CANADIAN NATURAL RESOURCES LTD
Form 40-F
March 27, 2019

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, 2018	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, 28 Liberty Street, New York, New York 10005
(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

Indicate the 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.
1,201,885,667 Common Shares outstanding as of December 31, 2018

Canadian Natural Resources Limited 1 Year Ended December 31, 2018

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the Registrant in connection with such Rule.

Yes [ ] No [X]

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 is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.

Emerging Growth Company [___]

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

[___]

† The term new or revised financial accounting standard refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

This Annual Report on Form 40-F shall be incorporated by reference into, or as an exhibit to, as applicable, the Registrant's Registration Statements on Form F-10 (File Nos. 333-219366 and 333-219367) 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 6, 2019 the reported Bank of Canada noon rate for one Canadian dollar was US$0.7438. On March 6, 2019 the reported Bank of Canada noon rate for one U.S. dollar was C$1.3444.

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, 2018.

B. Audited Annual Financial Statements

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2018 and 2017, including the report of independent registered public accounting firm with respect thereto.

C. Management's Discussion and Analysis

Canadian Natural's Management's Discussion and Analysis for the year ended December 31, 2018.

The following document is filed as an exhibit to this Annual Report on Form 40-F and is incorporated by reference herein:

A. Supplementary Oil & Gas Information (Unaudited)

For Canadian Natural's Supplementary Oil & Gas Information (Unaudited) for the year ended December 31, 2018, see Exhibit 99.1 to this Annual Report on Form 40-F.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2018

March 27, 2019

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DEFINITIONS AND ABBREVIATIONS

AOSP	Athabasca Oil Sands Project
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
C$ or $	Canadian dollars
"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
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
crude oil	includes light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, synthetic crude oil and bitumen (thermal oil)
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	discounted value of crude oil and natural gas reserves plus value of unproved land, less net debt
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
Quest	Quest Carbon Capture and Storage ("CCS") project
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

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the “Company”) in this Annual Information Form (“AIF”) 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”, “con “could”, “intend”, “may”, “potential”, “predict”, “should”, “will”, “objective”, “project”, “forecast”, “goal”, “guidance”, “outlo “schedule”, “proposed” or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, income tax expenses, and other guidance provided throughout this 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, AOSP and Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the cost and timing of 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, NGLs or SCO that the Company may be reliant upon to transport its products to market, development and deployment of technology and technological innovations, the assumption of operations at processing facilities, and the "2019 Activity" section of this AIF with respect to budgeted capital expenditures for 2019, also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts, and are 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 reserves 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, natural gas and NGL 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; the 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; the 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; the timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves 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 expenditures and production expenses); 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 national, federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available. For additional information refer to the "Risks Factors" section of this AIF.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this AIF could also have 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 applicable 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 the Company's estimates or opinions change.

SPECIAL NOTE REGARDING CURRENCY, FINANCIAL INFORMATION, PRODUCTION AND RESERVES

In this AIF, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data are presented on a "before royalties" or " company gross" basis unless otherwise stated and realized prices are net of blending and feedstock costs and exclude the effects of risk management activities. 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:1bbl conversion 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, 2018, 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, 2018, 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, 2018 and a preparation date of February 4, 2019. Sproule evaluated and reviewed 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 Oil Sands Mining and Upgrading SCO reserves. The evaluations and reviews were 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 98 to 105 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; adjusted funds flow (previously referred to as funds flow from operations); net capital expenditures; 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), cash flows from operating activities, and cash flows used in investing activities, as determined in accordance with IFRS, as an indication of the Company’s performance. The non-GAAP measure adjusted net earnings (loss) from operations is reconciled to net earnings (loss), as determined in accordance with IFRS in the “Financial and Operational Highlights" section of the MD&A for the year ended December 31, 2018. Additionally, the non-GAAP measure adjusted funds flow is reconciled to cash flows from operating activities, as determined in accordance with IFRS, in the "Financial and Operational Highlights" section of the MD&A. The non-GAAP measure net capital expenditures is reconciled to cash flows used in investing activities, as determined in accordance with IFRS, in the "Net Capital Expenditures" section of the MD&A. The derivation of adjusted cash production costs is included in the “Operating Highlights – Oil Sands Mining and Upgrading” section of the MD&A. The non-GAAP measure free cash flow represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital from operating activities, abandonment, certain movements in other long-term assets, less net capital expenditures and dividends paid on common shares of the Company.

Principal Documents Exhibits

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
January 1, 2003 - Rio Alto Exploration Ltd.
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.
January 1, 2019 - Laricina Energy Ltd.

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
CNR (Redwater) Limited	Alberta	100
Horizon Construction Management Ltd.	Alberta	100
Sukunka Natural Resources Inc.	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.

In the ordinary course of business, Canadian Natural restructures its subsidiaries and partnerships to maintain efficient operations.

The consolidated financial statements of Canadian Natural include the accounts of the Company and all of its subsidiaries and wholly owned partnerships as well as certain of the Company's activities which are conducted through joint arrangements.

GENERAL DEVELOPMENT OF THE BUSINESS

2016

In June 2016, the Company completed the net distribution of approximately 21.8 million PrairieSky Royalty Ltd. ("PrairieSky") common shares to the shareholders of record of the Company as at June 3, 2016, completing a previously announced Plan of Arrangement. As part of an earlier transaction, 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. 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.

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 May 31, 2017, the Company completed its acquisition of a direct and indirect 70% interest in AOSP, including 70% of the Scotford Upgrader and the Quest Carbon Capture and Storage ("CCS") project, as well as additional working interests in other producing and non-producing oil sands leases through a transaction with Shell Canada Limited and certain of its subsidiaries ("Shell”) and Marathon Oil Corporation (“Marathon Oil”).

Total purchase consideration of $12,541 million, subject to closing adjustments, was comprised of cash payments of $8,217 million, approximately 97.6 million common shares of the Company issued to Shell with a value of approximately $3,818 million as determined at the closing date, and deferred purchase consideration of $506 million (US$375 million). To finance the acquisition of the AOSP, the Company entered into a $3,000 million non-revolving term credit facility maturing May 2020. At December 31, 2017, this facility was fully drawn. As well, the Company issued $1,800 million of medium term notes comprised of $900 million 2.05% notes due June 2020, $600 million 3.42% notes due December 2026 and $300 million 4.85% notes due May 2047. The Company also issued US$3,000 million of debt securities comprised of US$1,000 million 2.95% notes due January 2023, US$1,250 million 3.85% notes due June 2027 and US$750 million 4.95% notes due June 2047.

In addition, in 2017 the Company extended $2,095 million of the $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021 with the remaining $330 million maturing June 2019 and the Company's $1,500 million non-revolving term credit facility was increased to $2,200 million with the maturity date being extended to October 2019 from April 2018. As well, the Company repaid US$1,100 million of 5.70% notes.

In the third quarter of 2017, the Company acquired assets in the Greater Pelican Lake region and other miscellaneous assets in northern Alberta with production of approximately 19,600 BOE/d, for gross cash consideration of $975 million.

In the fourth quarter of 2017, the Company completed the construction and commissioning of its Horizon Phase 3 expansion.

In December 2017, the Company announced a number of senior management promotions positioning it for continued growth in both the long life low decline assets and low capital exposure assets.

2018

In March 2018, the Company paid the deferred purchase consideration of US$375 million to Marathon Oil in connection with the AOSP acquisition.

In the second quarter of 2018, the Company extended its $2,425 million revolving syndicated credit facility originally maturing in June 2020 to June 2022 and extended its $2,200 million non-revolving facility from October 2019 to October 2020. In 2018, the Company also extended the $750 million non-revolving credit facility originally due February 2019 to February 2021, fully repaid and canceled the $125 million non-revolving credit facility maturing February 2019, repaid and canceled $1,200 million of the $3,000 million non-revolving term credit facility maturing May 2020, and repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.

In September, 2018, the Company completed the acquisition of all of the issued and outstanding common shares and senior notes of Laricina Energy Ltd. ("Laricina") for a total purchase price of $95 million. Laricina was amalgamated with the Company on January 1, 2019.

In September 2018, the Company also completed its acquisition of a 100% working interest in the Joslyn oil sands project for a total purchase consideration of $100 million cash on closing and annual cash payments of $25 million over each of the subsequent five years.

In 2018, the Gabonese Republic approved cessation of production from the Company's Olowi field and the terms of termination of the Olowi Production Sharing Contract and the surrender of the permit area back to the Gabonese Republic.

In November 2018, the Company announced certain senior management promotions positioning it for continued growth in both the long life low decline assets and low capital exposure assets.

2019

The government of Alberta announced a mandatory curtailment of crude oil and bitumen production on December 2, 2018, which took effect on January 1, 2019. The amount of the curtailment is subject to monthly adjustment by the government.

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 and cash flow 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, 2018, the Company had the following full time equivalent permanent employees:

North America, Exploration and Production	4,395
North America, Oil Sands Mining and Upgrading	4,948
North Sea and Offshore Africa	366
Total Company	9,709

Operational discipline, together with safe, effective and efficient operations and cost control, are fundamental to the Company. By consistently managing costs throughout all industry cycles, the Company believes it will achieve continued growth. Safe operations that are effective and efficient and cost control are attained by developing area knowledge and by maintaining high working interests and operator status in its properties. The Company has grown through a combination of internal growth and strategic acquisitions. Acquisitions are made with a view to either entering new core regions or increasing the Company's presence in existing core regions.

The Company's business approach is to maintain large project inventories and production diversification among each of its products: SCO, natural gas, light and medium crude oil and NGLs, bitumen (thermal oil), primary heavy crude oil and Pelican Lake heavy crude 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. SCO from the oil sands mining and upgrading operations in Northern Alberta accounted for 39% of 2018 production. Natural gas, primarily produced in Alberta, British Columbia and Saskatchewan, accounted for 24% of 2018 production. Light and medium crude oil and NGLs represented 13% of 2018 production, and were produced from Alberta, British Columbia, Saskatchewan and Manitoba, as well as from the Company's North Sea and Offshore Africa operations. Also produced from Alberta and Saskatchewan were bitumen (thermal oil), which accounted for 10% of 2018 production, primary heavy crude oil which accounted for 8% of 2018 production, and and Pelican Lake heavy crude oil, which accounted for 6% of 2018 production. The Company's 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. Midstream assets also include a 50% interest in the North West Redwater Partnership.

In addition, the Company has entered into a 20 year transportation agreement to ship 75,000 bbl/d of crude oil on the proposed Trans Mountain Pipeline Expansion. The National Energy Board has provided its recommendation that construction of the pipeline should proceed and related consultations by the federal government with Indigenous communities are ongoing. Subject to federal cabinet approval, the project could be issued a revised Certificate of Public Convenience and Necessity this summer with construction re-starting as early as August 2019. The Company has also entered into a 20 year transportation agreement to ship 175,000 bbl/d of crude oil on the proposed TransCanada Keystone XL Pipeline. The proponent is awaiting the completion of a new supplemental environmental review addressing issues raised through litigation in a Montana Federal Court case. A decision is also expected in April 2019 on the Nebraska Public Service Commission's route approval. Pre-construction activities have started and the proponent is working to maintain a 2021 in-service date.

A. ENVIRONMENTAL MATTERS

The Company carries 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 government regulatory authorities 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, water management and land management to minimize disturbance impacts. 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 (the "Plan") along with the Company's operating guidelines focus on minimizing the environmental impact of operations while meeting regulatory requirements, regional management frameworks for air, water and biodiversity, industry operating standards and guidelines, and internal corporate standards. Training and due diligence for operators and contractors is key to the effectiveness of the Company's environmental management programs and the prevention of incidents to protect the environment. The Company, as a part of its Plan, has implemented programs that include: environmental planning to assess impacts and implement avoidance and mitigation programs in order to preserve high value biodiversity; continued evaluation of new technologies to reduce environmental impacts including support for Canada’s Oil Sands Innovation Alliance (“COSIA”), the Petroleum Technology Alliance Canada and other research institutions; CO_2 reduction programs including carbon capture, CO_2 injection for EOR, CO_2 sequestration in tailings and the Quest carbon capture and storage facility; a methane emission reduction program, including solution gas conservation to reduce methane venting and an equipment retrofit program to reduce methane emissions from pneumatic equipment; optimization of efficiencies at the Company's facilities; water programs to improve efficiency of use and recycle rates as well as reduce fresh water use; and an effective reclamation and decommissioning program across the Company's operations, returning sites to their former state. In North America, the Company has implemented: programs for well abandonment and progressive reclamation of large contiguous areas of land, which advances biodiversity and establishes functional wildlife habitats; tailings management in Oil Sands Mining to minimize fine tailings and promote reclamation; monitoring programs to assess changes to biodiversity, wildlife and fisheries in order to manage construction and operation effects and to assess reclamation success; participation and support for the Oil Sands Monitoring Program of regionally important resources; groundwater monitoring for all thermal in situ and mine operations; an active spill prevention and management program; and an internal environmental compliance audit and inspection program of operating facilities.

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 2018, Canadian Natural continued its environmental liability reduction program with the abandonment of 1,293 inactive wells. In addition, reclamation was initiated at many of these sites with the eventual goal of reclamation certification. In 2018, the Company received 717 reclamation certificates representing 1,383 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 provincially regulated GHG emissions reporting programs and continues to quantify annual GHG emissions for internal reporting 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.

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’s integrated GHG emissions reduction strategy includes: integrating emission reduction in project planning and operations; leveraging technology to create value and enhance performance; investing in research and development and supporting collaboration; focusing on continuous improvement to drive long-term emissions reduction; leading in carbon capture and sequestration/storage; engaging in policy and regulatory development (including trading capacity and offsetting emissions); and considering and developing new business opportunities and trends.

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 continues to enhance its integrated emissions reduction strategy, to ensure it is able to comply with existing and future emissions reduction requirements, for both GHG 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.

The Company also continues to implement flaring, venting, fuel and solution gas conservation programs, which influence and direct its future plans for new projects and facilities. In 2018, the Company completed approximately 425 gas conservation projects in its primary heavy crude oil operations, resulting in a reduction of approximately 2.4 million tonnes/year of CO_2e. Over the past five years, the Company has spent over $72 million in its primary heavy crude oil and in situ oil sands operations to conserve the equivalent of over 16.8 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 and has ongoing methane reduction programs for pneumatic devices. Oil Sands Mining 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 that enables 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 through 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 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 federal or respective provincial governments, which give the holder the right to explore for and produce bitumen, crude oil, and natural gas. The remainder of the properties are held under freehold (private ownership) leases.

Conventional petroleum and natural gas leases issued by the provinces of Alberta, Saskatchewan and Manitoba have a primary term from two to five years, and British Columbia leases/licences presently have a term of up to ten years. Those portions of the leases that are producing or are capable of producing at the end of the primary term will "continue" for the productive life of the lease.

An Alberta oil sands permit and oil sands primary lease is issued for five and fifteen years respectively. If the minimum level of evaluation of an oil sands permit is attained, a primary oil sands lease will be issued. A primary oil sands lease is continued based on the minimum level of evaluation attained on such lease. Continued primary oil sands leases that are designated as "producing" will continue for their productive lives and are not subject to escalating rentals while those designated as "non-producing" can be continued by payment of escalating rentals.

The provincial governments regulate the production of crude oil and natural gas as well as the removal of natural gas and NGLs from their respective province. Government royalties are payable on crude oil, natural gas and NGLs production from leases owned by the province. The royalties are determined by regulation and are generally calculated as a percentage of production varied by a number of different factors including selling prices, production levels, recovery methods, transportation and processing costs, location and date of discovery.

Alberta 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 NGLs 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.

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. 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 (i) a comprehensive management system for air pollutants and has released regulations pertaining to certain boilers, heaters and compressor engines operated by the Company; and (ii) a Clean Fuel Standard, which may affect production and consumption of fuels in Canada.

Effective January 1, 2018, the Alberta government implemented the Carbon Competitiveness Incentive Regulation (CCIR) to replace the Specified Gas Emitters Regulation, for the regulation of GHG emissions from large facilities. The Alberta government has also finalized regulations to reduce methane emissions from the upstream oil and gas sector (consistent with the federal reduction target), with the first regulatory requirements coming into effect January 1, 2020. A previously announced carbon price on combustion emissions from the upstream oil and gas sector is scheduled to begin in 2023. In British Columbia, the provincial government has announced a methane reduction target, comparable to the federal target, and has released final regulations to achieve this target. The Saskatchewan government has also released a regulation to reduce methane emissions from crude oil production facilities, effective 2020. In Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually, or for those facilities that elect to "opt-in" to the regulations. The carbon price in Alberta is currently $30/tonne for emissions above the regulated limits. Eight of the Company's operated facilities (the Horizon and AOSP facilities, the Primrose/Wolf Lake in situ heavy crude oil facilities, the Kirby South in situ heavy crude oil facility, the Peace River in situ heavy crude oil facility, the Hays sour natural gas plant, the Wapiti gas plant and the Brintnell power generation facility) are subject to compliance under the regulation. The non-operated Scotford Upgrader is also subject to compliance under the regulations. The non-operated North West Redwater bitumen upgrader and refinery will not be subject to a reduction target until 2020. In British Columbia, carbon tax is currently being assessed at $35/tonne of CO_2e on fuel consumed and gas flared in the province, with the rate increasing to $40/tonne on April 1, 2019. The British Columbia government will be increasing the carbon tax at a rate of $5 per tonne of CO_2e annually to $50 per tonne of CO_2e on April 1, 2021. The British Columbia government is implementing a program (the CleanBC Plan) to partially mitigate the impact of the carbon tax increases on emission intensive trade exposed (EITE) sectors. The Saskatchewan government has released a regulation that applies to facilities emitting more than 25 kilotonnes of CO_2e annually and will require the North Tangleflags in situ heavy crude oil facility and the Senlac in situ heavy crude oil facility to meet reduction targets for GHG emissions effective 2019. The government of Canada has determined that a federal "backstop" carbon pricing system will apply beginning in 2019 in specific provinces and territories within Canada, including the provinces of Saskatchewan and Manitoba in which the Company operates. The federal backstop system will consist of an output-based pricing system for facilities that emit more than 25 kilotonnes CO2e annually, and a fuel charge that applies to facilities with emissions below this level.

The International Maritime Organization (IMO) will implement a new regulation (IMO 2020) effective January 1, 2020, that places sulphur content limits (currently 3.5% to 0.5%) on marine fuel oil consumed by vessels. In our North American operations, IMO 2020 is anticipated to have a net positive impact due to SCO from the Company's Oil Sands Mining and Upgrading operations, a large percentage of which can be processed and refined into low-sulphur diesel.

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 regulatory and 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 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.

During the fourth quarter of 2018, the Gabonese Republic approved cessation of production from the Company's Olowi Field and associated decommissioning obligations, as well as the terms of termination of the Olowi Production Sharing Contract and the surrender of the permit area back to the government.

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 price for 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, government mandated curtailment, the availability of alternate fuel sources and weather conditions, and other factors. Natural gas prices realized by the Company are affected primarily in North America by supply and demand, weather conditions, industrial demand and the ability to secure adequate transportation for products which could also be affected by pipeline constraints, government mandated curtailment, and prices of alternate sources of energy. Crude oil and natural gas producers in Canada may receive discounted prices for their production relative to international prices due in part to constraints on the ability to transport and sell products to international markets. A failure to resolve such constraints may result in continued discounted or reduced commodity prices realized by crude oil and natural gas producers, including the Company.

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, AOSP, Primrose, Pelican Lake, the Kirby Thermal Oil Sands Project, and international projects, or curtailment in production at some properties, or result in unutilized long-term transportation commitments, all of which could have a material adverse effect on the Company's financial condition.

Approximately 24% of the Company's 2018 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 periodic assessments of the carrying value of its assets in accordance with IFRS. If crude oil and natural gas forecast prices decline, the carrying value of related property, plant and equipment could be subject to downward revisions, and net earnings could be adversely affected.

Operational Risk

Exploring for, producing, mining, extracting, upgrading and transporting crude oil, natural gas and NGLs involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. These activities are subject to a number of hazards which may result in fires, explosions, spills, blow outs or other unexpected or dangerous conditions causing personal injury, property damage, environmental damage, interruption of operations and loss of production, whether caused by human error or nature. In addition to the foregoing, the oil sands mining and upgrading operations are also subject to loss of production, potential shutdowns and increased production expenses due to the integration of the various component parts.

The Company's business also carries risks associated with environmental and safety performance, which are closely scrutinized by governments, the public and the media, and could result in the suspension of or the inability to obtain regulatory approvals and permits, or, in the case of a major incident, fines, civil suits, and/or criminal charges against the Company.

The jurisdictions where Canadian Natural operates are subject to labour legislation and regulations that if changed may impact its operations. In addition, labour risk associated with work interruptions and the securing of necessary manpower may impact the timely and cost effective manner in which projects are completed.

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 national, 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 compliance, particularly in North America and the North Sea. In respect of its offshore operations, the Company also participates with regulators and industry partners in addressing environmental monitoring and emergency response protocols that are applicable to the Company's operations in these jurisdictions. 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 may have a material adverse effect on the Company’s financial condition, including the following:

l Greenhouse Gas Emissions Management

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 international, national, federal and provincial level. In Canada, the government of Alberta has proceeded with implementing the measures in the Climate Leadership Plan that were announced in November 2015, 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 modification of 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, reductions in pneumatic devices, CO_2 capture and sequestration in oil sands tailings, CO_2 capture and storage in association with EOR, CO_2 capture and storage at Quest, 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. The Canadian government and certain provincial governments have published regulations to reduce methane emissions from the oil and natural gas sector, in support of a joint commitment made by the US and Canadian governments to lower emissions from the sector by 2025.

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 the Company's existing and planned oil sands projects. This may have an adverse effect on the Company's financial condition.

l Air Emissions Management

The Company could face additional costs to retrofit certain equipment to meet the requirements of the federal Multi-Sector Air Pollutants Regulations in Canada. Additional costs may be required to retrofit other equipment in specific regions to meet ambient air quality objectives, as part of regional air zone management.

l Tailings Management

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 which was updated in October 2017. 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.

In 2018, the Company continued to implement and adhere to the conditions stipulated in the approved Tailings Management Plans for the Horizon Mine (the "Horizon TMP"), and the AOSP's Muskeg River Mine and Jackpine Mine and thereby met the requirements of the government of Alberta’s Tailings Management Framework (2015) and the Alberta Energy Regulator’s Directive 85. In the future, there is the potential risk of deviating above the approved site-specific tailings profiles resulting in the requirement to post additional security under the Mining Financial Security Plan as well as the potential application of a compliance levy.

In September 2018, the Company acquired the Joslyn oil sands project (now referred to as “Horizon South”). Prior to development, the AER requires the Company to prepare an updated mine plan that will incorporate tailings and closure planning considerations by November 13, 2019. As a result, it is anticipated that, in 2019, further updates will be required to the Horizon TMP to integrate the development of Horizon South.

In December 2018, Alberta Environment and Parks released the new Dam and Canal Safety Directive (the "Directive"). The Directive outlines a detailed process for all fluid holding infrastructure in Alberta (including tailings ponds), on application requirements, performance monitoring and reporting, and decommissioning and closure process. The Company is working with the regulator to determine how the Directive will be implemented and enforced. Muskeg River Mine has obtained several authorizations as it works through the decommissioning process for its External Tailings Facility, reducing the mine's environmental risk and liability.

l Regulatory and Policy Effectiveness

The Company operates under government regulation and policy for the crude oil and natural gas sector including, land tenure, royalties, taxes, production rates, environmental management, and safety performance. Before proceeding with major projects, the Company must follow a determined regulatory process to obtain project approvals and permits. These processes may include Indigenous and stakeholder consultation, environmental impact assessments and public hearings. Canadian Natural’s project execution and timelines could be impacted by delays experienced through the regulatory processes or by conditions placed on its operations through permit approvals. Changes in government policy, such as the federal government’s Bill-69, have the potential to impact the certainty and timelines for the regulatory process on large energy projects, including increased requirements for Indigenous consultation. The Company is working with industry peers, CAPP and others to ensure that its concerns regarding Bill C-69 are communicated to the Canadian government.

l Land Use, Water and Wildlife Management

Legislation and policies related to land management may affect development and operations risk through changes in regional limits on operating standards for air emissions, water use, land disturbance and reclamation. Land planning is used to set aside areas for conservation, reclamation and biodiversity that places limits on crude oil and natural gas development. Management frameworks establish limits and triggers for surface and ground water quality and quantity, land disturbance and air emissions that could increase the standards for operation of facilities.

Water licencing, use and release standards are becoming increasingly stringent both in the process of obtaining access to water and to manage it efficiently. Sub-basin water use licence restrictions and the inability to manage allocations of water licences effectively by transferring water to alternate uses has the potential to increase production expenses. Alberta Wetland Policy changes may increase requirements and payments for new project development.

The Species at Risk Act (Canada) requires the maintenance of habitat for a variety of species. In the case of Woodland Caribou, the requirements of undisturbed habitat combined with minimum herd population from all cumulative land changes may impact plans for crude oil and natural gas expansion. The presence of other species at risk such as birds or amphibians requires that operations be managed to avoid or mitigate effects resulting in potential operational inefficiencies and delays.

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 reserves base and acquiring or discovering additional reserves. Without additions to reserves through exploration, acquisition or development activities, the Company's production will decline over time as reserves are depleted. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent the Company's cash flow is 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 Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors, both internal and external, beyond the Company's control. 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. In general, estimates of economically recoverable crude oil, natural gas and NGLs reserves and the future net revenue therefrom are based upon a number of factors and assumptions made as of the date on which the reserves estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of royalty regimes, environmental and other regulation by governmental agencies and estimates of future commodity prices, production costs and the timing and amount of future development expenditures, 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 to fund current and future capital projects and carry out the business plan is dependent on Canadian Natural's ability to generate cash flow as well as raise capital in a timely manner under favourable terms and conditions and is impacted by the Company's credit ratings and the condition of the capital and credit markets. In addition, changes in credit ratings may affect the ability to, and the associated costs of, entering into ordinary course derivative or hedging transactions, as well as entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms. The Company also enters into various transactions with counterparties and is subject to credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts.

Dividends

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

Foreign Investments

The Company's foreign investments involve risks typically associated with investments in developing countries such as uncertain political, economic, legal and tax environments. These risks may include, among other things, currency restrictions and exchange rate fluctuations, loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, war, insurrection and other political risks, risk of increases in taxes and governmental royalties, renegotiation of contracts with governmental entities and quasi-governmental agencies, changes in laws and policies governing operations of foreign based companies, including compliance with existing and emerging anti-corruption laws, and other uncertainties arising out of foreign government sovereignty over the Company's international operations. In addition, if a dispute arises in its foreign operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of a court in Canada or the United States.

Canadian Natural's arrangement for the exploration and development of crude oil and natural gas properties in Canada and the UK sector of the North Sea differs distinctly from its arrangement for the exploration and development of crude oil and natural gas properties in other foreign jurisdictions. 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 reserves quantities and future net revenues 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 periodically 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 Security

The nature and complexity of information security risks that may negatively impact the Company continues to evolve as cyber criminals develop new schemes to target businesses and perpetrate cyber-related frauds that target the information technology and business systems of the Company. 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 combating 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 cybersecurity protocols and procedures to address this risk.

Other cybersecurity risks include cyber-related fraud and theft or destruction of financial and other assets of the Company whereby perpetrators attempt to spoof, manipulate, or take control of electronic communications from Company executives, suppliers, or other business partners, to divert payments and assets to accounts controlled by perpetrators of the scheme. A successful cyber-related fraud of this nature could result in the financial losses to the Company, remediation and recovery costs, and reputational issues with suppliers, customers and business partners who may also be impacted by the scheme. The Company has implemented training programs that allow personnel to identify potential threats of this nature in addition to the internal accounting and process controls implemented 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 royalty regimes, risk of litigation, risk to the Company's reputation resulting from operational activities that may cause personal injury, property damage or environmental damage, labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner, severe weather conditions, timing and success of integrating the business and operations of acquired companies and businesses, and the dependency on third party operators for certain 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 to repay the indebtedness of the Company.

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

For the year ended December 31, 2018, 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, 2018 and a preparation date of February 4, 2019. Sproule evaluated and reviewed 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 Oil Sands Mining and Upgrading SCO reserves. The evaluations and reviews were 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 annual report on Form 40-F filed with the SEC in the “Supplementary Oil and Gas Information” section of the Company’s Annual Report on pages 98 to 105 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. See "Special Note Regarding Forward-Looking Statements", "Special Note Regarding Currency, Financial Information, Production and Reserves", and "Risk Factors".

Summary of Company Gross Reserves
As of December 31, 2018
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	114	97	248	311	6,091	3,477	101	7,541
Developed Non-Producing	14	16	—	123	—	326	10	218
Undeveloped	66	69	57	1,106	—	2,794	156	1,920
Total Proved	194	182	305	1,540	6,091	6,597	267	9,679
Probable	74	70	140	1,519	941	3,036	130	3,379
Total Proved plus Probable	268	252	445	3,059	7,032	9,633	397	13,058
North Sea								
Proved								
Developed Producing	34					23		38
Developed Non-Producing	4					—		4
Undeveloped	81					4		82
Total Proved	119					27		124
Probable	67					11		69
Total Proved plus Probable	186					38		193
Offshore Africa								
Proved								
Developed Producing	41					17		44
Developed Non-Producing	—					—		—
Undeveloped	45					11		46
Total Proved	86					28		90
Probable	35					35		41
Total Proved plus Probable	121					63		131
Total Company								
Proved								
Developed Producing	189	97	248	311	6,091	3,517	101	7,623
Developed Non-Producing	18	16	—	123	—	326	10	222
Undeveloped	192	69	57	1,106	—	2,809	156	2,048
Total Proved	399	182	305	1,540	6,091	6,652	267	9,893
Probable	176	70	140	1,519	941	3,082	130	3,489

Total Proved plus Probable	575	252	445	3,059	7,032	9,734	397	13,382

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Summary of Company Net Reserves
As of December 31, 2018
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	101	81	189	252	5,125	3,183	80	6,358
Developed Non-Producing	12	14	—	104	—	303	8	189
Undeveloped	56	59	48	911	(8)	2,519	131	1,616
Total Proved	169	154	237	1,267	5,117	6,005	219	8,163
Probable	61	57	100	1,210	761	2,676	104	2,740
Total Proved plus Probable	230	211	337	2,477	5,878	8,681	323	10,903
North Sea								
Proved								
Developed Producing	34					23		38
Developed Non-Producing	4					—		4
Undeveloped	81					4		82
Total Proved	119					27		124
Probable	67					11		69
Total Proved plus Probable	186					38		193
Offshore Africa								
Proved								
Developed Producing	36					12		38
Developed Non-Producing	—					—		—
Undeveloped	36					9		38
Total Proved	72					21		76
Probable	26					23		30
Total Proved plus Probable	98					44		106
Total Company								
Proved								
Developed Producing	171	81	189	252	5,125	3,218	80	6,434
Developed Non-Producing	16	14	—	104	—	303	8	193
Undeveloped	173	59	48	911	(8)	2,532	131	1,736
Total Proved	360	154	237	1,267	5,117	6,053	219	8,363
Probable	154	57	100	1,210	761	2,710	104	2,839

Total Proved plus Probable	514	211	337	2,477	5,878	8,763	323	11,202

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 reserves 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 producibility at greater distances.

5. The reserves 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.

Summary of Net Present Values of Future Net Revenue Before Income Taxes (1)
As of December 31, 2018
Forecast Prices and Costs

MM$	Discount @ 0%	Discount @ 5%	Discount @ 10%	Discount @ 15%	Discount @ 20%	Unit Value Discounted at 10%/year ($/BOE) (2)
North America						
Proved						
Developed Producing	361,010	143,064	82,072	57,648	45,025	12.91
Developed Non-Producing	5,331	3,697	2,945	2,468	2,121	15.58
Undeveloped	39,173	27,921	15,804	9,128	5,416	9.78
Total Proved	405,514	174,682	100,821	69,244	52,562	12.35
Probable	152,532	45,299	20,981	12,563	8,664	7.66
Total Proved plus Probable	558,046	219,981	121,802	81,807	61,226	11.17
North Sea						
Proved						
Developed Producing	(258)	699	956	1,010	1,000	25.16
Developed Non-Producing	78	63	51	41	34	12.75
Undeveloped	4,339	3,320	2,624	2,129	1,764	32.00
Total Proved	4,159	4,082	3,631	3,180	2,798	29.28
Probable	5,129	3,255	2,289	1,732	1,381	33.17
Total Proved plus Probable	9,288	7,337	5,920	4,912	4,179	30.67
Offshore Africa						
Proved						
Developed Producing	1,293	1,265	1,175	1,080	996	30.92
Developed Non-Producing	—	—	—	—	—	
Undeveloped	2,137	1,399	972	707	533	25.58
Total Proved	3,430	2,664	2,147	1,787	1,529	28.25
Probable	2,557	1,656	1,157	860	671	38.57
Total Proved plus Probable	5,987	4,320	3,304	2,647	2,200	31.17
Total Company						
Proved						
Developed Producing	362,045	145,028	84,203	59,738	47,021	13.09
Developed Non-Producing	5,409	3,760	2,996	2,509	2,155	15.52
Undeveloped	45,649	32,640	19,400	11,964	7,713	11.18
Total Proved	413,103	181,428	106,599	74,211	56,889	12.75
Probable	160,218	50,210	24,427	15,155	10,716	8.60
Total Proved plus Probable	573,321	231,638	131,026	89,366	67,605	11.70

(1) Abandonment and reclamation costs included in the calculation of the Future Net Revenue (FNR) 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 Asset Retirement Obligation (ARO) for development existing as at December 31, 2018. The portion of the Company’s estimated ARO included in the reserves FNR is escalated at 2.0% per year after 2019. For additional information, refer to "Additional Information Concerning Future Net Revenue."

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

Summary of Net Present Values of Future Net Revenue After Income Taxes(1) (2)
As of December 31, 2018
Forecast Prices and Costs

MM$	Discount @ 0%	Discount @ 5%	Discount @ 10%	Discount @ 15%	Discount @ 20%
North America					
Proved					
Developed Producing	266,889	107,718	62,772	44,606	35,135
Developed Non-Producing	3,981	2,691	2,123	1,768	1,511
Undeveloped	28,784	19,876	10,827	5,896	3,182
Total Proved	299,654	130,285	75,722	52,270	39,828
Probable	111,673	32,859	15,080	8,958	6,137
Total Proved plus Probable	411,327	163,144	90,802	61,228	45,965
North Sea					
Proved					
Developed Producing	(82)	446	593	627	626
Developed Non-Producing	(103)	(3)	19	22	20
Undeveloped	2,765	2,089	1,652	1,346	1,122
Total Proved	2,580	2,532	2,264	1,995	1,768
Probable	3,105	1,985	1,406	1,072	860
Total Proved plus Probable	5,685	4,517	3,670	3,067	2,628
Offshore Africa					
Proved					
Developed Producing	1,008	1,032	980	914	851
Developed Non-Producing	—	—	—	—	—
Undeveloped	1,624	1,076	754	554	422
Total Proved	2,632	2,108	1,734	1,468	1,273
Probable	1,924	1,253	882	659	518
Total Proved plus Probable	4,556	3,361	2,616	2,127	1,791
Total Company					
Proved					
Developed Producing	267,815	109,196	64,345	46,147	36,612
Developed Non-Producing	3,878	2,688	2,142	1,790	1,531
Undeveloped	33,173	23,041	13,233	7,796	4,726
Total Proved	304,866	134,925	79,720	55,733	42,869
Probable	116,702	36,097	17,368	10,689	7,515
Total Proved plus Probable	421,568	171,022	97,088	66,422	50,384

(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 MD&A for the year ended December 31, 2018.

(2) Abandonment and reclamation costs included in the calculation of the Future Net Revenue (FNR) 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 Asset Retirement Obligation (ARO) for development existing as at December 31, 2018. The portion of the Company’s estimated ARO included in the reserves FNR is escalated at 2.0% per year after 2019. For additional information, refer to "Additional Information Concerning Future Net

Revenue."

Additional Information Concerning Future Net Revenue

The following table summarizes the undiscounted future net revenue as at December 31, 2018 using forecast prices and costs. Abandonment and reclamation costs included in the calculation of the future net revenue 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, 2018. The Company's estimated ARO at December 31, 2018 was $12,312 million, unescalated and undiscounted (escalated and discounted at 10%, ARO at December 31, 2018 was $1,456 million). Approximately $8,717 million of this unescalated and undiscounted amount was also included in the future net revenue and is escalated at 2.0% per year after 2019. Specifically, for North America (excluding SCO assets), future net revenue includes the costs associated with abandonment and reclamation of wells (wells, well sites, well site 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 facilities. In addition, the future net revenue for Horizon assets also includes abandonment and reclamation of the 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.

	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	958,011	1,288,755	13,308	21,629	7,334	10,122	978,653	1,320,506
Royalties	158,276	222,801	28	47	239	352	158,543	223,200
Production Costs	304,520	393,252	5,927	8,659	2,507	2,466	312,954	404,377
Development Costs	76,525	99,931	1,502	1,943	807	932	78,834	102,806
Abandonment and Reclamation Costs – Future Development	416	752	—	—	44	78	460	830
Abandonment and Reclamation Costs – Existing Development	12,760	13,973	1,692	1,692	307	307	14,759	15,972
Future Net Revenue Before Income Taxes	405,514	558,046	4,159	9,288	3,430	5,987	413,103	573,321
Income Taxes	105,860	146,719	1,579	3,603	798	1,431	108,237	151,753
Future Net Revenue After Income Taxes [(1)]	299,654	411,327	2,580	5,685	2,632	4,556	304,866	421,568

(1) 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 product type as at December 31, 2018 using forecast prices and costs. 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, 2018, which are not applied at the product type level.

Future Net Revenue By Product Type

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (discounted at 10%/year) (MM$)	Unit Value ($/BOE) (1)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	11,381	22.45
	Primary Heavy Crude Oil (including solution gas)	2,863	18.41
	Pelican Lake Heavy Crude Oil (including solution gas)	4,209	17.71
	Bitumen (Thermal Oil)	15,811	12.48
	Synthetic Crude Oil	66,689	13.03
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	6,852	6.35
	Abandonment and Reclamation Costs – Existing Development	(1,206)	
	Total	106,599	12.75
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	16,865	23.31
	Primary Heavy Crude Oil (including solution gas)	4,038	18.92
	Pelican Lake Heavy Crude Oil (including solution gas)	5,659	16.75
	Bitumen (Thermal Oil)	21,785	8.79
	Synthetic Crude Oil	74,353	12.65
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	9,588	6.10
	Abandonment and Reclamation Costs – Existing Development	(1,262)	
	Total	131,026	11.70

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

Principal Documents Exhibits

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, 2018. The following is a summary of the Sproule price forecast. All prices increase at a rate of 2% per year after 2023.

	2019	2020	2021	2022	2023
Crude Oil and NGLs					
WTI (1) (US$/bbl)	63.00	67.00	70.00	71.40	72.83
WCS (2) (C$/bbl)	59.47	62.31	67.45	69.53	71.66
Canadian Light Sweet (3) (C$/bbl)	75.27	77.89	82.25	84.79	87.39
Cromer LSB (4) (C$/bbl)	75.27	76.89	81.25	83.79	86.39
Edmonton C5+ (5) (C$/bbl)	75.32	80.00	83.75	85.50	87.29
North Sea Brent (6) (US$/bbl)	70.00	72.00	73.00	74.46	75.95
Natural Gas					
AECO (7) (C$/MMBtu)	1.95	2.44	3.00	3.21	3.30
BC Westcoast Station 2 (8) (C$/MMBtu)	1.35	1.94	2.60	2.81	2.90
Henry Hub (9) (US$/MMBtu)	3.00	3.25	3.50	3.57	3.64

(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 0.77 US$/C$ for 2019, and 0.80 US$/C$ after 2019 was used in the 2018 evaluation.

Production and capital costs are escalated at Sproule’s cost inflation rate of 0% per year for 2019 and 2% per year after 2019 for all products.

The Company’s 2018 average pricing, net of blending costs and excluding risk management activities, was $74.20/bbl for light and medium crude oil, $38.98/bbl for primary heavy crude oil, $43.30/bbl for Pelican Lake heavy crude oil, $33.66/bbl for bitumen (thermal oil), $68.61/bbl for SCO, $40.64 for NGLs, and $2.61/Mcf for natural gas.

Reconciliation of Company Gross Reserves
As of December 31, 2018
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, 2017	171	198	327	1,350	5,264	6,730	229	8,661
Discoveries	—	—	—	—	—	—	—	—
Extensions	12	14	—	171	808	122	9	1,034
Infill Drilling	17	6	—	4	—	470	38	143
Improved Recovery	—	—	1	2	—	3	—	4
Acquisitions	3	2	—	—	—	82	4	22
Dispositions	—	(5)	—	—	—	(3)	—	(5)
Economic Factors	—	1	1	—	—	(305)	(4)	(53)
Technical Revisions	10	(2)	(1)	52	175	42	6	247
Production	(19)	(32)	(23)	(39)	(156)	(544)	(15)	(374)
December 31, 2018	194	182	305	1,540	6,091	6,597	267	9,679
North Sea								
December 31, 2017	120					21		124
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	1					—		1
Improved Recovery	—					—		—
Acquisitions	8					—		8
Dispositions	—					—		—
Economic Factors	5					—		5
Technical Revisions	(6)					18		(3)
Production	(9)					(12)		(11)
December 31, 2018	119					27		124
Offshore Africa								
December 31, 2017	83					20		86
Discoveries	—					—		—
Extensions	—					—		—

Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	10					17		13
Production	(7)					(9)		(9)
December 31, 2018	86					28		90
Total Company								
December 31, 2017	374	198	327	1,350	5,264	6,771	229	8,871
Discoveries	—	—	—	—	—	—	—	—
Extensions	12	14	—	171	808	122	9	1,034
Infill Drilling	18	6	—	4	—	470	38	144
Improved Recovery	—	—	1	2	—	3	—	4
Acquisitions	11	2	—	—	—	82	4	30
Dispositions	—	(5)	—	—	—	(3)	—	(5)
Economic Factors	5	1	1	—	—	(305)	(4)	(48)
Technical Revisions	14	(2)	(1)	52	175	77	6	257
Production	(35)	(32)	(23)	(39)	(156)	(565)	(15)	(394)
December 31, 2018	399	182	305	1,540	6,091	6,652	267	9,893

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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, 2017	68	74	142	1,230	799	2,790	106	2,884
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	7	—	59	71	93	5	162
Infill Drilling	6	2	—	1	—	391	22	97
Improved Recovery	1	—	2	2	—	1	—	4
Acquisitions	1	1	—	403	—	22	1	410
Dispositions	—	(1)	—	—	—	(2)	—	(2)
Economic Factors	(1)	—	—	—	—	(104)	(1)	(19)
Technical Revisions	(5)	(13)	(4)	(176)	71	(155)	(3)	(157)
Production	—	—	—	—	—	—	—	—
December 31, 2018	74	70	140	1,519	941	3,036	130	3,379
North Sea								
December 31, 2017	60					11		61
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	5					—		5
Dispositions	—					—		—
Economic Factors	(5)					—		(5)
Technical Revisions	7					—		8
Production	—					—		—
December 31, 2018	67					11		69
Offshore Africa								
December 31, 2017	42					47		50
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—

Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	(7)					(12)		(9)
Production	—					—		—
December 31, 2018	35					35		41
Total Company								
December 31, 2017	170	74	142	1,230	799	2,848	106	2,995
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	7	—	59	71	93	5	162
Infill Drilling	6	2	—	1	—	391	22	97
Improved Recovery	1	—	2	2	—	1	—	4
Acquisitions	6	1	—	403	—	22	1	415
Dispositions	—	(1)	—	—	—	(2)	—	(2)
Economic Factors	(6)	—	—	—	—	(104)	(1)	(24)
Technical Revisions	(5)	(13)	(4)	(176)	71	(167)	(3)	(158)
Production	—	—	—	—	—	—	—	—
December 31, 2018	176	70	140	1,519	941	3,082	130	3,489

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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, 2017	239	272	469	2,580	6,063	9,520	335	11,545
Discoveries	—	—	—	—	—	—	—	—
Extensions	16	21	—	230	879	215	14	1,196
Infill Drilling	23	8	—	5	—	861	60	240
Improved Recovery	1	—	3	4	—	4	—	8
Acquisitions	4	3	—	403	—	104	5	432
Dispositions	—	(6)	—	—	—	(5)	—	(7)
Economic Factors	(1)	1	1	—	—	(409)	(5)	(72)
Technical Revisions	5	(15)	(5)	(124)	246	(113)	3	90
Production	(19)	(32)	(23)	(39)	(156)	(544)	(15)	(374)
December 31, 2018	268	252	445	3,059	7,032	9,633	397	13,058
North Sea								
December 31, 2017	180					32		185
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	1					—		1
Improved Recovery	—					—		—
Acquisitions	13					—		13
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	1					18		5
Production	(9)					(12)		(11)
December 31, 2018	186					38		193
Offshore Africa								
December 31, 2017	125					67		136
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—

Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	3					5		4
Production	(7)					(9)		(9)
December 31, 2018	121					63		131
Total Company								
December 31, 2017	544	272	469	2,580	6,063	9,619	335	11,866
Discoveries	—	—	—	—	—	—	—	—
Extensions	16	21	—	230	879	215	14	1,196
Infill Drilling	24	8	—	5	—	861	60	241
Improved Recovery	1	—	3	4	—	4	—	8
Acquisitions	17	3	—	403	—	104	5	445
Dispositions	—	(6)	—	—	—	(5)	—	(7)
Economic Factors	(1)	1	1	—	—	(409)	(5)	(72)
Technical Revisions	9	(15)	(5)	(124)	246	(90)	3	99
Production	(35)	(32)	(23)	(39)	(156)	(565)	(15)	(394)
December 31, 2018	575	252	445	3,059	7,032	9,734	397	13,382

(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.

2018 total Proved Crude Oil, Bitumen (Thermal Oil) and NGLs reserves increased by 1,042 MMbbl primarily due to the following:

- Extensions: Increase of 1,014 MMbbl primarily due to the addition of Horizon South to the Horizon oil sands mining and upgrading project (SCO), future Bitumen (Thermal Oil) well pad additions at Primrose and extension drilling/future offset additions at various Primary Heavy Crude Oil, Light Crude Oil and natural gas (NGLs) properties.
- Infill Drilling: Increase of 66 MMbbl primarily due to infill drilling/future offset additions at various Light Crude Oil, Primary Heavy Crude Oil and natural gas (NGLs) properties.
- Improved Recovery: Increase of 3 MMbbl.
- Acquisitions: Increase of 17 MMbbl primarily due to property acquisitions in North America and North Sea core areas.
- Dispositions: Decrease of 5 MMbbl from the Primary Heavy Crude Oil properties.
- Economic Factors: Increase of 3 MMbbl.
- Technical Revisions: Increase of 244 MMbbl primarily due to geological model changes and improved mine/extraction/upgrading performance at the oil sands mining and upgrading projects (SCO) and improved recoveries at Primrose (Bitumen (Thermal Oil)).
- Production: Decrease of 300 MMbbl.

2018 total Proved Natural Gas reserves decreased by 119 Bcf primarily due to the following:

- Extensions: Increase of 122 Bcf primarily due to extension drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Infill Drilling: Increase of 470 Bcf primarily due to infill drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Improved Recovery: Increase of 3 Bcf.
- Acquisitions: Increase of 82 Bcf primarily due to property acquisitions in North America core areas.
- Dispositions: Decrease of 3 Bcf.
- Economic Factors: Decrease of 305 Bcf due to uneconomic reserves in several North America Natural Gas areas.
- Technical Revisions: Increase of 77 Bcf primarily due to overall positive revisions in several North America, North Sea and Offshore Africa core areas as a result of increased recovery.
- Production: Decrease of 565 Bcf.

2018 total Proved plus Probable Crude Oil, Bitumen and NGLs reserves increased by 1,497 MMbbl primarily due to the following:

- Extensions: Increase of 1,160 MMbbl primarily due to the addition of Horizon South to the Horizon oil sands mining and upgrading project (SCO), future Bitumen (Thermal Oil) well pad additions at Primrose and extension drilling/future offset additions at various Primary Heavy Crude Oil, Light Crude Oil and natural gas (NGLs) properties.
- Infill Drilling: Increase of 97 MMbbl primarily due to infill drilling/future offset additions at various Light Crude Oil and natural gas (NGLs) properties.
- Improved Recovery: Increase of 8 MMbbl.
- Acquisitions: Increase of 428 MMbbl primarily due to property acquisitions at Germain (Bitumen (Thermal Oil)) and in North America and North Sea core areas.
- Dispositions: Decrease of 6 MMbbl from the Primary Heavy Crude Oil properties.
- Economic Factors: Decrease of 4 MMbbl.
- Technical Revisions: Increase of 114 MMbbl primarily due to geological model changes and improved mine/extraction/upgrading performance at the oil sands mining and upgrading projects (SCO), partially offset by the 50 year reserves life cutoff at Primrose (Bitumen (Thermal Oil)).
- Production: Decrease of 300 MMbbl.

2018 total Proved plus Probable Natural Gas reserves increased by 115 Bcf primarily due to the following:

-

Extensions: Increase of 215 Bcf primarily due to extension drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.

- Infill Drilling: Increase of 861 Bcf primarily due to infill drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.

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- Improved Recovery: Increase of 4 Bcf.
- Acquisitions: Increase of 104 Bcf primarily due to property acquisitions in North America core areas.
- Dispositions: Decrease of 5 Bcf.
- Economic Factors: Decrease of 409 Bcf due to uneconomic reserves in several North America Natural Gas areas.
- Technical Revisions: Decrease of 90 Bcf primarily due to overall negative revisions in the probable category as a result of transfers to proved categories, shut-in of uneconomic fields, and removal of future extension and infill undeveloped reserves in several North America properties because of revised Company development plans.
- Production: Decrease of 565 Bcf.

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)
2016								
First Attributed	14	3	—	55	—	282	13	132
Total	192	76	50	934	15	2,117	89	1,709
2017								
First Attributed	5	10	9	21	—	416	30	144
Total	188	75	61	994	—	2,366	119	1,831
2018								
First Attributed	25	10	—	175	—	518	42	338
Total	192	69	57	1,106	—	2,809	156	2,048

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)
2016								
First Attributed	10	2	—	30	—	130	8	72
Total	147	42	27	1,023	240	1,214	54	1,735
2017								
First Attributed	6	7	1	19	—	366	19	113
Total	97	41	26	1,006	—	1,561	73	1,503
2018								
First Attributed	9	8	—	463	359	464	26	942
Total	91	41	28	1,304	359	1,925	96	2,240

The IQRE reserves evaluation report documents the evaluation, assignment and rationale for undeveloped reserves beyond COGE Handbook development timing guidelines.

Bitumen (thermal oil) accounts for 54% of the Company's total proved undeveloped BOE reserves and 58% of the total probable undeveloped BOE reserves. These undeveloped reserves are scheduled to be developed in a staged approach to align with current operational capacities and efficient capital spending commitments over the next fifty years. Bitumen (thermal oil) development plans are continuously reviewed and updated for internal and external factors.

For products other than bitumen (thermal oil), the assignment of some undeveloped reserves beyond the COGE Handbook guidelines is based on Canadian Natural's capital development plan to optimize operations and align capital investments with estimated future net revenue. The extended development timing has no consequential impact on the confidence level associated with the reserves estimate in each category. Rationales for development timing include:

- large capital projects with facility constraints where development plans are designed to optimize operations and deliver supply for the life of the facility;
- resource plays with extensive ongoing development;
- EOR or waterflood projects with ongoing, extensive development opportunity;
- integrated development of several fields with common facilities to ensure the optimum use of capital;
- development plan is a function of prioritizing according to drainage concerns, maximizing capital efficiency and achieving strategic objectives for the Company; and
- deferral of ongoing development motivated by market conditions, capital constraints, and Company strategy, either separately or in combination.

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 "Uncertainty of Reserves Estimates" in the "Risk Factors" section of 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, 2018.

	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$)	Proved plus Probable (MM$)
2019	2,400	2,506	191	194	123	165	2,714	2,865
2020	4,122	4,341	197	203	132	132	4,451	4,676
2021	4,117	4,329	143	147	133	181	4,393	4,657
2022	3,663	3,976	154	158	91	126	3,908	4,260
2023	2,583	3,057	110	138	34	34	2,727	3,229
Thereafter	59,640	81,722	707	1,103	294	294	60,641	83,119
Total	76,525	99,931	1,502	1,943	807	932	78,834	102,806

Note: Total Future Development Costs discounted at 10% are:

North America		North Sea		Offshore Africa		Total	
Proved (MM$)	Proved plus Probable (MM$)	Proved (MM$)	Proved plus Probable (MM$)	Proved (MM$)	Proved plus Probable (MM$)	Proved (MM$)	Proved plus Probable (MM$)
26,271	30,985	918	1,033	542	645	27,731	32,663

Management believes that internally generated cash flows, existing credit facilities and access to debt capital markets are sufficient to fund future development costs. The Company does 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, 2018 and 2017.

Region	2018 Average Daily Production Rates		2017 Average Daily Production Rates	
	Crude Oil & NGLs (Mbbl)	Natural Gas (MMcf)	Crude Oil & NGLs (Mbbl)	Natural Gas (MMcf)
North America				
Northeast British Columbia	13	345	13	397
Northwest Alberta	46	667	42	662
Northern Plains	268	194	280	223
Southern Plains	18	282	19	316
Southeast Saskatchewan	6	2	6	3
Oil Sands Mining & Upgrading	426	—	282	—
North America Total	777	1,490	642	1,601
International				
North Sea UK Sector	24	32	23	39
Offshore Africa	20	26	20	22
International Total	44	58	43	61
Company Total	821	1,548	685	1,662

Northeast British Columbia

The Northeast British Columbia Region holds a significant portion of the Montney formation. This formation produces liquids rich natural gas and light oil from several stratigraphic intervals. The exploration strategy focuses on comprehensive evaluation through two dimensional seismic, three dimensional seismic and targeting economic prospects close to existing infrastructure. 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 liquids rich natural gas and light oil 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 structural area. In 2018, Canadian Natural agreed to acquire the Pine River plant, operated by a third party, which transaction is currently awaiting regulatory approval. The plant is currently operating at 90 MMcf/d.

Northwest Alberta

This region is located west of Edmonton, Alberta along the border of British Columbia and Alberta and provides a premium land base in the deep basin, multi-zone liquids rich natural gas and light oil fairway. Northwest Alberta has a significant Montney and Spirit River land base, and provides exploration and exploitation opportunities in combination with an extensive portfolio of 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. Locations are identified with two dimensional and three dimensional seismic to predict channel and shoreface fairways. The southwestern portion of this region also contains significant Foothills assets with natural gas produced from the deep Mississippian and Triassic aged reservoirs.

Northern Plains

This region extends just south of Edmonton, 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.

The Company targets low-risk exploration and development opportunities 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 78,000 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 expenses 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 100% owned and operated Pelican Lake Pipeline and four major oil batteries with a capacity of 95,000 bbl/d. The Company is using an EOR scheme through polymer flooding to increase the ultimate recoveries from the field. In 2018, polymer flood restoration on the acquired lands was completed ahead of schedule and at the end of 2018, approximately 62% of the field had been converted to polymer injection on an area basis.

Production of bitumen (thermal oil) from the 100% owned Primrose Field located near Bonnyville, Alberta and Kirby South field located near Lac la Biche, Alberta, involves processes that utilize steam to increase the recovery of the bitumen (averaging 8°-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 two processing plants (Wolf Lake and Kirby South) with capacity of 180,000 bbl/d. The Company also holds a 50% interest in a co-generation facility capable of producing 84 megawatts of electricity. The Company continues to optimize the CSS, SAGD and steamflood processes which results in significant improvements in well productivity and in ultimate bitumen recovery. Pad additions at Primrose continue to be on budget and ahead of schedule.

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 re-initiated the development of the Kirby North Project and engineering and procurement commenced in 2017. Cost performance remains on budget with the overall project being approximately 94% complete (87% complete as of December 31, 2018). Kirby North's overall capacity of 40,000 bbl/d of SAGD production is targeted for late 2020.

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 southeastern 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.

Oil Sands Mining and Upgrading

Horizon: Canadian Natural owns a 100% working interest in its Horizon oil sands leases which are located about 70 kilometers north of Fort McMurray, Alberta, of which the main lease is subject to a 5% net carried interest in the bitumen development. 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 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 180 megawatts provide power and steam for operations.

The Company received project sanction by the Board of Directors in February 2005, authorizing management to proceed with Phase 1 of Horizon with a design capacity of 110,000 bbl/d. First SCO production was achieved during 2009.

In 2014, the Company completed the Phase 2A coker plant tie-in, followed by the Phase 2B expansion in the third quarter of 2016. In the fourth quarter of 2017, the Company completed the Phase 3 expansion bringing total production capacity to approximately 250,000 bbl/d.

In the third quarter of 2018, the Company acquired the Joslyn oil sands project, adding to the Company's total oil sands mining and upgrading reserves. This incorporation of the Joslyn leases (now, Horizon South) to the mine plan will allow mining to continue south of the previously existing Horizon leases with opportunity for further cost optimizations.

AOSP: In May 2017, the Company acquired a combined direct and indirect 70% interest in AOSP which is an oil sands mining and upgrading joint venture located in Alberta, Canada. The Company operates AOSP's mining and extraction assets which are located in the Athabasca region near Fort McMurray, Alberta, and include the Muskeg River and the Jackpine mines. Shell operates the Scotford Upgrader, including the Quest project, which is located near Fort Saskatchewan, northeast of Edmonton, Alberta and utilizes LC FINING technology to efficiently hydrocrack residuum to high-quality fuel oils and transportation fuels.

Bitumen is produced from the oil sands deposits using conventional truck and shovel technology. The ore is then processed through extraction and froth treatment facilities to produce bitumen. Diluted bitumen blend from the Muskeg River and Jackpine mines is transported to the Scotford Upgrader on the third party owned Corridor Pipeline where the bitumen is upgraded into Premium Albian Synthetic crude oil, Albian Heavy Synthetic crude oil and Vacuum Gas Oil and, in certain circumstances, other heavy blends. Diluent is transported from the Scotford Upgrader back to the Muskeg River mine through the combined Corridor Pipeline transport system. A long term off-take agreement is in place with Shell to purchase Vacuum Gas Oil at market rates as well as agreements to sell volumes of Premium Albian Synthetic and Albian Heavy Synthetic from the Scotford Upgrader at market rates.

Gross design capacity of the combined AOSP mines is 280,000 bbl/d of bitumen (196,000 bbl/d net). Shell obtained the Joint Review Panel Approval along with other associated approvals in 2013 for a 100,000 bbl/d expansion of the Jackpine Mine and is subject to several additional auxiliary approvals.

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 2018, the Company produced from 10 crude oil fields.

The northerly fields are centered around the Ninian field where the Company has a 100% operated working interest, having acquired the remaining 12.9% working interest in 2018. The central processing facility is connected to other fields including the Columba 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 6 licences covering 10 blocks and part blocks surrounding the Ninian platform.

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 targeted to be completed in 2020.

Due to the Company's continued focus on proactive capital allocation and lowering overall operating and capital cost structures, the Company commenced abandonment of the Ninian North Platform in the second quarter of 2017. The decommissioning activities are targeted to be completed in approximately five years.

Offshore Africa

Côte d'Ivoire

The Company owns interests in two 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 from West Espoir in 2006. Crude oil from the East and West Espoir fields is produced to an FPSO with the associated natural gas delivered onshore for local power generation through a subsea pipeline.

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.

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 Platforms A and B. In December 2018, the Company ceased production at the Olowi field and expects to complete all decommissioning operations in the first half of 2019.

South Africa

In May 2012, the Company completed the conversion of its 100% owned oil sub-lease in respect of Block 11B/12B (the “Block”) off the southeast coast of South Africa into an exploration right for petroleum for this area. The Company currently has a 20% working interest in the Block, having disposed of a 50% interest in its exploration right in 2013 and an additional 30% interest in two separate farm out transactions in 2018. In December 2018, the operator re-entered the suspended Brudpadda exploration well and has subsequently announced the discovery of gas condensate from that prospect on the Block. The Company expects the cost of the current exploration well to be fully carried pursuant to the two farm out transactions completed in 2018. In the event that a commercial crude oil or natural gas discovery occurs resulting in the exploration right being converted into a production right, additional cash payments would be due to the Company at that time.

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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, 2018.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	28,803.0	23,377.3	11,819.0	10,517.6	40,622.0	33,894.9
British Columbia	2,042.0	1,780.5	219.0	202.5	2,261.0	1,983.0
Saskatchewan	10,691.0	9,803.6	2,654.0	1,632.0	13,345.0	11,435.6
Manitoba	—	—	236.0	199.9	236.0	199.9
Total Canada	41,536.0	34,961.4	14,928.0	12,552.0	56,464.0	47,513.4
United States Louisiana	—	—	2.0	0.3	2.0	0.3
North Sea UK Sector	1.0	0.7	57.0	53.9	58.0	54.6
Offshore Africa						
Côte d'Ivoire	—	—	26.0	15.1	26.0	15.1
Gabon	—	—	—	—	—	—
Total	41,537.0	34,962.1	15,013.0	12,621.3	56,550.0	47,583.4

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, 2018.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Non-Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	7,619.0	6,019.6	9,637.0	8,379.8	17,256.0	14,399.4
British Columbia	2,326.0	1,953.7	570.0	481.1	2,896.0	2,434.8
Saskatchewan	2,019.0	1,916.7	3,344.0	2,721.6	5,363.0	4,638.3
Manitoba	—	—	70.0	49.4	70.0	49.4
Northwest Territories	69.0	17.3	—	—	69.0	17.3
Total Canada	12,033.0	9,907.3	13,621.0	11,631.9	25,654.0	21,539.2
United States Louisiana	—	—	2.0	0.3	2.0	0.3
North Sea UK Sector	2.0	1.5	19.0	17.4	21.0	18.9
Offshore Africa						
Côte d'Ivoire	—	—	13.0	7.5	13.0	7.5
Gabon	—	—	13.0	12.0	13.0	12.0
Total	12,035.0	9,908.8	13,668.0	11,669.1	25,703.0	21,577.9

Properties With Attributed and No Attributed Reserves

The following table summarizes the Company's landholdings as at December 31, 2018.

	Proved Properties		Unproved Properties		Total Acreage		Average Working Interest	
Region (thousands of acres)	Gross	Net	Gross	Net	Gross	Net	%	
North America								
Northeast British Columbia	763	670	4,813	4,053	5,576	4,723	85	%
Northwest Alberta	1,770	1,348	3,543	2,709	5,313	4,057	76	%
Northern Plains	1,889							