

Management's Discussion and Analysis

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Definitions and Abbreviations

AECO	Alberta natural gas reference location	IFRS	International Financial Reporting Standards
AIF	Annual Information Form	LIBOR	London Interbank Offered Rate
AOSP	Athabasca Oil Sands Project	Mbbl	thousand barrels
API	specific gravity measured in degrees on the American Petroleum Institute scale	Mbbl/d	thousand barrels per day
ARO	asset retirement obligations	MBOE	thousand barrels of oil equivalent
barrel	barrel	MBOE/d	thousand barrels of oil equivalent per day
bbl/d	barrels per day	Mcf	thousand cubic feet
Bcf	billion cubic feet	Mcfe	thousand cubic feet equivalent
Bcf/d	billion cubic feet per day	Mcf/d	thousand cubic feet per day
Bitumen	a 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	MMbbl	million barrels
BOE	barrels of oil equivalent	MMBOE	million barrels of oil equivalent
BOE/d	barrels of oil equivalent per day	MMBtu	million British thermal units
Brent	Dated Brent	MMcf	million cubic feet
C\$	Canadian dollars	MMcf/d	million cubic feet per day
CAGR	compound annual growth rate	NGLs	natural gas liquids
CAPEX	capital expenditures	NYMEX	New York Mercantile Exchange
CO₂	carbon dioxide	NYSE	New York Stock Exchange
CO₂e	carbon dioxide equivalents	OPEC	Organization of the Petroleum Exporting Countries
Crude oil	includes light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and synthetic crude oil	PRT	Petroleum Revenue Tax
CSS	Cyclic Steam Stimulation	SAGD	Steam-Assisted Gravity Drainage
EOR	Enhanced Oil Recovery	SCO	synthetic crude oil
E&P	Exploration and Production	SEC	United States Securities and Exchange Commission
FASB	Financial Accounting Standards Board	Tcf	trillion cubic feet
FPSO	Floating Production, Storage and Offloading Vessel	TSX	Toronto Stock Exchange
GHG	greenhouse gas	UK	United Kingdom
GJ	gigajoules	US	United States
GJ/d	gigajoules per day	US GAAP	generally accepted accounting principles in the United States
Horizon	Horizon Oil Sands	US\$	United States dollars
IASB	International Accounting Standards Board	WCS	Western Canadian Select
		WCS Heavy Differential	WCS Heavy Differential from WTI
		WTI	West Texas Intermediate reference location at Cushing, Oklahoma

Advisory

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration" 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 Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including, without limitation, those in relation to the Company's assets at Horizon, AOSP, Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the Jackfish Thermal Oil Sands Project, the timing and future operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new, or expansion of existing, pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, natural gas liquids ("NGLs") or synthetic crude oil ("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 "Outlook" section of this MD&A, particularly in reference to the 2020 guidance provided with respect to budgeted capital expenditures, 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 earlier of the 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 (including as a result of demand and supply effects resulting from the COVID-19 virus pandemic and the actions of OPEC and non-OPEC countries) 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; 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 mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets; 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 (including production curtailments mandated by the Government of Alberta); 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, state 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.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this MD&A 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 in this MD&A, 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 NON-GAAP FINANCIAL MEASURES

This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings from operations; adjusted funds flow (previously referred to as funds flow from operations) and net capital expenditures. These financial measures are not defined by International Financial Reporting Standards ("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, 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 from operations is reconciled to net earnings, as determined in accordance with IFRS, in the "Financial and Operational Highlights" section of this MD&A. 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 this 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 this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

SPECIAL NOTE REGARDING CURRENCY, FINANCIAL INFORMATION, PRODUCTION AND RESERVES

This MD&A should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2019. It should also be read in conjunction with the Company's MD&A for the three months and year ended December 31, 2019, which is incorporated herein by reference. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's consolidated financial statements and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB"). Changes in the Company's accounting policies in accordance with IFRS, including the adoption of IFRS 16 "Leases" on January 1, 2019, are discussed in the "Changes in Accounting Policies" section of this MD&A. In accordance with the new IFRS 16 "Leases" standard, comparative balances in 2018 reported in this MD&A have not been restated.

Production volumes, per unit statistics and reserves data are presented throughout this MD&A on a "before royalties" or "company gross" basis, and realized prices are net of blending and feedstock costs and exclude the effect 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 ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO. Production on an "after royalties" or "company net" basis is also presented in this MD&A for information purposes only.

The following discussion and analysis refers primarily to the Company's 2019 financial results compared to 2018 and 2017, unless otherwise indicated. In addition, this MD&A details the Company's targeted capital program for 2020. Additional information relating to the Company, including its quarterly MD&A for the three months and year ended December 31, 2019, its Annual Information Form for the year ended December 31, 2019, and its audited consolidated financial statements for the year ended December 31, 2019, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Detailed guidance on production levels, capital expenditures and production expenses can be found on the Company's website at www.cnrl.com. Information on the Company's website, including such guidance, does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated March 18, 2020.

Objectives and Strategy

The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value ⁽¹⁾ on a per common share basis through the economic and sustainable development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves. The Company strives to meet these objectives in a sustainable and responsible way, maintaining a commitment to environmental stewardship and safety excellence.

The Company strives to meet these objectives by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a balanced approach to growth and investments and focuses on creating long-term shareholder value. The Company allocates its capital by maintaining:

- Balance among its products, namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil ⁽²⁾, bitumen (thermal oil), SCO and natural gas;
- A large, balanced, diversified, high quality, long life low decline asset base;
- Balance among acquisitions, exploitation and exploration;
- Balance between sources and terms of debt financing and a strong financial position; and
- Commitment to environmental stewardship throughout the decision-making process.

(1) Discounted value of crude oil and natural gas reserves plus value of unproved land, less net debt.

(2) Pelican Lake heavy crude oil is 12–17° API oil, which receives medium quality crude netbacks due to lower production expense and lower royalty rates.

The Company's three-phase crude oil marketing strategy includes:

- Blending various crude oil streams with diluents to create more attractive feedstock;
- Supporting and participating in pipeline expansions and/or new additions; and
- Supporting and participating in projects that will increase the downstream conversion capacity for heavy crude oil and bitumen (thermal oil).

Operational discipline, safe, effective and efficient operations, and cost control are fundamental to the Company and embraces the key piece of the Company's mission statement: "doing it right". By consistently managing costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Effective and efficient operations and cost control are attained by developing area knowledge, and by maintaining high working interests and operator status in its properties.

The Company is committed to maintaining a strong balance sheet and flexible capital structure. The Company believes it has built the necessary financial capacity to complete its growth projects. Additionally, the Company periodically utilizes its risk management hedging program to reduce the risk of volatility in commodity prices and foreign exchange rates and to support the Company's cash flow for its capital expenditure programs.

Strategic accretive acquisitions are a key component of the Company's strategy. The Company has used a combination of internally generated cash flows and debt and equity financing to selectively acquire properties generating future cash flows in its core areas. The Company's financial discipline, commitment to a strong balance sheet, and capacity to internally generate cash flows provides the means to responsibly and sustainably grow in the long term.

Financial and Operational Highlights

(\$ millions, except per common share amounts)		2019	2018	2017
Product sales ⁽¹⁾		\$ 24,394	\$ 22,282	\$ 18,360
Crude oil and NGLs		\$ 22,950	\$ 20,668	\$ 16,522
Natural gas		\$ 1,419	\$ 1,614	\$ 1,838
Net earnings		\$ 5,416	\$ 2,591	\$ 2,397
Per common share	– basic	\$ 4.55	\$ 2.13	\$ 2.04
	– diluted	\$ 4.54	\$ 2.12	\$ 2.03
Adjusted net earnings from operations ⁽²⁾		\$ 3,795	\$ 3,263	\$ 1,403
Per common share	– basic	\$ 3.19	\$ 2.68	\$ 1.19
	– diluted	\$ 3.18	\$ 2.67	\$ 1.19
Cash flows from operating activities		\$ 8,829	\$ 10,121	\$ 7,262
Adjusted funds flow ⁽³⁾		\$ 10,267	\$ 9,088	\$ 7,347
Per common share	– basic	\$ 8.62	\$ 7.46	\$ 6.25
	– diluted	\$ 8.61	\$ 7.43	\$ 6.21
Dividends declared per common share ⁽⁴⁾		\$ 1.50	\$ 1.34	\$ 1.10
Total assets		\$ 78,121	\$ 71,559	\$ 73,867
Total long-term liabilities		\$ 36,493	\$ 34,823	\$ 35,953
Cash flows used in investing activities		\$ 7,255	\$ 4,814	\$ 13,102
Net capital expenditures ⁽⁵⁾		\$ 7,121	\$ 4,731	\$ 17,129
Average sales price ⁽⁶⁾				
Crude oil and NGLs - Exploration and Production (\$/bbl)		\$ 55.08	\$ 46.92	\$ 48.57
Natural gas - Exploration and Production (\$/Mcf)		\$ 2.34	\$ 2.61	\$ 2.76
Oil Sands Mining and Upgrading (\$/bbl)		\$ 70.18	\$ 68.61	\$ 63.98
Daily production, before royalties (BOE/d)		1,098,957	1,078,813	962,264
Crude oil and NGLs (bbl/d)		850,393	820,778	685,236
Natural gas (MMcf/d)		1,491	1,548	1,662

- (1) Further details related to product sales, including 'Other' income for 2019 are disclosed in note 22 to the Company's audited consolidated financial statements.
- (2) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings as presented in the Company's consolidated Statements of Earnings, adjusted for the after-tax effects of certain items of a non-operational nature. The Company considers adjusted net earnings from operations a key measure in evaluating its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. The reconciliation "Adjusted Net Earnings from Operations, as Reconciled to Net Earnings" is presented in this MD&A. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.
- (3) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that 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, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls. The Company considers adjusted funds flow a key measure in evaluating its performance as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" is presented in this MD&A. Adjusted funds flow may not be comparable to similar measures presented by other companies.
- (4) On March 4, 2020, the Board of Directors approved an increase in the quarterly dividend to \$0.425 per common share, beginning with the dividend payable on April 1, 2020. On March 6, 2019, the Board of Directors approved an increase in the quarterly dividend to \$0.375 per common share, beginning with the dividend payable on April 1, 2019. On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to \$0.335 per common share, beginning with the dividend payable on April 1, 2018. On March 1, 2017, the Board of Directors approved an increase in the quarterly dividend to \$0.275 per common share, beginning with the dividend payable on April 1, 2017.
- (5) Net capital expenditures is a non-GAAP measure that represents cash flows used in investing activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, investment in other long-term assets, share consideration in business combinations and abandonment expenditures. The Company considers net capital expenditures a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. The reconciliation "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" is presented in the "Net Capital Expenditures" section of this MD&A. Net capital expenditures may not be comparable to similar measures presented by other companies.
- (6) Net of blending and feedstock costs and excluding risk management activities.

ADJUSTED NET EARNINGS FROM OPERATIONS, AS RECONCILED TO NET EARNINGS

(\$ millions)	2019	2018	2017
Net earnings, as reported	\$ 5,416	\$ 2,591	\$ 2,397
Share-based compensation, net of tax ⁽¹⁾	210	(146)	134
Unrealized risk management loss (gain), net of tax ⁽²⁾	14	(36)	33
Unrealized foreign exchange (gain) loss, net of tax ⁽³⁾	(548)	706	(821)
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax ⁽⁴⁾	—	146	—
Loss (gain) from investments, net of tax ^{(5) (6)}	321	374	(11)
Gain on acquisition, disposition and revaluation of properties, net of tax ⁽⁷⁾	—	(372)	(339)
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities ⁽⁸⁾	(1,618)	—	10
Adjusted net earnings from operations	\$ 3,795	\$ 3,263	\$ 1,403

- Share-based compensation includes costs incurred under the Company's Stock Option Plan and Performance Share Unit ("PSU") plans. The Company's employee stock option plan provides for a cash payment option. The PSU plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met. Accordingly, the fair value of the compensation under these plans is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings or are charged to (recovered from) the Oil Sands Mining and Upgrading segment.
- Derivative financial instruments are recorded at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than those amounts reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil, natural gas and foreign exchange.
- Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, partially offset by the impact of cross currency swaps, and are recognized in net earnings.
- During 2018, the Company repaid US\$600 million of 1.75% notes and US\$400 million of 5.90% notes.
- The Company's investment in the 50% owned North West Redwater Partnership ("Redwater Partnership") is accounted for using the equity method of accounting. Included in the non-cash loss (gain) from investments is the Company's pro rata share of the Redwater Partnership's equity loss (gain) recognized.
- The Company's investments in PrairieSky Royalty Ltd. ("PrairieSky") and Inter Pipeline Ltd. ("Inter Pipeline") have been accounted for at fair value through profit and loss and are measured each period with changes in fair value recognized in net earnings.
- During 2018, the Company recorded a pre-tax gain of \$16 million (\$12 million after-tax) on the disposition of a 30% interest in the exploration right in South Africa. Additionally, the Gabonese Republic approved cessation of production from the Company's Olowi field and associated asset retirement obligations, as well as the terms of termination of the Olowi Production Sharing Contract and the surrender of the permit area back to the Gabonese Republic, resulting in a pre-tax gain on disposition of property of \$20 million (\$14 million after-tax). The Company also recorded a pre-tax gain of \$277 million (\$263 million after-tax) related to acquisitions in the North America Exploration and Production segment. Additionally, the Company recorded a pre-tax gain of \$120 million (\$72 million after-tax) on the acquisition of the remaining interest at Ninian in the North Sea and a pre-tax gain of \$19 million (\$11 million after-tax) relating to the revaluation of the Company's previously held interest at Ninian. During 2017, the Company recorded a pre-tax revaluation gain of \$114 million (\$83 million after-tax) related to a previously held joint interest in a pipeline system. Additionally, the Company recorded a pre and after-tax gain of \$230 million on the acquisition of a direct and indirect 70% interest in AOSP and other assets from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), and a pre-tax gain of \$35 million (\$26 million after-tax) on the disposition of certain exploration and evaluation assets in the North America segment.
- All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to the underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted. During 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of these corporate income tax rate reductions, the Company's deferred corporate income tax liability decreased by \$1,618 million. During 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by \$10 million.

ADJUSTED FUNDS FLOW, AS RECONCILED TO CASH FLOWS FROM OPERATING ACTIVITIES ⁽¹⁾

(\$ millions)	2019	2018	2017
Cash flows from operating activities	\$ 8,829	\$ 10,121	\$ 7,262
Net change in non-cash working capital	1,033	(1,346)	(299)
Abandonment expenditures ⁽²⁾	296	290	274
Other ⁽³⁾	109	23	110
Adjusted funds flow	\$ 10,267	\$ 9,088	\$ 7,347

- Adjusted funds flow was previously referred to as funds flow from operations.
- The Company includes abandonment expenditures in "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" in the "Net Capital Expenditures" section of this MD&A.
- Movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls.

CONSOLIDATED NET EARNINGS AND ADJUSTED NET EARNINGS

For 2019, the Company reported net earnings of \$5,416 million compared with \$2,591 million for 2018 (2017 – \$2,397 million). Net earnings for 2019 included net after-tax income of \$1,621 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of realized foreign exchange losses on repayments of long-term debt, the loss from investments, gain on acquisition, disposition and revaluation of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities (2018 – \$672 million after-tax income; 2017 – \$994 million after-tax income). Excluding these items, adjusted net earnings from operations for 2019 were \$3,795 million compared with \$3,263 million for 2018 (2017 – \$1,403 million).

The increase in net earnings and adjusted net earnings from operations for 2019 from 2018 was primarily due to:

- higher crude oil and NGLs sales volumes and netbacks in the Exploration and Production segments; and
- higher realized foreign exchange gains;

partially offset by:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower natural gas netbacks in the Exploration and Production segments; and
- higher realized risk management losses.

Net earnings for 2019 as compared to net earnings for 2018 also reflected the Government of Alberta enacted decrease in the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. This resulted in a decrease in the Company's deferred corporate income tax liability of \$1,618 million. See the "Income Taxes" section of this MD&A.

The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates also contributed to the movements in net earnings for 2019 from 2018. For 2019, the adoption of IFRS 16 did not have a significant overall impact on net earnings or adjusted net earnings from operations. These items are discussed in detail in the relevant sections of this MD&A.

Subsequent to December 31, 2019, crude oil benchmark prices decreased substantially due to a drop in global crude oil demand triggered by the impact of the COVID-19 virus on the global economy. In March 2020, crude oil prices decreased further due to a breakdown in negotiations between OPEC and non-OPEC partners regarding proposed production cuts. The volatility in the crude oil pricing environment could impact the Company's earnings and cash flows.

CASH FLOWS FROM OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW

Cash flows from operating activities for 2019 decreased to \$8,829 million from \$10,121 million for 2018 (2017 – \$7,262 million). The decrease in cash flows from operating activities for 2019 from 2018 was primarily due to the impact of changes in non-cash working capital, primarily due to an increase in accounts receivable from 2018. Cash flows from operating activities was further impacted by factors previously noted relating to the fluctuations in net earnings and adjusted net earnings from operations (except for the effect of depletion, depreciation and amortization).

Adjusted funds flow for 2019 increased to \$10,267 million (\$8.62 per common share) from \$9,088 million for 2018 (\$7.46 per common share) (2017 – \$7,347 million; \$6.25 per common share). The increase in adjusted funds flow for 2019 from 2018 was primarily due to the factors previously noted relating to the fluctuations in cash flows from operating activities excluding the impact of the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls.

Cash flows from operating activities and adjusted funds flow for 2019 reflected an increase of \$237 million related to the adoption of IFRS 16 on January 1, 2019 as the principal portions of lease payments previously classified as cash flows from operating activities are now reported as cash flows used in financing activities. The adoption of IFRS 16 is discussed in the "Changes in Accounting Policies" section of this MD&A.

PRODUCT PRICING

In the Company's Exploration and Production activities, the 2019 average sales price per barrel of crude oil and NGLs increased 17% to average \$55.08 per bbl from \$46.92 per bbl in 2018 (2017 – \$48.57 per bbl), and the 2019 average natural gas price decreased 10% to average \$2.34 per Mcf from \$2.61 per Mcf in 2018 (2017 – \$2.76 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2019 average SCO sales price of \$70.18 per bbl compared with \$68.61 per bbl in 2018 (2017 – \$63.98 per bbl). Crude oil and NGLs and natural gas pricing are discussed in detail in the "Business Environment" section of this MD&A.

PRODUCTION VOLUMES

Total production of crude oil and NGLs before royalties for 2019 increased 4% to average 850,393 bbl/d from 820,778 bbl/d in 2018 (2017 – 685,236 bbl/d). The increase in crude oil and NGLs production from 2018 primarily reflected production from the acquisition of thermal and heavy oil assets from Devon Canada Corporation ("Devon"), offsetting the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. The Company continues to optimize its production volumes across the asset base during curtailment.

Total natural gas production before royalties for 2019 decreased 4% to average 1,491 MMcf/d from 1,548 MMcf/d in 2018 (2017 – 1,662 MMcf/d). The decrease in natural gas production from 2018 primarily reflected natural field declines, together with the strategic reduction of capital allocated to natural gas activities due to low natural gas prices.

Total production volumes before royalties for 2019 of 1,098,957 BOE/d was comparable with 1,078,813 BOE/d in 2018 (2017 – 962,264 BOE/d). Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

SUMMARY OF QUARTERLY FINANCIAL RESULTS

The following is a summary of the Company's quarterly financial results for the eight most recently completed quarters:

(\$ millions, except per common share amounts)

2019	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales ⁽¹⁾	\$ 24,394	\$ 6,335	\$ 6,587	\$ 5,931	\$ 5,541
Crude oil and NGLs	\$ 22,950	\$ 5,947	\$ 6,324	\$ 5,597	\$ 5,082
Natural gas	\$ 1,419	\$ 382	\$ 257	\$ 324	\$ 456
Net earnings (loss)	\$ 5,416	\$ 597	\$ 1,027	\$ 2,831	\$ 961
Net earnings (loss) per common share					
– basic	\$ 4.55	\$ 0.50	\$ 0.87	\$ 2.37	\$ 0.80
– diluted	\$ 4.54	\$ 0.50	\$ 0.87	\$ 2.36	\$ 0.80

(\$ millions, except per common share amounts)

2018	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales	\$ 22,282	\$ 3,831	\$ 6,327	\$ 6,389	\$ 5,735
Crude oil and NGLs	\$ 20,668	\$ 3,327	\$ 5,967	\$ 6,071	\$ 5,303
Natural gas	\$ 1,614	\$ 504	\$ 360	\$ 318	\$ 432
Net earnings (loss)	\$ 2,591	\$ (776)	\$ 1,802	\$ 982	\$ 583
Net earnings (loss) per common share					
– basic	\$ 2.13	\$ (0.64)	\$ 1.48	\$ 0.80	\$ 0.48
– diluted	\$ 2.12	\$ (0.64)	\$ 1.47	\$ 0.80	\$ 0.47

(1) Further details related to product sales, including 'Other' income for 2019 are disclosed in note 22 to the Company's audited consolidated financial statements.

Volatility in the quarterly net earnings (loss) over the eight most recently completed quarters was primarily due to:

- **Crude oil pricing** – Fluctuating global supply/demand including crude oil production levels from OPEC and its impact on world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the WCS Heavy Differential from the WTI including the impact of a shortage of takeaway capacity out of the Western Canadian Sedimentary Basin (the "Basin") and the impact of the differential between WTI and Brent benchmark pricing in the North Sea and Offshore Africa and the impact of production curtailments mandated by the Government of Alberta that came into effect on January 1, 2019.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, third-party pipeline maintenance and outages and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, production from Kirby South and Kirby North, the results from the Pelican Lake water and polymer flood projects, fluctuations in the Company's drilling program in North America and the International segments, the impact and timing of acquisitions, including the acquisition of assets from Devon, production from Horizon Phase 3 as well as the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, voluntarily curtailed production in late 2018 due to low commodity prices in North America and production curtailments mandated by the Government of Alberta that came into effect January 1, 2019. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.

- **Natural gas sales volumes** – Fluctuations in production due to the Company’s allocation of capital to higher return crude oil projects, natural decline rates, fluctuating capacity at the Pine River processing facility, shut-in production due to third party pipeline restrictions and related pricing impacts, shut-in production due to low commodity prices and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production volumes, the impact of seasonal costs, the impact of increased carbon tax and energy costs, cost optimizations across all segments, the impact and timing of acquisitions, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, maintenance activities in the International segments and the impact of the adoption of IFRS 16 on January 1, 2019.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company’s proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment and the impact of the adoption of IFRS 16 on January 1, 2019.
- **Share-based compensation** – Fluctuations due to the measurement of fair market value of the Company’s share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company’s risk management activities.
- **Interest expense** – Fluctuations due to the adoption of IFRS 16 on January 1, 2019, fluctuating long-term debt levels, and the impact of movements in benchmark interest rates on outstanding floating rate long-term debt.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company receives for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses were also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Gains on acquisition, disposition and revaluation of properties and gains/losses on investments** – Fluctuations due to the recognition of the acquisition, disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity loss on the Company’s interest in the Redwater Partnership.
- **Income tax expense** – Fluctuations in income tax expense due to statutory tax rate and other legislative changes substantively enacted in the various periods.

Business Environment

(Yearly average)	2019	2018	2017
WTI benchmark price (US\$/bbl)	\$ 57.04	\$ 64.78	\$ 50.93
Dated Brent benchmark price (US\$/bbl)	\$ 64.04	\$ 71.12	\$ 54.38
WCS Heavy Differential from WTI (US\$/bbl)	\$ 12.79	\$ 26.29	\$ 11.97
SCO price (US\$/bbl)	\$ 56.35	\$ 58.62	\$ 52.20
Condensate benchmark price (US\$/bbl)	\$ 52.84	\$ 60.98	\$ 51.65
Condensate Differential from WTI (US\$/bbl)	\$ 4.20	\$ 3.80	\$ (0.72)
NYMEX benchmark price (US\$/MMBtu)	\$ 2.63	\$ 3.08	\$ 3.11
AECO benchmark price (C\$/GJ)	\$ 1.54	\$ 1.45	\$ 2.30
US/Canadian dollar average exchange rate (US\$)	\$ 0.7536	\$ 0.7717	\$ 0.7701
US/Canadian dollar year end exchange rate (US\$)	\$ 0.7713	\$ 0.7328	\$ 0.7988

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are highly sensitive to fluctuations in foreign exchange rates. Product revenue continued to be impacted by the volatility of the Canadian dollar as the Canadian dollar sales price the Company received for its crude oil and natural gas sales is based on US dollar denominated benchmarks.

Effective January 1, 2019, the Government of Alberta implemented a mandatory curtailment program that has been successful in mitigating the discount in crude oil pricing received in Alberta for both light crude oil and heavy crude oil. The timing of program cessation remains uncertain. The Company continues to execute operational flexibility to maximize production volumes through its curtailment optimization strategy, and has significant additional capacity available to further increase production volumes should curtailment restrictions ease.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US\$57.04 per bbl for 2019, a decrease of 12% from US\$64.78 per bbl for 2018 (2017 – US\$50.93 per bbl).

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US\$64.04 per bbl for 2019, a decrease of 10% from US\$71.12 per bbl for 2018 (2017 – US\$54.38 per bbl).

WTI and Brent pricing for 2019 decreased from 2018 primarily due to increases in non-OPEC crude oil supply. In addition, global crude oil pricing has been impacted by ongoing trade disputes between the US and China.

The WCS Heavy Differential averaged US\$12.79 per bbl for 2019, a decrease of 51% from US\$26.29 per bbl for 2018 (2017 – US\$11.97 per bbl). The narrowing of the WCS Heavy Differential reflected the impact of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019.

The SCO price averaged US\$56.35 per bbl for 2019, a decrease of 4% from US\$58.62 per bbl for 2018 (2017 – US\$52.20 per bbl). The decrease in SCO pricing for 2019 from 2018 primarily reflected decreases in WTI benchmark pricing.

NYMEX natural gas prices averaged US\$2.63 per MMBtu for 2019, a decrease of 15% from US\$3.08 per MMBtu for 2018 (2017 – US\$3.11 per MMBtu). The decrease in NYMEX natural gas prices for 2019 from 2018 primarily reflected increased production levels in North America and the impact of seasonal weather conditions.

AECO natural gas prices averaged \$1.54 per GJ for 2019, an increase of 6% from \$1.45 per GJ for 2018 (2017 – \$2.30 per GJ). The increase in AECO natural gas prices for 2019 from 2018 primarily reflected additional egress capability and the impact of the TC Energy Temporary Service Protocol.

Analysis of Changes in Product Sales

(\$ millions)	Changes due to				2018	Changes due to			2019
	2017	Volumes	Prices	Other		Volumes	Prices	Other	
North America									
Crude oil and NGLs	\$ 7,655	\$ (188)	\$ (224)	\$ 11	\$ 7,254	\$ 1,055	\$ 1,375	\$ (5)	\$ 9,679
Natural gas	1,506	(105)	(136)	(9)	1,256	(40)	(76)	10	1,150
Other	—	—	—	—	—	—	—	6	6
	9,161	(293)	(360)	2	8,510	1,015	1,299	11	10,835
North Sea									
Crude oil and NGLs	666	(69)	155	1	753	114	(7)	—	860
Natural gas	118	(23)	45	—	140	(34)	(49)	—	57
Other	—	—	—	—	—	—	—	5	5
	784	(92)	200	1	893	80	(56)	5	922
Offshore Africa									
Crude oil and NGLs	579	(102)	164	(13)	628	72	(56)	(12)	632
Natural gas	53	10	7	—	70	(5)	1	1	67
Other	—	—	—	—	—	—	—	8	8
	632	(92)	171	(13)	698	67	(55)	(3)	707
Total Exploration and Production									
Crude oil and NGLs	8,900	(359)	95	(1)	8,635	1,241	1,312	(17)	11,171
Natural gas	1,677	(118)	(84)	(9)	1,466	(79)	(124)	11	1,274
Other	—	—	—	—	—	—	—	19	19
	10,577	(477)	11	(10)	10,101	1,162	1,188	13	12,464
Oil Sands Mining and Upgrading									
Crude oil and NGLs	7,072	3,696	722	31	11,521	(710)	560	(31)	11,340
Other	—	—	—	—	—	—	—	6	6
	7,072	3,696	722	31	11,521	(710)	560	(25)	11,346
Midstream and Refining									
	102	—	—	—	102	—	—	(14)	88
Intersegment eliminations and other ⁽¹⁾									
	609	—	—	(51)	558	—	—	(62)	496
Total	\$18,360	\$ 3,219	\$ 733	\$ (30)	\$ 22,282	\$ 452	\$ 1,748	\$ (88)	\$ 24,394

(1) Eliminates internal transportation and electricity charges and includes production, processing and other purchasing and selling activities that are not included in the above segments.

Product sales increased 9% to \$24,394 million for 2019 from \$22,282 million for 2018 (2017 – \$18,360 million). The increase was primarily due to higher realized crude oil and NGLs pricing in North America, together with increased crude oil and NGLs sales volumes in the North America Exploration and Production segment following the acquisition of thermal and heavy oil assets from Devon, offsetting the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. Crude oil and NGLs and natural gas pricing are discussed in detail in the "Business Environment" section of this MD&A. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

For 2019, 7% of the Company's crude oil and NGLs and natural gas product sales were generated outside of North America (2018 – 7%; 2017 – 8%). North Sea accounted for 4% of crude oil and NGLs and natural gas product sales for 2019 (2018 – 4%; 2017 – 4%), and Offshore Africa accounted for 3% of crude oil and NGLs and natural gas product sales for 2019 (2018 – 3%; 2017 – 4%).

Daily Production, Before Royalties

	2019	2018	2017
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	405,970	350,961	359,449
North America – Oil Sands Mining and Upgrading ⁽¹⁾	395,133	426,190	282,026
North Sea	27,919	23,965	23,426
Offshore Africa	21,371	19,662	20,335
	850,393	820,778	685,236
Natural gas (MMcf/d)			
North America	1,443	1,490	1,601
North Sea	24	32	39
Offshore Africa	24	26	22
	1,491	1,548	1,662
Total barrels of oil equivalent (BOE/d)	1,098,957	1,078,813	962,264
Product mix			
Light and medium crude oil and NGLs	13%	13%	14%
Pelican Lake heavy crude oil	5%	6%	6%
Primary heavy crude oil	8%	8%	10%
Bitumen (thermal oil)	15%	10%	12%
Synthetic crude oil ⁽¹⁾	36%	39%	29%
Natural gas	23%	24%	29%
Percentage of gross revenue^{(1) (2)}			
(excluding Midstream and Refining revenue)			
Crude oil and NGLs	94%	93%	90%
Natural gas	6%	7%	10%

(1) SCO production before royalties excludes SCO consumed internally as diesel.

(2) Net of blending costs and excluding risk management activities.

Daily Production, Net of Royalties

	2019	2018	2017
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	356,794	303,956	312,297
North America – Oil Sands Mining and Upgrading	375,048	405,731	274,437
North Sea	27,866	23,902	23,382
Offshore Africa	20,078	18,450	19,124
	779,786	752,039	629,240
Natural gas (MMcf/d)			
North America	1,400	1,432	1,528
North Sea	24	32	39
Offshore Africa	22	23	20
	1,446	1,487	1,587
Total barrels of oil equivalent (BOE/d)	1,020,749	999,857	893,702

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), SCO and natural gas.

Total 2019 production before royalties averaged 1,098,957 BOE/d, comparable with 1,078,813 BOE/d in 2018 (2017 – 962,264 BOE/d).

Total production of crude oil and NGLs before royalties for 2019 increased 4% to 850,393 bbl/d from 820,778 bbl/d for 2018 (2017 – 685,236 bbl/d). The increase in crude oil and NGLs production from 2018 primarily reflected production from the acquisition of thermal and heavy oil assets from Devon, offsetting the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. The Company continues to optimize its production volumes across the asset base during curtailment. Crude oil and NGLs production before royalties for 2019 was within the Company's previously issued guidance of 839,000 to 888,000 bbl/d.

Natural gas production before royalties accounted for 23% of the Company's total production in 2019 on a BOE basis. Natural gas production for 2019 decreased 4% to 1,491 MMcf/d from 1,548 MMcf/d for 2018 (2017 – 1,662 MMcf/d). The decrease in natural gas production from 2018 primarily reflected natural field declines, together with the strategic reduction of capital allocated to natural gas activities due to low natural gas prices. Natural gas production for 2019 was within the Company's previously issued guidance of 1,485 to 1,545 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for 2019 increased 16% to average 405,970 bbl/d from 350,961 bbl/d for 2018 (2017 – 359,449 bbl/d). The increase in production from 2018 primarily reflected the acquisition of thermal and heavy oil assets from Devon that closed in 2019 and increased production of thermal oil due to additional production from Kirby North and pad additions at Primrose, reflecting optimization of curtailment volumes across the Company's asset base.

Thermal oil production before royalties for 2019 averaged 167,942 bbl/d compared with 107,839 bbl/d for 2018 (2017 – 120,140 bbl/d). Production volumes in 2019 primarily reflected volumes from the acquisition of assets from Devon, together with new production from Kirby North and pad additions at Primrose, reflecting optimization of curtailment volumes across the Company's asset base.

Pelican Lake heavy crude oil production before royalties averaged production of 58,855 bbl/d in 2019 compared with 63,082 bbl/d in 2018 (2017 – 51,743 bbl/d).

Natural gas production before royalties for 2019 decreased 3% to average 1,443 MMcf/d from 1,490 MMcf/d for 2018 (2017 – 1,601 MMcf/d). The decrease in natural gas production from 2018 primarily reflected natural field declines, together with the strategic reduction of capital allocated to natural gas activities due to low natural gas prices.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for 2019 decreased 7% to 395,133 bbl/d from 426,190 bbl/d for 2018 (2017 – 282,026 bbl/d). The decrease in SCO production from 2018 primarily reflected the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. Production in 2019 was impacted by the Government of Alberta mandated production curtailments that came into effect on January 1, 2019.

North Sea

North Sea crude oil production before royalties for 2019 increased 16% to 27,919 bbl/d from 23,965 bbl/d for 2018 (2017 – 23,426 bbl/d). The increase in production from 2018 primarily reflected volumes from new wells.

Offshore Africa

Offshore Africa crude oil production before royalties for 2019 increased 9% to 21,371 bbl/d from 19,662 bbl/d for 2018 (2017 – 20,335 bbl/d). The increase in production from 2018 primarily reflected volumes from new wells drilled at Baobab, partially offset by the cessation of production at the Olowi field, Gabon in December 2018 and natural field declines.

Corporate Production Guidance for 2020

The Company targets production levels in 2020 to average between 910,000 bbl/d and 970,000 bbl/d of crude oil and NGLs and between 1,360 MMcf/d and 1,420 MMcf/d of natural gas.

INTERNATIONAL CRUDE OIL INVENTORY VOLUMES

The Company recognizes revenue on its crude oil production when control of the product passes to the customer and delivery has taken place. Revenue has not been recognized in the International business segments on crude oil volumes held in various storage facilities or FPSOs, as follows:

(bbl)	2019	2018	2017
North Sea	344,726	71,832	—
Offshore Africa	519,504	404,475	121,936
	864,230	476,307	121,936

Exploration and Production

OPERATING HIGHLIGHTS

	2019	2018	2017
Crude oil and NGLs (\$/bbl) ⁽¹⁾			
Sales price ⁽²⁾	\$ 55.08	\$ 46.92	\$ 48.57
Transportation	3.48	3.08	2.80
Realized sales price, net of transportation	51.60	43.84	45.77
Royalties	6.08	5.08	5.24
Production expense	13.81	15.69	14.89
Netback	\$ 31.71	\$ 23.07	\$ 25.64
Natural gas (\$/Mcf) ⁽¹⁾			
Sales price ⁽²⁾	\$ 2.34	\$ 2.61	\$ 2.76
Transportation	0.42	0.47	0.39
Realized sales price, net of transportation	1.92	2.14	2.37
Royalties	0.08	0.08	0.11
Production expense	1.22	1.36	1.27
Netback	\$ 0.62	\$ 0.70	\$ 0.99
Barrels of oil equivalent (\$/BOE) ⁽¹⁾			
Sales price ⁽²⁾	\$ 40.50	\$ 34.62	\$ 35.54
Transportation	3.14	2.96	2.66
Realized sales price, net of transportation	37.36	31.66	32.88
Royalties	4.09	3.27	3.40
Production expense	11.49	12.71	11.95
Netback	\$ 21.78	\$ 15.68	\$ 17.53

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of blending costs and excluding risk management activities.

PRODUCT PRICES

	2019	2018	2017
Crude oil and NGLs (\$/bbl) ^{(1) (2)}			
North America	\$ 51.43	\$ 41.82	\$ 45.85
North Sea	\$ 86.76	\$ 87.41	\$ 69.43
Offshore Africa	\$ 83.68	\$ 90.95	\$ 67.15
Company average	\$ 55.08	\$ 46.92	\$ 48.57
Natural gas (\$/Mcf) ^{(1) (2)}			
North America	\$ 2.18	\$ 2.33	\$ 2.58
North Sea	\$ 6.52	\$ 12.08	\$ 8.24
Offshore Africa	\$ 7.41	\$ 7.34	\$ 6.57
Company average	\$ 2.34	\$ 2.61	\$ 2.76
Company average (\$/BOE) ^{(1) (2)}	\$ 40.50	\$ 34.62	\$ 35.54

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of blending costs and excluding risk management activities.

North America - Product Prices

North America realized crude oil prices increased 23% to average \$51.43 per bbl for 2019 from \$41.82 per bbl for 2018 (2017 – \$45.85 per bbl), primarily due to the narrowing of the WCS Heavy Differential as a result of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019.

North America realized natural gas prices decreased 6% to average \$2.18 per Mcf for 2019 from \$2.33 per Mcf for 2018 (2017 – \$2.58 per Mcf). The decrease primarily reflected increased production levels in North America and the impact of seasonal weather conditions.

The Company continues to focus on its crude oil marketing strategy including a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil and bitumen (thermal oil) conversion capacity. During 2019, the Company contributed approximately 174,700 bbl/d of heavy crude oil blends to the WCS stream.

The Company has 20 year transportation agreements to ship 94,000 bbl/d of crude oil on the proposed Trans Mountain Pipeline Expansion. The Canadian Energy Regulator (formerly The National Energy Board) has provided its recommendation that construction of the pipeline should proceed and the Federal cabinet approved the project on June 18, 2019. On February 4, 2020, an appeal from Indigenous groups to the Federal Court of Appeal was dismissed. Pipeline construction, which had commenced, was permitted to continue subject to the outcome of the appeal to the Supreme Court of Canada. Leave to appeal to the Supreme Court of Canada was refused on March 5, 2020.

The Company also has 20 year transportation agreements to ship 200,000 bbl/d of crude oil on the proposed TC Energy Keystone XL Pipeline. On August 23, 2019 the Nebraska Supreme Court ruled that the Nebraska Public Service Commission's route approval was valid. The proponent is awaiting the decision from the Montana Federal Court case filed by various environmental groups challenging the Presidential Permit granted in 2019. Pre-construction activities have commenced and the proponent expects the construction program to be approximately two years once construction has commenced.

Comparisons of the prices received in North America Exploration and Production by product type were as follows:

(Yearly average)	2019	2018	2017
Wellhead Price ^{(1) (2)}			
Light and medium crude oil and NGLs (\$/bbl)	\$ 49.54	\$ 52.87	\$ 47.78
Pelican Lake heavy crude oil (\$/bbl)	\$ 57.82	\$ 43.30	\$ 48.30
Primary heavy crude oil (\$/bbl)	\$ 55.38	\$ 38.98	\$ 46.88
Bitumen (thermal oil) (\$/bbl)	\$ 48.27	\$ 33.66	\$ 42.49
Natural gas (\$/Mcf)	\$ 2.18	\$ 2.33	\$ 2.58

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of blending costs and excluding risk management activities.

North Sea - Product Prices

North Sea realized crude oil prices of \$86.76 per bbl for 2019 were comparable with \$87.41 per bbl for 2018 (2017 – \$69.43 per bbl). Realized crude oil prices per barrel in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting.

Offshore Africa - Product Prices

Offshore Africa realized crude oil prices decreased 8% to average \$83.68 per bbl for 2019 from \$90.95 per bbl for 2018 (2017 – \$67.15 per bbl). Realized crude oil prices per barrel in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The decrease in realized crude oil prices in 2019 reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES

	2019	2018	2017
Crude oil and NGLs (\$/bbl) ⁽¹⁾			
North America	\$ 6.56	\$ 5.36	\$ 5.69
North Sea	\$ 0.16	\$ 0.22	\$ 0.13
Offshore Africa	\$ 4.74	\$ 6.00	\$ 4.13
Company average	\$ 6.08	\$ 5.08	\$ 5.24
Natural gas (\$/Mcf) ⁽¹⁾			
North America	\$ 0.07	\$ 0.07	\$ 0.11
Offshore Africa	\$ 0.63	\$ 1.00	\$ 0.76
Company average	\$ 0.08	\$ 0.08	\$ 0.11
Company average (\$/BOE) ⁽¹⁾	\$ 4.09	\$ 3.27	\$ 3.40

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America - Royalties

Government royalties on a significant portion of North America crude oil and NGLs production fall under the oil sands royalty regime and are calculated on a project by project basis as a percentage of gross revenue less operating, capital and abandonment costs incurred ("net profit").

North America crude oil and natural gas royalty rates for 2019 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalty rates also reflected fluctuations in the WCS Heavy Differential and changes in the production mix between high and low royalty rate product types.

Crude oil and NGLs royalty rates averaged approximately 13% of product sales for 2019 compared with 14% of product sales for 2018 (2017 – 13%).

Natural gas royalty rates averaged approximately 3% of product sales for 2019 compared with 4% of product sales for 2018 (2017 – 5%).

Offshore Africa - Royalties

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital expenditures and production expenses, the status of payouts, and the timing of liftings from each field.

Royalty rates as a percentage of product sales averaged approximately 6% for 2019 compared with 7% of product sales for 2018 (2017 – 7%). Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

PRODUCTION EXPENSE

	2019	2018	2017
Crude oil and NGLs (\$/bbl) ⁽¹⁾			
North America	\$ 12.41	\$ 13.48	\$ 12.71
North Sea	\$ 36.39	\$ 39.89	\$ 36.60
Offshore Africa	\$ 11.21	\$ 26.34	\$ 24.07
Company average	\$ 13.81	\$ 15.69	\$ 14.89
Natural gas (\$/Mcf) ⁽¹⁾			
North America	\$ 1.16	\$ 1.25	\$ 1.19
North Sea ⁽²⁾	\$ 3.40	\$ 5.29	\$ 3.37
Offshore Africa ⁽²⁾	\$ 2.60	\$ 2.76	\$ 2.90
Company average	\$ 1.22	\$ 1.36	\$ 1.27
Company average (\$/BOE) ⁽¹⁾	\$ 11.49	\$ 12.71	\$ 11.95

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) North Sea and Offshore Africa natural gas production expense for 2019 reflected a decrease of \$23 million (\$2.66 per Mcf) and \$5 million (\$0.55 per Mcf) respectively, related to the adoption of IFRS 16.

North America - Production Expense

North America crude oil and NGLs production expense for 2019 decreased 8% to \$12.41 per bbl from \$13.48 per bbl for 2018 (2017 – \$12.71 per bbl). The decrease in crude oil and NGLs production expense for 2019 from 2018 primarily reflected the impact of operating cost synergies captured to date combined with added production from the acquisition of assets from Devon, Kirby North and pad additions at Primrose, offsetting the impact of higher fuel and energy costs. The Company continues to focus on cost control and achieving efficiencies across the entire asset base.

North America crude oil and NGLs production expense for 2019 also reflected a decrease of \$22 million (\$0.15 per bbl) related to the adoption of IFRS 16.

North America natural gas production expense for 2019 decreased 7% to \$1.16 per Mcf from \$1.25 per Mcf for 2018 (2017 – \$1.19 per Mcf). The decrease in natural gas production expense for 2019 from 2018 primarily reflected the strength of the Company's strategy to own and control its infrastructure, continued focus on cost control, and achieving efficiencies across the entire asset base.

North America natural gas production expense for 2019 also reflected a decrease of \$6 million (\$0.01 per Mcf) related to the adoption of IFRS 16.

North Sea - Production Expense

North Sea crude oil production expense for 2019 decreased 9% to \$36.39 per bbl from \$39.89 per bbl for 2018 (2017 – \$36.60 per bbl). The decrease in crude oil production expense for 2019 from 2018 primarily reflected increased production volumes, together with fluctuations in the Canadian dollar.

North Sea crude oil production expense for 2019 also reflected a decrease of \$21 million (\$2.10 per bbl) related to the adoption of IFRS 16.

Offshore Africa - Production Expense

Offshore Africa crude oil production expense was \$11.21 per bbl for 2019 compared with \$26.34 per bbl for 2018 (2017 – \$24.07 per bbl). The decrease in crude oil production expense for 2019 from 2018 primarily reflected the cessation of production at the Olowi field, Gabon in December 2018. Crude oil production expense also reflected the timing of liftings from various fields that have different cost structures, fluctuating production volumes on a relatively fixed cost base and fluctuations in the Canadian dollar.

Offshore Africa crude oil production expense for 2019 also reflected a decrease of \$20 million (\$2.56 per bbl) related to the adoption of IFRS 16.

DEPLETION, DEPRECIATION AND AMORTIZATION

(\$ millions, except per BOE amounts)	2019	2018	2017
North America	\$ 3,326	\$ 3,132	\$ 3,243
North Sea	308	257	509
Offshore Africa	242	201	205
Expense	\$ 3,876	\$ 3,590	\$ 3,957
\$/BOE ⁽¹⁾	\$ 15.22	\$ 15.12	\$ 15.82

(1) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, depreciation and amortization in 2019 of \$15.22 per BOE was comparable with \$15.12 per BOE for 2018 (2017 – \$15.82 per BOE). Depletion, depreciation and amortization expense for 2019 reflected an increase of \$168 million (\$0.66 per BOE) related to the adoption of IFRS 16.

ASSET RETIREMENT OBLIGATION ACCRETION

(\$ millions, except per BOE amounts)	2019	2018	2017
North America	\$ 95	\$ 87	\$ 80
North Sea	28	29	27
Offshore Africa	6	9	9
Expense	\$ 129	\$ 125	\$ 116
\$/BOE ⁽¹⁾	\$ 0.51	\$ 0.53	\$ 0.46

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

Asset retirement obligation accretion expense for 2019 decreased 4% to \$0.51 per BOE from \$0.53 per BOE for 2018 (2017 – \$0.46 per BOE). Fluctuations in asset retirement obligation accretion expense on a per BOE basis primarily reflect fluctuating sales volumes.

Oil Sands Mining and Upgrading

OPERATING HIGHLIGHTS

The Company continues to focus on safe, reliable and efficient operations and leveraging its technical expertise across the Horizon and AOSP sites. Production averaged 395,133 bbl/d during 2019, reflecting the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. Production levels during the year continued to be impacted by the Government of Alberta mandated production curtailments that came into effect January 1, 2019.

Through continuous focus on cost control and efficiencies, the Company has achieved a decrease of \$124 million (4%) in adjusted production costs, excluding natural gas costs for 2019 of \$3,032 million (\$20.89 per bbl), from \$3,156 million (\$20.39 per bbl) for 2018.

PRODUCT PRICES, ROYALTIES AND TRANSPORTATION

(\$/bbl) ⁽¹⁾	2019	2018	2017
SCO realized sales price ⁽²⁾	\$ 70.18	\$ 68.61	\$ 63.98
Bitumen value for royalty purposes ⁽³⁾	\$ 50.79	\$ 40.02	\$ 41.05
Bitumen royalties ⁽⁴⁾	\$ 3.31	\$ 3.09	\$ 1.64
Transportation	\$ 1.29	\$ 1.61	\$ 1.54

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

(2) Net of blending and feedstock costs.

(3) Calculated as the annual average of the bitumen valuation methodology price.

(4) Calculated based on bitumen royalties expensed during the year; divided by the corresponding SCO sales volumes.

The realized SCO sales price averaged \$70.18 per bbl for 2019, comparable with \$68.61 per bbl for 2018 (2017 – \$63.98 per bbl).

Transportation expense averaged \$1.29 per bbl for 2019, compared with \$1.61 per bbl for 2018 (2017 – \$1.54 per bbl). Transportation expense for 2019 reflected a decrease of \$78 million (\$0.53 per bbl) related to the adoption of IFRS 16.

PRODUCTION COSTS

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 22 to the Company's audited consolidated financial statements.

(\$ millions)	2019	2018	2017
Production costs	\$ 3,276	\$ 3,367	\$ 2,600
Less: costs incurred during turnaround periods	(119)	(109)	(216)
Adjusted production costs	\$ 3,157	\$ 3,258	\$ 2,384
Adjusted production costs, excluding natural gas costs	\$ 3,032	\$ 3,156	\$ 2,239
Natural gas costs	125	102	145
Adjusted production costs	\$ 3,157	\$ 3,258	\$ 2,384

(\$/bbl) ⁽¹⁾	2019	2018	2017
Adjusted production costs, excluding natural gas costs	\$ 20.89	\$ 20.39	\$ 21.98
Natural gas costs	0.86	0.66	1.42
Adjusted production costs	\$ 21.75	\$ 21.05	\$ 23.40
Sales (bbl/d)	397,735	424,112	279,084

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

Production costs for 2019 were \$22.56 per bbl compared with \$21.75 per bbl in 2018 (2017 – \$25.52 per bbl). Adjusted production costs for 2019 increased 3% to \$21.75 per bbl from \$21.05 per bbl for 2018 (2017 – \$23.40 per bbl). The increase in adjusted production costs per barrel for 2019 from 2018 primarily reflected reduced production volumes due to the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with increased natural gas costs.

Production costs for 2019 also reflected a decrease of \$29 million (\$0.20 per bbl) related to the adoption of IFRS 16.

DEPLETION, DEPRECIATION AND AMORTIZATION

(\$ millions, except per bbl amounts)	2019	2018	2017
Depletion, depreciation and amortization	\$ 1,656	\$ 1,557	\$ 1,220
Less: depreciation incurred during turnaround periods	(69)	(56)	(213)
Adjusted depletion, depreciation and amortization	\$ 1,587	\$ 1,501	\$ 1,007
\$/bbl ⁽¹⁾	\$ 10.94	\$ 9.70	\$ 9.89

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

Adjusted depletion, depreciation and amortization expense for 2019 increased 13% to \$10.94 per bbl from \$9.70 per bbl for 2018 (2017 – \$9.89 per bbl). This increase primarily reflected fluctuations in sales volumes from different underlying operations, a proactive piping replacement at Horizon, and the adoption of IFRS 16. Depletion, depreciation and amortization expense for 2019 also reflected an increase of \$92 million (\$0.63 per bbl) related to the adoption of IFRS 16.

ASSET RETIREMENT OBLIGATION ACCRETION

(\$ millions, except per bbl amounts)	2019	2018	2017
Expense	\$ 61	\$ 61	\$ 48
\$/bbl ⁽¹⁾	\$ 0.42	\$ 0.40	\$ 0.47

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

Asset retirement obligation accretion expense for 2019 increased 5% to \$0.42 per bbl from \$0.40 per bbl for 2018 (2017 – \$0.47 per bbl). Fluctuations in asset retirement obligation accretion expense on a per barrel basis primarily reflect fluctuating sales volumes.

Midstream and Refining

(\$ millions)	2019	2018	2017
Revenue	\$ 88	\$ 102	\$ 102
Less:			
Production expense	20	21	16
Depreciation	14	14	9
Equity loss (gain) from Redwater Partnership	287	5	(31)
Gain on revaluation of properties	—	—	(114)
Segment earnings (loss) before taxes	\$ (233)	\$ 62	\$ 222

The Company's Midstream assets consist of two crude oil pipeline systems, a 50% working interest in an 84-megawatt cogeneration plant at Primrose and the Company's 50% interest in the Redwater Partnership. Approximately 30% of the Company's heavy crude oil production was transported to international mainline liquid pipelines via the 100% owned and operated ECHO and Pelican Lake pipelines. The Midstream pipeline asset ownership allows the Company to control transportation costs, earn third party revenue, and manage the marketing of heavy crudes.

During 2017, the Company recorded a pre-tax revaluation gain of \$114 million (\$83 million after-tax) related to a previously held joint interest in a pipeline system.

Redwater Partnership has entered into agreements to construct and operate a 50,000 bbl/d bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 bbl/d of bitumen feedstock for the Company and 37,500 bbl/d of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

During 2018, Redwater Partnership commenced commissioning activities in the Project's light oil units while continuing work on the heavy oil units. In the first quarter of 2019, the light oil units transitioned from pre-commissioning and startup to operations and are processing synthetic crude oil into refined products. In December 2019, the light oil refinery completed activities relating to the planned maintenance shutdown. The Project continues to operate as a light oil refinery and will continue to process synthetic crude oil into refined products until the heavy oil units can reliably commence commercial processing of bitumen. Design modifications to the reactor burners in the gasifier unit are ongoing and have continued through the first quarter of 2020. As at December 31, 2019, the total estimate of capital costs incurred for the Project, net of margins from pre-commercial sales, was approximately \$10 billion.

During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect the agreed debt to equity ratio of 80/20. As at December 31, 2019, each party has provided \$439 million of subordinated debt, together with accrued interest thereon of \$213 million, for a Company total of \$652 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service tolls, currently consisting of interest and fees, with principal repayments beginning in 2020. The Company is unconditionally obligated to pay this portion of the cost of service tolls over the 30-year tolling period. As at December 31, 2019, the Company had recognized \$130 million in prepaid cost of service tolls (December 31, 2018 – \$62 million).

Redwater Partnership has a secured \$3,500 million syndicated credit facility, of which \$2,000 million is revolving and matures in June 2021 and the remaining \$1,500 million is fully drawn on a non-revolving basis. During 2019, Redwater Partnership extended the \$1,500 million non-revolving facility, previously scheduled to mature in February 2020, to February 2021. As at December 31, 2019, Redwater Partnership had borrowings of \$2,715 million under the secured syndicated credit facility.

The Company recognized an equity loss from Redwater Partnership of \$287 million for 2019 (2018 – loss of \$5 million), reducing the carrying value in Redwater Partnership to \$nil. The unrecognized share of losses from Redwater Partnership for 2019 was \$59 million. The equity loss for 2019 primarily reflected the impact of Redwater Partnership deferring cost of service toll revenue until it achieves commercial operations and is reliably processing toll payers' bitumen.

Corporate and Other

ADMINISTRATION EXPENSE

(\$ millions, except per BOE amounts)	2019	2018	2017
Expense	\$ 344	\$ 325	\$ 319
\$/BOE ⁽¹⁾	\$ 0.86	\$ 0.83	\$ 0.91

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense for 2019 increased 4% to \$0.86 per BOE from \$0.83 per BOE for 2018 (2017 – \$0.91 per BOE). Administration expense per BOE increased for 2019 from 2018 primarily due to higher personnel costs, including those associated with the acquisition of assets from Devon. Administration expense for 2019 also reflected a decrease of \$23 million (\$0.06 per BOE) related to the adoption of IFRS 16.

SHARE-BASED COMPENSATION

(\$ millions)	2019	2018	2017
Expense (recovery)	\$ 223	\$ (146)	\$ 134

The Company's Stock Option Plan provides current employees with the right to receive common shares or a cash payment in exchange for stock options surrendered. The PSU plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met.

The Company recorded a \$223 million share-based compensation expense for 2019, primarily as a result of the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period, and changes in the Company's share price. Included within the share-based compensation expense for 2019 was \$49 million related to PSUs granted to certain executive employees (2018 – \$8 million; 2017 – \$5 million). For 2019, the Company charged \$5 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (2018 – \$19 million recovered, 2017 – \$14 million charged).

INTEREST AND OTHER FINANCING EXPENSE

(\$ millions, except per BOE amounts and interest rates)	2019	2018	2017
Expense, gross	\$ 889	\$ 808	\$ 713
Less: capitalized interest	53	69	82
Expense, net	\$ 836	\$ 739	\$ 631
\$/BOE ⁽¹⁾	\$ 2.09	\$ 1.88	\$ 1.79
Average effective interest rate	4.0%	3.9%	3.8%

(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest and other financing expense for 2019 increased from 2018 primarily due to interest expense on lease liabilities recognized due to the adoption of IFRS 16. Capitalized interest of \$53 million for 2019 was related to Kirby North and residual project activities at Horizon.

Net interest and other financing expense for 2019 increased 11% to \$2.09 per BOE from \$1.88 per BOE for 2018 (2017 – \$1.79 per BOE). The increase for 2019 from 2018 primarily reflected the adoption of IFRS 16, together with lower capitalized interest and higher levels of debt in 2019. Net interest and other financing expense for 2019 reflected an increase of \$70 million (\$0.18 per BOE) related to the adoption of IFRS 16.

The Company's average effective interest rate of 4.0% for 2019 was consistent with 2018.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These derivative financial instruments are not intended for trading or speculative purposes.

(\$ millions)	2019	2018	2017
Crude oil and NGLs financial instruments	\$ 52	\$ (27)	\$ (32)
Natural gas financial instruments	(1)	5	(7)
Foreign currency contracts	13	(77)	37
Realized loss (gain)	\$ 64	\$ (99)	\$ (2)
Crude oil and NGLs financial instruments	\$ (17)	\$ 16	\$ —
Natural gas financial instruments	15	(4)	(6)
Foreign currency contracts	15	(47)	43
Unrealized loss (gain)	\$ 13	\$ (35)	\$ 37
Net loss (gain)	\$ 77	\$ (134)	\$ 35

During 2019, net realized risk management losses were related to the settlement of crude oil and NGLs financial instruments and foreign currency contracts. The Company recorded a net unrealized loss of \$13 million (\$14 million after-tax) on its risk management activities for 2019 (2018 – \$35 million unrealized gain, \$36 million after-tax; 2017 – \$37 million unrealized loss, \$33 million after-tax).

Complete details related to outstanding derivative financial instruments at December 31, 2019 are disclosed in note 19 to the Company's audited consolidated financial statements.

FOREIGN EXCHANGE

(\$ millions)	2019	2018	2017
Net realized (gain) loss	\$ (22)	\$ 121	\$ 34
Net unrealized (gain) loss	(548)	706	(821)
Net (gain) loss ⁽¹⁾	\$ (570)	\$ 827	\$ (787)

(1) Amounts are reported net of the hedging effect of cross currency swaps.

The net realized foreign exchange gain for 2019 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for 2019 was primarily related to the impact of the stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized (gain) loss for each of the periods presented included the impact of cross currency swaps (2019 – unrealized loss of \$71 million, 2018 – unrealized gain of \$118 million, 2017 – unrealized loss of \$280 million). The US/Canadian dollar exchange rate at December 31, 2019 was US\$0.7713 (December 31, 2018 – US\$0.7328, December 31, 2017 – US\$0.7988).

INCOME TAXES

(\$ millions, except income tax rates)	2019	2018	2017
North America ⁽¹⁾	\$ 354	\$ 312	\$ (145)
North Sea	112	28	57
Offshore Africa	44	54	45
PRT – North Sea	(89)	(29)	(132)
Other taxes	13	9	11
Current income tax expense (recovery)	434	374	(164)
Deferred corporate income tax (recovery) expense	(895)	540	586
Deferred PRT expense – North Sea	1	17	54
Deferred income tax (recovery) expense	(894)	557	640
	(460)	931	476
Income tax rate and other legislative changes	1,618	—	(10)
	\$ 1,158	\$ 931	\$ 466
Effective income tax rate on adjusted net earnings from operations ⁽²⁾	25%	21%	27%

(1) Includes North America Exploration and Production, Midstream and Refining, and Oil Sands Mining and Upgrading segments.

(2) Excludes the impact of current and deferred PRT expense and other current income tax expense.

The effective income tax rate for 2019 and the comparable years included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings.

The current corporate income tax and PRT in the North Sea in 2019 and the comparable years included the impact of carrybacks of abandonment expenditures related to decommissioning activities at the Company's platforms in the North Sea.

During 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of these corporate income tax rate reductions, the Company's deferred corporate income tax liability decreased by \$1,618 million.

During 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by \$10 million.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's reported results of operations, financial position or liquidity.

During 2019, the Company filed Scientific Research and Experimental Development claims of approximately \$250 million (2018 – \$265 million; 2017 – \$345 million) relating to qualifying research and development expenditures for Canadian income tax purposes.

Net Capital Expenditures ⁽¹⁾

(\$ millions)	2019	2018	2017
Exploration and Evaluation			
Net property acquisitions (dispositions) ^{(2) (3)}	\$ 90	\$ (74)	\$ 26
Net expenditures	74	122	123
Total Exploration and Evaluation	164	48	149
Property, Plant and Equipment			
Net property acquisitions ^{(2) (3)}	3,208	98	1,219
Well drilling, completion and equipping	775	1,446	1,001
Production and related facilities	1,028	1,262	860
Capitalized interest and other	81	106	91
Total Property, Plant and Equipment	5,092	2,912	3,171
Total Exploration and Production	5,256	2,960	3,320
Oil Sands Mining and Upgrading			
Project costs ⁽⁴⁾	436	438	821
Sustaining capital	933	665	561
Turnaround costs	118	112	155
Acquisitions of Exploration and Evaluation assets ^{(3) (5)}	—	218	219
Net property acquisitions ⁽³⁾	—	—	11,604
Capitalized interest and other	38	14	76
Total Oil Sands Mining and Upgrading	1,525	1,447	13,436
Midstream and Refining	10	13	80
Abandonments ⁽⁶⁾	296	290	274
Head office	34	21	19
Total net capital expenditures	\$ 7,121	\$ 4,731	\$ 17,129
By segment			
North America ^{(2) (3)}	\$ 4,831	\$ 2,671	\$ 3,056
North Sea	196	131	160
Offshore Africa	229	158	104
Oil Sands Mining and Upgrading ^{(3) (5)}	1,525	1,447	13,436
Midstream and Refining	10	13	80
Abandonments ⁽⁶⁾	296	290	274
Head office	34	21	19
Total	\$ 7,121	\$ 4,731	\$ 17,129

(1) Net capital expenditures exclude the impact of lease assets and fair value and revaluation adjustments, and include non-cash transfers of property, plant and equipment to inventory due to change in use.

(2) During 2019, cash consideration for the acquisition of assets from Devon included \$91 million for exploration and evaluation assets and \$3,126 million for property, plant and equipment.

(3) During 2017, total purchase consideration for the acquisition of AOSP of \$12,157 million included \$26 million of exploration and evaluation assets and \$308 million of property, plant and equipment within the North America segment, and \$219 million of exploration and evaluation assets and \$11,604 million of property, plant and equipment within the Oil Sands Mining and Upgrading segment.

(4) Includes Horizon Phase 2/3 construction costs.

(5) In the third quarter of 2018, total purchase consideration for the acquisition of the Joslyn oil sands project included \$222 million for exploration and evaluation assets and \$4 million for asset retirement obligations assumed. In the fourth quarter of 2018, following integration of the Joslyn oil sands project into the Horizon mine plan and determination of proved crude oil reserves, the exploration and evaluation assets were transferred to property, plant, and equipment.

(6) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

NET CAPITAL EXPENDITURES, AS RECONCILED TO CASH FLOWS USED IN INVESTING ACTIVITIES

(\$ millions)	2019	2018	2017
Cash flows used in investing activities	\$ 7,255	\$ 4,814	\$ 13,102
Net change in non-cash working capital ^{(1) (2)}	(430)	(345)	22
Investment in other long-term assets	—	(28)	(87)
Share consideration in business acquisitions	—	—	3,818
Abandonment expenditures ⁽³⁾	296	290	274
Net capital expenditures	\$ 7,121	\$ 4,731	\$ 17,129

(1) Includes net working capital and other long-term assets of \$195 million related to the acquisition of assets from Devon in 2019.

(2) Includes net working capital of \$291 million related to the acquisition of AOSP in 2017.

(3) The Company excludes abandonment expenditures from "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" in the "Financial and Operational Highlights" section of this MD&A.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core areas. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production expenses.

Net capital expenditures for 2019 were \$7,121 million compared with \$4,731 million for 2018 (2017 – \$17,129 million). Net capital expenditures for 2019 included \$3,217 million of cash consideration to acquire assets from Devon.

DRILLING ACTIVITY ⁽¹⁾

(number of wells)	2019	2018	2017
Net successful natural gas wells	19	18	21
Net successful crude oil wells ⁽²⁾	86	483	495
Dry wells	3	9	7
Stratigraphic test / service wells	447	615	289
Total	555	1,125	812
Success rate (excluding stratigraphic test / service wells)	97%	98%	99%

(1) Includes drilling activity for North America and International segments.

(2) Includes bitumen wells.

North America

During 2019, the Company targeted 20 net natural gas wells, 42 net primary heavy crude oil wells, 3 net bitumen (thermal oil) wells and 37 net wells targeting light crude oil.

North Sea

During 2019, the Company completed 5 gross production wells (4.9 on a net basis) and 2 gross injection wells (1.9 on a net basis), successfully completing the 2019 drilling program in the North Sea.

Offshore Africa

During 2019, the Company completed 1 gross production well (0.6 on a net basis) and 2 gross injection wells (1.2 on a net basis) at Baobab and 1 gross appraisal well (0.6 on a net basis) at Kossipo.

Liquidity and Capital Resources

(\$ millions, except ratios)	2019	2018	2017
Working capital ⁽¹⁾	\$ 241	\$ (601)	\$ 513
Long-term debt ^{(2) (3)}	\$ 20,982	\$ 20,623	\$ 22,458
Less: cash and cash equivalents	139	101	137
Long-term debt, net	\$ 20,843	\$ 20,522	\$ 22,321
Share capital	\$ 9,533	\$ 9,323	\$ 9,109
Retained earnings	25,424	22,529	22,612
Accumulated other comprehensive income (loss)	34	122	(68)
Shareholders' equity	\$ 34,991	\$ 31,974	\$ 31,653
Debt to book capitalization ^{(3) (4)}	37%	39%	41%
Debt to market capitalization ^{(3) (5)}	30%	34%	29%
After-tax return on average common shareholders' equity ⁽⁶⁾	16%	8%	8%
After-tax return on average capital employed ^{(3) (7)}	11%	6%	6%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.

(2) Includes the current portion of long-term debt (2019 - \$2,391 million, 2018 - \$1,141 million, 2017 - \$1,877 million).

(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and premiums and transaction costs.

(4) Calculated as net current and long-term debt; divided by the book value of common shareholders' equity plus net current and long-term debt.

(5) Calculated as net current and long-term debt; divided by the market value of common shareholders' equity plus net current and long-term debt.

(6) Calculated as net earnings for the year; as a percentage of average common shareholders' equity for the year.

(7) Calculated as net earnings plus after-tax interest and other financing expense for the year; as a percentage of average capital employed for the year.

As at December 31, 2019, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of this MD&A. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated cash flows from operating activities supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long-term and support its growth strategy.

On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing the Company's borrowing capacity:
 - During 2019, the Company fully repaid and cancelled the \$1,800 million non-revolving term credit facility scheduled to mature in May 2020.
 - During 2019, the \$2,200 million non-revolving term credit facility, originally due October 2020, was extended to February 2023 and increased to \$2,650 million.
 - During 2019, the Company entered into a \$3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon. The facility matures in June 2022 and is subject to annual amortization of 5% of the original balance.
 - Borrowings under the Company's non-revolving credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2019, the non-revolving credit facilities were fully drawn.
 - During 2019, the Company extended the \$2,425 million revolving syndicated credit facility, of which \$330 million was originally due June 2019 and \$2,095 million was originally due June 2021, to June 2023. The other \$2,425 million revolving credit facility matures in June 2022. Each of the \$2,425 million revolving credit facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. Borrowings under the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.

- During 2019, the Company reduced the £15 million demand credit facility, related to the Company's North Sea operations, to £5 million.
- During 2019, the Company repaid \$500 million of 2.60% medium-term notes and \$500 million of 3.05% medium-term notes.
- The Company's borrowings under its US commercial paper program are authorized up to a maximum of US\$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
- During 2019, the Company filed new base shelf prospectuses that allow for the offer for sale from time to time of up to \$3,000 million of medium-term notes in Canada and US\$3,000 million of debt securities in the United States, expiring in August 2021, and replacing the Company's previous base shelf prospectuses, which would have expired in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages. The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at December 31, 2019, the Company was in compliance with this covenant; and
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default.

As at December 31, 2019, the Company had in place revolving bank credit facilities of \$4,959 million of which \$4,737 million was available. Additionally, the Company had in place fully drawn term credit facilities of \$6,650 million. This excludes certain other dedicated credit facilities supporting letters of credit.

As at December 31, 2019, the Company had total US dollar denominated debt with a carrying amount of \$15,102 million (US\$11,649 million), before transaction costs and original issue discounts. This included \$6,545 million (US\$5,049 million) hedged by way of cross currency swaps (US\$1,050 million) and foreign currency forwards (US\$3,999 million). The fixed repayment amount of these hedging instruments is \$6,429 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately \$116 million to \$14,986 million as at December 31, 2019.

Net long-term debt was \$20,843 million at December 31, 2019, resulting in a debt to book capitalization ratio of 37% (December 31, 2018 – 39%, December 31, 2017 – 41%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at December 31, 2019 are discussed in note 11 to the Company's audited consolidated financial statements.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. As at December 31, 2019, 140,000 MMBtu/d of currently forecasted natural gas volumes were hedged using AECO basis swaps for January 2020 to March 2020. Additionally, at December 31, 2019, 102,500 GJ/d of currently forecasted natural gas volumes were hedged using AECO fixed price swaps for April 2020 to October 2020. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2019 are discussed in note 19 of the Company's audited consolidated financial statements.

The maturity dates of long-term debt and other long-term liabilities and related interest payments were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt ⁽¹⁾	\$ 2,391	\$ 1,552	\$ 8,921	\$ 8,226
Other long-term liabilities ⁽²⁾	\$ 370	\$ 196	\$ 436	\$ 1,014
Interest and other financing expense ⁽³⁾	\$ 881	\$ 813	\$ 1,771	\$ 4,856

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows: less than one year, \$233 million; one to less than two years, \$171 million; two to less than five years, \$391 million; and thereafter, \$1,014 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2019.

SHARE CAPITAL

As at December 31, 2019, there were 1,186,857,000 common shares outstanding (December 31, 2018 – 1,201,886,000 common shares) and 47,646,000 stock options outstanding. As at March 17, 2020, the Company had 1,180,854,000 common shares outstanding and 53,143,000 stock options outstanding.

On March 4, 2020, the Board of Directors approved an increase in the quarterly dividend to \$0.425 per common share, beginning with the dividend payable on April 1, 2020. On March 6, 2019, the Board of Directors approved an increase in the quarterly dividend to \$0.375 per common share. On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to \$0.335 per common share. On March 1, 2017, the Board of Directors approved an increase in the quarterly dividend to \$0.275 per common share. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On May 21, 2019, the Company's application was approved for a Normal Course Issuer Bid ("NCIB") to purchase through the facilities at the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 59,729,706 common shares, over a 12-month period commencing May 23, 2019 and ending May 22, 2020. The Company's NCIB approved in May 2018 expired on May 22, 2019.

During 2019, the Company purchased for cancellation 25,900,000 common shares at a weighted average price of \$36.32 per common share for a total cost of \$941 million. Retained earnings were reduced by \$738 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2019, the Company purchased 6,970,000 common shares at a weighted average price of \$38.84 per common share for a total cost of \$271 million.

Commitments and Contingencies

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at December 31, 2019 ⁽¹⁾:

(\$ millions)	2020	2021	2022	2023	2024	Thereafter
Product transportation ^{(2) (3)}	\$ 730	\$ 722	\$ 637	\$ 726	\$ 699	\$ 7,907
North West Redwater Partnership service toll ⁽⁴⁾	\$ 133	\$ 167	\$ 157	\$ 164	\$ 156	\$ 2,815
Offshore vessels and equipment	\$ 69	\$ 63	\$ 9	\$ —	\$ —	\$ —
Field equipment and power	\$ 27	\$ 21	\$ 20	\$ 21	\$ 20	\$ 249
Other	\$ 26	\$ 20	\$ 17	\$ 17	\$ 17	\$ 30

(1) Subsequent to adoption of IFRS 16, the Company reports its payments for lease liabilities in the maturity table in the 'Liquidity and Capital Resources' section of this MD&A.

(2) On June 27, 2019, the Company assumed \$2,381 million of product transportation commitments related to the acquisition of assets from Devon.

(3) Includes commitments pertaining to a 20 year product transportation agreement on the Trans Mountain Pipeline Expansion. In addition, the Company has entered into certain product transportation agreements on pipelines that have not yet received regulatory and other approvals. The Company may be required to reimburse certain construction costs to the service provider under certain conditions.

(4) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service tolls, currently consisting of interest and fees, with principal repayments beginning in 2020. Included in the cost of service tolls is \$1,260 million of interest payable over the 30 year tolling period.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of its various development projects. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

Reserves

For the years ended December 31, 2019, 2018 and 2017, the Company retained Independent Qualified Reserves Evaluators to evaluate and review all of the Company's proved and proved plus probable crude oil, NGLs and natural gas reserves. The evaluation and review was conducted and prepared 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 following are reconciliation tables of the company gross proved and proved plus probable reserves using forecast prices and costs as at the effective date of December 31, 2019:

Proved Reserves	Light and Medium Crude Oil	Primary Heavy Crude Oil	Pelican Lake Heavy Crude Oil	Bitumen (Thermal Oil)	Synthetic Crude Oil	Natural Gas	Natural Gas Liquids	Barrels of Oil Equivalent
	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(Bcf)	(MMbbl)	(MMBOE)
December 31, 2018	399	182	305	1,540	6,091	6,652	267	9,893
Discoveries	—	—	—	—	—	—	—	—
Extensions	3	6	—	17	385	112	11	440
Infill Drilling	5	5	—	—	—	206	8	52
Improved Recovery	—	—	—	237	—	2	—	238
Acquisitions	2	46	—	769	—	35	1	823
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(5)	(3)	(3)	—	—	(228)	(5)	(54)
Technical Revisions	(9)	(3)	12	(64)	20	225	11	3
Production	(37)	(30)	(21)	(61)	(144)	(544)	(16)	(401)
December 31, 2019 ⁽¹⁾	357	202	293	2,438	6,352	6,460	275	10,993

Proved Plus Probable Reserves	Light and Medium Crude Oil	Primary Heavy Crude Oil	Pelican Lake Heavy Crude Oil	Bitumen (Thermal Oil)	Synthetic Crude Oil	Natural Gas	Natural Gas Liquids	Barrels of Oil Equivalent
	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(Bcf)	(MMbbl)	(MMBOE)
December 31, 2018	575	252	445	3,059	7,032	9,734	397	13,382
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	12	—	26	—	177	17	89
Infill Drilling	6	7	—	—	—	476	15	108
Improved Recovery	—	—	—	329	—	3	—	329
Acquisitions	2	68	—	955	—	42	1	1,033
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(4)	(3)	(3)	—	—	(266)	(6)	(60)
Technical Revisions	(28)	(12)	4	(198)	9	(16)	(1)	(228)
Production	(37)	(30)	(21)	(61)	(144)	(544)	(16)	(401)
December 31, 2019 ⁽¹⁾	519	293	425	4,108	6,897	9,607	408	14,252

(1) Information in the reserves data tables may not add due to rounding. BOE values as presented may not calculate due to rounding.

At December 31, 2019, the company gross proved crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 9,917 MMbbl, and company gross proved plus probable crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 12,651 MMbbl. Proved reserves additions and revisions replaced 465% of 2019 production. Additions to proved reserves resulting from exploration and development activities, acquisitions, dispositions and future offset additions amounted to 1,494 MMbbl, and additions to proved plus probable reserves amounted to 1,443 MMbbl. Net negative revisions amounted to 51 MMbbl for proved reserves and 241 MMbbl for proved plus probable reserves, primarily due to technical revisions.

At December 31, 2019, the company gross proved natural gas reserves totaled 6,460 Bcf, and company gross proved plus probable natural gas reserves totaled 9,607 Bcf. Proved reserves additions and revisions replaced 65% of 2019 production. Additions to proved reserves resulting from exploration and development activities, acquisitions, dispositions and future offset additions amounted to 355 Bcf, and additions to proved plus probable reserves amounted to 698 Bcf. Net negative revisions amounted to 4 Bcf for proved reserves and 282 Bcf for proved plus probable reserves, primarily due to economic factors.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's Independent Qualified Reserves Evaluators to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and related net present value of future net revenue of the remaining reserves. Additional reserves information is annually disclosed in the AIF.

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 FASB 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.

Risks and Uncertainties

The Company is exposed to various operational risks inherent in the exploration, development, production and marketing of crude oil and NGLs and natural gas and the mining, extracting and upgrading of bitumen into SCO. These inherent risks include, but are not limited to, the following:

- Volatility in the prevailing prices of crude oil and NGLs and natural gas;
- The ability to find, produce and replace reserves, whether sourced from exploration, improved recovery or acquisitions, at a reasonable cost, including the risk of reserves revisions due to economic and technical factors. Reserves revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
- Reservoir quality and uncertainty of reserves estimates;
- Regulatory risk related to approval for exploration and development activities, which can add to costs or cause delays in projects;
- Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
- Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting and upgrading the Company's bitumen products;
- Timing and success of integrating the business and operations of acquired companies and assets;
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including derivative financial instruments and physical sales contracts as part of a hedging program;
- Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;
- Foreign exchange risk due to the effect of fluctuating exchange rates on the Company's US dollar denominated debt and revenue from sales predominantly based on US dollar denominated benchmarks;
- Environmental impact risk associated with exploration and development activities, including GHG;
- Geopolitical risks associated with changing governments or governmental policies, social instability and other political, economic or diplomatic developments in the regions where the Company has its operations;
- Future legislative and regulatory developments related to environmental regulation, including GHG and carbon;
- Potential actions of governments, regulatory authorities and other stakeholders that may result in costs or restrictions in the jurisdictions where the Company has operations, including but not limited to restrictions on production;
- Changing royalty regimes;
- Business interruptions because of unexpected events such as fires or explosions whether caused by human error or nature, severe storms and other calamitous acts of nature, blowouts, freeze-ups, mechanical or equipment failures of facilities and infrastructure and other similar events affecting the Company or other parties whose operations or assets directly or indirectly impact the Company and that may or may not be financially recoverable;
- Epidemics or pandemics, such as the newly identified COVID-19 virus pandemic, have the potential to disrupt the Company's operations, projects and financial condition through the disruption of the local or global supply chain and transportation services, or the loss of manpower resulting from quarantines that affect the Company's labour pools in their local communities, workforce camps or operating sites or that are instituted by local health authorities as a precautionary measure, any of which may require the Company to temporarily reduce or shutdown its operations depending on the extent and severity of a potential outbreak and the areas or operations impacted. Depending on the severity, a large scale global epidemic or pandemic could impact the international demand for commodities and have a corresponding impact on the prices realized by the Company, which could have a material adverse effect on the Company's financial condition;
- The ability to secure adequate transportation for products which could be affected by pipeline constraints, the construction by third parties of new or expansion of existing pipeline capacity and other factors;
- The access to markets for the Company's products;
- The risk of significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach that could adversely affect the Company's operations;
- Liquidity risk related to the Company's ability to fulfill financial obligations as they become due or ability to liquidate assets in a timely manner at a reasonable price; and
- Other circumstances affecting revenue and expenses.

The Company uses a variety of means to seek to mitigate and/or minimize these risks. The Company maintains a comprehensive property loss and business interruption insurance program to reduce risk. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company seeks to manage these risks by monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit

are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default. Derivative financial instruments are periodically utilized to help ensure targets are met and to manage commodity price, foreign currency and interest rate exposures. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company seeks to manage this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions. Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper and access to debt capital markets, to meet obligations as they become due. The Company has implemented cyber security protocols and procedures designed to reduce the risk of failure or a significant breach of the Company's information technology systems and related data and control systems.

The Company has safety, integrity and environmental management systems to recover and process crude oil and natural gas resources safely, efficiently, and in an environmentally sustainable manner and mitigate risk.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

For additional details regarding the Company's risks and uncertainties, refer to the Company's AIF for the year ended December 31, 2019.

Environment

The Company has a Corporate Statement on Environmental Management which affirms that environmental stewardship is a fundamental value of the Company. 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. Environmental, social, economic and health considerations are evaluated in new project designs and in operations to improve environmental performance. Processes are employed to avoid, mitigate, minimize or compensate for environmental effects. Working with local communities, the Company considers the interests and values of the people using the land in proximity to its operations, and where appropriate, adapts projects to recognize those matters.

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. Existing and expected legislation and regulations may require the Company to address and mitigate the effect of its activities on the environment. The Company believes 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. Increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings.

The Company's associated environmental risk management strategies incorporate working with legislators and regulators on any new or revised policies, legislation or regulations to 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's environmental risk management strategies employ an Environmental Management Plan (the "Plan"). As part of risk management, the Company develops, assesses and implements technologies and innovative practices that will improve environmental performance, often through collaborative efforts with industry partners, governments and research institutions. Details of the Plan, along with performance results, are presented to, and reviewed by, the Board of Directors quarterly.

The Plan and the Company's operating guidelines focus on minimizing the impact of operations while meeting regulatory requirements, regional management frameworks for air quality and emissions, ground and surface 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 part of this Plan, has implemented proactive 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"), Petroleum Technology Alliance Canada ("PTAC") and other research institutions;
- Mitigation of the Company's climate change impacts through implementation of various CO₂ emissions reduction and carbon capture projects including: CO₂ injection for EOR, CO₂ sequestration in tailings and the Quest carbon capture and storage facility; a methane emissions reduction program, including solution gas conservation to reduce methane venting, and an equipment retrofit program to reduce methane emissions from pneumatic equipment; and optimization of efficiencies at the Company's facilities;
- Water programs to improve efficiency of use and recycle rates as well as to reduce fresh water use;
- Groundwater monitoring for all thermal in situ and mine operations;

- Effective reclamation and decommissioning programs across the Company's operations, returning sites to their former state. In North America, well abandonment and progressive reclamation of large contiguous areas of land for the enhancement of biodiversity and the establishment of functional wildlife habitats. In the Company's International operations, decommissioning activities continued in Gabon as well as Murchison and Ninian platforms in the North Sea;
- 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 regional important resources;
- An active spill prevention and management program; and
- An internal environmental management system for compliance audit and inspection programs of operating facilities.

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 3.8% (2018 – 5.0%; 2017 – 4.7%). For 2019, the Company's capital expenditures included \$296 million for abandonment expenditures (2018 – \$290 million; 2017 – \$274 million). The Company's estimated discounted ARO at December 31, 2019 was as follows:

(\$ millions)	2019		2018
Exploration and Production			
North America	\$ 2,792	\$	1,665
North Sea	816		707
Offshore Africa	161		134
Oil Sands Mining and Upgrading	2,000		1,379
Midstream and Refining	2		1
	\$ 5,771	\$	3,886

The discounted ARO was based on estimates of future costs to abandon and restore wells, production facilities, mine sites, upgrading facilities and tailings, and offshore production platforms. Factors that affect costs include number of wells drilled, well depth, facility size and the specific environmental legislation. The estimated future costs are based on engineering estimates of current costs in accordance with present legislation, industry operating practice and the expected timing of abandonment.

GREENHOUSE GAS AND OTHER EMISSIONS

The Company has a large, diversified and balanced portfolio and a risk management strategy which incorporates an integrated GHG emissions reduction strategy and investments in technology and innovation to improve its GHG performance. The Company's integrated GHG emissions reduction strategy includes: 1) integrating emissions reduction in project planning and operations; 2) leveraging technology to create value and enhance performance; 3) investing in research and development and supporting collaboration with industry, entrepreneurs, academia and governments; 4) focusing on continuous improvement to drive long-term emissions reduction; 5) leading in carbon capture, sequestration and storage; 6) engaging in policy and regulatory development (including trading capacity and offsetting emissions); and, 7) reviewing and developing new business opportunities and trends.

The Company, through the Canadian Association of Petroleum Producers, is working with Canadian legislators and regulators as they develop and implement new GHG emission laws and regulations to support emissions reductions and properly reflect a balanced approach to sustainable development. Internally, the Company is pursuing an integrated emissions reduction strategy, to ensure that it is able to comply with existing and future emissions reduction requirements, for both GHGs and air pollutants (such as sulphur dioxide and oxides of nitrogen). The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new policies encourage technological innovation, energy efficiency, and targeted research and development while not impacting competitiveness.

Governments in jurisdictions in which the Company operates have developed or are developing GHG regulations as part of their national and international climate change commitments. The Company uses existing GHG regulations to determine the impact of compliance costs on current and future projects. The Company monitors the development of GHG regulations on an ongoing basis in the jurisdictions in which it operates to assess the impact of future regulatory developments on the Company's operations and planned projects. 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.

Carbon pricing regulatory systems in all provinces are subject to annual review by the federal government to assess the adequacy of the provincial systems against the federal Greenhouse Gas Pollution Pricing Act. Such future reviews may affect the carbon price and/or the stringency of provincial systems.

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. In 2019, nine of the Company's operated facilities: Horizon, AOSP, the Primrose/Wolf Lake, Kirby South, Jackfish, Peace River, Hays, Wapiti and the Brintnell power generation facility were subject to compliance under the regulation. Effective January 1, 2020, the CCIR was replaced with the Technology Innovation and Emissions Reduction Regulation ("TIER"). The coverage of TIER has expanded to include all of the Company's assets in Alberta (as an alternative to the federal fuel charge). The carbon price in Alberta is currently \$30/tonne for emissions above the TIER-regulated limits, and the Alberta government has announced its intention to increase the price to \$40/tonne in 2021 and \$50/tonne in 2022, in alignment with the federal carbon pricing schedule. Facilities with emissions in previous years above 100,000 tonnes of CO₂e/year, or that have voluntarily opted into TIER are required to comply with 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 is subject to a reduction target in 2020.

In British Columbia, carbon tax is currently being assessed at \$40/tonne of CO₂e on fuel consumed and gas flared in the province, with the rate increasing to \$45/tonne on April 1, 2020 and to \$50/tonne of CO₂e 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 emissions intensive trade exposed (EITE) sectors.

As part of its Prairie Resilience Plan, the Saskatchewan government has released a regulation ("The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations") that applies to facilities emitting more than 25 kilotonnes of CO₂e annually and requires the North Tangleflags in situ heavy oil facility and the Senlac in situ heavy crude oil facility to meet reduction targets for GHG emissions in 2019. This regulation also enables facilities below the threshold to aggregate and opt into the Saskatchewan regulatory system as an alternative to the federal fuel charge.

In Manitoba, the federal output-based pricing system applies for facilities with emissions greater than or equal to 10 kilotonnes of CO₂e annually, and the federal fuel charge applies for facilities with emissions of less than 10 kilotonnes of CO₂e annually.

The federal government's methane regulation has come into effect on January 1, 2020 and will apply nationally unless provinces reach equivalency agreements with the federal government, under which the federal regulation would not be in effect for those jurisdictions which have equivalency agreements. The Alberta government has also finalized regulations to reduce methane emissions from the upstream oil and gas sector (consistent with the federal reduction target), which came into effect on January 1, 2020. 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 oil production facilities, effective 2020.

Air pollutant standards and guidelines are being developed federally and provincially and the Company is participating in these discussions. Ambient air quality and sector based reductions in air emissions are being reviewed. Through Company and industry participation with stakeholders, guidelines are being developed that adopt a structured process to emission reductions that is commensurate with technological development and operational requirements.

In 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 CO₂ allocation. In Phase 2 (2008 - 2012) the Company's CO₂ allocation was decreased below the Company's operations emissions. In Phase 3 (2013 - 2020) the Company's CO₂ allocation was further reduced. Following the UK's withdrawal from the European Union ("EU") on January 31, 2020, the UK will continue to participate in the EU ETS for the 2020 compliance year, with decisions on the post-2020 GHG regulatory framework expected in 2020. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO₂ emissions at its offshore facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Accounting Policies and Standards

CHANGES IN ACCOUNTING POLICIES

IFRS 16 "Leases"

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaced IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and generally requires balance sheet recognition for all leases. Certain short-term (12 months or less) and low-value leases are exempt from the requirements, and the Company continues to treat these leases as expenses. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are also exempt from the standard.

The Company adopted IFRS 16 on January 1, 2019 using the modified retrospective approach with no impact to opening retained earnings at the date of adoption. In accordance with the transitional provisions in the standard, balances reported in the comparative periods have not been restated and continue to be reported using the Company's previous accounting policy under IAS 17.

On adoption, the Company applied the following practical expedients under the standard. Certain expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics;
- leases with a remaining lease term of twelve months or less as at January 1, 2019 were treated as short-term leases;
- exclusion of initial direct costs for the measurement of lease assets at the date of initial application; and
- the application of the Company's previous assessment for onerous contracts under IAS 37, instead of re-assessing impairment on the Company's lease assets as at January 1, 2019.

The Company did not apply any practical expedients pertaining to grandfathering of leases assessed under the previous standard.

In connection with the adoption of IFRS 16, the Company recognized lease liabilities (included in other long-term liabilities) of \$1,539 million, measured at the present value of the remaining lease payments, discounted at the Company's incremental borrowing rate at the transition date. Lease assets were measured at an amount equal to the lease liability. Under the new standard, the Company reports cash outflows for payment of the principal portion of the lease liability as cash flows used in financing activities. The interest portion of the lease payments is classified as cash flows from operating activities.

For further details of the Company's lease assets and lease liabilities on transition to the new Leases standard at January 1, 2019 and as at December 31, 2019, refer to the audited consolidated financial statements for the year ended December 31, 2019.

The impacts of the adoption of IFRS 16 are discussed within the respective sections of this MD&A. The most significant impacts of the adoption of the new Leases standard are as follows:

- Cash flow from operating activities and adjusted funds flow increased as the principal portion of lease payments, previously classified as cash flows from operating activities is now reported as cash flows used in financing activities;
- Increased depletion, depreciation and amortization expense and interest expense;
- Decreased production expense, transportation expense and administration expense; and
- Commitments for leases, previously reported in the "Commitments and Contingencies" section of this MD&A, are now reported in the maturity table in the "Liquidity and Capital Resources" section of this MD&A.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In October 2018, the IASB issued amendments to IFRS 3 "Definition of a Business" that narrowed and clarified the definition of a business. The amendments permit a simplified assessment of whether an acquired set of activities and assets is a group of assets rather than a business. The amendments are effective January 1, 2020 with earlier adoption permitted. The amendments apply to business combinations after the date of adoption. The Company prospectively adopted the amendments on January 1, 2020.

In October 2018, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" and IAS 8 "Accounting Policies, Changes in Accounting Estimates and Errors". The amendments make minor changes to the definition of the term "material" and align the definition across all IFRS Standards. Materiality is used in making judgments related to the preparation of financial statements. The amendments are effective January 1, 2020 with earlier adoption permitted. The Company prospectively adopted the amendments on January 1, 2020.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in this MD&A and the audited consolidated financial statements for the year ended December 31, 2019.

A) Depletion, Depreciation and Amortization and Impairment

Exploration and evaluation ("E&E") costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. The judgements associated with the estimation of proved reserves are described below in "Crude Oil and Natural Gas Reserves".

An alternative acceptable accounting method for E&E costs under IFRS 6 "Exploration for and Evaluation of Mineral Resources" is to charge exploratory dry holes and geological and geophysical exploration costs incurred after having obtained the legal rights to explore an area against net earnings in the period incurred rather than capitalizing to E&E assets.

E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of related Cash Generating Units ("CGUs"), aggregated at a segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. The determination of the fair value of CGUs requires the use of assumptions and estimates including future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and production costs, discount rates and income taxes. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Crude oil and natural gas properties in the Exploration and Production segments are depleted using the unit-of-production method over proved reserves, except for major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future estimated development expenditures required to develop proved reserves. Estimates of proved reserves have a significant impact on net earnings, as they are a key input to the calculation of depletion expense.

The Company assesses property, plant and equipment for impairment discounted at rates currently ranging from 10% to 12% whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low commodity prices for an extended period, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If an indication of impairment exists, the Company performs an impairment test related to the specific assets at the CGU level.

B) Crude Oil and Natural Gas Reserves

Reserves estimates are based on engineering data, estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations and judgements. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserves estimates would result in a higher or lower depletion, depreciation and amortization charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of E&E and property, plant and equipment carrying amounts.

C) Asset Retirement Obligations

The Company is required to recognize a liability for ARO associated with its property, plant and equipment. An ARO liability associated with the retirement of a tangible long-lived asset is recognized to the extent of a legal obligation resulting from an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total ARO amount. These individual assumptions may be subject to change.

The estimated present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's weighted average credit-adjusted risk-free interest rate, which is currently 3.8%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes in discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

D) Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated income tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted as at the date of the balance sheet. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

E) Risk Management Activities

The Company periodically uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The carrying amount of a risk management liability is adjusted for the Company's own credit risk. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

F) Purchase Price Allocations

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

The Company has made various assumptions in determining the fair values of acquired assets and liabilities. The most significant assumptions and judgements relate to the estimation of the fair value of crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates crude oil and natural gas reserves. Reserves estimates are based on the work performed by the Company's internal engineers and outside consultants. The judgements associated with these estimated reserves are described above in "Crude Oil and Natural Gas Reserves". Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

G) Share-Based Compensation

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

H) Leases

Purchase, extension and termination options are included in certain of the Company's leases to provide operational flexibility. To measure the lease liability, the Company uses judgment to assess the likelihood of exercising these options. These assessments are reviewed when significant events or circumstances indicate that the likelihood of exercising these options may have changed. The Company also uses estimates to determine its incremental borrowing costs if the interest rate implicit in the lease is not readily determinable.

Control Environment

The Company's management, including the President and the Chief Financial Officer and Senior Vice-President, Finance, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2019, and concluded that disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings and other reports filed with securities regulatory authorities in Canada and the United States is recorded, processed, summarized and reported within the time periods specified and such information is accumulated and communicated to the Company's management to allow timely decisions regarding required disclosures.

The Company's management, including the President and the Chief Financial Officer and Senior Vice-President, Finance, also evaluated the effectiveness of internal control over financial reporting as at December 31, 2019, and concluded that internal control over financial reporting is effective. Further, there were no changes in the Company's internal control over financial reporting during 2019 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal control over financial reporting provide a reasonable level of assurance they are effective, they recognize that all control systems have inherent limitations. Because of its inherent limitations, the Company's control systems may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Outlook

The Company continues to implement its strategy of maintaining a large portfolio of varied projects, which the Company believes will enable it, over an extended period of time, to provide consistent growth in production and create shareholder value. Annual budgets are developed, scrutinized throughout the year and revised if necessary in the context of targeted financial ratios, project returns, product pricing expectations, and balance in project risk and time horizons. The Company maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of capital expenditures in each of its project areas.

2020 CAPITAL BUDGET

Effective and efficient operations will continue to be a focus for the Company in 2020. Our 2020 capital budget is flexible and disciplined and was originally targeted, when finalized on December 4, 2019, at approximately \$4,050 million, driving corporate production guidance volumes of between 1,137,000 and 1,207,000 BOE/d. Subsequent to year end 2019, in early March 2020, as a result of the volatility in crude oil pricing, Canadian Natural reduced its 2020 capital budget by approximately \$100 million to \$3,950 million. With the continued volatility in commodity pricing, the Company in mid-March 2020 identified and implemented further opportunities to reduce its 2020 capital spending budget to approximately \$2,960 million, but with no impact to our stated production guidance volumes of between 1,137,000 and 1,207,000 BOE/d. Decisions regarding additional opportunities to further reduce capital spending will be made as part of the Company's prudent management of its capital expenditures.

Other

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flows from operating activities and net earnings due to changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2019, excluding mark-to-market gains (losses) on risk management activities and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flows from Operating Activities		Cash flows from Operating Activities		Net earnings		Net earnings	
	(\$ millions)		(per common share, basic)		(\$ millions)		(per common share, basic)	
Price changes								
Crude oil – WTI US\$1.00/bbl								
Excluding financial derivatives	\$	292	\$	0.24	\$	292	\$	0.24
Including financial derivatives	\$	292	\$	0.24	\$	292	\$	0.24
Natural gas – AECO C\$0.10/Mcf ⁽¹⁾								
Excluding financial derivatives	\$	23	\$	0.02	\$	23	\$	0.02
Including financial derivatives	\$	21	\$	0.02	\$	21	\$	0.02
Volume changes								
Crude oil – 10,000 bbl/d	\$	128	\$	0.11	\$	100	\$	0.08
Natural gas – 10 MMcf/d	\$	2	\$	—	\$	—	\$	—
Foreign currency rate change								
\$0.01 change in US\$ ⁽¹⁾								
Including financial derivatives	\$	161 - 165	\$	0.14	\$	52	\$	0.04
Interest rate change – 1%	\$	50	\$	0.04	\$	50	\$	0.04

(1) For details of financial instruments in place, refer to note 19 to the Company's audited consolidated financial statements as at December 31, 2019.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2019	2018	2017
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	319,437	344,665	450,662	506,571	405,970	350,961	359,449
North America – Oil Sands Mining and Upgrading	416,206	374,500	432,203	357,856	395,133	426,190	282,026
North Sea	25,714	27,594	27,454	30,860	27,919	23,965	23,426
Offshore Africa	22,155	23,650	21,227	18,495	21,371	19,662	20,335
Total	783,512	770,409	931,546	913,782	850,393	820,778	685,236
Natural gas (MMcf/d)							
North America	1,454	1,482	1,425	1,411	1,443	1,490	1,601
North Sea	28	23	20	25	24	32	39
Offshore Africa	28	27	24	19	24	26	22
Total	1,510	1,532	1,469	1,455	1,491	1,548	1,662
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	561,755	591,738	688,175	741,673	646,443	599,310	626,230
North America – Oil Sands Mining and Upgrading	416,206	374,500	432,203	357,856	395,133	426,190	282,026
North Sea	30,466	31,346	30,758	35,052	31,915	29,264	29,989
Offshore Africa	26,785	28,216	25,225	21,695	25,466	24,049	24,019
Total	1,035,212	1,025,800	1,176,361	1,156,276	1,098,957	1,078,813	962,264

PER UNIT RESULTS – EXPLORATION AND PRODUCTION

	Q1	Q2	Q3	Q4	2019	2018	2017
Crude oil and NGLs (\$/bbl) ⁽¹⁾							
Sales price ⁽²⁾	\$ 53.98	\$ 63.45	\$ 55.19	\$ 49.60	\$ 55.08	\$ 46.92	\$ 48.57
Transportation	3.26	3.35	3.69	3.53	3.48	3.08	2.80
Realized sales price, net of transportation	50.72	60.10	51.50	46.07	51.60	43.84	45.77
Royalties	5.95	6.35	6.02	6.03	6.08	5.08	5.24
Production expense	16.04	14.42	13.25	12.46	13.81	15.69	14.89
Netback	\$ 28.73	\$ 39.33	\$ 32.23	\$ 27.58	\$ 31.71	\$ 23.07	\$ 25.64
Natural gas (\$/Mcf) ⁽¹⁾							
Sales price ⁽²⁾	\$ 3.09	\$ 1.98	\$ 1.64	\$ 2.64	\$ 2.34	\$ 2.61	\$ 2.76
Transportation	0.46	0.40	0.40	0.43	0.42	0.47	0.39
Realized sales price, net of transportation	2.63	1.58	1.24	2.21	1.92	2.14	2.37
Royalties	0.12	0.08	0.01	0.11	0.08	0.08	0.11
Production expense	1.33	1.23	1.12	1.17	1.22	1.36	1.27
Netback	\$ 1.18	\$ 0.27	\$ 0.11	\$ 0.93	\$ 0.62	\$ 0.70	\$ 0.99
Barrels of oil equivalent (\$/BOE) ⁽¹⁾							
Sales price ⁽²⁾	\$ 39.27	\$ 43.38	\$ 40.36	\$ 39.20	\$ 40.50	\$ 34.62	\$ 35.54
Transportation	3.06	2.97	3.27	3.24	3.14	2.96	2.66
Realized sales price, net of transportation	36.21	40.41	37.09	35.96	37.36	31.66	32.88
Royalties	3.78	4.06	4.07	4.37	4.09	3.27	3.40
Production expense	12.68	11.68	11.11	10.79	11.49	12.71	11.95
Netback	\$ 19.75	\$ 24.67	\$ 21.91	\$ 20.80	\$ 21.78	\$ 15.68	\$ 17.53

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of blending costs and excluding risk management activities.

PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING

	Q1	Q2	Q3	Q4	2019	2018	2017
Crude oil and NGLs (\$/bbl) ⁽¹⁾							
SCO sales price ⁽²⁾	\$ 65.86	\$ 74.98	\$ 71.60	\$ 68.67	\$ 70.18	\$ 68.61	\$ 63.98
Bitumen royalties ⁽³⁾	2.31	3.79	3.76	3.47	3.31	3.09	1.64
Transportation	1.17	1.53	1.16	1.33	1.29	1.61	1.54
Adjusted production costs	21.46	24.17	18.82	23.02	21.75	21.05	23.40
Netback	\$ 40.92	\$ 45.49	\$ 47.86	\$ 40.85	\$ 43.83	\$ 42.86	\$ 37.40

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

(2) Net of blending and feedstock costs.

(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2019	2018
TSX – C\$						
Trading volume (thousands)	241,284	216,340	226,800	219,589	904,013	806,254
Share Price (\$/share)						
High	\$ 38.45	\$ 42.56	\$ 38.00	\$ 42.40	\$ 42.56	\$ 49.08
Low	\$ 31.52	\$ 34.25	\$ 30.01	\$ 32.26	\$ 30.01	\$ 30.11
Close	\$ 36.69	\$ 35.31	\$ 35.25	\$ 42.00	\$ 42.00	\$ 32.94
Market capitalization as at December 31 (\$ millions)					\$ 49,848	\$ 39,590
Shares outstanding (thousands)					1,186,857	1,201,886
NYSE – US\$						
Trading volume (thousands)	200,874	164,274	163,447	151,102	679,697	796,971
Share Price (\$/share)						
High	\$ 29.04	\$ 31.77	\$ 28.71	\$ 32.56	\$ 32.56	\$ 38.19
Low	\$ 23.09	\$ 25.42	\$ 22.58	\$ 24.20	\$ 22.58	\$ 21.85
Close	\$ 27.50	\$ 26.97	\$ 26.63	\$ 32.35	\$ 32.35	\$ 24.13
Market capitalization as at December 31 (\$ millions)					\$ 38,395	\$ 29,002
Shares outstanding (thousands)					1,186,857	1,201,886