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

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

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

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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.

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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	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
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	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
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								
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								
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	Net	Unproved Properties Gross	Net	Total Acreage Gross	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.

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	-	-	-	-	-	