CANADIAN NATURAL RESOURCES LTD
Form 40-F
March 23, 2017
United States
Securities and Exchange Commission
Washington, D.C. 20549

FORM 40-F
[ ] Registration Statement pursuant to section 12 of the Securities Exchange Act of 1934
[X] Annual report pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2016	Commission File Number: 001-12138

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

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

1311
(Primary Standard Industrial Classification Code Numbers)

Not Applicable
(I.R.S. Employer Identification Number (if applicable))

2100, 855-2nd Street S.W., Calgary, Alberta, Canada, T2P 4J8
Telephone: (403) 517-7345
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System, 111-Eighth Avenue, New York, New York 10011
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code)
of agent for service in the United States)
Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of Each Class:	**Name of each exchange on which registered:**
Common Shares, no par value	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act:
Title of Each Class: None
Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: None
For annual reports, indicate by check mark the information filed with this Form:
[X] Annual information form [X] Audited annual financial statements

Number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.
1,110,952,000 Common Shares outstanding as of December 31, 2016
Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.
Yes [X] No [ ]

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

Yes ___ No ___

This Annual Report on Form 40-F shall be incorporated by reference into, or as an exhibit to, as applicable, the Registrant's Registration Statement on Form F-10 (File No. 333-207578) under the Securities Act of 1933 as amended. All dollar amounts in this Annual Report on Form 40-F are expressed in Canadian dollars. On March 15, 2017 the reported Bank of Canada noon rate for one Canadian dollar was US$0.7434. On March 15, 2017 the reported Bank of Canada noon rate for one U. S. dollar was C$1.3451.

Principal Documents

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

A. Annual Information Form

Annual Information Form of Canadian Natural Resources Limited ("Canadian Natural") for the year ended December 31, 2016.

B. Audited Annual Financial Statements

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2016 and 2015, including the auditor's report with respect thereto.

C. Management's Discussion and Analysis

Canadian Natural's Management's Discussion and Analysis for the year ended December 31, 2016.

Supplementary Oil & Gas Information (Unaudited)

For Canadian Natural's Supplementary Oil & Gas Information (Unaudited) for the year ended December 31, 2016, see Exhibit 99.1 to this Annual Report on Form 40-F.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2016

March 23, 2017

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DEFINITIONS AND ABBREVIATIONS

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

API	Specific gravity measured in degrees on the American Petroleum Institute scale
ARO	Asset retirement obligations
bbl	barrel
bbl/d	barrels per day
Bcf	billion cubic feet
bitumen	Naturally occurring solid or semi-solid hydrocarbon, consisting mainly of heavier hydrocarbons that are too heavy or thick to flow at reservoir conditions, and recoverable at economic rates using thermal in-situ recovery methods
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 Stimulation
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

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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, 2016) 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

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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", "m "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "sc 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, and 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 2017 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 and assets, including the announced acquisition of a significant interest in the Athabasca Oil

Sands Project and certain other producing and non-producing oil and gas properties; 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,

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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, 2016, 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, 2016, 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, 2016 and a preparation date of February 6, 2017. 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 and 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 (loss) from operations, funds flow from operations (formerly referred to as 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 (loss) and cash flows from operating activities, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings (loss) from operations and funds flow from operations are reconciled to net earnings (loss), as determined in accordance with IFRS in the "Net Earnings (Loss) and Funds Flow from Operations" section of the Company's MD&A which is incorporated by reference into this document. The non-GAAP measure funds flow from operations is also reconciled to cash flows from operating activities in this section. 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.

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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 (Gabon) Limited	Gabon	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
CNRI (Gabon) SCS	Gabon	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. CNR International (South Africa) Limited as the limited partner and CNR

International (Gabon) Limited as the general partner are the partners of CNRI (Gabon) SCS.

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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

2014

During 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 were 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.

During 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%, US$500 million principal amount of 3.80% unsecured notes due April 15, 2024, 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. In addition, 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.

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.

During 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. The Company also issued $500 million of series 2 medium-term notes due August 2020 through the reopening of its previously issued 2.89% notes and repaid $400 million of 4.95% medium-term notes.

The Company commenced a review of its royalty lands and royalty revenue portfolio in 2014. 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 agreed with PrairieSky that, by no later than December 31, 2016, it would distribute sufficient common shares of PrairieSky to the Company's shareholders so that the Company, after such distribution, would hold less than 10% of the issued and outstanding common shares of PrairieSky.

2016

The Company previously entered into a 20 year transportation agreement to ship 75,000 bbl/d of crude oil on the proposed Kinder Morgan Trans Mountain Expansion from Edmonton, Alberta to Vancouver, British Columbia. This pipeline has received regulatory approval and plans are to begin construction in 2017.

During 2016, the Company completed the net distribution of approximately 21.8 million PrairieSky common shares to the shareholders of record of the Company as at June 3, 2016, completing the previously announced Plan of Arrangement. The distribution was recognized as a return of capital of $546 million. Subsequent to the distribution, the Company's ownership interest in PrairieSky was less than 10% of the issued and outstanding common shares of PrairieSky.

During 2016, the Company disposed of its ownership interest in the Cold Lake Pipeline. Net consideration on the disposition was comprised of $349 million in cash, together with $190 million of non-cash share consideration of approximately 6.4 million common shares of Inter Pipeline Ltd with a value of $29.57 per common share, determined as of the closing date.

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During 2016, the Company issued $1,000 million of 3.31% medium term notes due February 2022 and entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn at December 31, 2016. As well, the Company prepaid $250 million of the borrowings outstanding under the previously outstanding $1,000 million non-revolving term credit facility and extended the facility to February 2019 from January 2017. This $750 million facility was fully drawn at December 31, 2016. In addition, the Company repaid US$250 million of 6% notes and US$500 million of three-month LIBOR plus 0.375% notes.

2017

On March 9, 2017, the Company announced it entered into agreements, subject to receiving all required consents and regulatory and other approvals, to acquire 70% of the Athabasca Oil Sands Project (“AOSP”), including 70% of the Scotford Upgrader, as well as additional working interests in other producing and non-producing oil sands leases. The Company has agreed with Shell Canada Limited and certain subsidiaries (‘Shell”) to acquire its 60% working interest in the AOSP including an interest in the mining and extraction operations, north of Fort McMurray, Alberta; the Scotford Upgrader and the Quest Carbon Capture and Storage (CCS) project located north of Edmonton, Alberta: and its 100% working interest in its Peace River/Carmon Creek thermal in situ operations, its 100% working interest in the Cliffdale heavy oil field as well as other oil sands leases. As well, the Company will have access to use various technologies acquired and developed in conjunction with the acquired assets. Canadian Natural and Shell have also agreed with Marathon Oil Corporation (“Marathon Oil”) to jointly acquire Marathon Oil’s 20% share in AOSP and related oil sands investments. The total preliminary consideration of the transactions is approximately $12.7 billion.

The acquisitions are targeted to close in mid-2017. The aggregate consideration under the acquisition will comprise 97,560,795 common shares of the Company with an estimated value of approximately $4 billion at the announcement date and a cash payment of approximately $8.7 billion.

In conjunction with the acquisition and assumption of operatorship of the oil sands mines and in situ lands, approximately 3,100 employees will join the Company, with approximately 2,760 located at the mines, 110 located in the Peace River in situ region and 230 in Calgary.

In conjunction with the issuance of approximately $4 billion of Company common equity to Shell, Canadian Natural has fully committed acquisition financing arrangements of $9 billion comprised of a $3 billion term loan facility and up to $6 billion in bridge facility to bonds in the US and Canadian debt capital markets.

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, 2016, the Company had the following full time equivalent permanent employees:

North America, Exploration and Production	4,210
North America, Oil Sands Mining and Upgrading	2,667
North Sea	363
Offshore Africa	30
Total Company	7,270

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.

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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 35% of 2016 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 17% of 2016 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 13% of 2016 production, Pelican Lake heavy crude oil accounting for 6% of 2016 production, and our bitumen (thermal oil) accounting for 14% of 2016 production are in the provinces of Alberta and Saskatchewan. SCO from our oil sands mining operations in Northern Alberta accounted for approximately 15% of 2016 production. Midstream assets, primarily comprised of two 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. In Canada these requirements apply to all operators in the crude oil and natural gas industry and 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 carbon capture at hydrotreaters, the injection of CO_2 into tailings and for use in EOR; a program in place related to progressive reclamation and tailings management at Horizon including low fines mining; 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 2016, Canadian Natural continued its environmental liability reduction program with the abandonment of 406 inactive wells. In addition, reclamation was initiated at many of these sites with the eventual goal of reclamation certification. In 2016 the Company received 1,046 reclamation certificates representing 2,329 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

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purposes. 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, such as provincial and federal methane policy development. 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 2016, the Company completed approximately 407 gas conservation projects in its primary heavy crude oil operations, resulting in a reduction of 2.4 million tonnes/year of CO_2e. Over the past five years the Company has spent over $95 million in its primary heavy crude oil and in situ oil sands operations to conserve the equivalent of over 18.4 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, the sequestration of CO_2 in oil sands tailings and recovery of hydrocarbon liquids from refinery fuel gas. 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

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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 royalties on oil sands projects 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.

Effective January 1, 2017, the Alberta Government adopted the Modernized Royalty Framework (MRF) for conventional crude oil, natural gas and NGL royalties. Alberta will have a parallel royalty regime system with the existing Alberta Royalty Framework (ARF) for 10 years until December 31, 2026 and the MRF will apply to wells drilled on or after January 1, 2017. Under the MRF, conventional royalty rates will range from a minimum of 5% to a maximum of 36% for natural gas and NGLs and a minimum 5% to a maximum 40% for crude oil.

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.

The Company is subject to federal and provincial income taxes in Canada at a combined rate of approximately 27% after allowable deductions.

In Canada, the federal government has ratified the Paris climate change agreement, with a commitment to reduce GHG emissions by 30% from 2005 levels by 2030. Under the Pan-Canadian Framework on Clean Growth and Climate Change, the federal and provincial governments will be developing specific policy and regulatory measures to meet Canada's 2030 targets. Canada has also committed to reduce methane emissions from the upstream oil and natural gas sector by 40-45% by 2025, as compared to 2012 levels. The federal government is also developing a comprehensive management system for air pollutants, and has released regulations pertaining to certain boilers, heaters and compressor engines operated by the Company.

GHG reduction regulations came into effect July 1, 2007 in Alberta, 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.

For 2017, the Alberta provincial government has implemented increases in both the carbon price and stringency of the existing large-emitter regulatory system and the carbon pricing for large-emitter systems is $30/tonne. Effective 2018 the Alberta large-emitter system is expected to change from the current system of facility-specific baselines, to a system of output-based allocations (OBA). The details of the proposed OBA system are expected to be finalized in 2017. The Alberta Government has also announced 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 has also announced a methane reduction target, comparable to the federal target.

United Kingdom

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

Effective January 1, 2016 the PRT rate, which is a charge on certain crude oil and natural gas profits, was reduced to 0%. Allowable abandonment expenditures eligible for carryback to 2015 and prior taxation years for PRT purposes remain recoverable at 50%. In addition, the supplementary charge on oil and gas profits was reduced to 10%. An Investment Allowance on qualifying capital expenditures is deductible for supplementary charge purposes, subject to certain restrictions. As a result of these changes, the overall tax rate applicable to taxable income from oil and gas activities is 40%.

During 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 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

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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 33% of the Company's 2016 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 currently differs 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 currently differs 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

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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.

Current and potential climate change policies and regulations are considered when making decisions to advance the Company's business strategy. The Company is tracking the development of policies and regulations at the national and provincial level. 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.

Various jurisdictions 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 natural 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 March 2015, Alberta Environment and Parks released the Tailings Management Framework (TMF) policy. In July 2016, the Alberta Energy Regulator (AER), released Directive 85 - Fluid Tailings Management for Oil Sands Mining Projects. The 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 submitted an updated Tailings Management Plan application in September 2016 to meet the proposed Directive criteria.

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 funds flow 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 the Company’s control including the availability of skilled labour and manpower, the availability and proximity of pipeline capacity, weather, fires, 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, including the announced acquisition of a significant interest in the AOSP and certain other producing and non-producing oil and gas properties, is dependent on our ability to generate cash flow as well as 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.

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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.

Information Technology

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. Notwithstanding the Company's proactive approach to combatting cybersecurity threats, such threats frequently change and require evolving monitoring and detection efforts. Examples of such threats include unauthorized access to information technology systems due to social engineering, hacking, viruses and other causes. A successful cyber-attack could result in the loss, disclosure or theft of confidential information related to the Company's proprietary business activities and the personnel files of its employees. The Company has implemented cyber security protocols and procedures to address this 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 including the announced acquisition of a significant interest in the AOSP and certain other producing and non-producing oil and gas properties, and the dependency on third party operators for some of the Company's assets. 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.

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

For the year ended December 31, 2016, 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, 2016 and a preparation date of February 6, 2017. 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.

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Summary of Company Gross Reserves
As of December 31, 2016
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	115	95	211	322	2,544	4,074	100	4,066
Developed Non-Producing	10	16	3	13	-	369	9	113
Undeveloped	43	76	50	934	15	2,102	89	1,557
Total Proved	168	187	264	1,269	2,559	6,545	198	5,736
Probable	65	72	120	1,248	1,045	2,366	86	3,030
Total Proved plus Probable	233	259	384	2,517	3,604	8,911	284	8,766
North Sea								
Proved								
Developed Producing	28					31		33
Developed Non-Producing	2					2		2
Undeveloped	104					8		106
Total Proved	134					41		141
Probable	119					44		126
Total Proved plus Probable	253					85		267
Offshore Africa								
Proved								
Developed Producing	42					24		46
Developed Non-Producing	-					-		-
Undeveloped	45					7		46
Total Proved	87					31		92
Probable	46					49		54
Total Proved plus Probable	133					80		146
Total Company								
Proved								
Developed Producing	185	95	211	322	2,544	4,129	100	4,145
Developed Non-Producing	12	16	3	13	-	371	9	115
Undeveloped	192	76	50	934	15	2,117	89	1,709
Total Proved	389	187	264	1,269	2,559	6,617	198	5,969
Probable	230	72	120	1,248	1,045	2,459	86	3,210
Total Proved plus Probable	619	259	384	2,517	3,604	9,076	284	9,179

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Summary of Company Net Reserves
As of December 31, 2016
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	104	80	164	257	2,186	3,682	78	3,483
Developed Non-Producing	9	14	3	11	-	331	7	99
Undeveloped	38	65	41	767	9	1,832	76	1,301
Total Proved	151	159	208	1,035	2,195	5,845	161	4,883
Probable	55	59	83	976	864	2,043	69	2,447
Total Proved plus Probable	206	218	291	2,011	3,059	7,888	230	7,330
North Sea								
Proved								
Developed Producing	28					31		33
Developed Non-Producing	2					2		2
Undeveloped	104					8		106
Total Proved	134					41		141
Probable	118					44		125
Total Proved plus Probable	252					85		266
Offshore Africa								
Proved								
Developed Producing	39					17		42
Developed Non-Producing	-					-		-
Undeveloped	35					6		36
Total Proved	74					23		78
Probable	34					32		39
Total Proved plus Probable	108					55		117
Total Company								
Proved								
Developed Producing	171	80	164	257	2,186	3,730	78	3,558
Developed Non-Producing	11	14	3	11	-	333	7	101
Undeveloped	177	65	41	767	9	1,846	76	1,443
Total Proved	359	159	208	1,035	2,195	5,909	161	5,102
Probable	207	59	83	976	864	2,119	69	2,611
Total Proved plus Probable	566	218	291	2,011	3,059	8,028	230	7,713

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

A report on reserves data by the IQREs 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.

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Summary of Net Present Values of Future Net Revenue Before Income Taxes
As of December 31, 2016
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	151,065	72,123	45,331	33,426	26,874	13.01
Developed Non-Producing	2,306	1,524	1,133	898	741	11.44
Undeveloped	34,284	28,553	18,653	12,196	8,263	14.34
Total Proved	187,655	102,200	65,117	46,520	35,878	13.34
Probable	134,289	42,165	18,869	10,961	7,455	7.71
Total Proved plus Probable	321,944	144,365	83,986	57,481	43,333	11.46
North Sea						
Proved						
Developed Producing	(1,632)	(87)	290	375	386	8.79
Developed Non-Producing	103	88	75	65	56	37.50
Undeveloped	4,081	2,730	1,913	1,393	1,046	18.05
Total Proved	2,552	2,731	2,278	1,833	1,488	16.16
Probable	8,628	4,729	2,873	1,898	1,341	22.98
Total Proved plus Probable	11,180	7,460	5,151	3,731	2,829	19.36
Offshore Africa						
Proved						
Developed Producing	1,084	1,124	1,053	964	883	25.07
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	2,008	1,248	826	576	418	22.94
Total Proved	3,092	2,372	1,879	1,540	1,301	24.09
Probable	3,034	1,919	1,325	979	762	33.97
Total Proved plus Probable	6,126	4,291	3,204	2,519	2,063	27.38
Total Company						
Proved						
Developed Producing	150,517	73,160	46,674	34,765	28,143	13.12
Developed Non-Producing	2,409	1,612	1,208	963	797	11.96
Undeveloped	40,373	32,531	21,392	14,165	9,727	14.82
Total Proved	193,299	107,303	69,274	49,893	38,667	13.58
Probable	145,951	48,813	23,067	13,838	9,558	8.83
Total Proved plus Probable	339,250	156,116	92,341	63,731	48,225	11.97

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

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Summary of Net Present Values of Future Net Revenue After Income Taxes[1]
As of December 31, 2016
Forecast Prices and Costs

MM$	Discount @ 0%	Discount @ 5%	Discount @ 10%	Discount @ 15%	Discount @ 20%
North America					
Proved					
Developed Producing	112,270	55,391	35,549	26,571	21,565
Developed Non-Producing	1,707	1,112	821	647	532
Undeveloped	25,012	20,365	12,987	8,218	5,331
Total Proved	138,989	76,868	49,357	35,436	27,428
Probable	98,441	30,707	13,633	7,856	5,304
Total Proved plus Probable	237,430	107,575	62,990	43,292	32,732
North Sea					
Proved					
Developed Producing	(610)	40	204	242	245
Developed Non-Producing	103	61	47	39	34
Undeveloped	2,259	1,665	1,212	900	685
Total Proved	1,752	1,766	1,463	1,181	964
Probable	5,274	2,919	1,791	1,194	850
Total Proved plus Probable	7,026	4,685	3,254	2,375	1,814
Offshore Africa					
Proved					
Developed Producing	867	947	904	836	771
Developed Non-Producing	-	-	-	-	-
Undeveloped	1,524	958	642	453	332
Total Proved	2,391	1,905	1,546	1,289	1,103
Probable	2,269	1,447	1,009	753	593
Total Proved plus Probable	4,660	3,352	2,555	2,042	1,696
Total Company					
Proved					
Developed Producing	112,527	56,378	36,657	27,649	22,581
Developed Non-Producing	1,810	1,173	868	686	566
Undeveloped	28,795	22,988	14,841	9,571	6,348
Total Proved	143,132	80,539	52,366	37,906	29,495
Probable	105,984	35,073	16,433	9,803	6,747
Total Proved plus Probable	249,116	115,612	68,799	47,709	36,242

(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, 2016.

Additional Information Concerning Future Net Revenue

The following table summarizes the undiscounted future net revenue as at December 31, 2016 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	452,738	759,548	13,251	26,604	6,564	9,907	472,553	796,059
Royalties	69,565	128,021	26	42	213	358	69,804	128,421
Production Costs	143,080	237,502	5,920	8,913	2,079	2,145	151,079	248,560
Development Costs	43,455	61,537	2,497	4,023	772	837	46,724	66,397
Abandonment and Reclamation Costs – Future Development (1)	494	749	-	190	27	60	521	999
Abandonment and Reclamation Costs – Existing Development (1)	8,489	9,795	2,256	2,256	381	381	11,126	12,432
Future Net Revenue Before Income Taxes	187,655	321,944	2,552	11,180	3,092	6,126	193,299	339,250
Income Taxes	48,666	84,514	800	4,154	701	1,466	50,167	90,134
Future Net Revenue After Income Taxes (2)	138,989	237,430	1,752	7,026	2,391	4,660	143,132	249,116

(1) Abandonment and reclamation costs included in the calculation of the future net revenue for 2016 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, 2016. The Company’s estimated ARO at December 31, 2016 was $1,313 million, discounted at 10% (unescalated and undiscounted ARO at December 31, 2016 was $10,401 million). Approximately $6,646 million of this unescalated and undiscounted amount was also included in the future net revenue and is escalated at 2.0% per year after 2017. 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.

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The following table summarizes the future net revenue by production group as at December 31, 2016 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)	8,735	19.33
	Primary Heavy Crude Oil (including solution gas)	3,099	19.20
	Pelican Lake Heavy Crude Oil (including solution gas)	3,529	17.01
	Bitumen (Thermal Oil)	12,038	11.63
	Synthetic Crude Oil	34,256	15.61
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	8,386	7.98
	Abandonment and Reclamation Costs – Existing Development	(769)	-
	Total	69,274	13.58
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	14,481	20.30
	Primary Heavy Crude Oil (including solution gas)	4,401	19.90
	Pelican Lake Heavy Crude Oil (including solution gas)	4,746	16.29
	Bitumen (Thermal Oil)	18,409	9.15
	Synthetic Crude Oil	40,346	13.19
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	10,769	7.60
	Abandonment and Reclamation Costs – Existing Development	(811)	-
	Total	92,341	11.97

(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, 2016, which are not applied at the product type level.

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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, 2016. The following is a summary of the Sproule price forecast.

	2017	2018	2019	2020	2021	Average annual increase thereafter
Crude Oil and NGLs						
WTI[1] (US$/bbl)	$55.00	$65.00	$70.00	$71.40	$72.83	2.00 %
WCS[2] (C$/bbl)	$53.12	$61.85	$64.94	$66.93	$68.27	2.00 %
Canadian Light Sweet[3] (C$/bbl)	$65.58	$74.51	$78.24	$80.64	$82.25	2.00 %
Cromer LSB[4] (C$/bbl)	$64.58	$73.51	$77.24	$79.64	$81.25	2.00 %
Edmonton C5+[5] (C$/bbl)	$67.95	$75.61	$78.82	$80.47	$82.15	2.00 %
North Sea Brent[6] (US$/bbl)	$55.00	$65.00	$70.00	$71.40	$72.83	2.00 %
Natural Gas						
AECO[7] (C$/MMBtu)	$3.44	$3.27	$3.22	$3.91	$4.00	2.00 %
BC Westcoast Station 2[8] (C$/MMBtu)	$3.04	$2.87	$2.82	$3.51	$3.60	2.00 %
Henry Hub[9] (US$/MMBtu)	$3.50	$3.50	$3.50	$4.00	$4.08	2.00 %

(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 0.7800 US$/C$ for 2017, 0.8200 US$/C$ for 2018, and 0.8500 US$/C$ after 2018 was used in the 2016 evaluation.

Production and capital costs are escalated at Sproule's cost inflation rate of 0% per year for 2017 and 2.0% per year after 2017 for all products.

The Company's 2016 average pricing, net of blending costs and excluding risk management activities, was $51.95 /bbl for light and medium crude oil, $34.73/bbl for primary heavy crude oil, $36.03/bbl for Pelican Lake heavy crude oil, $30.47/bbl for bitumen (thermal oil), $58.59/bbl for SCO, $24.69/bbl for NGLs and $2.32/Mcf for natural gas.

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Reconciliation of Company Gross Reserves
As of December 31, 2016
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, 2015	138	213	268	1,225	2,408	6,038	195	5,453
Discoveries	1	-	-	-	-	3	-	2
Extensions	7	9	-	53	-	196	9	111
Infill Drilling	7	5	-	-	-	224	4	53
Improved Recovery	-	-	6	-	-	-	-	6
Acquisitions	15	-	-	3	-	103	5	40
Dispositions	-	-	-	-	-	(4)	-	(1)
Economic Factors	(5)	(3)	-	-	-	(102)	(1)	(26)
Technical Revisions	23	1	7	29	196	681	1	371
Production	(18)	(38)	(17)	(41)	(45)	(594)	(15)	(273)
December 31, 2016	168	187	264	1,269	2,559	6,545	198	5,736
North Sea								
December 31, 2015	158					39		165
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	1					-		1
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(16)					16		(14)
Production	(9)					(14)		(11)
December 31, 2016	134					41		141
Offshore Africa								
December 31, 2015	90					29		95
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	1					1		1
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	5					12		7
Production	(9)					(11)		(11)
December 31, 2016	87					31		92

Total Company

December 31, 2015	386	213	268	1,225	2,408	6,106	195	5,713
Discoveries	1	-	-	-	-	3	-	2
Extensions	7	9	-	53	-	196	9	111
Infill Drilling	9	5	-	-	-	225	4	55
Improved Recovery	-	-	6	-	-	-	-	6
Acquisitions	15	-	-	3	-	103	5	40
Dispositions	-	-	-	-	-	(4)	-	(1)
Economic Factors	(5)	(3)	-	-	-	(102)	(1)	(26)
Technical Revisions	12	1	7	29	196	709	1	364
Production	(36)	(38)	(17)	(41)	(45)	(619)	(15)	(295)
December 31, 2016	389	187	264	1,269	2,559	6,617	198	5,969

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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, 2015	54	81	120	1,182	1,225	2,300	88	3,134
Discoveries	-	-	-	-	-	2	1	1
Extensions	8	4	-	29	-	106	8	66
Infill Drilling	3	2	-	1	-	64	2	19
Improved Recovery	-	-	1	-	-	-	-	1
Acquisitions	4	-	-	1	-	22	1	10
Dispositions	-	-	-	-	-	(3)	-	-
Economic Factors	(1)	-	-	-	-	(32)	(2)	(8)
Technical Revisions	(3)	(15)	(1)	35	(180)	(93)	(12)	(193)
Production	-	-	-	-	-	-	-	-
December 31, 2016	65	72	120	1,248	1,045	2,366	86	3,030

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2015	126	57	135
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	1	-	1
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Technical Revisions	(8)	(13)	(10)
Production	-	-	-
December 31, 2016	119	44	126

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2015	52	45	59
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Technical Revisions	(6)	4	(5)
Production	-	-	-
December 31, 2016	46	49	54

Total Company

December 31, 2015	232	81	120	1,182	1,225	2,402	88	3,328
Discoveries	-	-	-	-	-	2	1	1
Extensions	8	4	-	29	-	106	8	66
Infill Drilling	4	2	-	1	-	64	2	20
Improved Recovery	-	-	1	-	-	-	-	1
Acquisitions	4	-	-	1	-	22	1	10
Dispositions	-	-	-	-	-	(3)	-	-
Economic Factors	(1)	-	-	-	-	(32)	(2)	(8)
Technical Revisions	(17)	(15)	(1)	35	(180)	(102)	(12)	(208)
Production	-	-	-	-	-	-	-	-
December 31, 2016	230	72	120	1,248	1,045	2,459	86	3,210

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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, 2015	192	294	388	2,407	3,633	8,338	283	8,587
Discoveries	1	-	-	-	-	5	1	3
Extensions	15	13	-	82	-	302	17	177
Infill Drilling	10	7	-	1	-	288	6	72
Improved Recovery	-	-	7	-	-	-	-	7
Acquisitions	19	-	-	4	-	125	6	50
Dispositions	-	-	-	-	-	(7)	-	(1)
Economic Factors	(6)	(3)	-	-	-	(134)	(3)	(34)
Technical Revisions	20	(14)	6	64	16	588	(11)	178
Production	(18)	(38)	(17)	(41)	(45)	(594)	(15)	(273)
December 31, 2016	233	259	384	2,517	3,604	8,911	284	8,766
North Sea								
December 31, 2015	284					96		300
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	2					-		2
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(24)					3		(24)
Production	(9)					(14)		(11)
December 31, 2016	253					85		267
Offshore Africa								
December 31, 2015	142					74		154
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	1					1		1
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(1)					16		2
Production	(9)					(11)		(11)
December 31, 2016	133					80		146
Total Company								
December 31, 2015	618	294	388	2,407	3,633	8,508	283	9,041

Discoveries	1	-	-	-	-	5	1	3
Extensions	15	13	-	82	-	302	17	177
Infill Drilling	13	7	-	1	-	289	6	75
Improved Recovery	-	-	7	-	-	-	-	7
Acquisitions	19	-	-	4	-	125	6	50
Dispositions	-	-	-	-	-	(7)	-	(1)
Economic Factors	(6)	(3)	-	-	-	(134)	(3)	(34)
Technical Revisions	(5)	(14)	6	64	16	607	(11)	156
Production	(36)	(38)	(17)	(41)	(45)	(619)	(15)	(295)
December 31, 2016	619	259	384	2,517	3,604	9,076	284	9,179

(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.

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At December 31, 2016, the company gross proved crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 4,866 MMbbl, and company gross proved plus probable crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 7,667 MMbbl. Proved reserve additions and revisions replaced 189% of 2016 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 126 MMbbl, and additions to proved plus probable reserves amounted to 192 MMbbl. Net positive revisions amounted to 237 MMbbl for proved reserves and 44 MMbbl for proved plus probable reserves, primarily due to technical revisions.

At December 31, 2016, the company gross proved natural gas reserves totaled 6,617 Bcf, and company gross proved plus probable natural gas reserves totaled 9,076 Bcf. Proved reserve additions and revisions replaced 183% of 2016 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 523 Bcf, and additions to proved plus probable reserves amounted to 714 Bcf. Net positive revisions amounted to 607 Bcf for proved reserves and 473 Bcf for proved plus probable reserves, primarily due to technical revisions.

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)
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
2016								
First Attributed	14	3	-	55	-	282	13	132
Total	192	76	50	934	15	2,117	89	1,709

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)
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
2016								
First Attributed	10	2	-	30	-	130	8	72

Total	147	42	27	1,023	240	1,214	54	1,735

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Bitumen (thermal oil) accounts for approximately 55% of the Company's total proved undeveloped BOE reserves and 59% 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, 2016.

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$)	Proved plus Probable (MM$)
2017	2,606	2,762	116	118	76	76	2,798	2,956
2018	2,988	3,224	223	243	79	79	3,290	3,546
2019	2,866	3,255	268	274	147	148	3,281	3,677
2020	2,568	2,805	269	324	233	233	3,070	3,362
2021	2,143	2,450	313	332	80	126	2,536	2,908
Thereafter	30,284	47,041	1,308	2,732	157	175	31,749	49,948
Total	43,455	61,537	2,497	4,023	772	837	46,724	66,397

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.

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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, 2016 and 2015.

Region	2016 Average Daily Production Rates Crude Oil & NGLs (Mbbl)	2016 Natural Gas (MMcf)	2015 Average Daily Production Rates Crude Oil & NGLs (Mbbl)	2015 Natural Gas (MMcf)
North America				
Northeast British Columbia	14	420	17	521
Northwest Alberta	40	677	42	679
Northern Plains	274	240	321	222
Southern Plains	17	282	14	238
Southeast Saskatchewan	6	3	6	3
Oil Sands Mining & Upgrading	123	-	123	-
North America Total	474	1,622	523	1,663
International				
North Sea UK Sector	24	38	22	36
Offshore Africa	26	31	19	27
International Total	50	69	41	63
Company Total	524	1,691	564	1,726

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

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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. This area includes a natural gas processing plant with a design capacity of 145 MMcf/d and 11,000 bbl/d of NGLs at our Septimus Montney gas play as well as a pipeline to a deep cut gas facility. 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.

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Northern Plains

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.

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 and a 20,000 bbl/d battery. The Company is using an EOR scheme through polymer flooding to increase the ultimate recoveries from the field. At the end of 2016, 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 processes employed by the Company are CSS, SAGD, and steamflood. These 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 and a processing plant with a capacity of 119,500 bbl/d. 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.

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During 2013, the Company discovered bitumen emulsion at surface in areas of the Primrose field. The Alberta Energy Regulator's ("AER") final investigation report on the Primrose flow to surface events was released on March 21, 2016. The AER's report was consistent with the Company's interim Causation Report submitted to the AER on June 27, 2014 as well as the Company's Final Report submitted on April 1, 2015.

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. 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. In 2016, the Company decided to re-initiate the development of the Kirby North Project with engineering and procurement commencing in 2017. The overall project is approximately 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 and produces primarily light sour crude oil from as many as seven productive horizons found at depths up to 2,700 meters.

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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 pipeline to the Edmonton area for distribution. Two on-site cogeneration plants with a combined design capacity of 182 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 123,265 bbl/day in 2016.

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

In the third quarter of 2016, the Company successfully completed the tie-in of the 45,000 bbl/d of additional production from the Phase 2B expansion.

At year-end 2016, Phase 3 expansion reached 89% physical completion. Within the scope of work for the combined hydrotreater, module installations and module interconnections are well advanced. Phase 3 includes the addition of extraction trains and the combined hydrotreater and sulphur recovery units.

Overall project completion is anticipated to be fourth quarter of 2017 and is targeted to increase Horizon SCO production to 250,000 bbl/d.

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United Kingdom North Sea

Through its wholly owned subsidiary CNR International (U.K.) Limited, formerly Ranger Oil (U.K.) Limited, the Company has operated in the North Sea for over 40 years and has developed a significant database, extensive operating experience and an experienced staff. In 2016, the Company produced from 9 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 also has a 73.5% working interest in the Strathspey field. In addition, the Company also has an interest in 9 licences covering 10 blocks and part blocks surrounding the Ninian platform 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.

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.

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 expected to be completed in approximately 3 years.

Due to the Company’s continued focus on proactive capital allocation and lowering overall operating and capital cost structures, the Company plans to commence abandonment of the Ninian North Platform in 2017.

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Offshore Africa

Côte d'Ivoire

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

The Company has a 58.7% operated interest 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 2016, the Company drilled 1 gross producing well and subsequently demobilized the drilling rig.

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. In 2016, the Company drilled 1 gross producing well and subsequently demobilized the drilling rig.

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

During 2013, the Company acquired a 60% operated working interest in Block CI-12 in Côte d'Ivoire, Offshore Africa. During the second quarter of 2016, the Company withdrew from Block CI-12.

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Gabon

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. The Company has no further development activities currently planned for 2017.

South Africa

In May 2012 the Company completed the conversion of its 100% owned oil 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 2018.

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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, 2016.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	27,904.0	22,484.4	10,922.0	9,534.4	38,826.0	32,018.8
British Columbia	2,389.0	2,062.4	263.0	233.8	2,652.0	2,296.2
Saskatchewan	10,748.0	9,757.7	2,997.0	1,802.6	13,745.0	11,560.3
Manitoba	-	-	207.0	202.6	207.0	202.6
Total Canada	41,041.0	34,304.5	14,389.0	11,773.4	55,430.0	46,077.9
United States	-	-	2.0	0.3	2.0	0.3
North Sea UK Sector	1.0	0.7	66.0	57.9	67.0	58.6
Offshore Africa						
Côte d'Ivoire	-	-	25.0	14.6	25.0	14.6
Gabon	-	-	11.0	10.2	11.0	10.2
Total	41,042.0	34,305.2	14,493.0	11,856.4	55,535.0	46,161.6

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, 2016.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Non Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	7,335.0	5,855.6	9,067.0	7,792.7	16,402.0	13,648.3
British Columbia	2,059.0	1,699.0	536.0	447.4	2,595.0	2,146.4
Saskatchewan	1,634.0	1,490.5	3,397.0	2,694.5	5,031.0	4,185.0
Manitoba	2.0	2.0	39.0	28.2	41.0	30.2
Northwest Territories	36.0	20.8	-	-	36.0	20.8
Total Canada	11,066.0	9,067.9	13,039.0	10,962.8	24,105.0	20,030.7
United States	1.0	0.1	2.0	0.3	3.0	0.4
North Sea UK Sector	3.0	2.2	30.0	27.3	33.0	29.5
Offshore Africa						
Côte d'Ivoire	-	-	11.0	6.3	11.0	6.3
Gabon	-	-	2.0	1.9	2.0	1.9
Total	11,070.0	9,070.2	13,084.0	10,998.6	24,154.0	20,068.8

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Properties With Attributed and No Attributed Reserves

The following table summarizes the Company's landholdings as at December 31, 2016.

Region (thousands of acres)	Proved Properties Gross	Proved Properties Net	Unproved Properties Gross	Unproved Properties Net	Total Acreage Gross	Total Acreage Net	Average Working Interest %
North America							
Northeast British Columbia	1,258	1,067	4,670	3,937	5,928	5,004	84 %
Northwest Alberta	2,051	1,505	3,514	2,740	5,565	4,245	76 %
Northern Plains	2,252	1,891	7,687	6,726	9,939	8,617	87 %
Southern Plains	3,005	2,546	2,860	2,473	5,865	5,019	86 %
Southeast Saskatchewan	121	109	126	117	247	226	91 %
Thermal In Situ Oil Sands	96	96	821	713	917	809	88 %
Oil Sands Mining & Upgrading	25	25	56	56	81	81	100 %
Non-core Regions	8	2	1,192	436	1,200	438	37 %
Fee Title	101	100	820	817	921	917	99 %
North America Total	8,917	7,341	21,746	18,015	30,663	25,356	83 %
International							
North Sea UK Sector	63	55	85	78	148	133	90 %
Offshore Africa							
Côte d'Ivoire	10	6	91	53	101	59	58 %
Gabon	-	-	152	140	152	140	92 %
South Africa	-	-	4,002	2,001	4,002	2,001	50 %
International Total	73	61	4,330	2,272	4,403	2,333	53 %
Company Total	8,990	7,402	26,076	20,287	35,066	27,689	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 0.9 million net acres attributed to our North America properties which are currently expected to expire by December 31, 2017.

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.

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2016 Costs Incurred in Crude Oil, Natural Gas and NGLs Activities

MM$	North America	North Sea	Offshore Africa	Total
Property Acquisitions				
Proved	50	-	-	50
Unproved	-	-	-	-
Exploration	17	-	9	26
Development	4,125	186	116	4,427
Add: Net non-cash and other costs [1]	(426)	(60)	26	(460)
Costs Incurred	3,766	126	151	4,043

(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.

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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, 2016 by geographic region along with a general discussion of 2017 activity.

2016 Exploratory Wells

		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	Total
North America							
Northeast British Columbia	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Northwest Alberta	Gross	1.0	2.0	-	-	-	3.0
	Net	1.0	2.0	-	-	-	3.0
Northern Plains	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Southern Plains	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Southeast Saskatchewan	Gross	1.0	-	-	-	-	1.0
	Net	0.3	-	-	-	-	0.3
Oil Sands Mining and Upgrading	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Non-core Regions	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
North America Total	Gross	2.0	2.0	-	-	-	4.0
	Net	1.3	2.0	-	-	-	3.3
North Sea UK Sector	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Offshore Africa	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Company Total	Gross	2.0	2.0	-	-	-	4.0
	Net	1.3	2.0	-	-	-	3.3

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2016 Development Wells		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	Total
North America							
Northeast British Columbia	Gross	-	4.0	-	-	3.0	7.0
	Net	-	4.0	-	-	3.0	7.0
Northwest Alberta	Gross	3.0	4.0	-	-	-	7.0
	Net	3.0	2.5	-	-	-	5.5
Northern Plains	Gross	174.0	1.0	7.0	10.0	4.0	196.0
	Net	164.0	0.3	6.8	10.0	4.0	185.1
Southern Plains	Gross	4.0	-	-	-	-	4.0
	Net	4.0	-	-	-	-	4.0
Southeast Saskatchewan	Gross	2.0	-	-	-	-	2.0
	Net	-	-	-	-	-	-
Oil Sands Mining and Upgrading	Gross	-	-	-	8.0	243.0	251.0
	Net	-	-	-	8.0	243.0	251.0
Non-core Regions	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
North America Total	Gross	183.0	9.0	7.0	18.0	250.0	467.0
	Net	171.0	6.8	6.8	18.0	250.0	452.6
North Sea UK Sector	Gross	1.0	-	-	-	-	1.0
	Net	0.9	-	-	-	-	0.9
Offshore Africa	Gross	2.0	-	-	-	-	2.0
	Net	1.2	-	-	-	-	1.2
Company Total	Gross	186.0	9.0	7.0	18.0	250.0	470.0
	Net	173.1	6.8	6.8	18.0	250.0	454.7

Total success rate, excluding service and stratigraphic test wells, for 2016 is 96%.

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2017 North America Exploration and Production Activity
Overall capital expenditures are targeted to be approximately $1,760 million.
2017 North Sea Exploration and Production Activity
A small drilling program at Ninian has commenced.
2017 Offshore Africa Exploration and Production Activity
No drilling activity is planned for 2017.
2017 Oil Sands Mining and Upgrading Activity
Horizon capital expenditures related to the completion of Phase 3 expansion which is anticipated to be complete in the fourth quarter 2017, are targeted to be approximately $1,055 million.
The above 2017 activity excludes the impact of the announced acquisition of a significant interest in the AOSP and certain other producing and non-producing oil and gas properties.

Production Estimates
The following table illustrates Canadian Natural's estimated 2017 company gross daily proved and probable production reflected in the reserve reports as of December 31, 2016 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	47,281	95,152	47,828	110,102	167,700	1,576	40,457	771,187
North Sea	21,153	-	-	-	-	50	-	29,486
Offshore Africa	21,121	-	-	-	-	29	-	25,954
Total Proved	89,555	95,152	47,828	110,102	167,700	1,655	40,457	826,627
PROBABLE								
North America	3,760	8,626	1,010	389	10,650	61	2,202	36,804
North Sea	2,838	-	-	-	-	2	-	3,171
Offshore Africa	2,216	-	-	-	-	3	-	2,716
Total Probable	8,814	8,626	1,010	389	10,650	66	2,202	42,691

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Production History

	2016				
	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)	48,268	46,939	50,135	48,523	48,471
Netbacks ($/bbl)					
Sales price [2]	$36.15	$50.95	$49.94	$56.27	$48.40
Transportation	3.16	3.52	3.17	3.11	3.24
Royalties	4.17	4.86	6.81	6.40	5.59
Production expenses	17.90	19.01	18.32	20.02	18.81
Netback	$10.92	$23.56	$21.64	$26.74	$20.76
Primary Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	114,263	103,850	102,483	96,675	104,292
Netbacks ($/bbl)					
Sales price [2]	$19.63	$38.84	$38.52	$43.89	$34.73
Transportation	3.51	3.55	3.16	4.01	3.55
Royalties	1.55	4.02	2.73	4.74	3.20
Production expenses	13.12	13.70	13.12	14.34	13.55
Netback	$1.45	$17.57	$19.51	$20.80	$14.43
Pelican Lake Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	47,611	47,797	47,608	47,531	47,637
Netbacks ($/bbl)					
Sales price [2]	$21.76	$40.60	$37.57	$43.96	$36.03
Transportation	3.64	4.36	3.97	4.09	4.02
Royalties	3.53	6.20	4.93	5.27	4.99
Production expenses	6.92	6.81	6.09	6.57	6.60
Netback	$7.67	$23.23	$22.58	$28.03	$20.42
Bitumen (Thermal Oil)					
Average daily production (before royalties) (bbl/d)	118,045	93,213	103,481	129,329	111,046
Netbacks ($/bbl)					
Sales price [2]	$15.72	$32.91	$33.68	$39.39	$30.47
Transportation	1.83	2.39	2.21	2.21	2.15
Royalties	1.14	3.44	2.76	4.23	2.91
Production expenses	10.60	12.19	11.58	11.21	11.34
Netback	$2.15	$14.89	$17.13	$21.74	$14.07
SCO					
	127,909	119,511	67,586	178,063	123,265

Average daily production					
(before royalties) (bbl/d) (3)					
Netbacks ($/bbl)					
Sales price (2)	$46.63	$61.78	$58.61	$64.51	$58.59
Transportation	2.07	1.34	3.40	1.22	1.77
Royalties (4)	0.13	0.39	0.62	0.88	0.54
Production expenses (5)	26.55	26.82	27.05	22.53	25.20
Netback	$17.88	$33.23	$27.54	$39.88	$31.08
Natural Gas					
Average daily production					
(before royalties) (MMcf/d)	1,722	1,620	1,567	1,578	1,622
Netbacks ($/Mcf)					
Sales price (2)	$2.05	$1.30	$2.30	$2.97	$2.15
Transportation	0.24	0.30	0.33	0.29	0.28
Royalties	0.07	0.01	0.09	0.17	0.08
Production expenses	1.18	1.17	1.04	1.07	1.12
Netback	$0.56	$(0.18)	$0.84	$1.44	$0.67

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Production History

	2016				
	Q1	Q2	Q3	Q4	Year Ended
Natural Gas Liquids					
Average daily production					
(before royalties) (bbl/d)	41,800	36,882	40,072	39,290	39,512
Netbacks ($/bbl)					
Sales price [2]	$19.35	$25.06	$23.44	$31.24	$24.69
Transportation	1.37	2.01	1.66	2.05	1.76
Royalties	1.69	0.76	4.17	6.60	3.33
Production expenses	7.15	7.25	6.69	6.79	6.97
Netback	$9.14	$15.04	$10.92	$15.80	$12.63
North Sea Production and Netbacks by Product Type [1]					
Light and Medium Crude Oil					
Average daily production					
(before royalties) (bbl/d)	23,317	23,360	23,450	24,085	23,554
Netbacks ($/bbl)					
Sales price [2]	$45.04	54.60	$60.00	$63.68	$55.91
Transportation	0.80	1.84	0.75	0.74	0.96
Royalties	0.10	0.18	0.12	0.13	0.13
Production expenses	47.69	40.74	39.41	41.66	42.47
Netback	$(3.55)	$11.84	$19.72	$21.15	$12.35
Natural Gas					
Average daily production					
(before royalties) (MMcf/d)	29	30	50	44	38
Netbacks ($/Mcf)					
Sales price [2]	$7.02	$6.83	$5.27	$7.75	$6.62
Transportation	2.96	3.79	2.78	2.25	2.86
Royalties	-	-	-	-	-
Production Expenses	4.09	3.33	2.15	3.36	3.09
Netback	$(0.03)	$(0.29)	$0.34	$2.14	$0.67
Offshore Africa Production and Netbacks by Product Type [1]					
Light and Medium Crude Oil					
Average daily production					
(before royalties) (bbl/d)	25,714	30,858	26,171	21,689	26,096
Netbacks ($/bbl)					
Sales price [2]	$42.99	$54.62	$58.30	$61.29	$54.96
Transportation	-	-	-	-	-
Royalties	1.90	2.12	2.47	2.71	2.31
Production expenses	17.07	20.13	16.32	19.05	18.48
Netback	$24.02	$32.37	$39.51	$39.53	$34.17
Natural Gas					

Average daily production					
(before royalties) (MMcf/d)	35	39	28	24	31
Netbacks ($/Mcf)					
Sales price (2)	$7.13	$6.01	$5.39	$5.75	$6.13
Transportation	0.18	0.18	0.16	0.18	0.17
Royalties	0.32	0.27	0.24	0.29	0.28
Production expenses	1.29	1.76	1.68	2.68	1.79
Netback	$5.34	$3.80	$3.31	$2.60	$3.89

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) 2016 SCO production before royalties excludes 1,966 bbl/d of SCO consumed internally as diesel.
(4) Calculated based on 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.

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SELECTED FINANCIAL INFORMATION

(MM$, except per common share information)	Year Ended December 31 2016	2015
Product sales	$11,098	$13,167
Net earnings (loss)	$(204)	$(637)
Per common share – basic	$(0.19)	$(0.58)
– diluted	$(0.19)	$(0.58)
Adjusted net earnings (loss) from operations (1)	$(669)	$263
Per common share – basic	$(0.61)	$0.24
– diluted	$(0.61)	$0.24
Funds flow from operations (1)	$4,293	$5,785
Per common share – basic	$3.90	$5.29
– diluted	$3.89	$5.28
Dividends declared per common share	$0.94	$0.92
Total assets	$58,648	$59,275
Total long-term liabilities	$27,289	$27,299
Net capital expenditures	$3,794	$3,853

(1) The derivation of these non-GAAP measures are discussed in the section "Net Earnings (Loss) and Funds Flow from Operations" 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.

	2016(1)	2015(1)	2014
Cash dividends declared per common share	$0.94	$0.92	$0.90

(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 and the actual dividends paid in 2016 were $0.69 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

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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)(3)]	Baa3	P-3	Stable
Standard & Poor's Rating Services ("S&P")[(3)]	BBB+	A-2	Stable
DBRS Limited ("DBRS")[(2)(3)]	BBB (high)	-	Stable

(1) Moody's and S&P assign a rating outlook to Canadian Natural and not to individual long-term debt instruments.

(2) The above table reflects changes to the DBRS trend and Moody's outlook which were changed from Negative to Stable in October 2016 and January, 2017 respectively.

(3) Following the announced acquisition of a significant interest in the Athabasca Oil Sands Project and certain other producing and non-producing oil and gas properties, Moody's affirmed the Company's ratings and outlook, S&P placed the Company on CreditWatch with negative implications and affirmed its A-2 short-term and commercial paper ratings, and DBRS place the Company Under Review with Developing Implications.

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.

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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 not made any other payments to the credit rating organizations in the last 2 years.

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 2016.

2016 Monthly Historical Trading on TSX

Month	High	Low	Close	Volume Traded
January	$30.72	$21.27	$29.99	95,357,026
February	$30.75	$25.68	$28.28	82,434,958
March	$36.99	$28.38	$35.13	84,237,266
April	$39.59	$33.11	$37.68	61,338,893
May	$39.52	$35.09	$38.97	45,499,313
June	$40.59	$36.26	$39.86	54,172,918
July	$41.85	$38.57	$39.54	38,341,095
August	$42.35	$38.36	$40.73	36,021,884
September	$42.43	$37.98	$41.94	38,721,764
October	$44.38	$41.64	$42.57	35,264,182
November	$46.30	$39.64	$45.33	40,285,939
December	$46.74	$42.69	$42.79	42,051,913

The Company's Normal Course Issuer Bid announced in 2015 expired in April 2016 and was not renewed. During 2016, the Company did not purchase any common shares for cancellation. On March 1, 2017, the Board of Directors approved the Company's application for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 27,814,309 common shares over a 12 month period commencing upon receipt of applicable regulatory and other approvals.

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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 15, 2017 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 63)	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, 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 the Calgary Stampede Foundation.
N. Murray Edwards, O.C. London, England	Executive Chairman and Director [5] (age 57)	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, England	Director [1][3] (age 72)	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 and ICE Futures Europe.
Honourable Gary A. Filmon, P.C., O.C., O.M. Winnipeg, Manitoba Canada	Director [1][4] (age 74)	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 67)	Corporate director. He has served continuously as a director of the Company since November 2010. He is currently serving on the board of directors of Computer Modelling Group Ltd.
Ambassador Gordon D. Giffin Atlanta, Georgia U.S.A	Director [1][4] (age 67)	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, ECN Capital Corp., and TransAlta Corporation.

Wilfred A. Gobert Calgary, Alberta Canada	Director (2)(4)(5) (age 69)	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 59)	Officer of the Company. He has served continuously as a director of the Company since August 2006.

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Name	Position Presently Held	Principal Occupation During Past 5 Years
Honourable Frank J. McKenna P.C., O.C., O.N.B., Q.C. Cap Pelé, New Brunswick Canada	Director (2)(4) (age 69)	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 67)	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 60)	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. 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 38)	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 East (age 60)	Officer of the Company.
Corey B. Bieber Calgary, Alberta Canada	Chief Financial Officer and Senior Vice-President, Finance (age 53)	Officer of the Company.
Bryan C. Bradley	Vice-President, Marketing	Officer of the Company.

Calgary, Alberta Canada	(age 51)	
Trevor J. Cassidy Calgary, Alberta Canada	Vice-President, Production Central (age 43)	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 57)	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.

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Name	Position Presently Held	Principal Occupation During Past 5 Years
William R. Clapperton Calgary, Alberta Canada	Vice-President, Regulatory, Stakeholder and Environmental Affairs (age 54)	Officer of the Company.
James F. Corson Calgary, Alberta Canada	Vice-President, Human Resources (age 66)	Officer of the Company.
Réal M. Cusson Calgary, Alberta Canada	Senior Vice-President, Marketing (age 66)	Officer of the Company.
Réal J. H. Doucet Calgary, Alberta Canada	Senior Vice-President, Horizon Projects (age 64)	Officer of the Company.
Darren M. Fichter Calgary, Alberta Canada	Executive Vice-President, Canadian Conventional (age 46)	Officer of the Company.
Allan E. Frankiw Calgary, Alberta Canada	Senior Vice-President, Production (age 60)	Officer of the Company.
Jay E. Froc Calgary, Alberta Canada	Vice-President, Infrastructure, Logistics and Project Controls (age 51)	Officer of the Company since June 2013. Most recently held various positions with Suncor Energy Inc. since 2006.
Christopher I. Grayston	Vice-President, Finance and E&P Accounting	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.

Calgary, Alberta Canada	(age 57)	
Dean W. Halewich Calgary, Alberta Canada	Vice-President, Thermal and Heavy Oil Facilities (age 49)	Officer of the Company.
Jon Halford Calgary, Alberta Canada	Vice-President, Commercial Operations (age 43)	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.
Ken Harke St. Albert, Alberta Canada	Vice-President, Thermal and East Conventional Operations (age 50)	Officer of the Company since April, 2016; prior thereto Area Superintendent, St. Albert and Edson, Alberta from January, 2003 to April, 2014 and most recently Manager, Operations North Central Alberta from April, 2014 to April, 2016.

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Name	Position Presently Held	Principal Occupation During Past 5 Years
Murray G. Harris Calgary, Alberta Canada	Vice-President, Financial Controller and Horizon Accounting (age 53)	Officer of the Company.
David B. Holt Calgary, Alberta Canada	Vice-President, Production, West (age 51)	Officer of the Company.
John A. Howard Calgary, Alberta Canada	Vice-President, Production East (age 58)	Officer of the Company.
Gerard Iannattone Calgary, Alberta Canada	Vice-President, Thermal Exploitation Athabasca (age 57)	Officer of the Company since March 2014; prior thereto Exploitation Manager, N.E. British Columbia from November 2006 to March 2014.
Kevin B. Kowbel Calgary, Alberta Canada	Vice-President, Drilling and Completions (age 46)	Officer of the Company.
Trevor D. Krause Calgary, Alberta Canada	Vice-President, Exploration, East (age 45)	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 58)	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 47)	Officer of the Company.

Raul Lanfranchi Calgary, Alberta Canada	Vice-President, Horizon Downstream Projects (age 59)	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.
Ken MacKenzie Calgary, Alberta Canada	Vice-President, Mining, Horizon Operations (age 51)	Officer of the Company since July 2016; prior thereto Director, Mine Technical Services from November 2011 to June 2016.
Pamela A. McIntyre Calgary, Alberta Canada	Vice-President, Safety and Asset Integrity (age 54)	Officer of the Company

Name	Position Presently Held	Principal Occupation During Past 5 Years
Tim S. McKay Calgary, Alberta Canada	Chief Operating Officer (age 55)	Officer of the Company.
Casey D. McWhan Calgary, Alberta Canada	Vice-President, Horizon Bitumen Production (age 54)	Officer of the Company.
Kevin Melnyk Calgary, Alberta Canada	Vice-President, Horizon Upgrading and Utilities (age 50)	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 51)	Officer of the Company.
S. John Parr Calgary, Alberta Canada	Vice-President, Conventional Facilities and Pipelines (age 56)	Officer of the Company.
David A. Payne Calgary, Alberta Canada	Vice-President, Exploitation, West (age 55)	Officer of the Company.
William R. Peterson Calgary, Alberta Canada	Senior Vice-President, Development Operations (age 50)	Officer of the Company.
Andrew Richardson	Vice-President, Production Thermal (age 49)	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,

Calgary, Alberta Canada		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 and Innovation (age 60)	Officer of the Company.
Sheldon L. Schroeder Fort McMurray, Alberta Canada	Vice-President, Horizon Upstream Projects (age 49)	Officer of the Company.

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Name	Position Presently Held	**Principal Occupation During Past 5 Years**
Michael Skipper Calgary, Alberta Canada	Vice-President, Exploitation, Central (age 40)	Officer of the Company since March 3, 2017; prior thereto Brintnell Exploitation Engineer from February 2011 to January 2012, Heavy Oil South Exploitation Manager from February 2012 to February 2016 and most recently Brintnell Exploitation Manager from February 2016 to March 2017.
Kara Slemko Calgary, Alberta Canada	Vice-President, Supply Management (age 47)	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 55)	Officer of the Company.
Scott G. Stauth Calgary, Alberta Canada	Senior Vice-President, North American Operations (age 51)	Officer of the Company.
Stephen C. Suche Calgary, Alberta Canada	Vice-President, Information and Corporate Services (age 57)	Officer of the Company.
Domenic Torriero Calgary, Alberta Canada	Vice-President, Thermal Exploration (age 52)	Officer of the Company.
Betty Yee Calgary, Alberta Canada	Vice-President, Land (age 52)	Officer of the Company since June 2013. Most recently was Manager of Acquisition and Divestments of the Company since 2003.
Daryl G. Youck	Vice-President, Thermal Exploitation	Officer of the Company.

Calgary, Alberta Canada	Primrose (age 48)	
Robin S. Zabek Calgary, Alberta Canada	Senior Vice-President, Exploitation (age 45)	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 5, 2016.

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As at December 31, 2016, 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 15, 2017 in respect of the Company's consolidated balance sheets as at December 31, 2016 and December 31, 2015, 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, 2016 and the Company's internal control over financial reporting as at December 31, 2016. 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

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committees of listed issuers. The education and experience of each member of the Audit Committee relevant to their responsibilities as an Audit Committee member is described below.

Ms. C. M. Best is a chartered accountant with 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 2016 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)	2016	2015
Audit fees	$2,512	$3,012
Audit related fees	246	250
Tax fees	410	495
All other fees	62	84
	$3,230	$3,841

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

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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 General Meeting and Information Circular dated March 15, 2017 in connection with the Annual General Meeting of Shareholders of Canadian Natural to be held on May 4, 2017 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, 2016 found on pages 18 to 53, 54 to 91 and 92 to 99 respectively, of the 2016 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

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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, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, 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, 2016, and identifies the respective portions thereof that we have evaluated and reviewed and reported on to the Company’s management and board of directors:

			Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate) ($ millions)			
Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation/Review Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	December 31, 2016	Canada and USA	-	43,300	789	44,089
Sproule International Limited	December 31, 2016	United Kingdom and Offshore Africa	-	8,355	-	8,355
GLJ Petroleum Consultants Ltd.	December 31, 2016	Canada	-	39,897	-	39,897
Total			-	91,522	789	92,341

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.

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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 1, 2017	Sproule International Limited Calgary, Alberta, Canada, March 1, 2017
Original Signed By	Original Signed By
SIGNED “CAMERON P. SIX” Cameron P. Six, P.Eng. President and CEO	SIGNED “CAMERON P. SIX” Cameron P. Six, P.Eng. President and CEO
Original Signed By	Original Signed By
SIGNED “NORA T. STEWART” Nora T. Stewart, P.Eng. Senior Vice President, Reserves Certification	SIGNED “SCOTT W. PENNEL” Scott W. Pennell, P.Eng. Senior Vice President, Engineering

Original Signed By

SIGNED “STEVEN J. GOLKO”
Steven J. Golko, P.Eng.
Vice President, Capital Strategies

Original Signed By

SIGNED “ALEC KOVALTCHOUK”
Alec Kovaltchouk, P.Geo.
Vice President, Geoscience

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada,
March 1, 2017

Original Signed By

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

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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.

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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 1st day of March, 2017

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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.

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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

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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 effect 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.

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Management's Report

The accompanying consolidated financial statements of Canadian Natural Resources Limited (the "Company") and all other information contained elsewhere in this Annual Report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies described in the accompanying notes. Where necessary, management has made informed judgements and estimates in accounting for transactions that were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board as appropriate in the circumstances. The financial information presented elsewhere in the Annual Report has been reviewed to ensure consistency with that in the consolidated financial statements.

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

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

- the Company's consolidated financial statements as at and for the year ended December 31, 2016; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2016.

Their report is presented with the consolidated financial statements.

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

(signed) "Steve W. Laut"	(signed) "Corey B. Bieber"	(signed) "Murray G. Harris"
Steve W. Laut President	Corey B. Bieber, CA Chief Financial Officer and Senior Vice-President, Finance	Murray G. Harris, CA Vice-President, Financial Controller and Horizon Accounting

Calgary, Alberta, Canada
March 15, 2017

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Management's Assessment of Internal Control over Financial Reporting

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

Management, including the Company's President and the Company's Chief Financial Officer and Senior Vice-President, Finance, performed an assessment of the Company's internal control over financial reporting based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on the assessment, management has concluded that the Company's internal control over financial reporting is effective as at December 31, 2016. Management recognizes that all internal control systems have inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, has provided an opinion on the Company's internal control over financial reporting as at December 31, 2016, as stated in their Independent Auditor's Report.

(signed) "Steve W. Laut"	(signed) "Corey B. Bieber"
Steve W. Laut	Corey B. Bieber, CA
President	Chief Financial Officer and Senior Vice-President, Finance

Calgary, Alberta, Canada
March 15, 2017

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Independent Auditor’s Report

To the Shareholders of
Canadian Natural Resources Limited

We have completed integrated audits of Canadian Natural Resources Limited’s 2016, 2015, and 2014 consolidated financial statements and its internal control over financial reporting as at December 31, 2016. Our opinions, based on our audits are presented below.

Report on the consolidated financial statements

We have audited the accompanying consolidated financial statements of Canadian Natural Resources Limited, which comprise the consolidated balance sheets as at December 31, 2016 and December 31, 2015 and 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, 2016, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management’s responsibility for the consolidated financial statements

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

Auditor’s responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards also require that we comply with ethical requirements.

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Canadian Natural Resources Limited as at December 31, 2016 and December 31, 2015 and its financial performance and its cash flows for each of the three years in the period ended December 31, 2016 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on internal control over financial reporting

We have also audited Canadian Natural Resources Limited’s internal control over financial reporting as at December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

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Management's responsibility for internal control over financial reporting

Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Assessment of Internal Control over Financial Reporting.

Auditor's responsibility

Our responsibility is to express an opinion on Canadian Natural Resources Limited's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on Canadian Natural Resources Limited's internal control over financial reporting.

Definition of internal control over financial reporting

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

Inherent limitations

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

Opinion

In our opinion, Canadian Natural Resources Limited maintained, in all material respects, effective internal control over financial reporting as at December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

Chartered Professional Accountants

Calgary, Alberta, Canada
March 15, 2017

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CONSOLIDATED BALANCE SHEETS

As at December 31

(millions of Canadian dollars)	Note	2016	2015
ASSETS			
Current assets			
Cash and cash equivalents		$17	$69
Accounts receivable		1,434	1,277
Current income taxes		851	677
Inventory	5	689	525
Prepaids and other		149	162
Investments	8	913	974
Current portion of other long-term assets	9	283	375
		4,336	4,059
Exploration and evaluation assets	6	2,382	2,586
Property, plant and equipment	7	50,910	51,475
Other long-term assets	9	1,020	1,155
		$58,648	$59,275
LIABILITIES			
Current liabilities			
Accounts payable		$595	$571
Accrued liabilities		2,222	2,089
Current portion of long-term debt	10	1,812	1,729
Current portion of other long-term liabilities	11	463	206
		5,092	4,595
Long-term debt	10	14,993	15,065
Other long-term liabilities	11	3,223	2,890
Deferred income taxes	12	9,073	9,344
		32,381	31,894
SHAREHOLDERS' EQUITY			
Share capital	13	4,671	4,541
Retained earnings		21,526	22,765
Accumulated other comprehensive income	14	70	75
		26,267	27,381
		$58,648	$59,275

Commitments and contingencies (note 19).

Approved by the Board of Directors on March 15, 2017

/s/ Catherine M. Best	/s/ N. Murray Edwards
Catherine M. Best	N. Murray Edwards
Chair of the Audit Committee and Director	Executive Chairman of the Board of Directors and Director

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CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)
For the years ended December 31

(millions of Canadian dollars, except per common share amounts)	Note	2016	2015	2014
Product sales		$11,098	$13,167	$21,301
Less: royalties		(575)	(804)	(2,438)
Revenue		10,523	12,363	18,863
Expenses				
Production		4,099	4,726	5,265
Transportation and blending		2,003	2,379	3,232
Depletion, depreciation and amortization	6, 7	4,858	5,483	4,880
Administration		345	390	367
Share-based compensation	11	355	(46)	66
Asset retirement obligation accretion	11	142	173	193
Interest and other financing expense	17	383	322	323
Risk management activities	18	33	(469)	(800)
Foreign exchange (gain) loss		(55)	761	303
Gain on disposition of properties and corporate acquisitions and dispositions	6, 7	(250)	(739)	(137)
(Gain) loss from investments	8, 9	(327)	50	8
		11,586	13,030	13,700
Earnings (loss) before taxes		(1,063)	(667)	5,163
Current income tax (recovery) expense	12	(618)	(261)	427
Deferred income tax (recovery) expense	12	(241)	231	807
Net earnings (loss)		$(204)	$(637)	$3,929
Net earnings (loss) per common share				
Basic	16	$(0.19)	$(0.58)	$3.60
Diluted	16	$(0.19)	$(0.58)	$3.58

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the years ended December 31

(millions of Canadian dollars)	2016	2015	2014
Net earnings (loss)	$(204)	$(637)	$3,929
Items that may be reclassified subsequently to net earnings (loss)			
Net change in derivative financial instruments designated as cash flow hedges			
Unrealized (loss) income, net of taxes of $3 million (2015 – $2 million, 2014 – $nil)	(18)	(23)	5
Reclassification to net earnings (loss), net of taxes of $2 million (2015 – $2 million, 2014 – $1 million)	(13)	(13)	8
	(31)	(36)	13
Foreign currency translation adjustment			
Translation of net investment	26	60	(4)
Other comprehensive income (loss), net of taxes	(5)	24	9
Comprehensive income (loss)	$(209)	$(613)	$3,938

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CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

For the years ended December 31

(millions of Canadian dollars)	Note	2016	2015	2014
Share capital	13			
Balance – beginning of year		$4,541	$4,432	$3,854
Issued upon exercise of stock options		559	91	488
Previously recognized liability on stock options exercised for common shares		117	18	129
Purchase of common shares under Normal Course Issuer Bid		—	—	(39)
Return of capital on PrairieSky Royalty Ltd. share distribution	8	(546)	—	—
Balance – end of year		4,671	4,541	4,432
Retained earnings				
Balance – beginning of year		22,765	24,408	21,876
Net earnings (loss)		(204)	(637)	3,929
Purchase of common shares under Normal Course Issuer Bid	13	—	—	(414)
Dividends on common shares	13	(1,035)	(1,006)	(983)
Balance – end of year		21,526	22,765	24,408
Accumulated other comprehensive income	14			
Balance – beginning of year		75	51	42
Other comprehensive (loss) income, net of taxes		(5)	24	9
Balance – end of year		70	75	51
Shareholders' equity		$26,267	$27,381	$28,891

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CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31

(millions of Canadian dollars)	Note	2016	2015	2014
Operating activities				
Net earnings (loss)		$(204)	$(637)	$3,929
Non-cash items				
Depletion, depreciation and amortization		4,858	5,483	4,880
Share-based compensation		355	(46)	66
Asset retirement obligation accretion		142	173	193
Unrealized risk management loss (gain)		25	374	(451)
Unrealized foreign exchange (gain) loss		(93)	858	256
Realized foreign exchange loss on repayment of US dollar debt securities		—	—	36
(Gain) loss from investments	8, 9	(299)	55	8
Deferred income tax (recovery) expense		(241)	231	807
Gain on disposition of properties and corporate acquisitions and dispositions		(250)	(739)	(137)
Current income tax on disposition of properties		—	33	—
Other		(32)	(22)	(38)
Abandonment expenditures		(267)	(370)	(346)
Net change in non-cash working capital	20	(542)	239	(744)
		3,452	5,632	8,459
Financing activities				
Issue of bank credit facilities and commercial paper, net		342	970	1,195
Issue of medium-term notes, net	10	998	107	992
(Repayment) issue of US dollar debt securities, net	10	(834)	—	1,482
Issue of common shares on exercise of stock options		559	91	488
Purchase of common shares under Normal Course Issuer Bid		—	—	(453)
Dividends on common shares		(758)	(1,251)	(955)
Net change in non-cash working capital	20	—	(40)	(22)
		307	(123)	2,727
Investing activities				
Net proceeds (expenditures) on exploration and evaluation assets (1)	20	6	236	(1,190)
Net expenditures on property, plant and equipment (1) (2)	20	(3,803)	(4,704)	(10,208)
Current income tax on disposition of properties		—	(33)	—
Investment in other long-term assets		(99)	(112)	(113)
Net change in non-cash working capital	20	85	(852)	334
		(3,811)	(5,465)	(11,177)
(Decrease) increase in cash and cash equivalents		(52)	44	9
Cash and cash equivalents – beginning of year		69	25	16
Cash and cash equivalents – end of year		$17	$69	$25
Interest paid, net		$617	$541	$521
Income taxes (received) paid		$(444)	$42	$792

(1) Net proceeds on exploration and evaluation assets and net expenditures on property, plant and equipment in 2015 exclude non-cash share consideration of $985 million received from PrairieSky Royalty Ltd. ("PrairieSky") on the disposition of royalty income assets.

(2) Net expenditures on property, plant and equipment in 2016 exclude non-cash share consideration of $190 million received from Inter Pipeline Ltd. ("Inter Pipeline") on the disposition of the Company's interest in the Cold Lake Pipeline.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire, Gabon, and South Africa in Offshore Africa.

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

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

The Company was incorporated in Alberta, Canada. The address of its registered office is 2100, 855 - 2 Street S.W., Calgary, Alberta, Canada.

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

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements have been prepared under the historical cost basis, unless otherwise required. The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and wholly owned partnerships. Subsidiaries are all entities over which the Company has control. Subsidiaries are consolidated from the date on which the Company obtains control. They are deconsolidated from the date that control ceases.

Certain of the Company's activities are conducted through joint arrangements in which two or more parties have joint control. Where the Company has a direct ownership interest in jointly controlled assets and obligations for the liabilities (a "joint operation"), the assets, liabilities, revenue and expenses related to the joint operation are included in the consolidated financial statements in proportion to the Company's interest. Where the Company has an interest in jointly controlled entities (a "joint venture"), it uses the equity method of accounting. Under the equity method, the Company's initial and subsequent investments are recognized at cost and subsequently adjusted for the Company's share of the joint venture's income or loss, less distributions received.

Joint ventures accounted for using the equity method of accounting are tested for impairment whenever objective evidence indicates that the carrying amount of the investment may not be recoverable. Indications of impairment include a history of losses, significant capital expenditure overruns, liquidity concerns, financial restructuring of the investee or significant adverse changes in the technological, economic or legal environment. The amount of the impairment is measured as the difference between the carrying amount of the investment and the higher of its fair value less costs of disposal and its value in use. Impairment losses are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized.

(B) SEGMENTED INFORMATION

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

(C) CASH AND CASH EQUIVALENTS

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

(D) INVENTORY

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

(E) EXPLORATION AND EVALUATION ASSETS

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

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

Once the technical feasibility and commercial viability of E&E assets are determined and a development decision is made by management, the E&E assets are tested for impairment upon reclassification to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. An E&E asset is derecognized upon disposal or when no future economic benefits are expected to arise from its use. Any gain or loss arising on derecognition of the asset is recognized in net earnings within depletion, depreciation and amortization.

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

(F) PROPERTY, PLANT AND EQUIPMENT

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

Exploration and Production

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

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

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

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Oil Sands Mining and Upgrading

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

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

Midstream and Head Office

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

Useful lives

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

Derecognition

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

Major maintenance expenditures

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

Impairment

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

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

(G) BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed in a business combination are recognized at their fair value at the date of the acquisition. Any excess of the consideration paid over the fair value of the net assets acquired is recognized as an asset. Any excess of the fair value of the net assets acquired over the consideration paid is recognized in net earnings.

(H) OVERBURDEN REMOVAL COSTS

Overburden removal costs incurred during the initial development of a mine at Horizon are capitalized to property, plant and equipment. Overburden removal costs incurred during the production of a mine are included in the cost of inventory, unless the overburden removal activity has resulted in a probable inflow of future economic benefits to the Company, in which case the costs are capitalized to property, plant and equipment. Capitalized overburden removal costs are depleted over the life of the mining reserves that directly benefit from the overburden removal activity.

(I) CAPITALIZED BORROWING COSTS

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

(J) LEASES

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

(K) ASSET RETIREMENT OBLIGATIONS

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

(L) FOREIGN CURRENCY TRANSLATION

Functional and presentation currency

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

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

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

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Transactions and balances

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

(M) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

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

Revenue represents the Company’s share net of royalty payments to governments and other mineral interest owners. Related costs of goods sold are comprised of production, transportation and blending, and depletion, depreciation and amortization expenses. These amounts have been separately presented in the consolidated statements of earnings.

(N) PRODUCTION SHARING CONTRACTS

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

(O) INCOME TAX

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

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

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

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

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

(P) SHARE-BASED COMPENSATION

The Company’s Stock Option Plan (the “Option Plan”) provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered. The liability for awards granted to employees is initially measured based on the grant date fair value of the awards and the number of awards expected to vest. The awards are re-measured each reporting period for subsequent changes in the fair value of the liability.

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Fair value is determined using the Black-Scholes valuation model under a graded vesting method. Expected volatility is estimated based on historic results. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by the employee and any previously recognized liability associated with the stock options are recorded as share capital.

The unamortized costs of employer contributions to the Company's share bonus program are included in other long-term assets.

(Q) FINANCIAL INSTRUMENTS

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

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

Cash and cash equivalents, accounts receivable and certain other long-term assets are classified as financial assets at amortized cost since it is the Company's intention to hold these assets to maturity and the related cash flows are mainly payments of principal and interest. Investments in publicly traded shares are classified as fair value through profit or loss. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as financial liabilities at amortized cost. Risk management assets and liabilities are classified as fair value through profit or loss.

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

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

Impairment of financial assets

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

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

(R) RISK MANAGEMENT ACTIVITIES

The Company periodically uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation

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models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The carrying amount of a risk management liability is adjusted for the Company's own credit risk.

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

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

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

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

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

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

Foreign currency forward contracts are periodically used to manage foreign currency cash requirements. The foreign currency forward contracts involve the purchase or sale of an agreed upon amount of US dollars at a specified future date at forward exchange rates. Changes in the fair value of foreign currency forward contracts designated as cash flow hedges are initially recorded in other comprehensive income and are reclassified to foreign exchange gains and losses when the hedged item is recognized in net earnings. Changes in the fair value of non-designated foreign currency forward contracts are recognized in risk management activities in net earnings.

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

(S) COMPREHENSIVE INCOME

Comprehensive income is comprised of the Company's net earnings and other comprehensive income. Other comprehensive income includes the effective portion of changes in the fair value of derivative financial instruments designated as cash flow hedges and foreign currency translation gains and losses arising from the net investment in foreign operations that do not have a Canadian dollar functional currency. Other comprehensive income is shown net of related income taxes.

(T) PER COMMON SHARE AMOUNTS

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

(U) SHARE CAPITAL

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

(V) DIVIDENDS

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

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2016, the Company adopted the amendment to IFRS 11 "Joint Arrangements" to clarify the accounting treatment when an entity acquires interests in joint ventures and joint operations. The amendment requires these acquisitions to be accounted for as business combinations. The Company adopted this amendment prospectively. Adoption of this amended standard did not result in an impact to the Company's consolidated financial statements.

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaces IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees. The new standard is effective January 1, 2019 with earlier adoption permitted providing that IFRS 15 has been adopted. The new standard is required to be applied retrospectively, with a policy alternative of restating comparative prior periods or recognizing the cumulative adjustment in opening retained earnings at the date of adoption. The Company is assessing the impact of this standard on its consolidated financial statements.

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" to provide guidance on the recognition of revenue and cash flows arising from an entity's contracts with customers, and related disclosures. The new standard replaces several existing standards related to recognition of revenue and states that revenue should be recognized as performance obligations related to the goods or services delivered are settled. IFRS 15 also provides revenue accounting guidance for contract modifications and multiple-element contracts and prescribes additional disclosure requirements. In 2015, the IASB deferred the effective date for the new standard to January 1, 2018. The new standard is required to be adopted retrospectively, with earlier adoption permitted. The Company is assessing the impact of this standard on its consolidated financial statements.

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Effective January 1, 2014, the Company adopted the version of IFRS 9 "Financial Instruments" issued November 2013. In July 2014, the IASB issued amendments to IFRS 9 to include accounting guidance to assess and recognize impairment losses on financial assets based on an expected loss model. The amendments are effective January 1, 2018. The Company is assessing the impact of this amendment on its consolidated financial statements.

4. CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

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

(A) Crude Oil and Natural Gas Reserves

Purchase price allocations, depletion, depreciation and amortization, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties, interpretations and judgements. The Company expects that, over time, its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices.

(B) Asset Retirement Obligations

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

(C) Income Taxes

The Company is subject to income taxes in numerous legal jurisdictions. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

(D) Fair Value of Derivatives and Other Financial Instruments

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

(E) Purchase Price Allocations

Purchase prices related to business combinations are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation, and amortization expense and impairment tests.

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(F) Share-Based Compensation

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

(G) Identification of CGUs

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

(H) Impairment of Assets

The recoverable amount of a CGU or an individual asset has been determined as the higher of the CGU's or the asset's fair value less costs of disposal and its value in use. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available, including information on future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and operating costs, after-tax discount rates currently ranging from 9.5% to 12%, and income taxes. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

(I) Contingencies

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

5. INVENTORY

	2016	2015
Product inventory	$263	$186
Materials and supplies	426	339
	$689	$525

As a result of fluctuations in crude oil prices, the Company recorded a write-down of its product inventory of $73 million from cost to net realizable value as at December 31, 2016 (2015 - $174 million).

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6. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2014	$3,426	$ —	$ 131	$ —	$3,557
Additions	132	—	35	—	167
Transfers to property, plant and equipment	(567)	—	—	—	(567)
Disposals/derecognitions [1]	(491)	—	(96)	—	(587)
Foreign exchange adjustments	—	—	16	—	16
At December 31, 2015	2,500	—	86	—	2,586
Additions	20	—	9	—	29
Transfers to property, plant and equipment	(211)	—	—	—	(211)
Disposals/derecognitions	(3)	—	(18)	—	(21)
Foreign exchange adjustments	—	—	(1)	—	(1)
At December 31, 2016	$2,306	$ —	$ 76	$ —	$2,382

(1) Refer to note 7 regarding the disposition of exploration and evaluation assets in the North America segment in 2015.

During 2016, the Company disposed of a number of North America exploration and evaluation assets totaling $3 million for consideration of $35 million, resulting in a pre-tax gain on sale of properties of $32 million. In addition, in connection with the Company's notice of withdrawal from Block CI-12 in Côte d'Ivoire, Offshore Africa, the Company derecognized $18 million of exploration and evaluation assets.

During 2015, in connection with the Company’s notice of withdrawal from Block CI-514 in Côte d’Ivoire, Offshore Africa, the Company derecognized $96 million of exploration and evaluation assets.

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7. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2014	$60,606	$6,182	$ 3,858	$ 21,948	$ 570	$ 352	$93,516
Additions	691	13	524	2,523	7	26	3,784
Transfers from E&E assets	567	—	—	—	—	—	567
Disposals/derecognitions	(1,324)	—	—	(128)	—	—	(1,452)
Foreign exchange adjustments and other	—	1,219	791	—	—	—	2,010
At December 31, 2015	60,540	7,414	5,173	24,343	577	378	98,425
Additions	1,462	186	116	2,822	6	17	4,609
Transfers from E&E assets	211	—	—	—	—	—	211
Disposals/derecognitions	(566)	—	—	(127)	(349)	—	(1,042)
Foreign exchange adjustments and other	—	(220)	(157)	—	—	—	(377)
At December 31, 2016	$61,647	$7,380	$ 5,132	$ 27,038	$ 234	$ 395	$101,826
Accumulated depletion and depreciation							
At December 31, 2014	$31,886	$4,049	$ 2,890	$ 1,864	$ 120	$ 227	$41,036
Expense	4,226	383	177	562	12	27	5,387
Disposals/derecognitions	(758)	—	—	(128)	—	—	(886)
Foreign exchange adjustments and other	(7)	832	592	(4)	—	—	1,413
At December 31, 2015	35,347	5,264	3,659	2,294	132	254	46,950
Expense	3,440	457	243	662	11	27	4,840
Disposals/derecognitions	(486)	—	—	(127)	(28)	—	