Canadian Natural

Canadian Natural Resources Limited

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE MONTHS AND YEAR ENDED DECEMBER 31, 2018

MANAGEMENT'S DISCUSSION AND ANALYSIS

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" 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 but not limited to the Horizon Oil Sands ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the cost and timing of construction and future operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas 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 and the assumption of operations at processing facilities 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 natural gas liquids ("NGLs") reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company’s operations have been, and in the future may be, affected by political developments and by national, federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company’s assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company’s course of action would depend upon its assessment of the future considering all information then available.

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, 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 (loss) from operations; adjusted funds flow (previously referred to as funds flow from operations); net capital expenditures; adjusted cash production costs and adjusted depreciation, depletion and amortization. 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 (loss), cash flows from operating activities, and cash flows used in investing activities as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measure adjusted net earnings (loss) from operations is reconciled to net earnings (loss), as determined in accordance with IFRS, in the “Financial 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 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 derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the "Operating Highlights - Oil Sands Mining and Upgrading" 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 and Production

This MD&A should be read in conjunction with the unaudited interim consolidated financial statements for the three months and year ended December 31, 2018 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2017. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company’s unaudited interim consolidated financial statements for the three months and year ended December 31, 2018 and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

Production volumes and per unit statistics are presented throughout this MD&A on a “before royalty” 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 royalty” or “net” basis is also presented for information purposes only.

The following discussion and analysis refers primarily to the Company’s financial results for the three months and year ended December 31, 2018 in relation to the comparable periods in 2017 and the third quarter of 2018. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2017, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com. This MD&A is dated March 6, 2019.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Dec 31 2018**	Sep 30 2018	Dec 31 2017	Year Ended **Dec 31 2018**	Dec 31 2017
Product sales	**$ 3,831**	$ 6,327	$ 5,516	**$ 22,282**	$ 18,360
Crude oil and NGLs	**$ 3,327**	$ 5,967	$ 5,098	**$ 20,668**	$ 16,522
Natural gas	**$ 504**	$ 360	$ 418	**$ 1,614**	$ 1,838
Net earnings (loss)	**$ (776)**	$ 1,802	$ 396	**$ 2,591**	$ 2,397
Per common share – basic	**$ (0.64)**	$ 1.48	$ 0.32	**$ 2.13**	$ 2.04
– diluted	**$ (0.64)**	$ 1.47	$ 0.32	**$ 2.12**	$ 2.03
Adjusted net earnings (loss) from operations (1)	**$ (255)**	$ 1,354	$ 565	**$ 3,263**	$ 1,403
Per common share – basic	**$ (0.21)**	$ 1.11	$ 0.46	**$ 2.68**	$ 1.19
– diluted	**$ (0.21)**	$ 1.11	$ 0.46	**$ 2.67**	$ 1.19
Cash flows from operating activities	**$ 1,397**	$ 3,642	$ 1,438	**$ 10,121**	$ 7,262
Adjusted funds flow (2)	**$ 1,229**	$ 2,830	$ 2,307	**$ 9,088**	$ 7,347
Per common share – basic	**$ 1.02**	$ 2.32	$ 1.89	**$ 7.46**	$ 6.25
– diluted	**$ 1.02**	$ 2.31	$ 1.88	**$ 7.43**	$ 6.21
Cash flows used in investing activities	**$ 1,042**	$ 1,265	$ 1,074	**$ 4,814**	$ 13,102
Net capital expenditures (3)	**$ 1,181**	$ 1,473	$ 1,143	**$ 4,731**	$ 17,129

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for the after-tax effects of certain items of a non-operational nature. The Company considers adjusted net earnings (loss) from operations a key measure in evaluating the Company's performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. The reconciliation "Adjusted Net Earnings (Loss) from Operations, as Reconciled to Net Earnings (Loss)" is presented in this MD&A. Adjusted net earnings (loss) from operations may not be comparable to similar measures presented by other companies.

(2) 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 and certain movements in other long-term assets. The Company considers adjusted funds flow a key measure 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.

(3) 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 acquisitions 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.

Adjusted Net Earnings (Loss) from Operations, as Reconciled to Net Earnings (Loss)

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Net earnings (loss)	***$ (776)***	*$ 1,802*	*$ 396*	***$ 2,591***	*$ 2,397*
Share-based compensation, net of tax (1)	***(148)***	*(85)*	*97*	***(146)***	*134*
Unrealized risk management loss (gain), net of tax (2)	***17***	*(11)*	*68*	***(36)***	*33*
Unrealized foreign exchange loss (gain), net of tax (3)	***548***	*(182)*	*(2)*	***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)	***134***	*89*	*(4)*	***374***	*(11)*
Gain on acquisition, disposition and revaluation of properties, net of tax (7)	***(30)***	*(259)*	—	***(372)***	*(339)*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (8)	**—**	—	*10*	**—**	*10*
Adjusted net earnings (loss) from operations	***$ (255)***	*$ 1,354*	*$ 565*	***$ 3,263***	*$ 1,403*

(1) The Company's employee stock option plan provides for a cash payment option. Accordingly, the fair value of the outstanding vested options is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings (loss) or are charged to (recovered from) the Oil Sands Mining and Upgrading segment.

(2) 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 (loss). 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.

(3) 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 (loss).

(4) During the first quarter of 2018, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.

(5) 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 accounting loss (gain) for the period.

(6) 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 (loss).

(7) During the fourth quarter of 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, during the fourth quarter of 2018, 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). During the third quarter of 2018, the Company recorded a pre-tax gain of $272 million ($259 million after-tax) related to acquisitions in the North America Exploration and Production segment. During the second quarter of 2018, 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 the third quarter of 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. During the second quarter of 2017, 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.

(8) During the fourth quarter of 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018, resulting in an increase in the Company's deferred income tax liability of $10 million.

Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities (1)

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Cash flows from operating activities	***$ 1,397***	*$ 3,642*	*$ 1,438*	***$ 10,121***	*$ 7,262*
Net change in non-cash working capital	***(279)***	*(889)*	*709*	***(1,346)***	*(299)*
Abandonment expenditures (2)	***93***	*57*	*63*	***290***	*274*
Other (3)	***18***	*20*	*97*	***23***	*110*
Adjusted funds flow	***$ 1,229***	*$ 2,830*	*$ 2,307*	***$ 9,088***	*$ 7,347*

(1) Adjusted funds flow was previously referred to as funds flow from operations.

(2) 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.

(3) Includes certain movements in other long-term assets.

SUMMARY OF FINANCIAL HIGHLIGHTS

Consolidated Net Earnings (Loss) and Adjusted Net Earnings (Loss)

Net earnings for the year ended December 31, 2018 were $2,591 million compared with net earnings of $2,397 million for the year ended December 31, 2017. Net earnings for the year ended December 31, 2018 included net after-tax expenses of $672 million compared with net after-tax income of $994 million for the year ended December 31, 2017 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 (gain) 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. Excluding these items, adjusted net earnings from operations for the year ended December 31, 2018 were $3,263 million compared with adjusted net earnings from operations of $1,403 million for the year ended December 31, 2017.

The net loss for the fourth quarter of 2018 was $776 million compared with net earnings of $396 million for the fourth quarter of 2017 and net earnings of $1,802 million for the third quarter of 2018. The net loss for the fourth quarter of 2018 included net after-tax expenses of $521 million compared with net after-tax expenses of $169 million for the fourth quarter of 2017 and net after-tax income of $448 million for the third quarter of 2018 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the loss (gain) 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. Excluding these items, the adjusted net loss from operations for the fourth quarter of 2018 was $255 million compared with adjusted net earnings from operations of $565 million for the fourth quarter of 2017 and adjusted net earnings of $1,354 million for the third quarter of 2018.

The increase in net earnings and adjusted net earnings from operations for the year ended December 31, 2018 from the year ended December 31, 2017 was primarily due to:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- higher realized SCO prices in the Oil Sands Mining and Upgrading segment;
- higher realized risk management gains; and
- higher crude oil and NGLs netbacks in the International segments;

partially offset by:

- lower crude oil and NGLs netbacks in the North America Exploration and Production segment;
- higher depletion, depreciation and amortization in the Oil Sands Mining and Upgrading segment;
- lower natural gas netbacks in the North America Exploration and Production segment; and
- lower crude oil and NGLs sales volumes in the Exploration and Production segments.

The net loss and adjusted net loss from operations for the fourth quarter of 2018 as compared to net earnings and adjusted net earnings from operations in the fourth quarter of 2017 and the third quarter of 2018 was primarily due to a significant decline in crude oil pricing in November and December 2018 as a result of an oversupplied domestic market environment and a lack of takeaway capacity, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system. The Western Canadian Select ("WCS") heavy differential averaged US$39.36 per bbl for the fourth quarter of 2018 (third quarter of 2018 - US$22.17 per bbl, fourth quarter of 2017 - US$12.28 per bbl). The SCO price averaged US$37.48 per bbl for the fourth quarter of 2018 (third quarter of 2018 - US$68.44 per bbl, fourth quarter of 2017 - US$58.64 per bbl).

Following the Government of Alberta's announcement on December 2, 2018 of a mandatory curtailment of crude oil production, the WCS heavy differential index narrowed to US$12.38 per bbl for the first quarter of 2019 and the differential between SCO and WTI benchmark pricing narrowed to US$2.70 per bbl for the first quarter of 2019. Crude oil and natural gas pricing are discussed in detail in the "Business Environment" 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 (loss) for the three months and year ended December 31, 2018 from the comparable periods. These items are discussed in detail in the relevant sections of this MD&A.

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the year ended December 31, 2018 were $10,121 million compared with $7,262 million for the year ended December 31, 2017. Cash flows from operating activities for the fourth quarter of 2018 were $1,397 million compared with $1,438 million for the fourth quarter of 2017 and $3,642 million for the third quarter of 2018. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors noted above relating to the fluctuations in net earnings (loss) and adjusted net earnings (loss) from operations (excluding the effect of depletion, depreciation and amortization), as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the year ended December 31, 2018 were $9,088 million compared with $7,347 million for the year ended December 31, 2017. Adjusted funds flow for the fourth quarter of 2018 were $1,229 million compared with $2,307 million for the fourth quarter of 2017 and $2,830 million for the third quarter of 2018. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above relating to the fluctuations in cash flows from operating activities excluding the impact of the net change in non-cash working capital, abandonment and certain movements in other long-term assets.

Production Volumes

Total production before royalties for the fourth quarter of 2018 increased 6% to 1,081,368 BOE/d from 1,020,094 BOE/d for the fourth quarter of 2017 and increased 2% from 1,060,629 BOE/d for the third quarter of 2018. 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)		**Dec 31 2018**		Sep 30 2018		Jun 30 2018		Mar 31 2018
Product sales	**$**	**3,831**	$	6,327	$	6,389	$	5,735
Crude oil and NGLs	**$**	**3,327**	$	5,967	$	6,071	$	5,303
Natural gas	**$**	**504**	$	360	$	318	$	432
Net earnings (loss)	**$**	**(776)**	$	1,802	$	982	$	583
Net earnings (loss) per common share								
– basic	**$**	**(0.64)**	$	1.48	$	0.80	$	0.48
– diluted	**$**	**(0.64)**	$	1.47	$	0.80	$	0.47
($ millions, except per common share amounts)		Dec 31 2017		Sep 30 2017		Jun 30 2017		Mar 31 2017
Product sales	$	5,516	$	4,725	$	4,127	$	3,992
Crude oil and NGLs	$	5,098	$	4,320	$	3,645	$	3,459
Natural gas	$	418	$	405	$	482	$	533
Net earnings (loss)	$	396	$	684	$	1,072	$	245
Net earnings (loss) per common share								
– basic	$	0.32	$	0.56	$	0.93	$	0.22
– diluted	$	0.32	$	0.56	$	0.93	$	0.22

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 the Organization of the Petroleum Exporting Countries ("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 West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America 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 Dated Brent ("Brent") benchmark pricing in the North Sea and Offshore Africa.
- **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, the results from the Pelican Lake water and polymer flood projects, fluctuations in the Company's drilling program in North America, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, 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 due to low commodity prices in North America, and the impact of the drilling program in the International segments. 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 a third-party 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 that are dependent on weather, the impact of increased carbon tax and energy costs, cost optimizations across all segments, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.
- **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, fluctuations in depletion, depreciation and amortization expense in the North Sea due to the cessation of production at the Ninian North platform in the second quarter of 2017, and the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model 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.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company received 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.
- **Income tax expense** – Fluctuations in income tax expense due to statutory tax rate and other legislative changes substantively enacted in the various periods.
- **Gains on acquisition, disposition and revaluation of properties and gains/losses on investments** – Fluctuations due to the recognition of gains on the acquisition of AOSP and other assets, 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 (gain) on the Company's interest in the Redwater Partnership.

BUSINESS ENVIRONMENT

(Average for the period)	Three Months Ended Dec 31 2018	Three Months Ended Sep 30 2018	Three Months Ended Dec 31 2017	Year Ended Dec 31 2018	Year Ended Dec 31 2017
WTI benchmark price (US$/bbl)	**$ 58.83**	$ 69.50	$ 55.39	**$ 64.78**	$ 50.93
Dated Brent benchmark price (US$/bbl)	**$ 67.45**	$ 75.46	$ 61.46	**$ 71.12**	$ 54.38
WCS heavy differential from WTI (US$/bbl)	**$ 39.36**	$ 22.17	$ 12.28	**$ 26.29**	$ 11.97
SCO price (US$/bbl)	**$ 37.48**	$ 68.44	$ 58.64	**$ 58.62**	$ 52.20
Condensate benchmark price (US$/bbl)	**$ 45.27**	$ 66.82	$ 57.96	**$ 60.98**	$ 51.65
NYMEX benchmark price (US$/MMBtu)	**$ 3.65**	$ 2.90	$ 2.94	**$ 3.08**	$ 3.11
AECO benchmark price (C$/GJ)	**$ 1.80**	$ 1.28	$ 1.85	**$ 1.45**	$ 2.30
US/Canadian dollar average exchange rate (US$)	**$ 0.7573**	$ 0.7651	$ 0.7865	**$ 0.7717**	$ 0.7701

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 Alberta 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 in 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.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$64.78 per bbl for the year ended December 31, 2018, an increase of 27% from US$50.93 per bbl for the year ended December 31, 2017. WTI averaged US$58.83 per bbl for the fourth quarter of 2018, an increase of 6% from US$55.39 per bbl for the fourth quarter of 2017, and a decrease of 15% from US$69.50 per bbl for the third quarter of 2018.

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$71.12 per bbl for the year ended December 31, 2018, an increase of 31% from US$54.38 per bbl for the year ended December 31, 2017. Brent averaged US$67.45 per bbl for the fourth quarter of 2018, an increase of 10% from US$61.46 per bbl for the fourth quarter of 2017, and a decrease of 11% from US$75.46 per bbl for the third quarter of 2018.

WTI and Brent pricing for the three months and year ended December 31, 2018 has increased from the comparable periods in 2017 primarily due to declines in global crude oil inventories, together with larger than anticipated increases in global demand for crude oil. The decrease in WTI and Brent pricing for the fourth quarter of 2018 as compared with the third quarter of 2018 reflected increased global supply with increases in the US and Saudi Arabia, and notwithstanding OPEC's previously announced production cuts.

The WCS heavy differential averaged US$26.29 per bbl for the year ended December 31, 2018, an increase of 120% from US$11.97 per bbl for the year ended December 31, 2017. The WCS heavy differential averaged US$39.36 per bbl for the fourth quarter of 2018, an increase of 221% from US$12.28 per bbl for the fourth quarter of 2017, and an increase of 78% from US$22.17 per bbl for the third quarter of 2018. The significant widening of the WCS heavy differential for the three months and year ended December 31, 2018 from the comparable periods reflected a shortage of takeaway capacity out of the Basin, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system in the fourth quarter of 2018. Following the Government of Alberta's announcement on December 2, 2018 of a mandatory curtailment of crude oil production, the WCS heavy differential index narrowed to US$12.38 per bbl for the first quarter of 2019.

The SCO price averaged US$58.62 per bbl for the year ended December 31, 2018, an increase of 12% from US$52.20 per bbl for the year ended December 31, 2017. The SCO price averaged US$37.48 per bbl for the fourth quarter of 2018, a decrease of 36% from US$58.64 per bbl for the fourth quarter of 2017, and a decrease of 45% from US$68.44 per bbl for the third quarter of 2018. The increase in SCO pricing for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected increases in WTI benchmark pricing through the third quarter of 2018, partially offset by decreased pricing in the fourth quarter of 2018 due to a shortage of takeaway capacity out of the Basin, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system. Following the Government of Alberta's announcement on December 2, 2018 of a mandatory curtailment of crude oil production, the differential between SCO and WTI benchmark pricing narrowed to US$2.70 per bbl for the first quarter of 2019.

Condensate pricing averaged US$60.98 per bbl for the year ended December 31, 2018, an increase of 18% from US$51.65 per bbl for the year ended December 31, 2017. Condensate pricing averaged US$45.27 per bbl for the fourth quarter of 2018, a decrease of 22% from US$57.96 per bbl for the fourth quarter of 2017, and a decrease of 32% from US$66.82 per bbl for the third quarter of 2018. Condensate pricing for the year ended December 31, 2018 increased from the year ended December 31, 2017 due to increasing underlying benchmark pricing. The decrease in condensate pricing for the fourth quarter of 2018 from the fourth quarter of 2017 and the third quarter of 2018 reflected the impact of increased condensate supply, incremental blending of light crude oil into condensate and decreased demand due to curtailment of heavy oil production in the Basin.

NYMEX natural gas prices averaged US$3.08 per MMBtu for the year ended December 31, 2018, comparable with US$3.11 per MMBtu for the year ended December 31, 2017. NYMEX natural gas prices averaged US$3.65 per MMBtu for the fourth quarter of 2018, an increase of 24% from US$2.94 per MMBtu for the fourth quarter of 2017, and an increase of 26% from US$2.90 per MMBtu for the third quarter of 2018. The increase in NYMEX natural gas prices for the fourth quarter of 2018 compared with the fourth quarter of 2017 and third quarter of 2018 primarily reflected low storage inventory levels in North America and seasonal demand factors.

AECO natural gas prices averaged $1.45 per GJ for the year ended December 31, 2018, a decrease of 37% from $2.30 per GJ for the year ended December 31, 2017. AECO natural gas prices averaged $1.80 per GJ for the fourth quarter of 2018, a decrease of 3% from $1.85 per GJ for the fourth quarter of 2017, and an increase of 41% from $1.28 per GJ for the third quarter of 2018. The decrease in AECO natural gas prices for the three months and year ended December 31, 2018 from the comparable periods in 2017 reflected third party pipeline constraints limiting flow of natural gas to export markets as well as increased natural gas production in the Basin. The increase in AECO natural gas prices for the fourth quarter of 2018 compared with the third quarter of 2018 reflected the easing of third party pipeline constraints as well as seasonal demand factors.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**343,054**	359,856	383,537	**350,961**	359,449
North America – Oil Sands Mining and Upgrading [1]	**447,048**	394,382	321,496	**426,190**	282,026
North Sea	**21,071**	28,702	19,548	**23,965**	23,426
Offshore Africa	**22,185**	18,802	19,519	**19,662**	20,335
	833,358	801,742	744,100	**820,778**	685,236
Natural gas (MMcf/d)					
North America	**1,441**	1,489	1,596	**1,490**	1,601
North Sea	**22**	38	37	**32**	39
Offshore Africa	**25**	26	23	**26**	22
	1,488	1,553	1,656	**1,548**	1,662
Total barrels of oil equivalent (BOE/d)	**1,081,368**	1,060,629	1,020,094	**1,078,813**	962,264
Product mix					
Light and medium crude oil and NGLs	**13%**	13%	13%	**13%**	14%
Pelican Lake heavy crude oil	**6%**	6%	6%	**6%**	6%
Primary heavy crude oil	**7%**	9%	10%	**8%**	10%
Bitumen (thermal oil)	**10%**	11%	12%	**10%**	12%
Synthetic crude oil	**41%**	37%	32%	**39%**	29%
Natural gas	**23%**	24%	27%	**24%**	29%
Percentage of gross revenue [1] [2] (excluding Midstream revenue)					
Crude oil and NGLs	**85%**	95%	92%	**93%**	90%
Natural gas	**15%**	5%	8%	**7%**	10%

(1) Fourth quarter 2018 SCO production before royalties excludes 3,363 bbl/d of SCO consumed internally as diesel (third quarter 2018 – 2,758 bbl/d; fourth quarter 2017 – 1,730 bbl/d; year ended December 31, 2018 – 3,093 bbl/d; year ended December 31, 2017 – 651 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**304,324**	307,668	333,698	**303,956**	312,297
North America – Oil Sands Mining and Upgrading	**421,421**	372,521	309,777	**405,731**	274,437
North Sea	**21,021**	28,609	19,518	**23,902**	23,382
Offshore Africa	**21,366**	17,264	17,885	**18,450**	19,124
	768,132	726,062	680,878	**752,039**	629,240
Natural gas (MMcf/d)					
North America	**1,396**	1,455	1,538	**1,432**	1,528
North Sea	**22**	38	37	**32**	39
Offshore Africa	**22**	22	20	**23**	20
	1,440	1,515	1,595	**1,487**	1,587
Total barrels of oil equivalent (BOE/d)	**1,008,210**	978,481	946,731	**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.

Crude oil and NGLs production for the year ended December 31, 2018 increased 20% to 820,778 bbl/d from 685,236 bbl/d for the year ended December 31, 2017. Crude oil and NGLs production for the fourth quarter of 2018 of 833,358 bbl/d increased 12% from 744,100 bbl/d for the fourth quarter of 2017, and increased 4% from 801,742 bbl/d in the third quarter of 2018. The increase in crude oil and NGLs production for the year ended December 31, 2018 from the year ended December 31, 2017 was primarily due to the impact of Phase 3 production at Horizon and acquisitions completed in 2017, partially offset by the impact of proactive measures taken by the Company to voluntarily curtail crude oil production and reduce heavy oil drilling. The increase in crude oil and NGLs production for the fourth quarter of 2018 compared to the fourth quarter of 2017 and the third quarter of 2018 reflected strong production in the Oil Sands Mining and Upgrading segment, partially offset by the impact of proactive measures taken by the Company to voluntarily curtail crude oil production and reduce heavy oil drilling.

Annual 2018 crude oil and NGLs production was above the midpoint of the Company's previously issued guidance of 812,000 to 822,000 bbl/d. First quarter 2019 crude oil and NGLs production guidance is targeted to average between 759,000 and 817,000 bbl/d. Annual crude oil and NGLs production guidance for 2019 is targeted to average between 782,000 and 861,000 bbl/d. Crude oil and NGLs production guidance for 2019 reflects production curtailments as currently mandated by the Government of Alberta for the first quarter of 2019.

Natural gas production for the year ended December 31, 2018 decreased 7% to 1,548 MMcf/d from 1,662 MMcf/d for the year ended December 31, 2017. Natural gas production for the fourth quarter of 2018 averaged 1,488 MMcf/d, a decrease of 10% from 1,656 MMcf/d for the fourth quarter of 2017, and a decrease of 4% from 1,553 MMcf/d for the third quarter of 2018. The decrease in natural gas production for the three months and year ended December 31, 2018 from the comparable periods primarily reflected the impact of shut-in volumes due to low natural gas prices, natural field declines and reduced drilling activity, together with downtime and restricted capacity at the third-party Pine River processing facility. Production in the fourth quarter of 2018 also reflected the impact of reduced pipeline capacity due to a failure on a natural gas transmission line in British Columbia (T-South) in October 2018. Subject to regulatory approval, the Company targets to take over operations at the processing facility in the first half of 2019.

Annual 2018 natural gas production was within the Company's previously issued guidance of 1,545 to 1,555 MMcf/d. First quarter 2019 natural gas production guidance is targeted to average between 1,490 and 1,520 MMcf/d. Annual natural gas production guidance for 2019 is targeted to average between 1,485 and 1,545 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production for the year ended December 31, 2018 averaged 350,961 bbl/d, a decrease of 2% from 359,449 bbl/d for the year ended December 31, 2017. North America crude oil and NGLs production for the fourth quarter of 2018 of 343,054 bbl/d decreased 11% from 383,537 bbl/d for the fourth quarter of 2017, and decreased 5% from 359,856 bbl/d for the third quarter of 2018. The decrease in production for the three months and year ended December 31, 2018 from the comparable periods primarily reflected the impact of proactive measures taken by the Company to voluntarily curtail crude oil production, together with reduced heavy oil drilling and natural field declines.

Operating performance at Pelican Lake continued to be strong, leading to production of 62,428 bbl/d in the fourth quarter of 2018 compared with 65,654 bbl/d in the fourth quarter of 2017 and 62,727 bbl/d in the third quarter of 2018. The decrease in production from the fourth quarter of 2017 reflected the impact of the Company restoring polymer flood on the acquired Pelican assets to 62% of the field during 2018. Production in the third and fourth quarters of 2018 has been relatively stable.

Overall thermal oil production for the fourth quarter of 2018 averaged 102,112 bbl/d compared with 124,121 bbl/d for the fourth quarter of 2017 and 112,542 bbl/d for the third quarter of 2018. Annual 2018 thermal oil production of 107,839 bbl/d was at the high end of the Company's previously issued guidance of 106,000 to 108,000 bbl/d. First quarter 2019 thermal oil production guidance is targeted to average between 92,000 and 98,000 bbl/d. Annual thermal oil production guidance for 2019 is targeted to average between 104,000 and 124,000 bbl/d. Thermal oil production guidance reflects production curtailments as currently mandated by the Government of Alberta for the first quarter of 2019.

Annual 2018 crude oil and NGLs production, including thermal oil, was above the Company's previously issued guidance of 346,000 to 350,000 bbl/d. First quarter 2019 crude oil and NGLs production guidance, including thermal oil, is targeted to average between 313,000 and 327,000 bbl/d. Annual crude oil and NGLs production guidance for 2019, including thermal oil, is targeted to average between 325,000 and 365,000 bbl/d. Crude oil production guidance reflects production curtailments as currently mandated by the Government of Alberta for the first quarter of 2019.

Natural gas production for the year ended December 31, 2018 decreased 7% to 1,490 MMcf/d from 1,601 MMcf/d for the year ended December 31, 2017. Natural gas production for the fourth quarter of 2018 averaged 1,441 MMcf/d, a decrease of 10% from 1,596 MMcf/d for the fourth quarter of 2017, and a decrease of 3% from 1,489 MMcf/d in the third quarter of 2018. The decrease in production for the three months and year ended December 31, 2018 from the comparable periods primarily reflected the impact of shut-in volumes due to low natural gas prices, natural field declines and reduced drilling activity, together with downtime and restricted capacity at the third-party Pine River processing facility. Production in the fourth quarter of 2018 also reflected the impact of reduced pipeline capacity due to a failure on a natural gas transmission line in British Columbia (T-South) in October 2018.

North America – Oil Sands Mining and Upgrading

SCO production for the year ended December 31, 2018 of 426,190 bbl/d increased 51% from 282,026 bbl/d for the year ended December 31, 2017. SCO production for the fourth quarter of 2018 increased 39% to average 447,048 bbl/d from 321,496 bbl/d for the fourth quarter of 2017 and increased 13% from 394,382 bbl/d for the third quarter of 2018. The increase in SCO production for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected the impact of Phase 3 production at Horizon and the acquisition of AOSP. The increase in the fourth quarter of 2018 from the fourth quarter of 2017 primarily reflected one full quarter of production at Horizon Phase 3. The increase in the fourth quarter of 2018 from the third quarter of 2018 reflected strong production and effective and efficient operations at Horizon following the successful completion of the planned turnaround in the third quarter of 2018.

Annual 2018 SCO production was within the Company's previously issued guidance of 424,000 to 428,000 bbl/d. First quarter 2019 SCO production guidance is targeted to average between 400,000 and 440,000 bbl/d. Annual SCO production guidance for 2019 is targeted to average between 415,000 and 450,000 bbl/d. SCO production guidance reflects production curtailments as currently mandated by the Government of Alberta for the first quarter of 2019 and the moving forward of planned maintenance activities at Horizon from April 2019 to March 2019.

North Sea

North Sea crude oil production for the year ended December 31, 2018 of 23,965 bbl/d increased 2% from 23,426 bbl/d for the year ended December 31, 2017. North Sea crude oil production for the fourth quarter of 2018 increased 8% to 21,071 bbl/d from 19,548 bbl/d for the fourth quarter of 2017 and decreased 27% from 28,702 bbl/d in the third quarter of 2018. The increase in production for the three months and year ended December 31, 2018 from the comparable periods in 2017 primarily reflected the successful drilling program completed in 2018, offsetting planned maintenance at the Ninian Central and Tiffany platforms as well as on the Banff FPSO during the fourth quarter of 2018 together with natural field declines. The decrease in production for the fourth quarter of 2018 from the third quarter of 2018 primarily reflected the planned turnarounds and maintenance activities completed during the fourth quarter as well as natural field declines.

Offshore Africa

Offshore Africa crude oil production for the year ended December 31, 2018 decreased 3% to 19,662 bbl/d from 20,335 bbl/d for the year ended December 31, 2017. Offshore Africa crude oil production for the fourth quarter of 2018 of 22,185 bbl/d increased 14% from 19,519 bbl/d for the fourth quarter of 2017 and increased 18% from 18,802 bbl/d in the third quarter of 2018. The decrease in production for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected natural field declines. The increase in production for the fourth quarter of 2018 from the fourth quarter of 2017 and the third quarter of 2018 primarily reflected volumes from new wells drilled at Baobab in 2018, partially offset by the cessation of production at the Olowi field in December, together with natural field declines.

International Guidance

Annual 2018 International crude oil production of 43,627 bbl/d was above the midpoint of the Company's previously issued guidance of 42,000 to 44,000 bbl/d. First quarter 2019 International crude oil production guidance is targeted to average between 46,000 and 50,000 bbl/d. Annual International crude oil production guidance for 2019 is targeted to average between 42,000 and 46,000 bbl/d.

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 that were stored in various storage facilities or FPSOs, as follows:

(bbl)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017
North Sea	**71,832**	881,768	—
Offshore Africa	**404,475**	868,589	121,936
	476,307	1,750,357	121,936

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 25.95**	$ 57.89	$ 53.42	**$ 46.92**	$ 48.57
Transportation	**2.94**	3.00	2.82	**3.08**	2.80
Realized sales price, net of transportation	**23.01**	54.89	50.60	**43.84**	45.77
Royalties	**0.92**	7.08	5.84	**5.08**	5.24
Production expense	**16.93**	14.47	15.03	**15.69**	14.89
Netback	**$ 5.16**	$ 33.34	$ 29.73	**$ 23.07**	$ 25.64
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 3.46**	$ 2.32	$ 2.55	**$ 2.61**	$ 2.76
Transportation	**0.42**	0.42	0.46	**0.47**	0.39
Realized sales price, net of transportation	**3.04**	1.90	2.09	**2.14**	2.37
Royalties	**0.10**	0.05	0.08	**0.08**	0.11
Production expense	**1.32**	1.33	1.33	**1.36**	1.27
Netback (3)	**$ 1.62**	$ 0.52	$ 0.68	**$ 0.70**	$ 0.99
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 24.04**	$ 40.77	$ 38.78	**$ 34.62**	$ 35.54
Transportation	**2.77**	2.83	2.86	**2.96**	2.66
Realized sales price, net of transportation	**21.27**	37.94	35.92	**31.66**	32.88
Royalties	**0.80**	4.44	3.75	**3.27**	3.40
Production expense	**13.51**	11.91	12.28	**12.71**	11.95
Netback	**$ 6.96**	$ 21.59	$ 19.89	**$ 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.

(3) Natural gas netbacks exclude netbacks derived from the sale of NGLs. Combining natural gas and NGLs, the netback for the three months ended December 31, 2018 was $1.84/Mcfe (three months ended September 30, 2018 - $1.05/Mcfe, three months ended December 31, 2017 - $1.20/Mcfe; year ended December 31, 2018 - $1.18/Mcfe, year ended December 31, 2017 - $1.31/Mcfe).

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 17.03**	$ 52.45	$ 50.51	**$ 41.82**	$ 45.85
North Sea	**$ 78.45**	$ 97.77	$ 76.71	**$ 87.41**	$ 69.43
Offshore Africa	**$ 81.15**	$ 98.66	$ 73.43	**$ 90.95**	$ 67.15
Company average	**$ 25.95**	$ 57.89	$ 53.42	**$ 46.92**	$ 48.57
Natural gas ($/Mcf) (1) (2)					
North America	**$ 3.23**	$ 1.96	$ 2.33	**$ 2.33**	$ 2.58
North Sea	**$ 14.09**	$ 12.67	$ 9.77	**$ 12.08**	$ 8.24
Offshore Africa	**$ 7.32**	$ 7.78	$ 6.73	**$ 7.34**	$ 6.57
Company average	**$ 3.46**	$ 2.32	$ 2.55	**$ 2.61**	$ 2.76
Company average ($/BOE) (1) (2)	**$ 24.04**	$ 40.77	$ 38.78	**$ 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

North America realized crude oil prices decreased 9% to $41.82 per bbl for the year ended December 31, 2018 from $45.85 per bbl for the year ended December 31, 2017. North America realized crude oil prices averaged $17.03 per bbl for the fourth quarter of 2018, a decrease of 66% compared with $50.51 per bbl for the fourth quarter of 2017, and a decrease of 68% compared with $52.45 per bbl for the third quarter of 2018. The decrease in realized crude oil prices for the three months and year ended December 31, 2018 from the comparable periods was primarily due to the widening of the WCS heavy differential, which reflected a shortage of takeaway capacity out of the Basin, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system. The Company continues to focus on its crude oil blending marketing strategy and in the fourth quarter of 2018 contributed approximately 174,500 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 10% to average $2.33 per Mcf for the year ended December 31, 2018 from $2.58 per Mcf for the year ended December 31, 2017. North America realized natural gas prices increased 39% to average $3.23 per Mcf for the fourth quarter of 2018 compared with $2.33 per Mcf for the fourth quarter of 2017, and increased 65% compared with $1.96 per Mcf for the third quarter of 2018. The decrease in realized natural gas prices for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected third party pipeline constraints limiting the flow of natural gas to the export market, together with increased natural gas production in the Basin. The increase in realized natural gas prices for the fourth quarter of 2018 from the fourth quarter of 2017 and the third quarter of 2018 primarily reflected the easing of third party pipeline constraints as well as seasonal demand factors.

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

(Quarterly Average)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 34.62**	$ 62.81	$ 54.09
Pelican Lake heavy crude oil ($/bbl)	**$ 12.40**	$ 54.57	$ 52.44
Primary heavy crude oil ($/bbl)	**$ 11.33**	$ 50.91	$ 50.71
Bitumen (thermal oil) ($/bbl)	**$ 7.70**	$ 43.54	$ 46.58
Natural gas ($/Mcf)	**$ 3.23**	$ 1.96	$ 2.33

(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

North Sea realized crude oil prices increased 26% to average $87.41 per bbl for the year ended December 31, 2018 from $69.43 per bbl for the year ended December 31, 2017. North Sea realized crude oil prices increased 2% to average $78.45 per bbl for the fourth quarter of 2018 from $76.71 per bbl for the fourth quarter of 2017 and decreased 20% from $97.77 per bbl for the third quarter of 2018. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three months and year ended December 31, 2018 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 35% to average $90.95 per bbl for the year ended December 31, 2018 from $67.15 per bbl for the year ended December 31, 2017. Offshore Africa realized crude oil prices increased 11% to average $81.15 per bbl for the fourth quarter of 2018 from $73.43 per bbl for the fourth quarter of 2017 and decreased 18% from $98.66 per bbl for the third quarter of 2018. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three months and year ended December 31, 2018 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 0.82**	$ 7.44	$ 6.20	**$ 5.36**	$ 5.69
North Sea	**$ 0.18**	$ 0.31	$ 0.12	**$ 0.22**	$ 0.13
Offshore Africa	**$ 3.00**	$ 8.07	$ 6.15	**$ 6.00**	$ 4.13
Company average	**$ 0.92**	$ 7.08	$ 5.84	**$ 5.08**	$ 5.24
Natural gas ($/Mcf) [(1)]					
North America	**$ 0.09**	$ 0.04	$ 0.07	**$ 0.07**	$ 0.11
Offshore Africa	**$ 0.80**	$ 1.20	$ 0.84	**$ 1.00**	$ 0.76
Company average	**$ 0.10**	$ 0.05	$ 0.08	**$ 0.08**	$ 0.11
Company average ($/BOE) [(1)]	**$ 0.80**	$ 4.44	$ 3.75	**$ 3.27**	$ 3.40

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

North America

North America crude oil and natural gas royalties for the three months and year ended December 31, 2018 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS heavy differential.

Crude oil and NGLs royalty rates averaged approximately 14% of product sales for the year ended December 31, 2018 compared with 13% of product sales for the year ended December 31, 2017. Crude oil and NGLs royalty rates averaged approximately 6% of product sales for the fourth quarter of 2018 compared with 13% for the fourth quarter of 2017 and 15% for the third quarter of 2018. The increase in royalty rates for the year ended December 31, 2018 from the year ended December 31, 2017 was primarily due to higher realized crude oil prices for the majority of 2018, offsetting the impact of lower realized crude oil prices in the fourth quarter of 2018. The decrease in royalty rates for the fourth quarter of 2018 from the fourth quarter of 2017 and the third quarter of 2018 reflected significantly lower realized crude oil prices in the fourth quarter of 2018.

Natural gas royalty rates averaged approximately 4% of product sales for the year ended December 31, 2018 compared with 5% of product sales for the year ended December 31, 2017. Natural gas royalty rates averaged approximately 3% of product sales for the fourth quarter of 2018 compared with 4% for the fourth quarter of 2017 and 2% for the third quarter of 2018. The decrease in royalty rates for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected lower realized natural gas prices. The decrease in royalty rates for the fourth quarter of 2018 from the fourth quarter of 2017 primarily reflected gas cost allowance adjustments, offsetting the impact of higher realized natural gas prices. The increase in royalty rates for the fourth quarter of 2018 from the third quarter of 2018 primarily reflected the impact of higher realized natural gas prices in the fourth quarter of 2018.

Offshore Africa

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 7% for the year ended December 31, 2018, compared with 7% of product sales for the year ended December 31, 2017. Royalty rates as a percentage of product sales averaged approximately 4% for the fourth quarter of 2018, compared with 9% of product sales for the fourth quarter of 2017 and 9% for the third quarter of 2018. Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 13.36**	$ 12.67	$ 12.84	**$ 13.48**	$ 12.71
North Sea	**$ 44.20**	$ 37.32	$ 44.37	**$ 39.89**	$ 36.60
Offshore Africa	**$ 32.15**	$ 19.53	$ 17.96	**$ 26.34**	$ 24.07
Company average	**$ 16.93**	$ 14.47	$ 15.03	**$ 15.69**	$ 14.89
Natural gas ($/Mcf) (1)					
North America	**$ 1.23**	$ 1.20	$ 1.26	**$ 1.25**	$ 1.19
North Sea	**$ 5.76**	$ 5.22	$ 3.98	**$ 5.29**	$ 3.37
Offshore Africa	**$ 3.00**	$ 2.69	$ 2.26	**$ 2.76**	$ 2.90
Company average	**$ 1.32**	$ 1.33	$ 1.33	**$ 1.36**	$ 1.27
Company average ($/BOE) (1)	**$ 13.51**	$ 11.91	$ 12.28	**$ 12.71**	$ 11.95

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

North America

North America crude oil and NGLs production expense for the year ended December 31, 2018 increased 6% to $13.48 per bbl from $12.71 per bbl for the year ended December 31, 2017. North America crude oil and NGLs production expense for the fourth quarter of 2018 of $13.36 per bbl increased 4% from $12.84 per bbl in the fourth quarter of 2017 and increased 5% from $12.67 per bbl for the third quarter of 2018. Crude oil and NGLs production expense for the year ended December 31, 2018 as compared with the year ended December 31, 2017 reflected increased carbon tax and energy costs in 2018 together with increased costs associated with the Company's proactive measures to voluntarily curtail crude oil production, partially offset by the Company's continuous focus on cost control and achieving efficiencies across the entire asset base. The increase per barrel for the fourth quarter of 2018 from the comparable periods reflected both lower sales volumes and increased costs associated with the curtailment of crude oil production.

North America natural gas production expense for the year ended December 31, 2018 averaged $1.25 per Mcf, an increase of 5% from $1.19 per Mcf for the year ended December 31, 2017. North America natural gas production expense for the fourth quarter of 2018 of $1.23 per Mcf was comparable with $1.26 per Mcf for the fourth quarter of 2017 and $1.20 per Mcf for the third quarter of 2018. The increase in natural gas production expense for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected the impact of lower volumes on a relatively fixed cost base due to low natural gas prices, reduced pipeline capacity as a result of a failure on a natural gas transmission line in British Columbia (T-South) in October 2018 and a turnaround at the third-party Pine River processing facility. Production expense in 2018 also reflected additional costs associated with the shut-in of production due to low natural gas pricing during 2018, partially offset by the Company's continuous focus on cost control and achieving efficiencies across the entire asset base.

North Sea

North Sea crude oil production expense for the year ended December 31, 2018 increased 9% to $39.89 per bbl from $36.60 per bbl for the year ended December 31, 2017. North Sea crude oil production expense of $44.20 per bbl for the fourth quarter of 2018 was comparable with $44.37 per bbl for the fourth quarter of 2017 and increased 18% from $37.32 per bbl in the third quarter of 2018. The increase in crude oil production expense for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected higher carbon tax costs and the strengthening of the UK pound sterling compared to the Canadian dollar. The increase in production expense for the fourth quarter of 2018 from the third quarter of 2018 primarily reflected the timing of liftings from various fields that have different cost structures and additional maintenance costs, together with decreased production.

Offshore Africa

Crude oil production expense for the Baobab and Espoir fields in Côte d'Ivoire for the year ended December 31, 2018 was $13.30 per bbl, while total crude oil production expense for the Offshore Africa segment, including the Olowi field in Gabon, was $26.34 per bbl. Production expense for the fourth quarter of 2018 relating to Côte d'Ivoire was $11.68 per bbl, while total crude oil production expense for the Offshore Africa segment, including the Olowi field in Gabon, was $32.15 per bbl. Total Offshore Africa crude oil production expense for the three months and year ended December 31, 2018 reflected the timing of liftings from various fields, including the Olowi field in Gabon, that have different cost structures, fluctuating production volumes on a relatively fixed cost base, and planned maintenance activities. Production expense was also impacted by movements in the Canadian dollar.

During the fourth quarter of 2018, the Gabonese Republic approved cessation of production from the Company's Olowi field, 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, including associated asset retirement obligations of $69 million. The transaction resulted in a pre-tax gain on disposition of property of $20 million ($14 million after-tax). In January 2019, the Company completed FPSO demobilization and sail away activities.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Expense	**$ 929**	$ 917	$ 939	**$ 3,590**	$ 3,957
$/BOE [(1)]	**$ 15.50**	$ 15.11	$ 14.46	**$ 15.12**	$ 15.82

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

Depletion, depreciation and amortization per BOE for the year ended December 31, 2018 decreased 4% to $15.12 per BOE from $15.82 per BOE for the year ended December 31, 2017. Depletion, depreciation and amortization expense per BOE for the fourth quarter of 2018 increased 7% to $15.50 per BOE from $14.46 per BOE for the fourth quarter of 2017 and increased 3% from $15.11 per BOE for the third quarter of 2018.

The decrease in depletion, depreciation and amortization expense per BOE for the year ended December 31, 2018 from the year ended December 31, 2017 was primarily due to the impact of additional depletion, depreciation and amortization expense in 2017 related to the abandonment of the Ninian North platform in the North Sea. The increase in depletion, depreciation and amortization expense per BOE for the fourth quarter of 2018 from the comparable periods reflected the impact of fluctuations in sales volumes from different underlying operations. The increase per BOE for the fourth quarter of 2018 from the fourth quarter of 2017 also reflected a higher depletable base in North America.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Expense	**$ 31**	$ 31	$ 30	**$ 125**	$ 116
$/BOE (1)	**$ 0.52**	$ 0.52	$ 0.45	**$ 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 per BOE for the year ended December 31, 2018 increased 15% to $0.53 per BOE from $0.46 per BOE for the year ended December 31, 2017. Asset retirement obligation accretion expense for the fourth quarter of 2018 increased 16% to $0.52 per BOE from $0.45 per BOE for the fourth quarter of 2017, and was comparable with $0.52 per BOE for the third quarter of 2018.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable and efficient operations and leveraging its expertise in capturing synergies following the acquisition completed in 2017. Production averaged 447,048 bbl/d during the fourth quarter of 2018 and 426,190 bbl/d for the year, reflecting strong, reliable operations at Horizon, together with incremental reliability at AOSP. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability of operations, adjusted cash production costs averaged $19.97 per bbl during the fourth quarter and $21.05 per bbl during the year.

PRODUCT PRICES, ROYALTIES AND TRANSPORTATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($/bbl) (1)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
SCO realized sales price (2)	**$ 42.73**	$ 81.69	$ 70.85	**$ 68.61**	$ 63.98
Bitumen value for royalty purposes (3)	**$ 29.93**	$ 51.64	$ 44.78	**$ 40.02**	$ 41.05
Bitumen royalties (4)	**$ 2.03**	$ 4.31	$ 2.45	**$ 3.09**	$ 1.64
Transportation	**$ 1.56**	$ 1.73	$ 1.88	**$ 1.61**	$ 1.54

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

(2) Net of blending and feedstock costs.

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

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

The realized SCO sales price for the Oil Sands Mining and Upgrading segment averaged $68.61 per bbl for the year ended December 31, 2018, an increase of 7% from $63.98 per bbl for the year ended December 31, 2017. For the fourth quarter of 2018, the realized sales price decreased 40% to $42.73 per bbl from $70.85 per bbl for the fourth quarter of 2017 and decreased 48% from $81.69 per bbl for the third quarter of 2018. The increase in realized sales prices for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected WTI benchmark pricing. The decrease in realized prices for the fourth quarter of 2018 from the fourth quarter of 2017 and the third quarter of 2018 reflected the impact of a shortage of takeaway capacity out of the Basin, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 18 to the Company's unaudited interim consolidated financial statements.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Cash production costs	**$ 797**	$ 842	$ 846	**$ 3,367**	$ 2,600
Less: costs incurred during turnaround periods	**—**	(109)	(137)	**(109)**	(216)
Adjusted cash production costs	**$ 797**	$ 733	$ 709	**$ 3,258**	$ 2,384
Adjusted cash production costs, excluding natural gas costs	**$ 773**	$ 714	$ 668	**$ 3,156**	$ 2,239
Natural gas costs	**24**	19	41	**102**	145
Adjusted cash production costs	**$ 797**	$ 733	$ 709	**$ 3,258**	$ 2,384

	Three Months Ended			Year Ended	
($/bbl) [1]	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Adjusted cash production costs, excluding natural gas costs	**$ 19.37**	$ 19.43	$ 23.56	**$ 20.39**	$ 21.98
Natural gas costs	**0.60**	0.52	1.43	**0.66**	1.42
Adjusted cash production costs	**$ 19.97**	$ 19.95	$ 24.99	**$ 21.05**	$ 23.40
Sales (bbl/d)	**433,970**	399,514	308,067	**424,112**	279,084

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

Adjusted cash production costs for the year ended December 31, 2018 decreased 10% to $21.05 per bbl from $23.40 per bbl for the year ended December 31, 2017. Adjusted cash production costs for the fourth quarter of 2018 averaged $19.97 per bbl, a decrease of 20% from $24.99 per bbl for the fourth quarter of 2017 and comparable with $19.95 per bbl for the third quarter of 2018. The decrease in adjusted cash production costs per barrel for the three months and year ended December 31, 2018 from the comparable periods in 2017 primarily reflected the Company's high utilization rates and reliability and the capture of cost synergies between the operations, as well as additional capacity from Phase 3 production at Horizon and the acquisition of AOSP.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Expense	**$ 396**	$ 385	$ 464	**$ 1,557**	$ 1,220
Less: depreciation incurred during turnaround period	**—**	(56)	(188)	**(56)**	(213)
Adjusted depletion, depreciation and amortization	**$ 396**	$ 329	$ 276	**$ 1,501**	$ 1,007
$/bbl [1]	**$ 9.92**	$ 8.96	$ 9.75	**$ 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 per barrel for the Oil Sands Mining and Upgrading segment for the year ended December 31, 2018 decreased 2% to $9.70 per bbl from $9.89 per bbl for the year ended December 31, 2017. Adjusted depletion, depreciation and amortization expense per barrel for the fourth quarter of 2018 of $9.92 per bbl increased 2% from $9.75 per bbl for the fourth quarter of 2017, and increased 11% from $8.96 per bbl for the third quarter of 2018.

The decrease in adjusted depletion, depreciation and amortization expense per barrel for the year ended December 31, 2018 from the year ended December 31, 2017 was primarily due to the impact of AOSP, which has a lower depletion rate. The increase in adjusted depletion, depreciation and amortization expense per barrel for the fourth quarter of 2018 from the fourth quarter of 2017 and the third quarter of 2018 was primarily due to the impact of fluctuations in sales volumes from different underlying operations, with a higher proportion of sales during the fourth quarter of 2017 and third quarter of 2018 subject to a lower depletion rate, as compared with the fourth quarter of 2018.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Expense	**$ 15**	$ 16	$ 15	**$ 61**	$ 48
$/bbl (1)	**$ 0.38**	$ 0.41	$ 0.53	**$ 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 per bbl for the year ended December 31, 2018 decreased 15% to $0.40 per bbl from $0.47 per bbl for the year ended December 31, 2017 due to higher sales volumes. Asset retirement obligation accretion expense of $0.38 per bbl for the fourth quarter of 2018 decreased 28% from $0.53 per bbl for the fourth quarter of 2017 and decreased 7% from $0.41 per bbl for the third quarter of 2018, primarily due to higher sales volumes.

MIDSTREAM

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Revenue	**$ 24**	$ 26	$ 28	**$ 102**	$ 102
Less:					
Production expense	**5**	5	4	**21**	16
Depreciation	**3**	4	3	**14**	9
Equity loss (gain) on investment	**—**	2	1	**5**	(31)
Gain on revaluation of properties (1)	**—**	—	—	**—**	(114)
Segment earnings before taxes	**$ 16**	$ 15	$ 20	**$ 62**	$ 222

(1) During the third quarter of 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.

The Company has a 50% interest in the Redwater Partnership. Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day 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.

The facility capital cost ("FCC") budget for the Project is currently estimated to be $9,700 million. The Project is currently in the commissioning phase, with completion targeted for the second quarter of 2019. 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 maintain the agreed debt to equity ratio of 80/20. To December 31, 2018, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $152 million, for a Company total of $591 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 toll, 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 toll over the 30 year tolling period. As at December 31, 2018, the Company had recognized $62 million in prepaid service tolls.

As at December 31, 2018, Redwater Partnership had borrowings of $2,333 million under its secured $3,500 million syndicated credit facility. During the first quarter of 2018, Redwater Partnership extended $2,000 million of the $3,500 million revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

ADMINISTRATION EXPENSE

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Expense	**$ 91**	$ 77	$ 84	**$ 325**	$ 319
$/BOE (1)	**$ 0.91**	$ 0.79	$ 0.90	**$ 0.83**	$ 0.91

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

Administration expense per BOE for the year ended December 31, 2018 decreased 9% to $0.83 per BOE from $0.91 per BOE for the year ended December 31, 2017. Administration expense for the fourth quarter of 2018 of $0.91 per BOE was comparable with $0.90 per BOE for the fourth quarter of 2017 and increased 15% from $0.79 per BOE for the third quarter of 2018. Administration expense per BOE decreased for the year ended December 31, 2018 from the year ended December 31, 2017 primarily due to higher sales volumes. The increase in the fourth quarter of 2018 from the third quarter of 2018 was primarily due to higher personnel and other corporate costs.

SHARE-BASED COMPENSATION

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
(Recovery) expense	**$ (148)**	$ (85)	$ 97	**$ (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 Company recorded an $146 million share-based compensation recovery for the year ended December 31, 2018, primarily as a result of remeasurement 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 recovery for the year ended December 31, 2018 was an expense of $8 million related to performance share units granted to certain executive employees (December 31, 2017 – $5 million). For the year ended December 31, 2018, the Company recovered $19 million of share-based compensation costs from the Oil Sands Mining and Upgrading segment (December 31, 2017 – $14 million costs charged).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts and interest rates)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Expense, gross	**$ 198**	$ 198	$ 187	**$ 808**	$ 713
Less: capitalized interest	**19**	18	18	**69**	82
Expense, net	**$ 179**	$ 180	$ 169	**$ 739**	$ 631
$/BOE (1)	**$ 1.78**	$ 1.85	$ 1.81	**$ 1.88**	$ 1.79
Average effective interest rate	**4.1%**	4.0%	3.7%	**3.9%**	3.8%

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

Gross interest and other financing expense for the three months and year ended December 31, 2018 increased from the comparable periods in 2017 primarily due to the impact of higher average debt levels as a result of acquisitions completed in 2017 and higher interest rates in 2018. Gross interest and other financing expense for the fourth quarter of 2018 was comparable with the third quarter of 2018. Capitalized interest of $69 million for the year ended December 31, 2018 was primarily related to Kirby North and residual project activities at Horizon.

Net interest and other financing expense per BOE for the year ended December 31, 2018 increased 5% to $1.88 per BOE from $1.79 per BOE for the year ended December 31, 2017. Net interest and other financing expense per BOE for the fourth quarter of 2018 decreased 2% to $1.78 per BOE from $1.81 per BOE for the fourth quarter of 2017 and decreased 4% from $1.85 per BOE for the third quarter of 2018. The increase in net interest and other financing expense per BOE for the year ended December 31, 2018 from the year ended December 31, 2017 was primarily due to higher average debt levels as a result of acquisitions completed in 2017 and lower capitalized interest related to the completion of Horizon Phase 3. The decrease for the fourth quarter of 2018 from the comparable periods was primarily due to higher sales volumes and lower average debt levels in the fourth quarter of 2018.

The Company's average effective interest rate for the year ended December 31, 2018 was consistent with the year ended December 31, 2017. The increase for the fourth quarter of 2018 from the fourth quarter of 2017 reflected the impact of higher benchmark interest rates on the Company's outstanding bank credit facilities.

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.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs financial instruments	**$ (27)**	$ —	$ —	**$ (27)**	$ (32)
Natural gas financial instruments	**2**	6	(2)	**5**	(7)
Foreign currency contracts	**(20)**	(14)	(71)	**(77)**	37
Realized gain	**(45)**	(8)	(73)	**(99)**	(2)
Crude oil and NGLs financial instruments	**41**	(25)	7	**16**	—
Natural gas financial instruments	**(6)**	(14)	2	**(4)**	(6)
Foreign currency contracts	**(8)**	18	66	**(47)**	43
Unrealized loss (gain)	**27**	(21)	75	**(35)**	37
Net (gain) loss	**$ (18)**	$ (29)	$ 2	**$ (134)**	$ 35

During the year ended December 31, 2018, net realized risk management gains were related to the settlement of foreign currency contracts and crude oil and NGLs financial instruments. The Company recorded a net unrealized gain of $35 million ($36 million after-tax) on its risk management activities for the year ended December 31, 2018, including an unrealized loss of $27 million ($17 million after-tax) for the fourth quarter of 2018 (September 30, 2018 – unrealized gain of $21 million, $11 million after-tax; December 31, 2017 – unrealized loss of $75 million, $68 million after-tax).

Further details related to outstanding derivative financial instruments at December 31, 2018 are disclosed in note 16 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Net realized (gain) loss	**$ (2)**	$ 14	$ (15)	**$ 121**	$ 34
Net unrealized loss (gain)	**548**	(182)	(2)	**706**	(821)
Net loss (gain) [1]	**$ 546**	$ (168)	$ (17)	**$ 827**	$ (787)

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

The net realized foreign exchange loss for the year ended December 31, 2018 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes. The net unrealized foreign exchange loss for the year ended December 31, 2018 was primarily related to the impact of the weakening Canadian dollar with respect to outstanding US dollar debt, partially offset by the reversal of the net unrealized foreign exchange loss on the repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (three months ended December 31, 2018 – unrealized gain of $76 million, September 30, 2018 – unrealized loss of $23 million, December 31, 2017 – unrealized gain of $1 million; year ended December 31, 2018 – unrealized gain of $118 million, December 31, 2017 – unrealized loss of $280 million). The US/Canadian dollar exchange rate at December 31, 2018 was US$0.7328 (September 30, 2018 – US$0.7738, December 31, 2017 – US$0.7988).

INCOME TAXES

	Three Months Ended			Year Ended	
($ millions, except income tax rates)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
North America [1]	**$ (254)**	$ 169	$ (93)	**$ 312**	$ (145)
North Sea	**8**	12	10	**28**	57
Offshore Africa	**11**	22	17	**54**	45
PRT – North Sea	**—**	(9)	(25)	**(29)**	(132)
Other taxes	**1**	3	3	**9**	11
Current income tax (recovery) expense	**(234)**	197	(88)	**374**	(164)
Deferred corporate income tax expense	**112**	145	307	**540**	586
Deferred PRT expense – North Sea	**(1)**	1	(13)	**17**	54
Deferred income tax expense	**111**	146	294	**557**	640
	(123)	343	206	**931**	476
Income tax rate and other legislative changes [2]	**—**	—	(10)	**—**	(10)
	$ (123)	$ 343	$ 196	**$ 931**	$ 466
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**33%**	19%	32%	**21%**	27%

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

(2) During the fourth quarter of 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018, resulting in an increase in the Company's deferred income tax liability of $10 million.

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

The effective income tax rate for the three months and year ended December 31, 2018 and the comparable periods 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 (loss).

The current PRT recovery in the North Sea for the year ended December 31, 2018 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the Murchison and Ninian North platforms.

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.

For 2019, current income tax expense is targeted to range from $300 million to $400 million in Canada and $55 million to $85 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended **Dec 31 2018**	Sep 30 2018	Dec 31 2017	Year Ended **Dec 31 2018**	Dec 31 2017
Exploration and Evaluation					
Net (proceeds) expenditures [2] [3] [4]	**$ (95)**	$ 79	$ 16	**$ 48**	$ 149
Property, Plant and Equipment					
Net property acquisitions [2] [3] [4]	**1**	5	19	**98**	1,219
Well drilling, completion and equipping	**359**	416	212	**1,446**	1,001
Production and related facilities	**365**	325	258	**1,262**	860
Capitalized interest and other [5]	**32**	26	27	**106**	91
Net expenditures	**757**	772	516	**2,912**	3,171
Total Exploration and Production	**662**	851	532	**2,960**	3,320
Oil Sands Mining and Upgrading					
Project costs [6]	**178**	131	248	**438**	821
Sustaining capital	**235**	173	214	**665**	561
Turnaround costs	**12**	41	69	**112**	155
Acquisitions of Exploration and Evaluation assets [2] [4] [7]	**—**	218	—	**218**	219
Net property acquisitions [2] [4]	**—**	—	—	**—**	11,604
Capitalized interest and other [5]	**(8)**	(3)	26	**14**	76
Total Oil Sands Mining and Upgrading	**417**	560	557	**1,447**	13,436
Midstream	**2**	2	2	**13**	80
Abandonments [8]	**93**	57	63	**290**	274
Head office	**7**	3	(11)	**21**	19
Total net capital expenditures	**$ 1,181**	$ 1,473	$ 1,143	**$ 4,731**	$ 17,129
By segment					
North America [2] [3] [4]	**$ 604**	$ 727	$ 444	**$ 2,671**	$ 3,056
North Sea [3]	**58**	35	52	**131**	160
Offshore Africa [3]	**—**	89	36	**158**	104
Oil Sands Mining and Upgrading [4] [7]	**417**	560	557	**1,447**	13,436
Midstream	**2**	2	2	**13**	80
Abandonments [8]	**93**	57	63	**290**	274
Head office	**7**	3	(11)	**21**	19
Total	**$ 1,181**	$ 1,473	$ 1,143	**$ 4,731**	$ 17,129

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

(2) Includes business combinations.

(3) Includes proceeds from the acquisition and disposition of properties.

(4) In the second quarter of 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.

(5) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.

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

(7) 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.

(8) 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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Cash flows used in investing activities	***$ 1,042***	*$ 1,265*	*$ 1,074*	***$ 4,814***	*$ 13,102*
Net change in non-cash working capital (1)	***46***	*151*	*49*	***(345)***	*22*
Investment in other long-term assets	**—**	—	*(43)*	***(28)***	*(87)*
Share consideration in business acquisitions	**—**	—	—	**—**	*3,818*
Abandonment expenditures (2)	***93***	*57*	*63*	***290***	*274*
Net capital expenditures	***$ 1,181***	*$ 1,473*	*$ 1,143*	***$ 4,731***	*$ 17,129*

(1) Includes net working capital of $291 million related to the acquisition of AOSP in the second quarter of 2017.

(2) The Company excludes abandonment expenditures from “Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities” in the "Financial 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 costs.

Net capital expenditures for the year ended December 31, 2018 decreased to $4,731 million compared with $17,129 million for the year ended December 31, 2017. Net capital expenditures for the year ended December 31, 2017 included $12,157 million related to the acquisition of AOSP and other assets and $921 million related to the acquisition of assets in the Greater Pelican Lake region and other miscellaneous assets. Net capital expenditures for the fourth quarter of 2018 were $1,181 million, compared with $1,143 million for the fourth quarter of 2017 and $1,473 million for the third quarter of 2018.

Net capital expenditures for the year ended December 31, 2018 included:

- $105 million (US$79 million) of proceeds for the disposal of a 30% interest in the exploration right in South Africa, comprised of exploration and evaluation assets of $89 million, including a recovery of $14 million of past incurred costs in the Offshore Africa segment;
- $218 million of consideration for the acquisition of the Joslyn oil sands project in the Oil Sands Mining and Upgrading segment (comprising $100 million cash on closing with the remaining balance paid equally over the next five years);
- $22 million of cash consideration for the acquisition of Laricina Energy Ltd. in the North America Exploration and Production segment (net of $24 million of cash acquired); and
- $73 million of cash proceeds for the acquisition of the remaining interest at the Ninian field in the North Sea.

2019 Capital Budget

On December 5, 2018, the Company announced its 2019 Capital Budget. The 2019 budget targets a base capital program of $3,700 million, including $3,100 million to maintain current production levels and approximately $600 million directed toward long-term growth projects. The Company maintains capital flexibility in its 2019 budget. Should market access conditions improve, the Company has the capability to adjust 2019 capital spending.

Drilling Activity

(number of net wells)	Three Months Ended Dec 31 2018	Sep 30 2018	Dec 31 2017	Year Ended Dec 31 2018	Dec 31 2017
Net successful natural gas wells	**3**	6	2	**18**	21
Net successful crude oil wells [(1)]	**102**	178	125	**483**	495
Dry wells	**2**	5	3	**9**	7
Stratigraphic test / service wells	**91**	47	51	**615**	289
Total	**198**	236	181	**1,125**	812
Success rate (excluding stratigraphic test / service wells)	**98%**	97%	98%	**98%**	99%

(1) Includes bitumen wells.

North America

During the fourth quarter of 2018, the Company targeted 3 net natural gas wells in Northwest Alberta. The Company also targeted 103 net crude oil wells. The majority of these net wells were concentrated in the Company's Northern Plains region where 24 primary heavy crude oil wells, 41 bitumen (thermal oil) wells, 4 Pelican Lake heavy crude oil wells and 1 light crude oil well were drilled. Another 33 wells targeting light crude oil were drilled outside the Northern Plains region.

The Company's strategic and proactive decisions and its ability to utilize capital flexibility based on its large, balanced and diverse asset base has been reflected in the North America drilling program. During 2018, the Company reallocated capital spending from primary heavy crude oil to light crude oil, with an increase of 32 net wells in light crude oil and a corresponding decrease of 137 net wells in primary heavy crude oil.

North Sea

During the year ended December 31, 2018, the Company completed four gross production wells and one gross injection well (4.9 on a net basis), successfully completing the 2018 drilling program in the North Sea.

Offshore Africa

During the fourth quarter of 2018, the Company completed two gross production wells (1.2 on a net basis) at Baobab (year ended December 31, 2018 – three gross production wells (1.7 on a net basis)).

The Company has retained a 20% working interest in Block 11B/12B, off the southern coast of South Africa. In late December, the operator of the exploration right commenced the drilling of an exploratory well. Subsequent to December 31, 2018, the operator announced that drilling results indicate the presence of natural gas condensate. The Company expects the cost of the current exploration well to be fully carried pursuant to two separate farm-out agreements that were completed in 2018.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		Dec 31 2018		Sep 30 2018		Dec 31 2017
Working capital (1)	**$**	**(601)**	$	111	$	513
Long-term debt (2) (3)	**$**	**20,623**	$	19,733	$	22,458
Less: cash and cash equivalents		**101**		296		137
Long-term debt, net	**$**	**20,522**	$	19,437	$	22,321
Share capital	**$**	**9,323**	$	9,393	$	9,109
Retained earnings		**22,529**		24,033		22,612
Accumulated other comprehensive income (loss)		**122**		(33)		(68)
Shareholders' equity	**$**	**31,974**	$	33,393	$	31,653
Debt to book capitalization (3) (4)		**39.1%**		36.8%		41.4%
Debt to market capitalization (3) (5)		**34.1%**		27.4%		28.9%
After-tax return on average common shareholders' equity (6)		**8.0%**		11.6%		8.0%
After-tax return on average capital employed (3) (7)		**5.9%**		8.0%		5.6%

(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.

(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 (loss) for the twelve month trailing period; as a percentage of average common shareholders' equity for the twelve month trailing period.

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

As at December 31, 2018, 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 the Company's annual MD&A for the year ended December 31, 2017. 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;
- For the year ended December 31, 2018, the Company utilized cash flows from operating activities to facilitate net repayment of bank credit facilities and US dollar debt securities of $3,312 million, excluding the impact of foreign exchange on debt balances, including:
    - repayment and cancellation of the $125 million non-revolving credit facility;
    - repayment and cancellation of $1,200 million of the $3,000 million non-revolving credit facility; and
    - repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes.
- Additionally, the Company utilized available liquidity to settle the deferred payment to Marathon for $481 million, resulting in total net repayments of debt of $2,831 million.

- Reviewing the Company's borrowing capacity:
  - During the second quarter of 2018, the Company extended the $2,425 million revolving syndicated credit facility originally due June 2020 to June 2022. Each of the $2,425 million revolving 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 these 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 the second quarter of 2018, the Company extended the $2,200 million non-revolving credit facility originally due October 2019 to October 2020. Borrowings under the $2,200 million non-revolving credit facility 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, 2018, the $2,200 million facility was fully drawn.
  - During the first quarter of 2018, the Company extended the $750 million non-revolving credit facility originally due in February 2019 to February 2021. Borrowings under the $750 million non-revolving term credit facility 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, 2018, the $750 million facility was fully drawn.
  - 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 bank credit facilities for amounts outstanding under this program.
  - In July 2017, the Company filed 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, which expire 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; 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, 2018, the Company had in place revolving bank credit facilities of $4,976 million of which $4,723 million was available. Additionally, the Company had in place fully drawn term credit facilities of $4,750 million. This excludes certain other dedicated credit facilities supporting letters of credit.

As at December 31, 2018, the Company had total US dollar denominated debt with a carrying amount of $14,611 million (US$10,708 million), before transaction costs and original issue discounts. This included $5,604 million (US$4,108 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$3,058 million). The fixed repayment amount of these hedging instruments is $5,256 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $348 million to $14,263 million as at December 31, 2018.

Net long-term debt was $20,522 million at December 31, 2018, resulting in a debt to book capitalization ratio of 39.1% (December 31, 2017 – 41.4%); 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, 2018 are discussed in note 9 of the Company's unaudited interim consolidated financial statements.

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, 2018, the Company was in compliance with this covenant.

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, 2018, 28,000 bbl/d of currently forecasted crude oil volumes were hedged using WCS differential swaps for January to March 2019 and 8,000 bbl/d were hedged for January to September

2019. Additionally, 10,000 MMbtu/d of currently forecasted natural gas volumes were hedged using AECO basis swaps for January to March 2019, 30,000 GJ/d were hedged using AECO fixed price swaps for January to March 2019 and 10,000 GJ/d were hedged for April to October 2019. Subsequent to December 31, 2018, the Company has hedged an additional 105,000 GJ/d of currently forecasted natural gas volumes using AECO fixed price swaps for April to October 2019. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2018 are discussed in note 16 of the Company's unaudited interim consolidated financial statements.

Share Capital

As at December 31, 2018, there were 1,201,886,000 common shares outstanding (December 31, 2017 – 1,222,769,000 common shares) and 46,685,000 stock options outstanding. As at March 5, 2019, the Company had 1,199,849,000 common shares outstanding and 50,413,000 stock options outstanding.

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 (previous quarterly dividend rate of $0.275 per common share). The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On May 16, 2018, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 61,454,856 common shares, over a 12-month period commencing May 23, 2018 and ending May 22, 2019. The Company's Normal Course Issuer Bid announced in March 2017 expired on May 22, 2018.

For the year ended December 31, 2018, the Company purchased for cancellation 30,857,727 common shares at a weighted average price of $41.56 per common share for a total cost of $1,282 million. Retained earnings were reduced by $1,044 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2018, the Company purchased 4,340,000 common shares at a weighted average price of $35.86 per common share for a total cost of $156 million.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at December 31, 2018:

($ millions)	2019	2020	2021	2022	2023	Thereafter
Product transportation and pipeline	$ 692	$ 664	$ 620	$ 516	$ 381	$ 3,991
North West Redwater Partnership debt service toll (1)	$ 86	$ 126	$ 157	$ 158	$ 157	$ 2,858
Offshore equipment operating leases	$ 94	$ 73	$ 75	$ 8	$ —	$ —
Long-term debt (2)	$ 1,141	$ 5,996	$ 1,444	$ 1,003	$ 1,365	$ 9,793
Interest and other financing expense (3)	$ 836	$ 755	$ 610	$ 558	$ 500	$ 5,327
Office leases	$ 42	$ 42	$ 39	$ 31	$ 32	$ 89
Other	$ 85	$ 35	$ 32	$ 32	$ 31	$ 424

(1) 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 toll, currently consisting of interest and fees, with principal repayments beginning in 2020. Included in the service toll is $1,301 million of interest payable over the 30 year tolling period.

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

(3) *Interest and other financing payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2018.*

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.

CHANGES IN ACCOUNTING POLICIES

For the impact of new accounting standards, refer to the audited consolidated financial statements for the year ended December 31, 2017 and the unaudited interim consolidated financial statements for the three months and year ended December 31, 2018.

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 also 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 date of adoption. The Company is assessing the impact of these amendments on its consolidated financial statements.

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 is assessing the impact of these amendments on its consolidated financial statements.

In October 2017, the IASB issued amendments to IAS 28 "Investments in Associates and Joint Ventures" to clarify that the impairment provisions in IFRS 9 apply to financial instruments in an associate or joint venture that are not accounted for using the equity method, including long-term assets that form part of the net investment in the associate or joint venture. The amendments are effective January 1, 2019 with earlier adoption permitted. The amendments are required to be adopted retrospectively. The Company has determined that these amendments have no significant impact on its consolidated financial statements.

In June 2017, the IASB issued IFRIC 23 "Uncertainty over Income Tax Treatments". The interpretation provides guidance on how to reflect the effects of uncertainty in accounting for income taxes where IAS 12 is unclear. The interpretation is effective January 1, 2019. The Company has determined that this interpretation has no significant impact on its consolidated financial statements.

IFRS 16 "Leases"

In January 2016, the IASB issued IFRS 16 “Leases”, which provides guidance on accounting for leases. The new standard replaces IAS 17 “Leases” and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and requires balance sheet recognition for all leases. Certain short-term (less than 12 months) and low-value leases (as defined in the standard) are exempt from the requirements, and may continue to be treated as an expense. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are exempt from the standard.

The Company will adopt IFRS 16 on January 1, 2019 using the retrospective with cumulative effect method 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 will not be restated.

On initial adoption, the Company intends to use 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 less than twelve months as at January 1, 2019 will be treated as short-term leases; and
- exclusion of indirect costs for the measurement of lease assets at the date of initial application.

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

On adoption of IFRS 16, the Company will recognize lease assets and liabilities at the present value of the remaining lease payments, discounted using the Company’s applicable borrowing rate on January 1, 2019. The Company expects to report additional lease assets and corresponding liabilities of between $1.5 billion and $1.6 billion. The Company continues to finalize its accounting for leases in accordance with IFRS 16, and the above estimates are subject to change based on finalization of the Company's review of its lease arrangements. In the statement of earnings, depletion, depreciation and amortization expense and interest expense will increase, with corresponding decreases in production, transportation and administration expenses. The Company does not expect to report a material impact on net earnings. Under the new standard, the Company will report cash outflows for repayment of the principal portion of the lease liability as cash flows from financing activities. The interest portion of the lease payments will continue to be classified as cash flows from operating activities.

Where the Company, acting as the operator, signs a lease on behalf of a joint operation and assumes the legal liability for that lease, the Company will recognize 100% of the related lease asset and lease liability. As the Company recovers its joint operation partners' share of the costs of the lease contract, these recoveries will be recognized in the consolidated statements of earnings.

The Company continues to finalize its evaluation of its contracts that are potentially leases under IFRS 16, as well as implementing changes to policies, internal controls, information systems, and business accounting processes.

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 the annual MD&A and the audited consolidated financial statements for the year ended December 31, 2017.