 74. In September 2015 the AER released a draft Directive to replace Directive 74, *Fluid Tailings Management for Oil Sands Mining Projects*. The proposed Directive establishes performance criteria for tailings operations and sets out the requirements for approval, monitoring and reporting in respect of tailings ponds and tailings management plans. The Company will submit an updated Tailings Management Plan application in 2016 to meet the proposed Directive criteria. There is a risk the Company will not be successful in meeting the stipulated performance criteria once the new tailings process commences which could 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.

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, natural gas and NGLs 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, natural gas and NGLs 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.

Project 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.

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 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. The Company also enters into various transactions with counterparties and is subject to credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts.

Dividends

The Company's payment of future dividends on common shares is dependent on, among other things, its financial condition and other business factors considered relevant by the Board of Directors. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

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, risk 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, including compliance with existing and emerging anti-corruption laws, 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.

Risk Management 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 regulatory issues, risk of increases in government taxes and changes to the royalty regime, risk of litigation, risk to the Company's reputation resulting from operational activities that may cause personal injury, property damage or environmental damage, labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner, severe weather conditions, timing and success of integrating the business and operations of acquired companies, and the dependency on third party operators for some of the Company's assets. The Company utilizes a variety of information systems in its operations. A significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach of security could adversely affect the Company's operations. 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, 2015, the Company retained Independent Qualified Reserves Evaluators ("IQRE"), 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, 2015 and a preparation date of February 1, 2016. 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.

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 IQRE to review the qualifications of and procedures used by each IQRE 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, natural gas and NGLs reserves provided herein are estimates only and there is no guarantee the estimated reserves will be recovered. Actual crude oil, natural gas and NGLs reserves may be greater or less than the estimate provided herein.

Summary of Company Gross Reserves

As of December 31, 2015
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	102	112	222	351	2,283	3,848	99	3,810
Developed Non-Producing	8	20	4	-	-	270	6	83
Undeveloped	28	81	42	874	125	1,920	90	1,560
Total Proved	138	213	268	1,225	2,408	6,038	195	5,453
Probable	54	81	120	1,182	1,225	2,300	88	3,134
Total Proved plus Probable	192	294	388	2,407	3,633	8,338	283	8,587
North Sea								
Proved								
Developed Producing	3					26		7
Developed Non-Producing	21					9		23
Undeveloped	134					4		135
Total Proved	158					39		165
Probable	126					57		135
Total Proved plus Probable	284					96		300
Offshore Africa								
Proved								
Developed Producing	50					22		54
Developed Non-Producing	1					-		1
Undeveloped	39					7		40
Total Proved	90					29		95
Probable	52					45		59
Total Proved plus Probable	142					74		154
Total Company								
Proved								
Developed Producing	155	112	222	351	2,283	3,896	99	3,871
Developed Non-Producing	30	20	4	-	-	279	6	107
Undeveloped	201	81	42	874	125	1,931	90	1,735
Total Proved	386	213	268	1,225	2,408	6,106	195	5,713
Probable	232	81	120	1,182	1,225	2,402	88	3,328
Total Proved plus Probable	618	294	388	2,407	3,633	8,508	283	9,041

Summary of Company Net Reserves

As of December 31, 2015
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	90	96	168	276	1,926	3,495	73	3,211
Developed Non-Producing	7	16	3	-	-	239	5	71
Undeveloped	25	69	33	700	87	1,649	71	1,260
Total Proved	122	181	204	976	2,013	5,383	149	4,542
Probable	45	66	82	908	993	1,978	67	2,491
Total Proved plus Probable	167	247	286	1,884	3,006	7,361	216	7,033
North Sea								
Proved								
Developed Producing	3					26		7
Developed Non-Producing	21					9		22
Undeveloped	134					4		135
Total Proved	158					39		164
Probable	126					57		136
Total Proved plus Probable	284					96		300
Offshore Africa								
Proved								
Developed Producing	43					15		46
Developed Non-Producing	-					-		-
Undeveloped	31					6		32
Total Proved	74					21		78
Probable	39					29		43
Total Proved plus Probable	113					50		121
Total Company								
Proved								
Developed Producing	136	96	168	276	1,926	3,536	73	3,264
Developed Non-Producing	28	16	3	-	-	248	5	93
Undeveloped	190	69	33	700	87	1,659	71	1,427
Total Proved	354	181	204	976	2,013	5,443	149	4,784
Probable	210	66	82	908	993	2,064	67	2,670
Total Proved plus Probable	564	247	286	1,884	3,006	7,507	216	7,454

NOTES

1. “Company gross reserves” are Canadian Natural’s working interest share of reserves before deduction of royalties and without including any royalty interests of the Company.

2. “Company net reserves” are the company gross reserves less all royalties payable to others plus royalties receivable from others.

3. References to “light and medium crude oil” means “light crude oil and medium crude oil combined”.

4. “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 significant 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.

5. 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 IQRE to be reasonable.

6. Amendments to NI 51-101 effective July 1, 2015 included changes to the definition of natural gas. Natural gas reserves disclosure is consistent with the prior year.

7. BOE values as presented may not calculate due to rounding.

A report on reserves data by the Evaluators is provided in Schedule “A” to this AIF. A report by the Company’s management and directors on crude oil, natural gas and NGLs reserves disclosure is provided in Schedule “B” to this AIF.

Summary of Net Present Values of Future Net Revenue Before Income Taxes

As of December 31, 2015
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	140,590	58,766	36,051	26,450	21,124	11.23
Developed Non-Producing	1,592	1,214	953	773	644	13.42
Undeveloped	39,900	38,964	24,741	15,630	10,245	19.64
Total Proved	182,082	98,944	61,745	42,853	32,013	13.59
Probable	152,865	45,391	19,341	10,843	7,195	7.76
Total Proved plus Probable	334,947	144,335	81,086	53,696	39,208	11.53
North Sea						
Proved						
Developed Producing	(985)	(289)	(79)	(7)	23	(11.29)
Developed Non-Producing	(164)	(143)	(128)	(118)	(109)	(5.82)
Undeveloped	3,884	2,648	1,790	1,218	833	13.26
Total Proved	2,735	2,216	1,583	1,093	747	9.65
Probable	8,995	5,085	3,114	2,049	1,432	22.90
Total Proved plus Probable	11,730	7,301	4,697	3,142	2,179	15.66
Offshore Africa						
Proved						
Developed Producing	1,399	1,224	1,049	906	794	22.80
Developed Non-Producing	24	18	14	12	9	-
Undeveloped	1,912	1,224	852	632	492	26.63
Total Proved	3,335	2,466	1,915	1,550	1,295	24.55
Probable	3,361	2,019	1,329	938	699	30.91
Total Proved plus Probable	6,696	4,485	3,244	2,488	1,994	26.81
Total Company						
Proved						
Developed Producing	141,004	59,701	37,021	27,349	21,941	11.34
Developed Non-Producing	1,452	1,089	839	667	544	9.02
Undeveloped	45,696	42,836	27,383	17,480	11,570	19.19
Total Proved	188,152	103,626	65,243	45,496	34,055	13.64
Probable	165,221	52,495	23,784	13,830	9,326	8.91
Total Proved plus Probable	353,373	156,121	89,027	59,326	43,381	11.94

(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, 2015
Forecast Prices and Costs

MM$	Discount @ 0%	Discount @ 5%	Discount @ 10%	Discount @ 15%	Discount @ 20%
North America					
Proved					
Developed Producing	105,376	46,041	29,102	21,764	17,617
Developed Non-Producing	1,150	879	688	556	461
Undeveloped	28,456	27,753	17,256	10,554	6,614
Total Proved	134,982	74,673	47,046	32,874	24,692
Probable	112,574	33,130	13,992	7,782	5,129
Total Proved plus Probable	247,556	107,803	61,038	40,656	29,821
North Sea					
Proved					
Developed Producing	(987)	(296)	(90)	(20)	8
Developed Non-Producing	(195)	(170)	(152)	(139)	(128)
Undeveloped	2,883	1,691	1,055	676	433
Total Proved	1,701	1,225	813	517	313
Probable	4,256	2,426	1,528	1,045	763
Total Proved plus Probable	5,957	3,651	2,341	1,562	1,076
Offshore Africa					
Proved					
Developed Producing	1,019	925	805	701	618
Developed Non-Producing	19	14	11	9	7
Undeveloped	1,445	933	655	491	385
Total Proved	2,483	1,872	1,471	1,201	1,010
Probable	2,513	1,522	1,010	717	538
Total Proved plus Probable	4,996	3,394	2,481	1,918	1,548
Total Company					
Proved					
Developed Producing	105,408	46,670	29,817	22,445	18,243
Developed Non-Producing	974	723	547	426	340
Undeveloped	32,784	30,377	18,966	11,721	7,432
Total Proved	139,166	77,770	49,330	34,592	26,015
Probable	119,343	37,078	16,530	9,544	6,430
Total Proved plus Probable	258,509	114,848	65,860	44,136	32,445

(1) After-tax net present values consider the Company's existing tax pool balances and current tax regulations and do not represent an estimate of the value at the consolidated entity level, which may be significantly different. For information at the consolidated entity level, refer to the Company's Consolidated Financial Statements and the Management's Discussion and Analysis for the year ended December 31, 2015.

Additional Information Concerning Future Net Revenue

The following table summarizes the undiscounted future net revenue as at December 31, 2015 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	451,421	785,008	18,185	33,814	6,891	10,960	476,497	829,782
Royalties	79,276	147,943	37	57	236	402	79,549	148,402
Production Costs	136,945	229,930	9,315	14,039	2,322	2,566	148,582	246,535
Development Costs	43,911	61,640	4,050	5,324	758	1,027	48,719	67,991
Abandonment and Reclamation Costs – Future Development[1]	573	892	16	193	19	48	608	1,133
Abandonment and Reclamation Costs – Existing Development[1]	8,634	9,656	2,032	2,471	221	221	10,887	12,348
Future Net Revenue Before Income Taxes	182,082	334,947	2,735	11,730	3,335	6,696	188,152	353,373
Income Taxes	47,100	87,391	1,034	5,773	852	1,700	48,986	94,864
Future Net Revenue After Income Taxes [2]	134,982	247,556	1,701	5,957	2,483	4,996	139,166	258,509

(1) Due to amendments to NI 51-101 effective July 1, 2015, abandonment and reclamation costs included in the calculation of the future net revenue for 2015 consist of both forecast estimates of abandonment and reclamation costs attributable to future development activity, as well as certain costs already included in the Company's ARO for development existing as at December 31, 2015. The Company's estimated ARO at December 31, 2015 was $1,415 million, discounted at 10% (unescalated and undiscounted ARO at December 31, 2015 was $12,137 million). Approximately $8,188 million of this unescalated and undiscounted amount was also included in the future net revenue and is escalated at 1.5% per year. Specifically, for North America (excluding SCO assets), future net revenue includes the costs associated with abandonment and reclamation of wells (wells, well sites, wellsite equipment and pipelines) with assigned reserves. For SCO assets, future net revenue includes the costs associated with the abandonment and reclamation of the mine site and all mining and upgrading facilities. For North Sea and Offshore Africa, future net revenue includes the costs associated with the abandonment and reclamation of offshore wells and facilities with 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, 2015 using forecast prices and costs.

Future Net Revenue By Product Type [1] [2]

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) (MM$)	Unit Value ($/BOE)
Proved Reserves	**Light and Medium Crude Oil** (including solution gas and other by-products)	6,924	16.43
	Primary Heavy Crude Oil (including solution gas)	3,109	16.99
	Pelican Lake Heavy Crude Oil (including solution gas)	3,650	17.84
	Bitumen (Thermal Oil)	13,806	14.14
	Synthetic Crude Oil	33,009	16.40
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	5,416	5.49
	Abandonment and Reclamation Costs – Existing Development	(671)	-
	Total	**65,243**	**13.64**
Proved Plus Probable Reserves	**Light and Medium Crude Oil** (including solution gas and other by-products)	12,445	18.51
	Primary Heavy Crude Oil (including solution gas)	4,619	18.47
	Pelican Lake Heavy Crude Oil (including solution gas)	4,923	17.15
	Bitumen (Thermal Oil)	19,875	10.55
	Synthetic Crude Oil	40,230	13.38
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	7,725	5.70
	Abandonment and Reclamation Costs – Existing Development	(790)	-
	Total	**89,027**	**11.94**

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

(2) The net present values of the future net revenue for each product type includes the forecast estimates of abandonment and reclamation costs attributable to future development activity. The net present value of the future net revenue for the "Abandonment and Reclamation Costs – Existing Development" contains certain costs already included in the Company's ARO for development existing as at December 31, 2015, which are not applied at the product type level.

Pricing Assumptions

The crude oil, natural gas and NGLs 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, 2015. The following is a summary of the Sproule price forecast.

	2016	2017	2018	2019	2020	Average annual increase thereafter
Crude Oil and NGLs						
WTI[1] (US$/bbl)	$ 45.00	$ 60.00	$ 70.00	$ 80.00	$ 81.20	1.50%
WCS[2] (C$/bbl)	$ 45.26	$ 57.96	$ 65.88	$ 75.11	$ 77.03	1.50%
Canadian Light Sweet[3] (C$/bbl)	$ 55.20	$ 69.00	$ 78.43	$ 89.41	$ 91.71	1.50%
Cromer LSB[4] (C$/bbl)	$ 54.20	$ 68.00	$ 77.43	$ 88.41	$ 90.71	1.50%
Edmonton C5+[5] (C$/bbl)	$ 59.10	$ 73.88	$ 83.98	$ 95.73	$ 98.19	1.50%
North Sea Brent[6] (US$/bbl)	$ 45.00	$ 60.00	$ 70.00	$ 80.00	$ 81.20	1.50%
Natural Gas						
AECO[7] (C$/MMBtu)	$ 2.25	$ 2.95	$ 3.42	$ 3.91	$ 4.20	1.50%
BC Westcoast Station 2[8] (C$/MMBtu)	$ 1.45	$ 2.55	$ 3.02	$ 3.51	$ 3.80	1.50%
Henry Hub[9] (US$/MMBtu)	$ 2.25	$ 3.00	$ 3.50	$ 4.00	$ 4.25	1.50%

(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) "Canadian Light Sweet" refers to the price of light gravity (40˚ API), low sulphur content Mixed Sweet Blend (MSW) crude oil at Edmonton, Alberta; reference price used in the preparation of light and medium crude oil and SCO reserves.

(4) "Cromer LSB" refers to the price of light sour blend (35˚ API) physical crude oil at Cromer, Manitoba; reference price used in the preparation of light and medium crude oil in SE Saskatchewan and SW Manitoba reserves.

(5) "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.

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

(7) "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.

(8) "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.

(9) "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 0.7500 US$/C$ for 2016, 0.8000 US$/C$ for 2017, 0.8300 US$/C$ for 2018 and 0.8500 US$/C$ after 2018 was used in the 2015 evaluation.

Production costs are escalated at Sproule's cost inflation rate of 0% per year for 2016 to 2017 and 1.5% per year after 2017 for all products. Capital costs are escalated at Sproule's cost inflation rate of 0% per year for 2016, 4% per year for 2017 to 2019 and 1.5% per year after 2019 for North America light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil and natural gas. Capital costs are escalated at Sproule's cost inflation rate of 1.5% per year for bitumen (thermal oil), SCO and International light and medium crude oil.

The Company's 2015 average pricing, net of blending costs and excluding risk management activities, was $59.72/bbl for light and medium crude oil, $40.71/bbl for primary heavy crude oil, $41.09/bbl for Pelican Lake heavy crude oil, $34.37/bbl for bitumen (thermal oil), $61.39/bbl for SCO, $23.30/bbl for NGLs and $3.16/Mcf for natural gas.

Reconciliation of Company Gross Reserves

As of December 31, 2015
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, 2014	145	229	274	1,217	2,158	5,869	188	5,189
Discoveries	1	-	-	-	-	14	2	5
Extensions	1	4	-	23	220	252	10	300
Infill Drilling	4	10	-	-	-	298	7	71
Improved Recovery	-	-	2	26	-	-	-	28
Acquisitions	5	4	-	7	-	414	8	93
Dispositions	(3)	-	-	-	-	(7)	-	(4)
Economic Factors	(6)	(3)	-	-	7	(385)	(6)	(72)
Technical Revisions	10	16	10	(1)	68	190	1	135
Production	(19)	(47)	(18)	(47)	(45)	(607)	(15)	(292)
December 31, 2015	**138**	**213**	**268**	**1,225**	**2,408**	**6,038**	**195**	**5,453**

North Sea

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2014	204	83	218
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	(2)	(7)	(3)
Technical Revisions	(36)	(24)	(40)
Production	(8)	(13)	(10)
December 31, 2015	**158**	**39**	**165**

Offshore Africa

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2014	96	49	104
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	1	-	1
Technical Revisions	-	(10)	(1)
Production	(7)	(10)	(9)
December 31, 2015	**90**	**29**	**95**

Total Company

Total Company	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, 2014	445	229	274	1,217	2,158	6,001	188	5,511
Discoveries	1	-	-	-	-	14	2	5
Extensions	1	4	-	23	220	252	10	300
Infill Drilling	4	10	-	-	-	298	7	71
Improved Recovery	-	-	2	26	-	-	-	28
Acquisitions	5	4	-	7	-	414	8	93
Dispositions	(3)	-	-	-	-	(7)	-	(4)
Economic Factors	(7)	(3)	-	-	7	(392)	(6)	(74)
Technical Revisions	(26)	16	10	(1)	68	156	1	94
Production	(34)	(47)	(18)	(47)	(45)	(630)	(15)	(311)
December 31, 2015	**386**	**213**	**268**	**1,225**	**2,408**	**6,106**	**195**	**5,713**

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, 2014	58	88	121	1,095	1,435	2,057	70	3,210
Discoveries	-	-	-	-	-	3	-	1
Extensions	1	2	-	88	(175)	106	5	(61)
Infill Drilling	4	3	-	-	-	444	22	103
Improved Recovery	-	-	1	14	-	1	-	15
Acquisitions	1	1	-	2	-	101	2	23
Dispositions	(2)	-	-	-	-	(2)	-	(3)
Economic Factors	-	-	-	-	-	(117)	(2)	(22)
Technical Revisions	(8)	(13)	(2)	(17)	(35)	(293)	(9)	(132)
Production	-	-	-	-	-	-	-	-
December 31, 2015	**54**	**81**	**120**	**1,182**	**1,225**	**2,300**	**88**	**3,134**

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2014	104	31	109
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	7	1
Technical Revisions	22	19	25
Production	-	-	-
December 31, 2015	**126**	**57**	**135**

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2014	53	49	61
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	(1)	1	(1)
Technical Revisions	-	(5)	(1)
Production	-	-	-
December 31, 2015	**52**	**45**	**59**

Total Company	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, 2014	215	88	121	1,095	1,435	2,137	70	3,380
Discoveries	-	-	-	-	-	3	-	1
Extensions	1	2	-	88	(175)	106	5	(61)
Infill Drilling	4	3	-	-	-	444	22	103
Improved Recovery	-	-	1	14	-	1	-	15
Acquisitions	1	1	-	2	-	101	2	23
Dispositions	(2)	-	-	-	-	(2)	-	(3)
Economic Factors	(1)	-	-	-	-	(109)	(2)	(22)
Technical Revisions	14	(13)	(2)	(17)	(35)	(279)	(9)	(108)
Production	-	-	-	-	-	-	-	-
December 31, 2015	**232**	**81**	**120**	**1,182**	**1,225**	**2,402**	**88**	**3,328**

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, 2014	203	317	395	2,312	3,593	7,926	258	8,399
Discoveries	1	-	-	-	-	17	2	6
Extensions	2	6	-	111	45	358	15	239
Infill Drilling	8	13	-	-	-	742	29	174
Improved Recovery	-	-	3	40	-	1	-	43
Acquisitions	6	5	-	9	-	515	10	116
Dispositions	(5)	-	-	-	-	(9)	-	(7)
Economic Factors	(6)	(3)	-	-	7	(502)	(8)	(94)
Technical Revisions	2	3	8	(18)	33	(103)	(8)	3
Production	(19)	(47)	(18)	(47)	(45)	(607)	(15)	(292)
December 31, 2015	**192**	**294**	**388**	**2,407**	**3,633**	**8,338**	**283**	**8,587**

North Sea

December 31, 2014	308					114		327
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	(2)					-		(2)
Technical Revisions	(14)					(5)		(15)
Production	(8)					(13)		(10)
December 31, 2015	**284**					**96**		**300**

Offshore Africa

December 31, 2014	149					98		165
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					1		-
Technical Revisions	-					(15)		(2)
Production	(7)					(10)		(9)
December 31, 2015	**142**					**74**		**154**

Total Company

December 31, 2014	660	317	395	2,312	3,593	8,138	258	8,891
Discoveries	1	-	-	-	-	17	2	6
Extensions	2	6	-	111	45	358	15	239
Infill Drilling	8	13	-	-	-	742	29	174
Improved Recovery	-	-	3	40	-	1	-	43
Acquisitions	6	5	-	9	-	515	10	116
Dispositions	(5)	-	-	-	-	(9)	-	(7)
Economic Factors	(8)	(3)	-	-	7	(501)	(8)	(96)
Technical Revisions	(12)	3	8	(18)	33	(123)	(8)	(14)
Production	(34)	(47)	(18)	(47)	(45)	(630)	(15)	(311)
December 31, 2015	**618**	**294**	**388**	**2,407**	**3,633**	**8,508**	**283**	**9,041**

(1) Discoveries are additions to reserves in reservoirs where no reserves were previously booked.
(2) Extensions are additions to reserves resulting from step-out drilling or recompletions.
(3) Infill Drilling are additions to reserves resulting from drilling or recompletions within the known boundaries of a reservoir.
(4) Improved Recovery are additions to reserves resulting from the implementation of improved recovery schemes.
(5) Negative volumes, if any, for probable reserves result from the transfer of probable reserves to proved reserves. If reserves previously assigned to a discovery, an extension, an infill drilling, or an improved recovery reserves change category are initially classified as probable, they may be classified as a proved addition, in the same reserves change category, in the year when the reserves are reclassified as proved.
(6) Economic Factors are changes primarily due to price forecasts.
(7) Technical Revisions include changes in previous estimates resulting from new technical data or revised interpretations.

At December 31, 2015, the company gross proved crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 4,695 MMbbl, and company gross proved plus probable crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 7,623 MMbbl. Proved reserve additions and revisions replaced 189% of 2015 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 331 MMbbl, and additions to proved plus probable reserves amounted to 300 MMbbl. Net positive revisions amounted to 59 MMbbl for proved reserves and net negative revisions amounted to 6 MMbbl for proved plus probable reserves, primarily due to technical revisions to prior estimates.

At December 31, 2015, the company gross proved natural gas reserves totaled 6,106 Bcf, and company gross proved plus probable natural gas reserves totaled 8,508 Bcf. Proved reserve additions and revisions replaced 117% of 2015 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 971 Bcf, and additions to proved plus probable reserves amounted to 1,624 Bcf. Net negative revisions amounted to 236 Bcf for proved reserves and 624 Bcf for proved plus probable reserves, primarily due to economic factors.

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 IQRE in accordance with the procedures and standards contained in the COGE Handbook.

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)
2013								
First Attributed	3	20	2	-	-	180	13	68
Total	251	98	41	746	363	1,170	43	1,737
2014								
First Attributed	7	13	-	91	-	653	36	256
Total	264	82	39	846	189	1,741	87	1,797
2015								
First Attributed	3	4	-	29	125	487	15	257
Total	201	81	42	874	125	1,931	90	1,735

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)
2013								
First Attributed	3	16	-	16	-	267	20	100
Total	145	50	22	1,001	978	744	42	2,362
2014								
First Attributed	7	7	-	44	358	343	18	491
Total	155	44	23	1,083	1,326	864	40	2,815
2015								
First Attributed	4	3	-	90	4	507	26	212
Total	164	46	26	968	1,043	1,176	57	2,500

Bitumen (thermal oil) accounts for approximately 50% of the Company's total proved undeveloped BOE reserves and 39% 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 approximately 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 approximately 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, 2015.

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$)	Proved plus Probable (MM$)
2016	2,962	3,048	139	139	184	341	3,285	3,528
2017	2,962	3,167	487	498	43	43	3,492	3,708
2018	3,353	3,701	525	593	11	11	3,889	4,305
2019	2,746	3,237	374	440	195	242	3,315	3,919
2020	2,351	2,554	261	400	42	42	2,654	2,996
Thereafter	29,537	45,933	2,264	3,254	283	348	32,084	49,535
Total	**43,911**	**61,640**	**4,050**	**5,324**	**758**	**1,027**	**48,719**	**67,991**

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

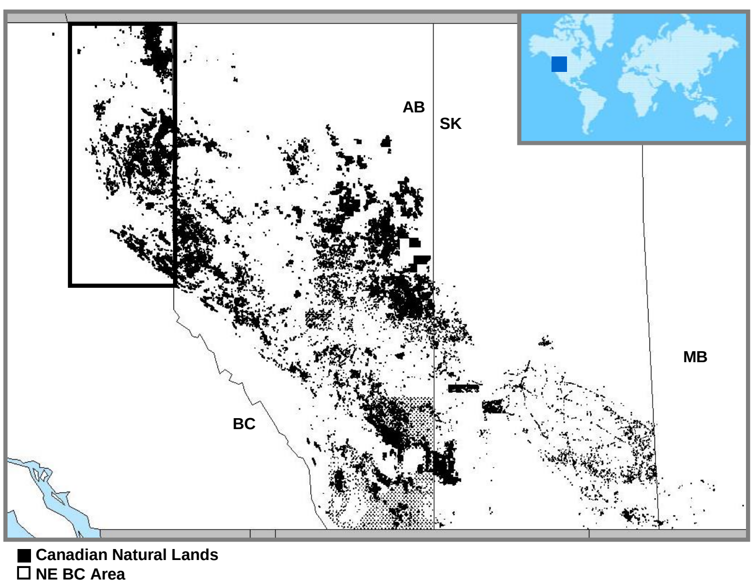
Other Oil and Gas Information

Daily Production

Set forth below is a summary of the production, before royalties, from crude oil, natural gas and NGLs properties for the fiscal years ended December 31, 2015 and 2014.

	2015 Average Daily Production Rates		2014 Average Daily Production Rates	
Region	**Crude Oil & NGLs (Mbbl)**	**Natural Gas (MMcf)**	Crude Oil & NGLs (Mbbl)	Natural Gas (MMcf)
North America				
Northeast British Columbia	**17**	**521**	17	494
Northwest Alberta	**42**	**679**	39	624
Northern Plains	**321**	**222**	315	217
Southern Plains	**14**	**238**	13	190
Southeast Saskatchewan	**6**	**3**	7	2
Oil Sands Mining & Upgrading	**123**	**-**	111	-
North America Total	**523**	**1,663**	502	1,527
International				
North Sea UK Sector	**22**	**36**	17	7
Offshore Africa	**19**	**27**	12	21
International Total	**41**	**63**	29	28
Company Total	**564**	**1,726**	531	1,555

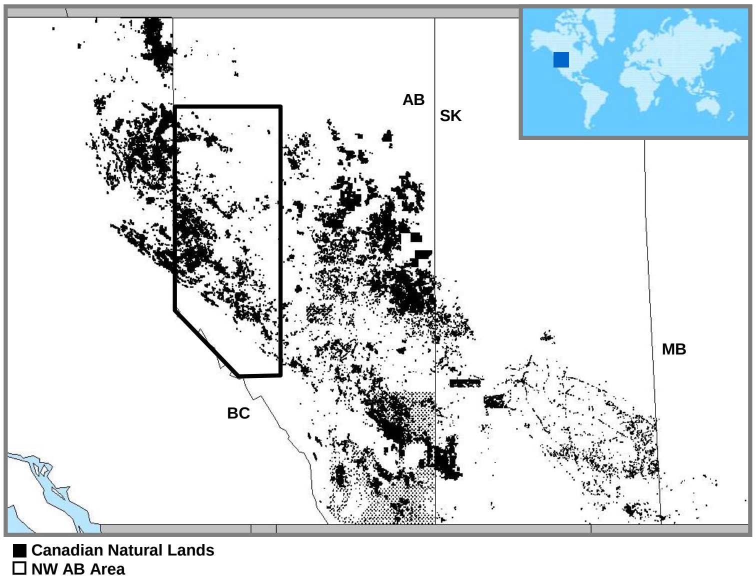
Northeast British Columbia



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

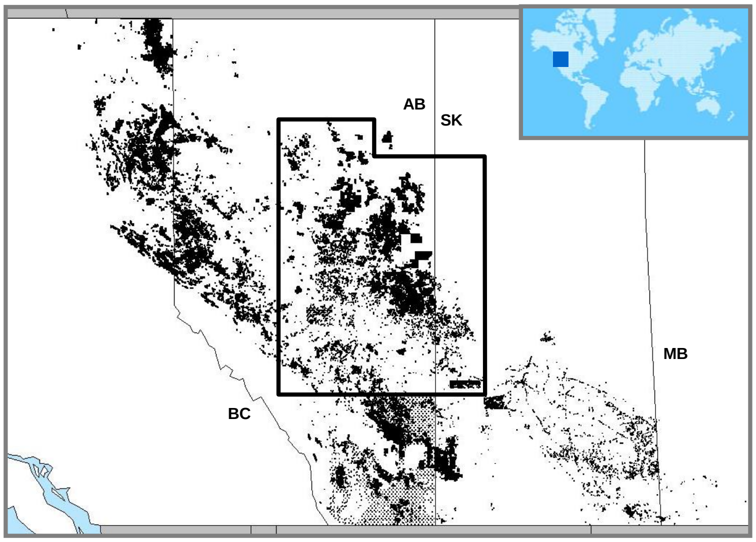
Crude oil reserves are found primarily in the Halfway formation, while natural gas and associated NGLs are found in numerous carbonate and sandstone formations at depths up to 4,500 vertical meters. The exploration strategy focuses on comprehensive evaluation through two dimensional seismic, three dimensional 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 gas plays. 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. In 2013, a plant expansion was completed and production capacity of 145 MMcf/d and 11,000 bbl/d of liquids was achieved in 2014 with the completion of new wells. During 2014, the Company acquired additional production and land in the area. The southern portion of this region encompasses the Company's BC Foothills assets where natural gas is produced from the deep Mississippian and Triassic aged reservoirs in this highly deformed structural area.

Northwest Alberta



This region is located along the border of British Columbia and Alberta west of Edmonton, Alberta. 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. Northwest Alberta provides exploration and exploitation opportunities in combination with an extensive owned and operated infrastructure. In this region, the Company 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 continues to pursue development of 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



■ Canadian Natural Lands
□ Northern Plains Area

This region extends just south of Edmonton, Alberta and north to Fort McMurray, Alberta and from the Northwest Alberta region 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, light crude oil and NGLs 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 gas exploration in this area. During 2014, the Company acquired additional production and land in the 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 acquisitions. 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 87,000 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.

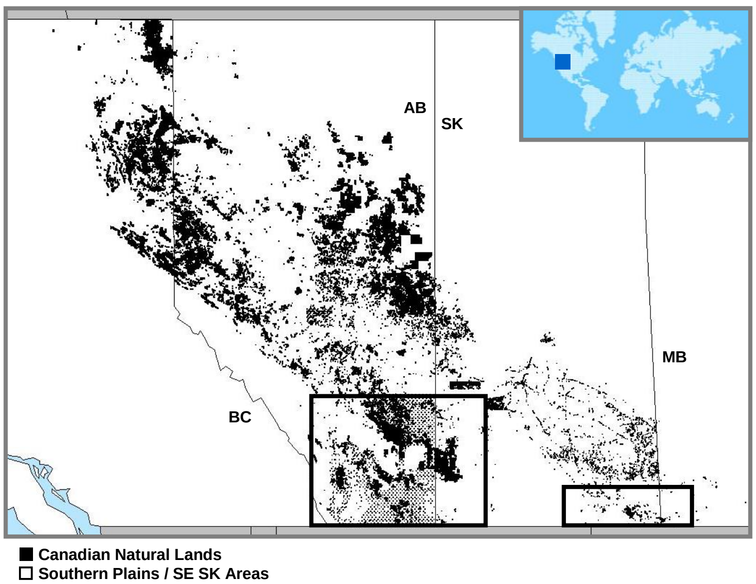
Included in the northern part of this region, approximately 200 miles north of Edmonton, Alberta are the Company's holdings at Pelican Lake. These assets produce Pelican Lake heavy crude oil from the Wabasca formation with gravities of 12°-17° API. Production costs are low due to the absence of sand production and its associated disposal requirements, as well as the gathering and pipeline facilities in place. The Company has the major ownership position in the necessary infrastructure, 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. A 20,000 bbl/d battery was completed in the first half of 2013. The Company is using an EOR scheme through polymer flooding to increase the ultimate recoveries from the field. At the end of 2015, approximately 56% of the field had been converted to polymer injection.

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. In order to expand its pipeline infrastructure the Company participated in the expansion of the Cold Lake pipeline system and commissioning was completed on the expansion in the first quarter of 2015. 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. The Company continues to optimize the CSS process which results in a significant improvement in well productivity and in ultimate bitumen recovery.

During 2013, the Company discovered bitumen emulsion at surface in areas of the Primrose field. The Company continues to work with the regulator on the causation review of the bitumen emulsion seepage. The Company's near-term steaming plan at Primrose has been modified, with steaming being reduced in certain areas.

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. First steam injection was achieved at Kirby South in September 2013. 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 Expansion Project"). The Kirby North Phase 1 project received all regulatory permits with facility construction commencing in the third quarter of 2014. In 2015, in response to declining commodity prices, the Company chose to temporarily delay spending on major construction activities on the Kirby North Project. The overall project is 46% complete.

Southern Plains and Southeast Saskatchewan



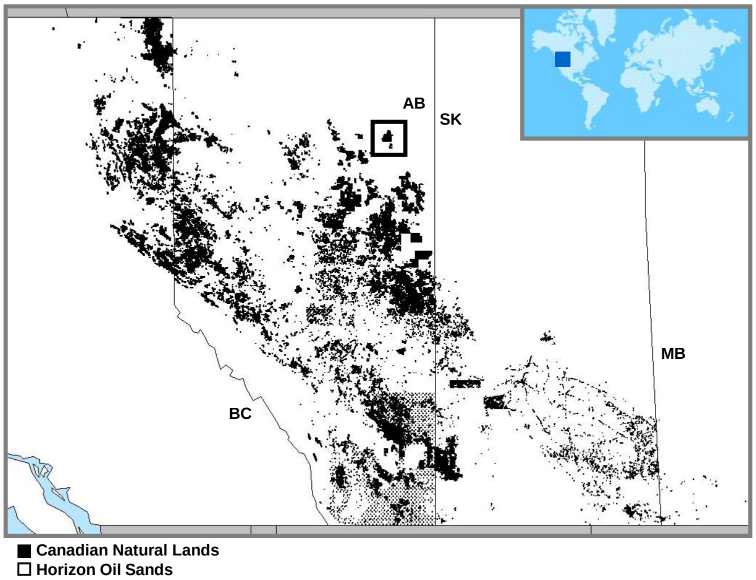
The Southern Plains region is principally located south of the Northern Plains region to the United States border and extending into western Saskatchewan.

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 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 area 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. 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, Alberta. 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 34ºAPI SCO. The SCO is transported from the site by a 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.

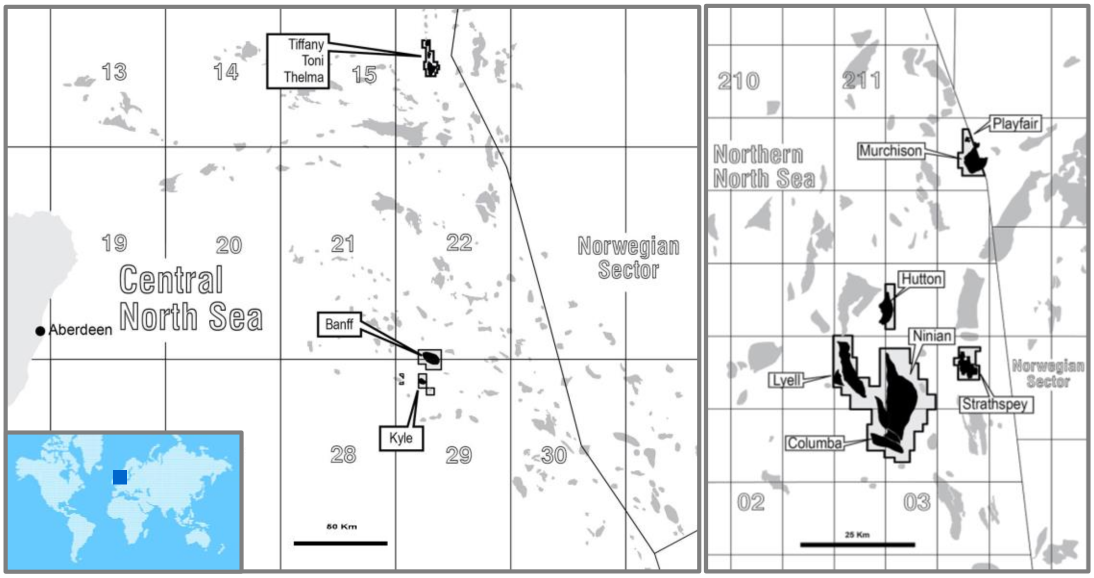
Site clearing and pre-construction preparation activities commenced in 2004 following regulatory approvals and the Company received project sanction by the Board of Directors in February 2005, authorizing management to proceed with Phase 1 of Horizon. First SCO production was achieved during 2009 and production averaged 122,911 bbl/day in 2015.

In September 2014, the Company successfully completed the expansion of the Coker Plant (Phase 2A) increasing plant name plate capacity to 137,000 bbl/d.

At year-end 2015, Phase 2B and Phase 3 are 79% and 74% physically complete, respectively. Phase 2/3 expansion activity in 2015 continued to focus on field construction of the hydrogen unit, hydrotreater unit, vacuum distillation unit and distillation recovery unit, tank farms, tailings re-handling plant, froth treatment, froth tank, tailings transfer pumphouses and pipelines, extraction plant, ore preparation plants, and superpot along with engineering, procurement and construction related to tailings retrofit, sour water concentrator, combined hydrotreater and sulphur recovery units. In addition, the new extraction trains 3 and 4 were commissioned.

The Company targets to complete Phase 2B in 2016. Overall project completion is anticipated to be fourth quarter of 2017 and is targeted to increase Horizon SCO production to 250,000 bbl/d.

United Kingdom North Sea



Canadian Natural Lands – Central North Sea
Crude Oil and Natural Gas Fields

Canadian Natural Lands – Northern North Sea
Crude Oil and Natural Gas Fields

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 2015, the Company produced from 10 crude oil fields.

The northerly fields are centered around the Ninian field where the Company has an 87.1% operated 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 acquired an additional 67.0% working interest in the Strathspey field in July 2013 and assumed operatorship of the field with total working interest of 73.5%. The Company also has an interest in 7 licences covering 10 blocks and part blocks surrounding the Ninian and Murchison platforms and 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.

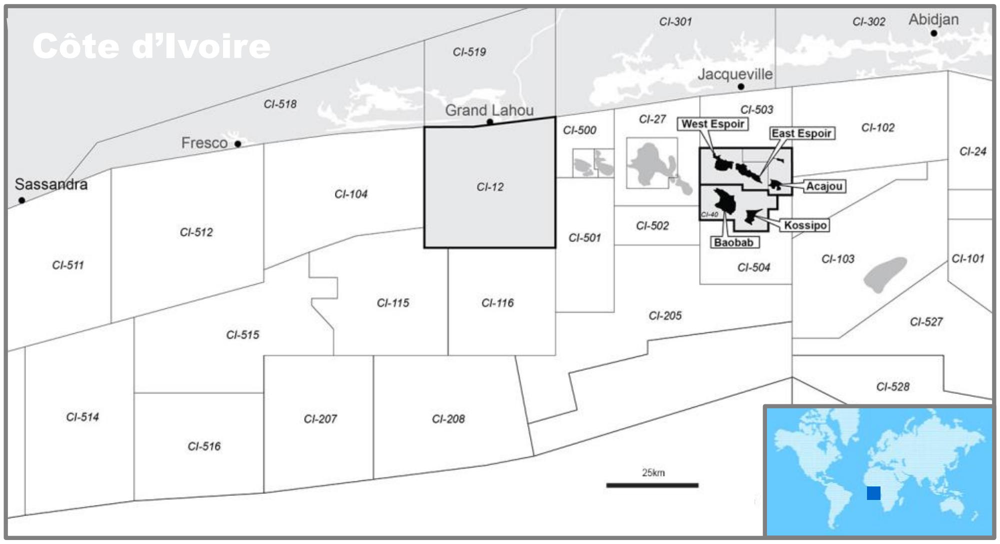
In 2013, the Company received Brownfield Allowance approvals for the Tiffany and Ninian fields. The Company completed two wells at the Tiffany field in 2013 and five wells at the Ninian field in 2014.

The decommissioning activities at the Murchison platform commenced in the fourth quarter of 2013 and cessation of production occurred in the first quarter of 2014. The decommissioning activities are ongoing and are expected to continue for approximately 5 years.

During 2015, the Company completed one injection well and no further drilling activities are currently planned for 2016.

Offshore Africa

Côte d'Ivoire



Canadian Natural Lands – Côte d'Ivoire
Crude Oil and Natural Gas Fields

The Company owns interests in three exploration licences offshore Côte d'Ivoire.

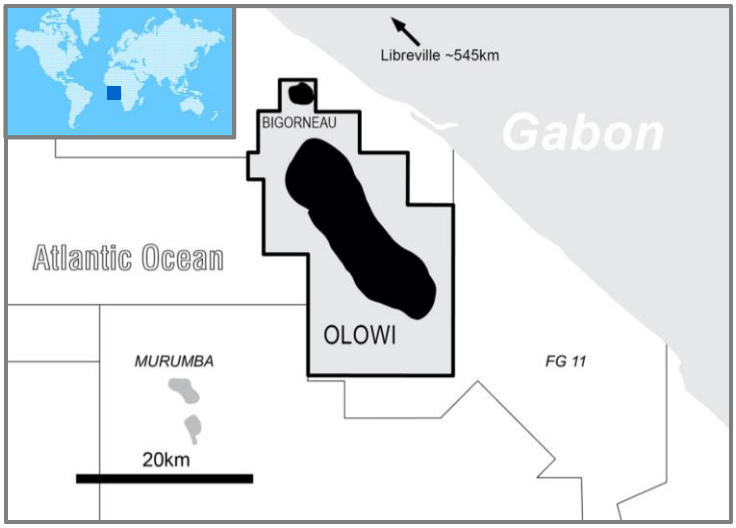
The Company has a 58.7% operated interested in the Espoir field in Block CI-26 which is located in water depths ranging from 100 to 700 meters. Production from East Espoir commenced in 2002 and development drilling of West Espoir was completed in 2008. Crude oil from the East and West Espoir fields is produced to an FPSO with the associated natural gas delivered onshore through a subsea pipeline for local power generation. In 2014, the Company contracted a drilling rig for a 10 gross well development program. During 2015, the Company drilled 5 gross producing wells and 1 injector well. In 2016, upon completion of the sixth gross producing well, no additional wells will be drilled in the program.

The Company has a 57.6% operated 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. During 2015, the Company drilled 5 gross producing wells. In late December, the Baobab field was temporarily shut-in due to a riser failure, delaying first oil on the fifth gross producing well. After inspection of the riser system, production was reinstated in late January 2016. In 2016, upon completion of the sixth gross producing well, no additional wells will be drilled in the program.

In 2012, the Company acquired a 36% non-operated working interest in Block CI-514. During the fourth quarter of 2015, the Company provided notice of its withdrawal from Block CI-514 in Côte d'Ivoire, Offshore Africa.

In 2013, the Company acquired a 60% operated working interest in Block CI-12 which is prospective for deepwater channel/fan structures. The block is located approximately 35 kilometers west of the Company's current production at Espoir and Baobab. A 3D seismic program has been completed and the data is currently being assessed to determine whether to drill an exploration well.

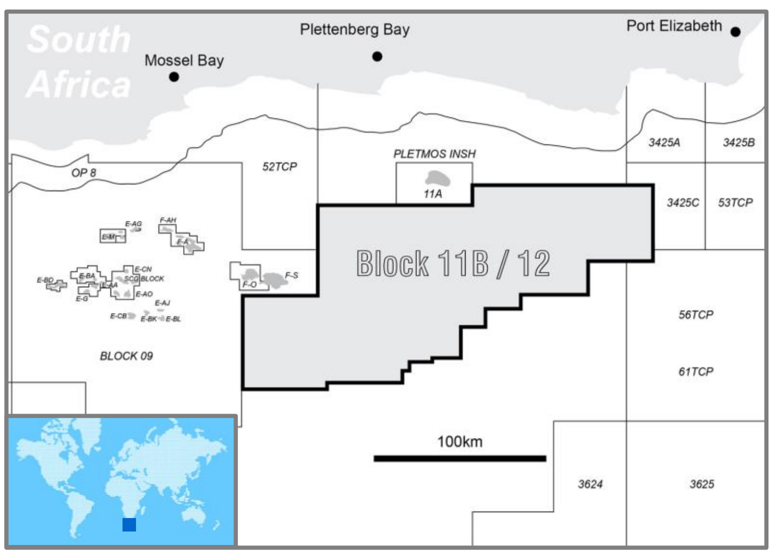
Gabon



■ Canadian Natural Lands – Gabon
■ Crude Oil and Natural Gas Fields

The Company has a permit comprising a 92% 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. The mid-water arch was stabilized and production was reinstated in late Q1 2013. The Company has no further development activities currently planned for 2016.

South Africa



■ Canadian Natural Lands – 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. During 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for net cash consideration of US$255 million. In the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US$450 million for a commercial crude oil discovery and US$120 million for a commercial natural gas discovery. In 2014, the exploration well drilled on Block 11B/12B was suspended due to mechanical issues with marine equipment on the drilling rig. The rig safely left the well location and, as the available drilling window had ended, it was demobilized by the operator. The South African authorities have formally confirmed the well drilled satisfies the work obligation for the initial period of the Block 11B/12B Exploration Right. The operator is reviewing the course of action to re-enter the well, and has indicated drilling operations are unlikely to resume in the area before 2017.

Producing and Non Producing Crude Oil and 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, 2015.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	27,968.0	21,595.6	11,167.0	9,700.2	39,135.0	31,295.8
British Columbia	2,763.0	2,200.1	313.0	269.1	3,076.0	2,469.2
Saskatchewan	10,684.0	9,675.8	3,792.0	2,381.6	14,476.0	12,057.4
Manitoba	-	-	210.0	203.6	210.0	203.6
Total Canada	41,415.0	33,471.5	15,482.0	12,554.5	56,897.0	46,026.0
United States	-	-	2.0	0.3	2.0	0.3
North Sea UK Sector	2.0	1.5	72.0	62.8	74.0	64.3
Offshore Africa						
Côte d’Ivoire	-	-	25.0	14.6	25.0	14.6
Gabon	-	-	13.0	12.0	13.0	12.0
Total	41,417.0	33,473.0	15,594.0	12,644.2	57,011.0	46,117.2

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, 2015.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Non Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	7,551.0	5,990.1	7,182.0	6,111.2	14,733.0	12,101.3
British Columbia	1,878.0	1,530.9	453.0	371.7	2,331.0	1,902.6
Saskatchewan	1,760.0	1,583.7	2,896.0	2,211.8	4,656.0	3,795.5
Manitoba	2.0	2.0	27.0	24.4	29.0	26.4
Northwest Territories	36.0	20.8	-	-	36.0	20.8
Total Canada	11,227.0	9,127.5	10,558.0	8,719.1	21,785.0	17,846.6
United States	1.0	0.1	2.0	0.3	3.0	0.4
North Sea UK Sector	2.0	1.5	25.0	23.3	27.0	24.8
Offshore Africa						
Côte d’Ivoire	-	-	10.0	5.8	10.0	5.8
Gabon	-	-	-	-	-	-
Total	11,230.0	9,129.1	10,595.0	8,748.5	21,825.0	17,877.6

Properties With Attributed and No Attributed Reserves

The following table summarizes the Company's landholdings as at December 31, 2015.

	Proved Properties		Unproved Properties		Total Acreage		Average Working Interest
Region (thousands of acres)	Gross	Net	Gross	Net	Gross	Net	%
North America							
Northeast British Columbia	1,068	881	5,043	4,240	6,111	5,121	84%
Northwest Alberta	1,726	1,235	3,940	3,076	5,666	4,311	76%
Northern Plains	2,051	1,712	8,230	7,262	10,281	8,974	87%
Southern Plains	2,562	2,148	3,003	2,554	5,565	4,702	85%
Southeast Saskatchewan	130	117	126	117	256	234	91%
Thermal In Situ Oil Sands	93	91	930	825	1,023	916	90%
Oil Sands Mining & Upgrading	24	24	57	57	81	81	100%
Non-core Regions	8	3	1,192	432	1,200	435	36%
Fee Title	90	83	842	830	932	913	98%
North America Total	**7,752**	**6,294**	**23,363**	**19,393**	**31,115**	**25,687**	**83%**
International							
North Sea UK Sector	63	55	101	93	164	148	90%
Offshore Africa							
Côte d'Ivoire	10	6	360	214	370	220	59%
Gabon	-	-	152	140	152	140	92%
South Africa	-	-	4,002	2,001	4,002	2,001	50%
International Total	**73**	**61**	**4,615**	**2,448**	**4,688**	**2,509**	**54%**
Company Total	**7,825**	**6,355**	**27,978**	**21,841**	**35,803**	**28,196**	**79%**

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, 2016.

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.

2015 Costs Incurred in Crude Oil, Natural Gas and NGLs Activities

MM$	North America	North Sea	Offshore Africa	Total
Property Acquisitions				
Proved	(556)	-	-	(556)
Unproved	(446)	-	-	(446)
Exploration	87	-	35	122
Development	2,845	13	524	3,382
	1,930	13	559	2,502
Add: Net non-cash and other costs (1)	681	217	49	947
Costs Incurred	2,611	230	608	3,449

(1) Non-cash and other costs are comprised primarily of changes in ARO as well as proceeds on disposition of properties in excess of original cost.

Exploration and Development Activities

Set forth below are summaries of crude oil, natural gas and NGLs drilling activities completed by the Company for the fiscal year ended December 31, 2015 by geographic region along with a general discussion of 2016 activity.

		2015 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	-	-	-	5.0
	Net	-	5.0	-	-	-	5.0
Northern Plains	Gross	3.0	-	-	-	-	3.0
	Net	3.0	-	-	-	-	3.0
Southern Plains	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Southeast Saskatchewan	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Oil Sands Mining and Upgrading	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Non-core Regions	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
North America Total	Gross	3.0	6.0	-	-	-	9.0
	Net	3.0	6.0	-	-	-	9.0
North Sea UK Sector	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Offshore Africa	Gross	-	-	-	-	1.0	1.0
	Net	-	-	-	-	0.4	0.4
Company Total	Gross	3.0	6.0	-	-	1.0	10.0
	Net	3.0	6.0	-	-	0.4	9.4

		2015 Development Wells					
		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	Total
North America							
Northeast British Columbia	Gross	-	2.0	-	-	-	2.0
	Net	-	2.0	-	-	-	2.0
Northwest Alberta	Gross	4.0	18.0	-	-	-	22.0
	Net	3.1	9.3	-	-	-	12.4
Northern Plains	Gross	108.0	6.0	6.0	26.0	52.0	198.0
	Net	102.8	1.9	5.8	25.5	17.0	153.0
Southern Plains	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Southeast Saskatchewan	Gross	8.0	-	-	3.0	-	11.0
	Net	0.3	-	-	-	-	0.3
Oil Sands Mining and Upgrading	Gross	-	-	-	31.0	91.0	122.0
	Net	-	-	-	31.0	91.0	122.0
Non-core Regions	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
North America Total	Gross	120.0	26.0	6.0	60.0	143.0	355.0
	Net	106.2	13.2	5.8	56.5	108.0	289.7
North Sea UK Sector	Gross	-	-	-	1.0	-	1.0
	Net	-	-	-	0.9	-	0.9
Offshore Africa	Gross	10.0	-	-	-	1.0	11.0
	Net	5.8	-	-	-	0.5	6.3
Company Total	Gross	130.0	26.0	6.0	61.0	144.0	367.0
	Net	112.0	13.2	5.8	57.4	108.5	296.9

Total success rate, excluding service and stratigraphic test wells, for 2015 is 96%.

2016 North America Activity

The Company maintains capital flexibility to increase or decrease activity in the conventional operations depending on the economic and pricing environment. Capital expenditures for North America are targeted to be approximately $1,085-1,335 million.

2016 Oil Sands Mining and Upgrading Activity

The Company targets to complete Phase 2B in 2016 and continue to progress Phase 3 construction. Overall capital expenditures for Horizon are targeted to be approximately $2,415-2,565 million.

2016 North Sea Activity

No further drilling activities are currently planned for 2016.

2016 Offshore Africa Activity

In 2016, upon completion of the sixth gross producing well at each field, no additional wells will be drilled for either the Espoir or Baobab programs.

Production Estimates

The following table illustrates Canadian Natural's estimated 2016 company gross daily proved and probable production reflected in the reserve reports as of December 31, 2015 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	41,822	101,546	49,500	121,126	116,900	1,432	39,368	708,928
North Sea	20,587	-	-	-	-	46	-	28,254
Offshore Africa	25,828	-	-	-	-	27	-	30,328
Total Proved	88,237	101,546	49,500	121,126	116,900	1,505	39,368	767,510
PROBABLE								
North America	2,442	8,870	1,747	18	9,850	73	1,821	36,915
North Sea	2,060	-	-	-	-	3	-	2,560
Offshore Africa	4,328	-	-	-	-	3	-	4,828
Total Probable	8,830	8,870	1,747	18	9,850	79	1,821	44,303

Production History

	2015				
	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)	55,382	51,454	49,599	48,773	51,279
Netbacks ($/bbl)					
Sales price [2]	$ 50.55	$ 69.64	$ 55.33	$ 50.12	$ 56.39
Transportation	3.56	3.72	3.42	3.44	3.54
Royalties	6.30	7.29	6.56	6.90	6.75
Production expenses	22.06	20.72	19.52	19.14	20.41
Netback	**$ 18.63**	**$ 37.91**	**$ 25.83**	**$ 20.64**	**$ 25.69**
Primary Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	137,687	128,781	125,662	120,269	128,046
Netbacks ($/bbl)					
Sales price [2]	$ 37.64	$ 53.85	$ 39.97	$ 31.14	$ 40.71
Transportation	2.99	3.03	2.98	3.01	3.00
Royalties	3.32	6.05	3.22	2.86	3.86
Production expenses	17.21	14.92	13.81	13.90	15.01
Netback	**$ 14.12**	**$ 29.85**	**$ 19.96**	**$ 11.37**	**$ 18.84**
Pelican Lake Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	51,085	52,015	50,852	49,340	50,818
Netbacks ($/bbl)					
Sales price [2]	$ 36.21	$ 54.87	$ 39.54	$ 33.25	$ 41.09
Transportation	3.49	4.07	3.61	4.36	3.88
Royalties	6.47	10.24	5.45	5.27	6.88
Production expenses	8.62	6.98	6.64	6.75	7.24
Netback	**$ 17.63**	**$ 33.58**	**$ 23.84**	**$ 16.87**	**$ 23.09**
Bitumen (Thermal Oil)					
Average daily production (before royalties) (bbl/d)	146,086	105,018	133,183	135,135	129,835
Netbacks ($/bbl)					
Sales price [2]	$ 30.25	$ 44.63	$ 37.46	$ 27.92	$ 34.37
Transportation	1.60	2.57	2.46	2.40	2.23
Royalties	3.64	6.25	4.41	2.92	4.17
Production expenses	10.64	12.18	9.74	9.59	10.43
Netback	**$ 14.37**	**$ 23.63**	**$ 20.85**	**$ 13.01**	**$ 17.54**
SCO					
Average daily production (before royalties) (bbl/d) [3]	96,607	134,166	131,779	129,050	122,911
Netbacks ($/bbl)					
Sales price [2]	$ 56.75	$ 73.05	$ 60.66	$ 57.49	$ 61.39
Transportation	1.83	1.98	1.82	1.66	1.81
Royalties [4]	1.01	0.99	1.32	0.99	1.08
Production expenses [5]	29.73	29.25	27.04	28.56	28.61
Netback	**$ 24.18**	**$ 40.83**	**$ 30.48**	**$ 26.28**	**$ 29.89**
Natural Gas					
Average daily production (before royalties) (MMcf/d)	1,713	1,716	1,592	1,635	1,663
Netbacks ($/Mcf)					
Sales price [2]	$ 3.14	$ 2.80	$ 2.99	$ 2.73	$ 2.91
Transportation	0.31	0.30	0.31	0.30	0.30
Royalties	0.12	0.05	0.11	0.10	0.09
Production expenses	1.38	1.28	1.25	1.17	1.27
Netback	**$ 1.33**	**$ 1.17**	**$ 1.32**	**$ 1.16**	**$ 1.25**

Production History

	2015				
	Q1	**Q2**	**Q3**	**Q4**	**Year Ended**
Natural Gas Liquids					
Average daily production (before royalties) (bbl/d)	42,179	37,772	38,596	41,491	40,004
Netbacks ($/bbl)					
Sales price [2]	$ 23.34	$ 27.51	$ 22.31	$ 20.37	$ 23.30
Transportation	2.02	1.88	1.33	1.06	1.57
Royalties	1.70	1.49	3.44	3.16	2.46
Production expenses	8.58	7.89	7.76	6.98	7.80
Netback	**$ 11.04**	**$ 16.25**	**$ 9.78**	**$ 9.17**	**$ 11.47**

North Sea Production and Netbacks by Product Type [1]

	Q1	**Q2**	**Q3**	**Q4**	**Year Ended**
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	23,036	20,330	22,387	23,110	22,216
Netbacks ($/bbl)					
Sales price [2]	$ 64.59	73.57	$ 62.28	$ 57.50	$ 65.13
Transportation	1.23	0.83	0.83	1.77	1.14
Royalties	0.16	0.11	0.17	0.14	0.14
Production expenses	65.23	60.61	72.69	56.97	63.67
Netback	**$ (2.03)**	**$ 12.02**	**$ (11.41)**	**$ (1.38)**	**$ 0.18**
Natural Gas					
Average daily production (before royalties) (MMcf/d)	34	38	35	36	36
Netbacks ($/Mcf)					
Sales price [2]	$ 10.18	$ 9.54	$ 9.44	$ 9.53	$ 9.66
Transportation	3.49	3.91	3.95	4.46	3.96
Royalties	-	-	-	-	-
Production Expenses	3.89	6.47	3.85	3.27	4.41
Netback	**$ 2.80**	**$ (0.84)**	**$ 1.64**	**$ 1.80**	**$ 1.29**

Offshore Africa Production and Netbacks by Product Type [1]

	Q1	**Q2**	**Q3**	**Q4**	**Year Ended**
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	13,188	17,070	21,077	24,832	19,079
Netbacks ($/bbl)					
Sales price [2]	$ 71.75	$ 74.84	$ 65.31	$ 53.37	$ 63.13
Transportation	-	-	-	-	-
Royalties	3.27	3.19	2.89	2.61	2.87
Production expenses	15.46	43.88	40.53	26.08	33.32
Netback	**$ 53.02**	**$ 27.77**	**$ 21.89**	**$ 24.68**	**$ 26.94**
Natural Gas					
Average daily production (before royalties) (MMcf/d)	24	25	26	32	27
Netbacks ($/Mcf)					
Sales price [2]	$ 11.70	$ 10.49	$ 9.01	$ 7.63	$ 9.53
Transportation	0.16	0.16	0.17	0.18	0.17
Royalties	0.54	0.48	0.41	0.44	0.46
Production expenses	2.80	1.42	1.43	1.55	1.76
Netback	**$ 8.20**	**$ 8.43**	**$ 7.00**	**$ 5.46**	**$ 7.14**

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) 2015 SCO production before royalties excludes 2,122 bbl/d of SCO consumed internally as diesel.
(4) Calculated based on actual bitumen royalties expensed during the year; divided by the corresponding SCO sales volumes.
(5) Adjusted cash production costs on a per unit basis are based on sales volumes excluding turnaround periods.

SELECTED FINANCIAL INFORMATION

(MM$, except per common share information)	Year Ended December 31 2015	2014
Product sales	$ **13,167**	$ 21,301
Net earnings (loss)	$ **(637)**	$ 3,929
Per common share – basic	$ **(0.58)**	$ 3.60
– diluted	$ **(0.58)**	$ 3.58
Adjusted net earnings from operations (1)	$ **263**	$ 3,811
Per common share – basic	$ **0.24**	$ 3.49
– diluted	$ **0.24**	$ 3.47
Cash flow from operations (1)	$ **5,785**	$ 9,587
Per common share – basic	$ **5.29**	$ 8.78
– diluted	$ **5.28**	$ 8.74
Dividends declared per common share	$ **0.92**	$ 0.90
Total assets	$ **59,275**	$ 60,200
Total long-term liabilities	$ **27,299**	$ 26,167
Capital expenditures, net of dispositions	$ **3,853**	$ 11,744

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

DIVIDEND HISTORY

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 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.

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

	2015(1)	2014	2013
Cash dividends declared per common share	$ **0.92**	$ 0.90	$ 0.575

(1) On December 31, 2015, the Company paid the dividend it would historically have paid on January 1st of the following year. As a result, the actual dividends paid in 2015 were $1.145 per common share.

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. 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 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 AIF.

	Senior Unsecured Debt Securities	Commercial Paper	Outlook/Trend(1)
Moody's Investors Service, Inc. ("Moody's") (2)	Baa3	P-3	Negative
Standard & Poor's Rating Services ("S&P")	BBB+	A-2	Stable
DBRS Limited ("DBRS") (2)	BBB (high)	-	Negative

(1) Moody's and S&P assign a rating outlook to Canadian Natural and not to individual long-term debt instruments.
(2) The above rating and outlook of Moody's reflect changes made in February 2016 and the outlook of DBRS reflects a change made in January 2016.

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. A negative, positive or developing outlook indicates a higher likelihood of a rating change 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-3 by Moody's is the third highest of four categories and indicates an acceptable 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 obligation. 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 typically six months to two years. A "Stable" outlook indicates that a rating is not likely to change during that time period. 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 seven categories and indicates that the obligor is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in the highest rating category, 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 in question, with rating trends falling into one of three categories – "Positive", "Stable", or "Negative. The rating trend indicates the direction in which DBRS considers the rating may move if present circumstances continue, or in certain cases, unless challenges are addressed.

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 2015.

2015 Monthly Historical Trading on TSX

Month	High	Low	Close	Volume Traded
January	$ 37.24	$ 31.20	$ 36.84	76,468,663
February	$ 40.80	$ 36.36	$ 36.36	50,169,720
March	$ 39.51	$ 35.37	$ 38.82	61,417,637
April	$ 42.46	$ 38.70	$ 40.09	44,459,484
May	$ 40.38	$ 37.30	$ 38.38	42,261,245
June	$ 38.78	$ 33.61	$ 33.90	49,860,822
July	$ 34.01	$ 29.95	$ 31.92	53,981,483
August	$ 33.57	$ 25.01	$ 29.65	68,168,213
September	$ 29.38	$ 25.47	$ 25.99	71,185,316
October	$ 32.69	$ 25.32	$ 30.32	89,804,865
November	$ 34.51	$ 29.91	$ 32.34	60,772,620
December	$ 32.57	$ 27.71	$ 30.22	59,483,109

During 2015, the Company did not purchase common shares under its previously filed Normal Course Issuer Bid.

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. Further detail on the Directors and Named Executive Officers are found in the Company's Information Circular dated March 16, 2016 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 62)	Corporate director. 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, Aston Hill Financial Inc., Badger Daylighting Ltd. 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 and serves as a volunteer member of the Audit Committee of the Calgary Stampede.
N. Murray Edwards, O.C. London, United Kingdom	Executive Chairman and Director (5) (age 56)	Corporate director and investor. He has served continuously as a director of the Company since September 1988. Prior to December 2015, he was President of Edco Financial Holdings Ltd. (private management and consulting company). Currently, he is Chairman and serving on the board of directors of Ensign Energy Services Inc. and Magellan Aerospace Corporation.
Timothy W. Faithfull London, United Kingdom	Director (1)(3) (age 71)	Corporate director. He has served continuously as a director of the Company since November 2010. He is Chairman of the Starehe Endowment Fund in the UK and sits as a Council Member of the Canada – UK Colloquia. He is currently serving on the board of directors of TransAlta Corporation, ICE Futures Europe and LIFFE Administration and Management.
Honourable Gary A. Filmon, P.C., O.C., O.M. Winnipeg, Manitoba Canada	Director (1)(4) (age 73)	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 Arctic Glacier Income Trust, and Exchange Income Corporation.
Christopher L. Fong Calgary, Alberta Canada	Director (3)(5) (age 66)	Corporate director. 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 is currently serving on the board of directors of Anderson Energy Inc., Computer Modelling Group Ltd. and sits on the Petroleum Advisory Committee of the Alberta Securities Commission.
Ambassador Gordon D. Giffin Atlanta, Georgia U.S.A	Director (1)(4) (age 66)	Partner, Dentons US LLP (law firm); prior thereto Senior Partner, McKenna Long & Aldridge LLP (law firm) from May 2001 until its merger with Dentons in 2015. 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, Element Financial Corporation, and TransAlta Corporation.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Wilfred A. Gobert Calgary, Alberta Canada	Director (2)(4)(5) (age 68)	Independent businessman. He has served continuously as a director since November 2010. He is currently serving on the board of directors of Gluskin Sheff & Associates and Trilogy Energy Corp.
Steve W. Laut Calgary, Alberta Canada	President and Director (3) (age 58)	Officer of the Company. He has served continuously as a director of the Company since August 2006.
Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C. Cap Pelé, New Brunswick Canada	Director (2)(4) (age 68)	Deputy Chair, TD Bank Group. 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.
David A. Tuer Calgary, Alberta Canada	Director (1)(5) (age 66)	Chairman, Optiom Inc. (private insurance company); prior thereto, from 2010 to 2015, the 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. from 2008 to 2010. Prior thereto he was Chairman, Calgary Health Region from 2001 to 2008. He has served continuously as a director of the Company since May 2002.
Annette M. Verschuren, O.C. Toronto, Ontario Canada	Director(2)(3) (age 59)	Ms. A. M. Verschuren is the Chair and Chief Executive Officer of NRStor Inc., an energy storage project developer of energy storage technologies. She has served as a director of the Corporation since November 2014. She was President of The Home Depot Canada from 1996 to 2011 where she oversaw the company's successful growth in Canada leading to its entry into China. She currently serves as Chancellor of Cape Breton University and as a director of Liberty Mutual Insurance Group and a board member of numerous non-profit organizations. Currently serving on the board of directors of Air Canada and Saputo Inc.
Troy J.P. Anderson Calgary, Alberta Canada	Vice-President, West Conventional Operations (age 37)	Officer of the Company since January 2015; prior thereto UK1 Production Manager from March 2009 to July 2011, Production Manager from July 2011 to October 2013 and most recently Northern Operations Manager from October 2013 to January 2015.
Jeffrey J. Bergeson Calgary, Alberta Canada	Vice-President, Exploitation West (age 59)	Officer of the Company.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Corey B. Bieber Calgary, Alberta Canada	Chief Financial Officer and Senior Vice-President, Finance (age 52)	Officer of the Company.
Bryan C. Bradley Calgary, Alberta Canada	Vice-President, Marketing (age 50)	Officer of the Company since November 2011; prior thereto Manager Crude Oil Marketing from November 2006 to November 2011.
Trevor J. Cassidy Calgary, Alberta Canada	Vice-President, Production Central (age 42)	Officer of the Company since August 2014; prior thereto Production Manager from April 2005 to August 2014.
Mark Chalmers Calgary, Alberta Canada	Vice-President, Exploration Central (age 56)	Officer of the Company since January 2015; prior thereto Exploration Manager, British Columbia North from December 2006 to September 2010 and most recently Exploration Manager, Northern Plains from September 2010 to January 2015.
William R. Clapperton Calgary, Alberta Canada	Vice-President, Regulatory, Stakeholder and Environmental Affairs (age 53)	Officer of the Company.
James F. Corson Calgary, Alberta Canada	Vice-President, Human Resources (age 65)	Officer of the Company.
Réal M. Cusson Calgary, Alberta Canada	Senior Vice-President, Marketing (age 65)	Officer of the Company.
Réal J. H. Doucet Calgary, Alberta Canada	Senior Vice-President, Horizon Projects (age 63)	Officer of the Company.
Darren M. Fichter Calgary, Alberta Canada	Senior Vice-President, Exploitation (age 45)	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 59)	Officer of the Company.
Jay E. Froc Calgary, Alberta Canada	Vice-President, Horizon Infrastructure, Logistics and Project Controls (age 50)	Officer of the Company since June 2013. Most recently held various positions with Suncor Energy Inc. since 2006.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Christopher I. Grayston Calgary, Alberta Canada	Vice-President, Finance and E&P Accounting (age 56)	Officer of the Company since May 2015; prior thereto Assistant Controller, Operations Accounting from November 2010 to March 2014 and most recently Controller, Operations Accounting from March 2014 to May 2015.
Dean W. Halewich Calgary, Alberta Canada	Vice-President, Facilities and Pipelines (age 48)	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.
Jon Halford Calgary, Alberta Canada	Vice-President, Commercial Operations (age 42)	Officer of the Company since January 2015; prior thereto Manager, Materials and Contracts from June 2010 to November 2010 and most recently Director, Supply Management – Major Projects.
Murray G. Harris Calgary, Alberta Canada	Vice-President, Financial Controller and Horizon Accounting (age 52)	Officer of the Company since March 2012; prior thereto Financial Controller from June 2005 to March 2012.
David B. Holt Calgary, Alberta Canada	Vice-President, Production, West (age 50)	Officer of the Company since September 2011; prior thereto Production Manager, Heavy Oil North from January 2003 to September 2011.
John A. Howard Calgary, Alberta Canada	Vice-President, Thermal Production Primrose (age 57)	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.
Gerard Iannattone Calgary, Alberta Canada	Vice-President, Thermal Exploitation Athabasca (age 56)	Officer of the Company since March 2014; prior thereto Exploitation Manager, N. E. British Columbia from November 2006 to March 2014.
Terry J. Jocksch Calgary, Alberta Canada	Senior Vice-President, Thermal (age 48)	Officer of the Company.
Philip A. Keele Calgary, Alberta Canada	Vice-President, Mining (age 56)	Officer of the Company.
Kevin B. Kowbel Calgary, Alberta Canada	Vice-President, Drilling and Completions (age 45)	Officer of the Company since January 2012; prior thereto Drilling Manager from April 2006 to January 2012.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Trevor D. Krause Calgary, Alberta Canada	Vice-President, Exploration, East (age 44)	Officer of the Company since January 2015; prior thereto Exploration Manager, N. E. Alberta from April 2007 to July 2011 and most recently Exploration Manager, Heavy Oil South from July 2011 to January 2015.
Dan H. Krentz Calgary, Alberta Canada	Vice-President, Exploration, West (age 57)	Officer of the Company since March 2014; prior thereto Exploration Manager, Foothills from November 2006 to April 2011 and most recently Exploration Manager, Deep Basin from April 2011 to March 2014.
Ronald K. Laing Calgary, Alberta Canada	Senior Vice-President, Corporate Development and Land (age 46)	Officer of the Company.
Raul Lanfranchi Calgary, Alberta Canada	Vice-President, Horizon Downstream Projects (age 58)	Officer of the Company since February 2016; prior thereto Project Manager, Horizon from July 2006 to March 2013, Project Director, Horizon Downstream from April 2013 to January 2016.
Pamela A. McIntyre Calgary, Alberta Canada	Vice-President, Safety and Asset Integrity (age 53)	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.
Tim S. McKay Calgary, Alberta Canada	Chief Operating Officer (age 54)	Officer of the Company.
Casey D. McWhan Calgary, Alberta Canada	Vice-President, Horizon Bitumen Production (age 53)	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.
Kevin Melnyk Calgary, Alberta Canada	Vice-President, Horizon Upgrading and Utilities (age 49)	Officer of the Company since November 2015; prior thereto Agrium Plant Manager, Fort Saskatchewan Nitrogen Operations 2009 to 2012, Redwater Nitrogen Operations 2012-2015 and most recently Director, Utilities and Upgrading from January 2015 to October 2015.
Paul M. Mendes Calgary, Alberta Canada	Vice-President, Legal, General Counsel and Corporate Secretary (age 50)	Officer of the Company.
S. John Parr Calgary, Alberta Canada	Vice-President, Thermal Projects (age 55)	Officer of the Company.

Name	Position Presently Held	Principal Occupation During Past 5 Years
David A. Payne Calgary, Alberta Canada	Vice-President, Exploitation, Central (age 54)	Officer of the Company.
William R. Peterson Calgary, Alberta Canada	Senior Vice-President, Production and Development Operations (age 49)	Officer of the Company.
Andrew Richardson Calgary, Alberta Canada	Vice-President, Thermal Production Athabasca (age 48)	Officer of the Company since March 2014; prior thereto Manager Production Engineering, Long Lake with Nexen Inc. from August 2006 to January 2012, Manager CSS Production with the Company from January 2012 to November 12, 2012 and most recently Manager, Wolf Lake and Production Development from December 2012 to March 2014.
Joy P. Romero Calgary, Alberta Canada	Vice-President, Technology Development (age 59)	Officer of the Company.
Sheldon L. Schroeder Fort McMurray, Alberta Canada	Vice-President, Horizon Upstream Projects (age 48)	Officer of the Company.
Kara Slemko Calgary, Alberta Canada	Vice-President, Supply Management (age 46)	Officer of the Company since January 2015; prior thereto Director Operations with Canadian National Railway from February 2003 to February 2011, Management Consultant with Ernst & Young LLP from March 2011 to September 2012 and most recently Director, Supply Management, Operations with the Corporation from September 2012 to January 2015.
Kendall W. Stagg Calgary, Alberta Canada	Senior Vice-President, Exploration (age 54)	Officer of the Company.
Scott G. Stauth Calgary, Alberta Canada	Senior Vice-President, North American Operations (age 50)	Officer of the Company.
Lyle G. Stevens Calgary, Alberta Canada	Executive Vice-President, Canadian Conventional (age 61)	Officer of the Company.
Stephen C. Suche Calgary, Alberta Canada	Vice-President, Information and Corporate Services (age 56)	Officer of the Company.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Domenic Torriero Calgary, Alberta Canada	Vice-President, Thermal Exploration (age 51)	Officer of the Company.
Gregory A. Ulrich Calgary, Alberta Canada	Vice-President, Thermal And East Conventional Field Operations (age 53)	Officer of the Company since March 2014; prior thereto Field Operations Manager from November 2006 to March 2014.
Betty Yee Calgary, Alberta Canada	Vice-President, Land (age 51)	Officer of the Company since June 2013. Most recently was Manager of Acquisition and Divestments of the Company since 2003.
Daryl G. Youck Calgary, Alberta Canada	Vice-President, Thermal Exploitation Primrose (age 47)	Officer of the Company.
Robin S. Zabek Calgary, Alberta Canada	Vice-President, Exploitation East (age 44)	Officer of the Company since March 2014; prior thereto Manager Exploitation from September 2006 to March 2014.

(1) Member of the Audit Committee.

(2) Member of the Compensation Committee.

(3) Member of the Health, Safety, Asset Integrity and Environmental Committee.

(4) Member of the Nominating, Governance and Risk 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 General Meeting of Shareholders held on May 7, 2015.

As at December 31, 2015, 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, PricewaterhouseCoopers LLP, have prepared an independent auditors' report dated March 2, 2016 in respect of the Company's consolidated balance sheets as at December 31, 2015 and December 31, 2014, the consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2015 and the Company's internal control over financial reporting as at December 31, 2015. 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 Professional 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. T.W. Faithfull, G. A. Filmon, G. D. Giffin and D. A. Tuer, each of whom is independent and financially literate as those terms are defined under Canadian securities regulations, National Instrument 52-110 and the NYSE listing standards as they pertain to audit committees of listed issuers. 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 over 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 from the University of Oxford (Philosophy, Politics and 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 2015 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 expatriate visa application assistance and to accessing resource materials through PwC’s accounting literature library. Fees accrued to PwC are shown in the table below.

Auditor service (000’s)		**2015**		2014
Audit fees	**$**	**3,012**	$	3,047
Audit related fees		**250**		259
Tax fees		**495**		523
All other fees		**84**		87
	$	**3,841**	$	3,916

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

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 16, 2016 in connection with the Annual and Special Meeting of Shareholders of Canadian Natural to be held on May 5, 2016 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, 2015 found on pages 20 to 53, 54 to 91 and 92 to 99 respectively, of the 2015 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:
2100, 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 "Company"):

1. We have evaluated and reviewed the Company's reserves data as at December 31, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, estimated using forecast prices and costs.

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

3. We carried out our evaluation and review in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. 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.

5. The following table shows the net present value of 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 Company evaluated and reviewed for the year ended December 31, 2015, and identifies the respective portions thereof that we have evaluated and reviewed and reported on to the Company's management and board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective 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	December 31, 2015	Canada and USA	-	40,021	1,225	41,246
Sproule International Limited	December 31, 2015	United Kingdom and Offshore Africa	-	7,941	-	7,941
GLJ Petroleum Consultants Ltd.	December 31, 2015	Canada	-	39,840	-	39,840
Total			**-**	**87,802**	**1,225**	**89,027**

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

8. 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 referred to above:

Sproule Associates Limited
Calgary, Alberta, Canada,
March 2, 2016

Original Signed By

SIGNED "HARRY J. HELWERDA"
Harry J. Helwerda, P.Eng., FEC, FGC (Hon)
President and Director

Original Signed By

SIGNED "NORA T. STEWART"
Nora T. Stewart, P.Eng.
Vice President, Reserves Certification
and Director

Original Signed By

SIGNED "STEVEN J. GOLKO"
Steven J. Golko, P.Eng.
Vice President, Field Development & Capital
Strategies and Partner

Original Signed By

SIGNED "CAMERON P. SIX"
Cameron P. Six, P.Eng.
Vice President Engineering, Chief
Engineer and Director

Sproule International Limited
Calgary, Alberta, Canada,
March 2, 2016

Original Signed By

SIGNED "HARRY J. HELWERDA"
Harry J. Helwerda, P.Eng., FEC, FGC (Hon)
President and Director

Original Signed By

SIGNED "SCOTT W. PENNELL"
Scott W. Pennell, P.Eng.
Vice President, Engineering
and Director

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada,
March 2, 2016

Original Signed By

SIGNED "TIM R. FREEBORN"
Tim R. Freeborn, P. Eng.
Vice President
Mineable Oil Sands and Shales

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 “Company”) are responsible for the preparation and disclosure of information with respect to the Company’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

Independent qualified reserves evaluators have evaluated and reviewed the Company’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 Company has

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

(b) met with 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 Company’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 "COREY B. BIEBER"

Corey B. Bieber

Chief Financial Officer and Senior Vice President, Finance

Original Signed By

SIGNED "DAVID A TUER"

David A. Tuer

Independent Director and Chair of the Reserves Committee

Original Signed By

SIGNED "CHRISTOPHER L. FONG"

Christopher L. Fong

Independent Director and Member of the Reserves Committee

Dated this 2nd day of March, 2016

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, Governance and Risk 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.