Canadian Natural Resources Limited

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE MONTHS AND YEAR ENDED DECEMBER 31, 2017 AND 2016

MANAGEMENT'S DISCUSSION AND ANALYSIS

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, operating costs, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansions, 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 of construction and future operations of the North West Redwater bitumen upgrader and refinery, and construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and 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 reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets, including the interests in AOSP as well as additional working interests in certain other producing and non-producing oil and gas properties (the "other assets"), acquired by the Company on May 31, 2017; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by 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 report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management's estimates or opinions change.

Management's Discussion and Analysis

This MD&A of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the three months and year ended December 31, 2017 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2016.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the period ended December 31, 2017 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. 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, funds flow from operations (previously referred to as cash flow from operations), and adjusted cash production costs. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings (loss) and cash flows from operating activities, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings (loss) from operations and funds flow from operations are reconciled to net earnings (loss), as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The non-GAAP measure funds flow from operations is also reconciled to cash flows from operating activities in this section. The derivation of adjusted cash production costs 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.

A Barrel of Oil Equivalent ("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 volumes and per unit statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of blending and feedstock costs and exclude the effect of risk management activities. 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, 2017 in relation to the comparable periods in 2016 and the third quarter of 2017. 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, 2016, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated February 28, 2018.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)		Three Months Ended		Year Ended	
	Dec 31 2017	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Product sales	**$ 5,323**	$ 4,547	$ 3,672	**$ 17,669**	$ 11,098
Net earnings (loss)	**$ 396**	$ 684	$ 566	**$ 2,397**	$ (204)
Per common share – basic	**$ 0.32**	$ 0.56	$ 0.51	**$ 2.04**	$ (0.19)
– diluted	**$ 0.32**	$ 0.56	$ 0.51	**$ 2.03**	$ (0.19)
Adjusted net earnings (loss) from operations (1)	**$ 565**	$ 229	$ 439	**$ 1,403**	$ (669)
Per common share – basic	**$ 0.46**	$ 0.19	$ 0.40	**$ 1.19**	$ (0.61)
– diluted	**$ 0.46**	$ 0.19	$ 0.40	**$ 1.19**	$ (0.61)
Funds flow from operations (2)	**$ 2,307**	$ 1,675	$ 1,677	**$ 7,347**	$ 4,293
Per common share – basic	**$ 1.89**	$ 1.38	$ 1.52	**$ 6.25**	$ 3.90
– diluted	**$ 1.88**	$ 1.37	$ 1.50	**$ 6.21**	$ 3.89
Net capital expenditures	**$ 1,143**	$ 2,094	$ 411	**$ 17,129**	$ 3,794

(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 certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings (loss) from operations. The reconciliation "Adjusted Net Earnings (Loss) from Operations" presented in this MD&A, presents the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings (loss) from operations may not be comparable to similar measures presented by other companies.

(2) Funds flow 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 certain non-cash items and current income tax on disposition of properties. The Company evaluates its performance based on funds flow from operations. The Company considers funds flow from operations 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 "Funds Flow from Operations, as Reconciled to Net Earnings (Loss)" presented in this MD&A, includes certain non-cash items that are disclosed in the Company's financial results as presented in the Company's consolidated Statements of Cash Flows. Funds flow from operations may not be comparable to similar measures presented by other companies.

Funds flow from operations can also be derived by adjusting the GAAP measure Cash Flows from Operating Activities presented in the Company's consolidated Statements of Cash Flows for the net change in non-cash working capital, and abandonment and other expenditures. Accordingly, the Company has provided a second reconciliation, "Funds Flow from Operations, as Reconciled to Cash Flows from Operating Activities" in this MD&A.

Adjusted Net Earnings (Loss) from Operations

($ millions)	Three Months Ended Dec 31 2017	Sep 30 2017	Dec 31 2016	Year Ended Dec 31 2017	Dec 31 2016
Net earnings (loss) as reported	**$ 396**	$ 684	$ 566	**$ 2,397**	$ (204)
Share-based compensation, net of tax (1)	**97**	114	42	**134**	355
Unrealized risk management loss (gain), net of tax (2)	**68**	(6)	(7)	**33**	21
Unrealized foreign exchange (gain) loss, net of tax (3)	**(2)**	(404)	162	**(821)**	(93)
Gain from investments, net of tax (4) (5)	**(4)**	(76)	(106)	**(11)**	(299)
Gain on acquisition, disposition and revaluation of properties, net of tax (6)	**—**	(83)	(218)	**(339)**	(241)
Derecognition of exploration and evaluation assets,net of tax (7)	**—**	—	—	**—**	13
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (8)	**10**	—	—	**10**	(221)
Adjusted net earnings (loss) from operations	**$ 565**	$ 229	$ 439	**$ 1,403**	$ (669)

(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) Oil Sands Mining and Upgrading.

(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 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) 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 (gain) loss from investments is the Company's pro rata share of the Redwater Partnership's accounting (gain) loss for the period.

(5) 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 remeasured each period with changes in fair value recognized in net earnings (loss).

(6) 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. During the fourth quarter of 2016, the Company recorded a pre and after-tax gain of $218 million on the disposition of Midstream property, plant and equipment. During the first quarter of 2016, the Company recorded a pre-tax gain of $32 million ($23 million after-tax) on the disposition of certain exploration and evaluation assets.

(7) In connection with the Company's notice of withdrawal from Block CI-12 in Côte d'Ivoire, Offshore Africa in the second quarter of 2016, the Company derecognized $18 million ($13 million after-tax) of exploration and evaluation assets through depletion, depreciation and amortization expense.

(8) In 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. In the third quarter of 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. During the first quarter of 2016, the UK government enacted tax rate reductions relating to Petroleum Revenue Tax ("PRT"), resulting in a decrease in the Company's net deferred income tax liability of $114 million.

Funds Flow from Operations, as Reconciled to Net Earnings (Loss)

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Net earnings (loss)	***$ 396***	*$ 684*	*$ 566*	***$ 2,397***	*$ (204)*
Non-cash items:					
Depletion, depreciation and amortization	***1,406***	*1,271*	*1,249*	***5,186***	*4,858*
Share-based compensation	***97***	*114*	*42*	***134***	*355*
Asset retirement obligation accretion	***45***	*44*	*35*	***164***	*142*
Unrealized risk management loss (gain)	***75***	*8*	*(7)*	***37***	*25*
Unrealized foreign exchange (gain) loss	***(2)***	*(404)*	*162*	***(821)***	*(93)*
Gain from investments	***(4)***	*(76)*	*(106)*	***(11)***	*(299)*
Deferred income tax expense (recovery)	***294***	*148*	*(46)*	***640***	*(241)*
Gain on acquisition, disposition and revaluation of properties	**—**	*(114)*	*(218)*	***(379)***	*(250)*
Funds flow from operations	***$ 2,307***	*$ 1,675*	*$ 1,677*	***$ 7,347***	*$ 4,293*

Funds Flow from Operations, as Reconciled to Cash Flows from Operating Activities

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Cash flows from operating activities	***$ 1,438***	*$ 2,522*	*$ 1,255*	***$ 7,262***	*$ 3,452*
Net change in non-cash working capital	***709***	*(918)*	*317*	***(299)***	*542*
Abandonment expenditures	***63***	*65*	*35*	***274***	*267*
Other	***97***	*6*	*70*	***110***	*32*
Funds flow from operations	***$ 2,307***	*$ 1,675*	*$ 1,677*	***$ 7,347***	*$ 4,293*

SUMMARY OF CONSOLIDATED NET EARNINGS (LOSS) AND FUNDS FLOW FROM OPERATIONS

Net earnings for the year ended December 31, 2017 were $2,397 million compared with a net loss of $204 million for the year ended December 31, 2016. Net earnings for the year ended December 31, 2017 included net after-tax income of $994 million compared with net after-tax income of $465 million for the year ended December 31, 2016 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, gain from investments, gain on acquisition, disposition and revaluation of properties, the derecognition of exploration and evaluation assets 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, 2017 were $1,403 million compared with an adjusted net loss of $669 million for the year ended December 31, 2016.

Net earnings for the fourth quarter of 2017 were $396 million compared with a net earnings of $566 million for the fourth quarter of 2016 and net earnings of $684 million for the third quarter of 2017. Net earnings for the fourth quarter of 2017 included net after-tax expenses of $169 million compared with net after-tax income of $127 million for the fourth quarter of 2016 and net after-tax income of $455 million for the third quarter of 2017 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, 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 fourth quarter of 2017 were $565 million compared with adjusted net earnings of $439 million for the fourth quarter of 2016 and adjusted net earnings of $229 million for the third quarter of 2017.

The increase in adjusted net earnings (loss) for the year ended December 31, 2017 from the year ended December 31, 2016 was primarily due to:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment, due to volumes associated with both the acquisition of AOSP and new Phase 2B and Phase 3 sales volumes at Horizon;
- higher crude oil and NGLs and natural gas netbacks in the Exploration and Production segments; and
- higher realized SCO prices in the Oil Sands Mining and Upgrading segment;

partially offset by:

- higher depletion, depreciation and amortization;
- higher interest and financing expense; and
- the strengthening of the Canadian dollar relative to the US dollar.

The increase in adjusted net earnings (loss) for the fourth quarter of 2017 from the fourth quarter of 2016 was primarily due to:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment, due to volumes associated with both the acquisition of AOSP and new Phase 2B and Phase 3 sales volumes at Horizon;
- higher crude oil and NGLs sales volumes in the North America Exploration and Production segment;
- higher crude oil and NGLs netbacks in the Exploration and Production segments; and
- higher realized risk management gains;

partially offset by:

- lower natural gas netbacks in the North America Exploration and Production segment;
- higher depletion, depreciation and amortization;
- higher interest and financing expense; and
- the strengthening of the Canadian dollar relative to the US dollar.

The increase in adjusted net earnings (loss) for the fourth quarter of 2017 from the third quarter of 2017 was primarily due to:

- higher realized SCO prices in the Oil Sands Mining and Upgrading segment;
- higher crude oil and NGLs netbacks in the Exploration and Production segments;
- higher crude oil and NGLs sales volumes in the North America Exploration and Production segment;
- higher realized risk management gains; and
- the weakening of the Canadian dollar relative to the US dollar;

partially offset by:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment, due to the planned major turnaround at Horizon and planned pitstops at AOSP; and
- higher depletion, depreciation and amortization.

The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates are expected to continue to contribute to significant volatility in consolidated net earnings (loss) and are discussed in detail in the relevant sections of this MD&A.

Funds flow from operations for the year ended December 31, 2017 was $7,347 million compared with $4,293 million for the year ended December 31, 2016. Funds flow from operations for the fourth quarter of 2017 was $2,307 million compared with $1,677 million for the fourth quarter of 2016 and $1,675 million for the third quarter of 2017. The fluctuations in funds flow from operations from the comparable periods were primarily due to the factors noted above relating to the fluctuations in adjusted net earnings (loss), as well as due to the impact of fluctuations in cash taxes.

Total production before royalties for the fourth quarter of 2017 increased 19% to 1,020,094 BOE/d from 859,577 BOE/d for the fourth quarter of 2016 and decreased 2% from 1,036,499 BOE/d for the third quarter of 2017.

SUMMARY OF QUARTERLY RESULTS

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

($ millions, except per common share amounts)		**Dec 31 2017**		Sep 30 2017		Jun 30 2017		Mar 31 2017
Product sales	**$**	**5,323**	$	4,547	$	3,927	$	3,872
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
($ millions, except per common share amounts)		**Dec 31 2016**		**Sep 30 2016**		**Jun 30 2016**		**Mar 31 2016**
Product sales	$	3,672	$	2,477	$	2,686	$	2,263
Net earnings (loss)	$	566	$	(326)	$	(339)	$	(105)
Net earnings (loss) per common share								
– basic	$	0.51	$	(0.29)	$	(0.31)	$	(0.10)
– diluted	$	0.51	$	(0.29)	$	(0.31)	$	(0.10)

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 Western Canadian Select ("WCS") Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America and the impact of the differential between WTI and 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 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, new production from Horizon Phase 2B and Phase 3, the impact of turnarounds at Horizon and pitstops at AOSP, shut-in production due to low commodity prices, and the impact of the drilling program in Côte d’Ivoire in Offshore Africa. 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, an outage 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, the impact of seasonal costs that are dependent on weather, cost optimizations across all segments, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, turnarounds at Horizon and pitstops at AOSP, 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 at Horizon.
- **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 impacted 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 include statutory tax rate and other legislative changes substantively enacted in the various periods.
- **Gain on acquisition, disposition and revaluation of properties and gain/loss on investments** – Fluctuations due to the recognition of gains on the acquisition of AOSP and other assets, the disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity (gain) loss in North West Redwater.

BUSINESS ENVIRONMENT

(Average for the period)	Three Months Ended Dec 31 2017	Sep 30 2017	Dec 31 2016	Year Ended Dec 31 2017	Dec 31 2016
WTI benchmark price (US$/bbl)	**$ 55.39**	$ 48.19	$ 49.33	**$ 50.93**	$ 43.37
Dated Brent benchmark price (US$/bbl)	**$ 61.46**	$ 51.76	$ 50.27	**$ 54.38**	$ 43.96
WCS blend differential from WTI (US$/bbl)	**$ 12.28**	$ 9.94	$ 14.59	**$ 11.97**	$ 13.91
SCO price (US$/bbl)	**$ 58.64**	$ 48.83	$ 48.91	**$ 52.20**	$ 43.94
Condensate benchmark price (US$/bbl)	**$ 57.96**	$ 47.96	$ 48.37	**$ 51.65**	$ 42.51
NYMEX benchmark price (US$/MMBtu)	**$ 2.94**	$ 3.00	$ 2.99	**$ 3.11**	$ 2.45
AECO benchmark price (C$/GJ)	**$ 1.85**	$ 1.94	$ 2.67	**$ 2.30**	$ 1.98
US/Canadian dollar average exchange rate (US$)	**$ 0.7865**	$ 0.7983	$ 0.7496	**$ 0.7701**	$ 0.7548

Substantially all of the Company’s production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Dated Brent ("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$50.93 per bbl for the year ended December 31, 2017, an increase of 17% from US$43.37 per bbl for the year ended December 31, 2016. WTI averaged US$55.39 per bbl for the fourth quarter of 2017, an increase of 12% from US$49.33 per bbl for the fourth quarter of 2016, and an increase of 15% from US$48.19 per bbl for the third quarter of 2017.

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$54.38 per bbl for the year ended December 31, 2017, an increase of 24% from US$43.96 per bbl for the year ended December 31, 2016. Brent averaged US$61.46 per bbl for the fourth quarter of 2017, an increase of 22% from US$50.27 per bbl for the fourth quarter of 2016, and an increase of 19% from US$51.76 per bbl for the third quarter of 2017.

WTI and Brent pricing for the three months and year ended December 31, 2017 has increased from the comparable periods due to declines in global crude oil inventories as a result of OPEC’s adherence to previously announced production cuts, together with larger than anticipated increases in global demand for crude oil.

The WCS Heavy Differential averaged US$11.97 per bbl for the year ended December 31, 2017, a decrease of 14% from US$13.91 per bbl for the year ended December 31, 2016. The WCS Heavy Differential averaged US$12.28 per bbl for the fourth quarter of 2017, a decrease of 16% from US$14.59 per bbl for the fourth quarter of 2016, and an increase of 24% from US$9.94 per bbl for the third quarter of 2017. The WCS Heavy Differential reflects US Gulf Coast pricing, adjusted for transportation costs. The fluctuations in the WCS Heavy Differential for the three months and year ended December 31, 2017 from the comparable periods reflected seasonal supply and demand factors and changes in transportation logistics. Subsequent to December 31, 2017, the WCS Heavy Differential widened due to third party pipeline outages.

The SCO price averaged US$52.20 per bbl for the year ended December 31, 2017, an increase of 19% from US$43.94 per bbl for the year ended December 31, 2016. The SCO price averaged US$58.64 per bbl for the fourth quarter of 2017, an increase of 20% from US$48.91 per bbl for the fourth quarter of 2016, and an increase of 20% from US$48.83 per bbl for the third quarter of 2017. The increase in SCO pricing for the three months and year ended December 31, 2017 from the comparable periods was primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US$3.11 per MMBtu for the year ended December 31, 2017, an increase of 27% from US$2.45 per MMBtu for the year ended December 31, 2016. NYMEX natural gas prices averaged US$2.94 per MMBtu for the fourth quarter of 2017, a decrease of 2% from US$2.99 per MMBtu for the fourth quarter of 2016, and a decrease of 2% from US$3.00 per MMBtu for the third quarter of 2017.

AECO natural gas prices averaged $2.30 per GJ for the year ended December 31, 2017, an increase of 16% from $1.98 per GJ for the year ended December 31, 2016. AECO natural gas prices averaged $1.85 per GJ for the fourth quarter of 2017, a decrease of 31% from $2.67 per GJ for the fourth quarter of 2016, and a decrease of 5% from $1.94 per GJ for the third quarter of 2017.

The increase in natural gas prices for the year ended December 31, 2017 compared with the year ended December 31, 2016 primarily reflected the rebalancing of natural gas storage inventory to historically normal levels.

The decrease in AECO natural gas prices in the fourth quarter of 2017 compared with the fourth quarter of 2016 and third quarter of 2017 continued to reflect third party pipeline constraints limiting flow of natural gas to discretionary storage and export markets as well as increased natural gas production in the basin.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2017	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**383,537**	361,216	361,348	**359,449**	350,958
Oil Sands Mining and Upgrading – Horizon [1]	**141,275**	156,465	178,063	**170,089**	123,265
Oil Sands Mining and Upgrading – AOSP	**180,221**	197,900	—	**111,937**	—
North Sea	**19,548**	24,832	24,085	**23,426**	23,554
Offshore Africa	**19,519**	18,776	21,689	**20,335**	26,096
	744,100	759,189	585,185	**685,236**	523,873
Natural gas (MMcf/d)					
North America	**1,596**	1,593	1,578	**1,601**	1,622
North Sea	**37**	46	44	**39**	38
Offshore Africa	**23**	25	24	**22**	31
	1,656	1,664	1,646	**1,662**	1,691
Total barrels of oil equivalent (BOE/d)	**1,020,094**	1,036,499	859,577	**962,264**	805,782
Product mix					
Light and medium crude oil and NGLs	**13%**	13%	15%	**14%**	17%
Pelican Lake heavy crude oil	**6%**	5%	6%	**6%**	6%
Primary heavy crude oil	**10%**	10%	11%	**10%**	13%
Bitumen (thermal oil)	**12%**	11%	15%	**12%**	14%
Synthetic crude oil	**32%**	34%	21%	**29%**	15%
Natural gas	**27%**	27%	32%	**29%**	35%
Percentage of gross revenue [1] [2] (excluding Midstream revenue)					
Crude oil and NGLs	**92%**	92%	85%	**90%**	85%
Natural gas	**8%**	8%	15%	**10%**	15%

(1) Fourth quarter 2017 SCO production before royalties excludes 1,730 bbl/d of SCO consumed internally as diesel (third quarter 2017 – 0 bbl/d; fourth quarter 2016 – 1,619 bbl/d; year ended December 31, 2017 – 651 bbl/d; year ended December 31, 2016 – 1,966 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2017	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**333,698**	310,497	315,090	**312,297**	311,059
Oil Sands Mining and Upgrading – Horizon	**138,435**	154,757	175,860	**167,248**	122,258
Oil Sands Mining and Upgrading – AOSP	**171,342**	190,310	—	**107,189**	—
North Sea	**19,518**	24,784	24,034	**23,382**	23,497
Offshore Africa	**17,885**	17,735	20,730	**19,124**	24,995
	680,878	698,083	535,714	**629,240**	481,809
Natural gas (MMcf/d)					
North America	**1,538**	1,543	1,480	**1,528**	1,559
North Sea	**37**	46	44	**39**	38
Offshore Africa	**20**	22	23	**20**	30
	1,595	1,611	1,547	**1,587**	1,627
Total barrels of oil equivalent (BOE/d)	**946,731**	966,528	793,483	**893,702**	752,974

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, 2017 increased 31% to 685,236 bbl/d from 523,873 bbl/d for the year ended December 31, 2016. Crude oil and NGLs production for the fourth quarter of 2017 of 744,100 bbl/d increased 27% from 585,185 bbl/d for the fourth quarter of 2016, and decreased 2% from 759,189 bbl/d in the third quarter of 2017. The increase in crude oil and NGLs production for the year ended December 31, 2017 from the year ended December 31, 2016 was primarily due to acquisitions completed in 2017 and new Phase 2B and Phase 3 production at Horizon. The increase in crude oil and NGLs production for the fourth quarter of 2017 from the fourth quarter of 2016 was primarily due to acquisitions completed in 2017 and new Phase 3 production at Horizon, partially offset by the planned major turnaround. The decrease in production for the fourth quarter of 2017 from the third quarter of 2017 reflected the planned major turnaround at Horizon, planned pitstops at AOSP and the proactive shut-in of thermal and heavy crude oil production related to pricing in late December, partially offset by new Phase 3 production at Horizon in December and the impact of acquisitions in the third quarter of 2017.

Annual 2017 crude oil and NGLs production was within the Company's previously issued guidance of 663,000 to 717,000 bbl/d. First quarter 2018 crude oil and NGLs production guidance is targeted to average between 821,000 and 869,000 bbl/d. Annual crude oil and NGLs production guidance for 2018 is targeted to average between 815,000 and 885,000 bbl/d.

Natural gas production for the year ended December 31, 2017 decreased 2% to 1,662 MMcf/d from 1,691 MMcf/d for the year ended December 31, 2016. Natural gas production for the fourth quarter of 2017 averaged 1,656 MMcf/d, comparable with 1,646 MMcf/d for the fourth quarter of 2016 and 1,664 MMcf/d for the third quarter of 2017. Natural gas production continued to be impacted by low natural gas prices and reliability issues at a third party facility. During the fourth quarter of 2017, the Company shut-in production volumes of 24 MMcf/d related to low natural gas prices and 39 MMcf/d related to the impact of reliability issues at the third party facility. As a result of continued integrity issues, capacity at this facility has now been reduced to a one train operation.

Annual 2017 natural gas production was within the Company's previously issued guidance of 1,655 to 1,705 MMcf/d. First quarter 2018 natural gas production guidance is targeted to average between 1,600 and 1,650 MMcf/d. Annual natural gas production guidance for 2018 is targeted to average between 1,650 and 1,710 MMcf/d.

North America - Exploration and Production

North America crude oil and NGLs production for the year ended December 31, 2017 averaged 359,449 bbl/d, an increase of 2% from 350,958 bbl/d for the year ended December 31, 2016. North America crude oil and NGLs production for the fourth quarter of 2017 increased 6% to 383,537 bbl/d from 361,348 bbl/d for the fourth quarter of 2016, and increased 6% from 361,216 bbl/d for the third quarter of 2017. The increase in production for the three months and year ended December 31, 2017 from the comparable periods was primarily due to acquisitions completed in 2017. North America crude oil and NGLs production for the fourth quarter of 2017 also reflected the proactive shut-in of thermal and heavy crude oil production related to pricing in late December.

Annual 2017 crude oil and NGLs production was within the Company's previously issued guidance of 348,000 to 368,000 bbl/d. First quarter 2018 crude oil and NGLs production guidance is targeted to average between 348,000 and 362,000 bbl/d. Annual crude oil and NGLs production guidance for 2018 is targeted to average between 360,000 and 390,000 bbl/d.

Natural gas production for the year ended December 31, 2017 averaged 1,601 MMcf/d, comparable with 1,622 MMcf/d for the year ended December 31, 2016. Natural gas production for the fourth quarter of 2017 averaged 1,596 MMcf/d, comparable with 1,578 MMcf/d for the fourth quarter of 2016 and 1,593 MMcf/d in the third quarter of 2017. Natural gas production continued to be impacted by low natural gas prices and reliability issues at a third party facility. During the fourth quarter of 2017, shut-in production volumes of 24 MMcf/d related to low natural gas prices and 39 MMcf/d related to the impact of reliability issues at the third party facility. As a result of continued integrity issues, capacity at this facility has now been reduced to a one train operation.

Horizon

Horizon SCO production for the year ended December 31, 2017 of 170,089 bbl/d increased 38% from 123,265 bbl/d for the year ended December 31, 2016. Horizon SCO production for the fourth quarter of 2017 decreased 21% to average 141,275 bbl/d from 178,063 bbl/d for the fourth quarter of 2016 and decreased 10% from 156,465 bbl/d for the third quarter of 2017. The increase in production for the year ended December 31, 2017 from the year ended December 31, 2016 primarily reflected new Phase 2B and Phase 3 production at Horizon. The decrease in production for the fourth quarter of 2017 from the fourth quarter of 2016 and third quarter of 2017 reflected the impact of the planned major turnaround that was completed in the fourth quarter of 2017, followed by the successful ramp-up of Phase 3 production to approximately 247,200 bbl/d in December. Annual 2017 Horizon SCO production was within the Company’s previously issued guidance of 170,000 to 184,000 bbl/d.

Athabasca Oil Sands Project

AOSP achieved annualized SCO production for the year ended December 31, 2017 of 111,937 bbl/d. AOSP SCO production for the fourth quarter of 2017 decreased 9% to average 180,221 bbl/d from 197,900 bbl/d in the third quarter of 2017. The decrease in production for the fourth quarter of 2017 from the third quarter of 2017 primarily reflected the completion of the planned pitstops at the Jackpine and Muskeg River mines. Annualized 2017 AOSP SCO production was within the Company's previously issued guidance of 102,000 to 116,000 bbl/d.

Oil Sands Mining and Upgrading Guidance

First quarter 2018 Oil Sands Mining and Upgrading SCO production guidance is targeted to average between 435,000 and 465,000 bbl/d. Annual Oil Sands Mining and Upgrading SCO production guidance for 2018 is targeted to average between 415,000 and 450,000 bbl/d.

North Sea

North Sea crude oil production for the year ended December 31, 2017 averaged 23,426 bbl/d, comparable with 23,554 bbl/d for the year ended December 31, 2016. North Sea crude oil production for the fourth quarter of 2017 decreased 19% to 19,548 bbl/d from 24,085 bbl/d for the fourth quarter of 2016 and decreased 21% from 24,832 bbl/d in the third quarter of 2017. The decrease in production for the fourth quarter of 2017 from the fourth quarter of 2016 was primarily due to the impact of the shut-in of the Ninian North platform in May 2017 and natural field declines, partially offset by new wells at Ninian South and production optimization. The decrease in production for the fourth quarter of 2017 from the third quarter of 2017 was due to temporary unplanned shut-ins of the Ninian South platform as well as the Forties Pipeline System which impacted the Tiffany platform in December 2017.

Offshore Africa

Offshore Africa crude oil production for the year ended December 31, 2017 decreased 22% to 20,335 bbl/d from 26,096 bbl/d for the year ended December 31, 2016. Offshore Africa crude oil production for the fourth quarter of 2017 decreased 10% to 19,519 bbl/d from 21,689 bbl/d for the fourth quarter of 2016 and increased 4% from 18,776 bbl/d in the third quarter of 2017. The decrease in production for the three months and year ended December 31, 2017 from the comparable periods in 2016 primarily reflected natural field declines. The increase in production for the fourth quarter of 2017 from the third quarter of 2017 primarily reflected the resumption of production at Baobab following the successful completion of the planned turnaround during the third quarter of 2017.

International Guidance

Annual 2017 International crude oil production of 43,761 bbl/d was within the Company's previously issued guidance of 43,000 to 49,000 bbl/d. First quarter 2018 international crude oil production guidance is targeted to average between 38,000 and 42,000 bbl/d. Annual international crude oil production guidance for 2018 is targeted to average between 40,000 and 45,000 bbl/d.

International Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers 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 2017**	Sep 30 2017	Dec 31 2016
North Sea	**—**	506,748	987,316
Offshore Africa	**121,936**	639,622	1,126,999
	121,936	1,146,370	2,114,315

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2017	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 53.42**	$ 46.33	$ 45.00	**$ 48.57**	$ 36.93
Transportation	**2.82**	2.81	2.70	**2.80**	2.61
Realized sales price, net of transportation	**50.60**	43.52	42.30	**45.77**	34.32
Royalties	**5.84**	5.33	4.62	**5.24**	3.40
Production expense	**15.03**	14.71	14.28	**14.89**	14.10
Netback	**$ 29.73**	$ 23.48	$ 23.40	**$ 25.64**	$ 16.82
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 2.55**	$ 2.29	$ 3.14	**$ 2.76**	$ 2.32
Transportation	**0.46**	0.33	0.34	**0.39**	0.33
Realized sales price, net of transportation	**2.09**	1.96	2.80	**2.37**	1.99
Royalties	**0.08**	0.07	0.17	**0.11**	0.09
Production expense	**1.33**	1.22	1.15	**1.27**	1.18
Netback	**$ 0.68**	$ 0.67	$ 1.48	**$ 0.99**	$ 0.72
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 38.78**	$ 33.27	$ 34.54	**$ 35.54**	$ 27.58
Transportation	**2.86**	2.51	2.46	**2.66**	2.44
Realized sales price, net of transportation	**35.92**	30.76	32.08	**32.88**	25.14
Royalties	**3.75**	3.36	3.16	**3.40**	2.21
Production expense	**12.28**	11.73	11.34	**11.95**	11.18
Netback	**$ 19.89**	$ 15.67	$ 17.58	**$ 17.53**	$ 11.75

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

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2017	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 50.51**	$ 43.56	$ 42.56	**$ 45.85**	$ 34.31
North Sea	**$ 76.71**	$ 66.07	$ 63.68	**$ 69.43**	$ 55.91
Offshore Africa	**$ 73.43**	$ 64.14	$ 61.29	**$ 67.15**	$ 54.96
Company average	**$ 53.42**	$ 46.33	$ 45.00	**$ 48.57**	$ 36.93
Natural gas ($/Mcf) (1) (2)					
North America	**$ 2.33**	$ 2.07	$ 2.97	**$ 2.58**	$ 2.15
North Sea	**$ 9.77**	$ 7.73	$ 7.75	**$ 8.24**	$ 6.62
Offshore Africa	**$ 6.73**	$ 6.56	$ 5.75	**$ 6.57**	$ 6.13
Company average	**$ 2.55**	$ 2.29	$ 3.14	**$ 2.76**	$ 2.32
Company average ($/BOE) (1) (2)	**$ 38.78**	$ 33.27	$ 34.54	**$ 35.54**	$ 27.58

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

North America

North America realized crude oil prices increased 34% to $45.85 per bbl for the year ended December 31, 2017 from $34.31 per bbl for the year ended December 31, 2016. North America realized crude oil prices averaged $50.51 per bbl for the fourth quarter of 2017, an increase of 19% compared with $42.56 per bbl for the fourth quarter of 2016 and an increase of 16% compared with $43.56 per bbl for the third quarter of 2017. The increase in realized crude oil prices for the three months and year ended December 31, 2017 from the comparable periods in 2016 was primarily due to higher WTI benchmark pricing. The increase in realized crude oil prices for the fourth quarter of 2017 from the third quarter of 2017 was primarily due to higher WTI benchmark pricing. The Company continues to focus on its crude oil blending marketing strategy and in the fourth quarter of 2017, contributed approximately 190,400 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 20% to average $2.58 per Mcf for the year ended December 31, 2017 from $2.15 per Mcf for the year ended December 31, 2016. North America realized natural gas prices decreased 22% to average $2.33 per Mcf for the fourth quarter of 2017 compared with $2.97 per Mcf for the fourth quarter of 2016, and increased 13% compared with $2.07 per Mcf for the third quarter of 2017. The increase in realized natural gas prices per Mcf for the year ended December 31, 2017 from the year ended December 31, 2016 reflected the rebalancing of natural gas storage inventory to historically normal levels.

The decrease in realized natural gas prices for the fourth quarter of 2017 compared with the fourth quarter of 2016 reflected third party pipeline constraints limiting flow of natural gas to discretionary storage and export markets as well as increased natural gas production in the basin.

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

(Quarterly Average)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 54.09**	$ 43.27	$ 45.05
Pelican Lake heavy crude oil ($/bbl)	**$ 52.44**	$ 45.67	$ 43.96
Primary heavy crude oil ($/bbl)	**$ 50.71**	$ 45.55	$ 43.89
Bitumen (thermal oil) ($/bbl)	**$ 46.58**	$ 41.38	$ 39.39
Natural gas ($/Mcf)	**$ 2.33**	$ 2.07	$ 2.97

(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 24% to average $69.43 per bbl for the year ended December 31, 2017 from $55.91 per bbl for the year ended December 31, 2016. North Sea realized crude oil prices increased 20% to average $76.71 per bbl for the fourth quarter of 2017 from $63.68 per bbl for the fourth quarter of 2016 and increased 16% from $66.07 per bbl for the third quarter of 2017. 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, 2017 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 22% to average $67.15 per bbl for the year ended December 31, 2017 from $54.96 per bbl for the year ended December 31, 2016. Offshore Africa realized crude oil prices increased 20% to average $73.43 per bbl for the fourth quarter of 2017 from $61.29 per bbl for the fourth quarter of 2016 and increased 14% from $64.14 per bbl for the third quarter of 2017. Realized crude oil prices per bbl in any particular year 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, 2017 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 2017	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 6.20**	$ 5.84	$ 5.05	**$ 5.69**	$ 3.69
North Sea	**$ 0.12**	$ 0.13	$ 0.13	**$ 0.13**	$ 0.13
Offshore Africa	**$ 6.15**	$ 3.56	$ 2.71	**$ 4.13**	$ 2.31
Company average	**$ 5.84**	$ 5.33	$ 4.62	**$ 5.24**	$ 3.40
Natural gas ($/Mcf) [(1)]					
North America	**$ 0.07**	$ 0.05	$ 0.17	**$ 0.11**	$ 0.08
Offshore Africa	**$ 0.84**	$ 0.95	$ 0.29	**$ 0.76**	$ 0.28
Company average	**$ 0.08**	$ 0.07	$ 0.17	**$ 0.11**	$ 0.09
Company average ($/BOE) [(1)]	**$ 3.75**	$ 3.36	$ 3.16	**$ 3.40**	$ 2.21

(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, 2017 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 royalties averaged approximately 13% of product sales for the year ended December 31, 2017 compared with 12% of product sales for the year ended December 31, 2016. Crude oil and NGLs royalties averaged approximately 13% of product sales for the fourth quarter of 2017 compared with 13% for the fourth quarter of 2016 and 14% for the third quarter of 2017. The increase in royalties for the year ended December 31, 2017 from the year ended December 31, 2016 was primarily due to higher realized crude oil prices during 2017. The decrease for the fourth quarter of 2017 from the third quarter of 2017 reflected royalty adjustments in the third quarter of 2017 to reflect higher average annual bitumen prices. North America crude oil and NGLs royalties per bbl are anticipated to average 10% to 12% of product sales for 2018.

Natural gas royalties averaged approximately 5% of product sales for the year ended December 31, 2017 compared with 4% of product sales for the year ended December 31, 2016. Natural gas royalties averaged approximately 4% of product sales for the fourth quarter of 2017 compared with 6% for the fourth quarter of 2016 and 3% for the third quarter of 2017. The fluctuations in natural gas royalties for the three months and year ended December 31, 2017 from the comparable periods was primarily due to fluctuations in realized natural gas prices. North America natural gas royalties are anticipated to average 4% to 6% of product sales for 2018.

Offshore Africa

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital and operating costs, 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, 2017, compared with 4% of product sales for the year ended December 31, 2016. Royalty rates as a percentage of product sales averaged approximately 9% for the fourth quarter of 2017, compared with 4% of product sales for the fourth quarter of 2016 and 6% for the third quarter of 2017. Royalties as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields. Offshore Africa royalty rates are anticipated to average 7% to 9% of product sales for 2018.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2017	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 12.84**	$ 12.10	$ 12.13	**$ 12.71**	$ 11.89
North Sea	**$ 44.37**	$ 35.72	$ 41.66	**$ 36.60**	$ 42.47
Offshore Africa	**$ 17.96**	$ 29.24	$ 19.05	**$ 24.07**	$ 18.48
Company average	**$ 15.03**	$ 14.71	$ 14.28	**$ 14.89**	$ 14.10
Natural gas ($/Mcf) [1]					
North America	**$ 1.26**	$ 1.15	$ 1.07	**$ 1.19**	$ 1.12
North Sea	**$ 3.98**	$ 3.09	$ 3.36	**$ 3.37**	$ 3.09
Offshore Africa	**$ 2.26**	$ 2.32	$ 2.68	**$ 2.90**	$ 1.79
Company average	**$ 1.33**	$ 1.22	$ 1.15	**$ 1.27**	$ 1.18
Company average ($/BOE) [1]	**$ 12.28**	$ 11.73	$ 11.34	**$ 11.95**	$ 11.18

(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, 2017 increased 7% to $12.71 per bbl from $11.89 per bbl for the year ended December 31, 2016. North America crude oil and NGLs production expense for the fourth quarter of 2017 of $12.84 per bbl increased 6% from $12.13 per bbl in the fourth quarter of 2016 and increased 6% from $12.10 per bbl for the third quarter of 2017. The Company continues to focus on cost control and achieving efficiencies on acquired assets and across the entire asset base. Production expense per barrel for the three months and year ended December 31, 2017 reflected higher maintenance, trucking and other service costs. The increase in production expense per barrel in the fourth quarter of 2017 from the third quarter of 2017 was primarily due to higher fuel costs in the Company's thermal areas and higher maintenance, trucking and other service costs. Crude oil and NGLs production expense for 2017 was within annual guidance of $11.50 to $13.50 per bbl. North America crude oil and NGLs production expense is anticipated to average $11.50 to $13.50 per bbl for 2018.

North America natural gas production expense for the year ended December 31, 2017 averaged $1.19 per Mcf, an increase of 6% from $1.12 per Mcf for the year ended December 31, 2016. North America natural gas production expense for the fourth quarter of 2017 increased 18% to $1.26 per Mcf from $1.07 per Mcf for the fourth quarter of 2016 and increased 10% from $1.15 per Mcf for the third quarter of 2017. The Company continues to focus on cost control and achieving efficiencies on acquired assets and across the entire asset base. The increase in production expense for the year ended December 31, 2017 from the year ended December 31, 2016 primarily reflected the impact of higher maintenance and other service costs. The increase for the fourth quarter of 2017 from the third quarter of 2017 reflected seasonality. North America natural gas production expense is anticipated to average $1.00 to $1.20 per Mcf for 2018.

North Sea

North Sea crude oil production expense for the year ended December 31, 2017 decreased 14% to $36.60 per bbl from $42.47 per bbl for the year ended December 31, 2016. North Sea crude oil production expense for the fourth quarter of 2017 increased 7% to $44.37 per bbl from $41.66 per bbl for the fourth quarter of 2016 and increased 24% from $35.72 per bbl in the third quarter of 2017. The decrease for the year ended December 31, 2017 from the year ended December 31, 2016 reflected the Company's continuous focus on cost control, efficiencies and production optimization. The increase in production expense for the fourth quarter of 2017 from the fourth quarter of 2016 and third quarter of 2017 primarily reflected the impact of lower volumes on a relatively fixed cost base due to temporary unplanned shut-ins as well as fluctuations in the Canadian dollar and the UK pound sterling. As a result, crude oil and NGLs production expense for 2017 was slightly above annual guidance of $33.00 to $36.00 per bbl. North Sea crude oil production expense is anticipated to average $36.00 to $39.00 per bbl for 2018.

Offshore Africa

Offshore Africa crude oil production expense of $24.07 per bbl for the year ended December 31, 2017 included production expense of $12.41 per bbl relating to the Baobab and Espoir fields in Côte d'Ivoire. Production expense of $17.96 per bbl for the fourth quarter of 2017 included production expense of $12.22 per bbl relating to the Baobab and Espoir fields in Côte d'Ivoire. Total Offshore Africa crude oil production expense for the three months and year ended December 31, 2017 primarily reflected the timing of liftings from various fields, including the Olowi field, which have different cost structures, fluctuating production volumes on a relatively fixed cost base and fluctuations in the Canadian dollar.

On a standalone basis, Offshore Africa production expense for 2017 related to the Baobab and Espoir fields in Côte d'Ivoire was $12.41 per bbl and was within annual guidance of $10.50 to $12.50 per bbl. Offshore Africa production expense related to Côte d'Ivoire is anticipated to average $11.00 to $13.00 per bbl for 2018.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Expense	**$ 939**	$ 945	$ 1,049	**$ 3,957**	$ 4,185
$/BOE (1)	**$ 14.46**	$ 14.87	$ 16.71	**$ 15.82**	$ 16.79

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

Depletion, depreciation and amortization on a per barrel basis for the year ended December 31, 2017 decreased 6% to $15.82 per BOE from $16.79 per BOE for the year ended December 31, 2016. Depletion, depreciation and amortization expense on a per barrel basis for the fourth quarter of 2017 decreased 13% to $14.46 per BOE from $16.71 per BOE for the fourth quarter of 2016 and decreased 3% from $14.87 per BOE for the third quarter of 2017.

The decrease in depletion, depreciation and amortization expense on a per BOE basis for the year ended December 31, 2017 from the year ended December 31, 2016 was primarily due to a lower depletable base in North America, partially offset by additional depletion, depreciation and amortization in the North Sea related to the abandonment of the Ninian North platform. The decrease for the fourth quarter of 2017 from the fourth quarter of 2016 was primarily due to a lower depletable base in North America.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Expense	**$ 30**	$ 29	$ 28	**$ 116**	$ 113
$/BOE [1]	**$ 0.45**	$ 0.47	$ 0.45	**$ 0.46**	$ 0.45

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

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

Asset retirement obligation accretion expense for the year ended December 31, 2017 of $0.46 per BOE was comparable with $0.45 per BOE for the year ended December 31, 2016. Asset retirement obligation accretion expense for the fourth quarter of 2017 of $0.45 per BOE was comparable with $0.45 per BOE for the fourth quarter of 2016 and $0.47 per BOE for the third quarter of 2017.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

On May 31, 2017 the Company completed the acquisition of a direct and indirect 70% interest in AOSP, including a 70% interest in the mining and extraction operations north of Fort McMurray, Alberta and 70% of the Scotford Upgrader and Quest Carbon Capture and Storage ("CCS") project. The acquisition strengthened the Company's portfolio of long life no decline synthetic crude oil assets. Effective May 31, 2017, the Oil Sands Mining and Upgrading segment of this MD&A reflects the mining, extraction and upgrading operations at both Horizon and AOSP.

The Company continues to focus on reliable and efficient operations. The Oil Sands Mining and Upgrading segment achieved production during the fourth quarter of 2017 averaging 321,496 bbl/d following the addition of new production volumes from the acquisition of and successful integration of the Company's interest in AOSP as well as new Phase 3 production at Horizon, partially offset by the impact of the planned major turnaround which was successfully completed in the fourth quarter of 2017.

Horizon Operations Update

Horizon SCO production averaged 141,275 bbl/d during the fourth quarter of 2017, reflecting the impact of the planned major turnaround partially offset by new Phase 3 production. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, together with additional production from new Phase 3, adjusted cash production costs averaging $21.13 per bbl were achieved during the quarter.

The Horizon Phase 3 expansion was completed on schedule and within budget. Phase 3 activities included the expansion tie-in and commissioning of the production plant. SCO production for the month of December averaged approximately 247,200 bbl/d reflecting new Phase 3 production.

AOSP Operations Update

AOSP SCO production averaged 180,221 bbl/d during the fourth quarter of 2017, reflecting the successful completion of the planned pitstops at the Jackpine and Muskeg River Mines. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability of AOSP operations, cash production costs of $27.95 per bbl were achieved during the quarter.

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

($/bbl) (1)	Three Months Ended Dec 31 2017	Sep 30 2017	Dec 31 2016	Year Ended Dec 31 2017	Dec 31 2016
Sales Price (2) (3)	**$ 70.85**	$ 56.55	$ 64.51	**$ 63.98**	$ 58.59
Bitumen value for royalty purposes (4)	**$ 44.78**	$ 40.69	$ 35.92	**$ 41.05**	$ 27.57
Bitumen Royalties (5)	**$ 2.45**	$ 1.39	$ 0.88	**$ 1.64**	$ 0.54
Transportation	**$ 1.88**	$ 1.61	$ 1.22	**$ 1.54**	$ 1.77

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

(2) The realized sales price for the periods presented in 2017 reflects the weighted average price of Horizon SCO and AOSP SCO while the realized sales price for the comparable periods in 2016 reflects the Horizon SCO price only. The Horizon realized sales price reflects a premium light sweet SCO compared to the blend at AOSP.

(3) Net of blending and feedstock costs.

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

(5) 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 $63.98 per bbl for the year ended December 31, 2017, an increase of 9% from $58.59 per bbl for the year ended December 31, 2016. For the fourth quarter of 2017, the realized sales price increased 10% to $70.85 per bbl from $64.51 per bbl for the fourth quarter of 2016 and increased 25% from $56.55 per bbl for the third quarter of 2017. The fluctuations in realized sales prices for the three months and year ended December 31, 2017 from the comparable periods primarily reflected WTI benchmark pricing, together with the impact of new AOSP SCO sales volumes. The increase in realized sales prices for the fourth quarter of 2017 from the third quarter of 2017 reflected WTI benchmark pricing.

The realized SCO sales price for Horizon averaged $67.74 per bbl for the year ended December 31, 2017, an increase of 16% from $58.59 per bbl for the year ended December 31, 2016. For the fourth quarter of 2017, the realized sales price increased 19% to $76.69 per bbl from $64.51 per bbl for the fourth quarter of 2016 and increased 26% from $60.84 per bbl for the third quarter of 2017.

The realized SCO sales price for AOSP averaged $66.36 per bbl for the three months ended December 31, 2017, an increase of 25% from $53.24 per bbl for the third quarter of 2017.

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 17 to the Company's unaudited interim consolidated financial statements.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Cash production costs	**$ 846**	$ 829	$ 376	**$ 2,600**	$ 1,292
Less: costs incurred during turnaround periods	**(137)**	(79)	—	**(216)**	(151)
Adjusted cash production costs	**$ 709**	$ 750	$ 376	**$ 2,384**	$ 1,141
Adjusted cash production costs, excluding natural gas costs	**$ 668**	$ 717	$ 336	**$ 2,239**	$ 1,057
Adjusted natural gas costs	**41**	33	40	**145**	84
Adjusted cash production costs	**$ 709**	$ 750	$ 376	**$ 2,384**	$ 1,141

	Three Months Ended			Year Ended	
($/bbl) (1)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Adjusted cash production costs, excluding natural gas costs	**$ 23.56**	$ 21.68	$ 20.17	**$ 21.98**	$ 23.36
Adjusted natural gas costs	**1.43**	1.01	2.36	**1.42**	1.84
Adjusted cash production costs	**$ 24.99**	$ 22.69	$ 22.53	**$ 23.40**	$ 25.20
Sales (bbl/d)	**308,067**	359,748	181,523	**279,084**	123,652

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

Adjusted cash production costs for the year ended December 31, 2017 decreased 7% to $23.40 per bbl from $25.20 per bbl for the year ended December 31, 2016. Adjusted cash production costs for the fourth quarter of 2017 averaged $24.99 per bbl, an increase of 11% from $22.53 per bbl for the fourth quarter of 2016 and an increase of 10% from $22.69 per bbl for the third quarter of 2017. The decrease in adjusted cash production costs on a per barrel basis for the year ended December 31, 2017 from the year ended December 31, 2016 primarily reflected the Company's continuous focus on cost control and efficiencies and high utilization rates and reliability, together with additional capacity from new Phase 2B and Phase 3 production at Horizon, partially offset by the impact of the acquisition of AOSP. The increase in adjusted cash production costs on a per barrel basis for the fourth quarter of 2017 from the fourth quarter of 2016 primarily reflected the impact of the acquisition of AOSP. The increase for the fourth quarter of 2017 from the third quarter of 2017 primarily reflected the planned pitstops at AOSP and unplanned maintenance. For 2018, Oil Sands Mining and Upgrading cash production costs, including turnaround costs, are anticipated to average $22.50 to $26.50 per bbl.

Horizon adjusted cash production costs for the year ended December 31, 2017 decreased 15% to $21.46 per bbl from $25.20 per bbl for the year ended December 31, 2016. Adjusted cash production costs for the fourth quarter of 2017 averaged $21.13 per bbl, a decrease of 6% from $22.53 per bbl for the fourth quarter of 2016 and a 4% increase from $20.24 per bbl for the third quarter of 2017. Cash production costs of $24.98 per bbl for 2017, including turnaround costs, were within the Company's previously issued guidance of $24.00 to $27.00 per bbl.

AOSP annualized cash production costs for the year ended December 31, 2017 were $26.34. Cash production costs for the fourth quarter of 2017 averaged $27.95 per bbl, an increase of 14% from $24.60 per bbl for the third quarter of 2017. Cash production costs for 2017 were below the Company's previously issued guidance of $27.00 to $31.00 per bbl.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Expense	**$ 464**	$ 324	$ 198	**$ 1,220**	$ 662
Less: depreciation incurred during turnaround period	**(188)**	(25)	—	**(213)**	(99)
Adjusted depletion, depreciation and amortization	**$ 276**	$ 299	$ 198	**$ 1,007**	$ 563
$/bbl [(1)]	**$ 9.75**	$ 9.03	$ 11.84	**$ 9.89**	$ 12.43

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

Adjusted depletion, depreciation and amortization expense on a per barrel basis for the Oil Sands Mining and Upgrading segment for the year ended December 31, 2017 decreased 20% to $9.89 per bbl from $12.43 per bbl for the year ended December 31, 2016. Adjusted depletion, depreciation and amortization expense on a per barrel basis for the fourth quarter of 2017 decreased 18% to $9.75 per bbl from $11.84 per bbl for the fourth quarter of 2016 and increased 8% from $9.03 per bbl for the third quarter of 2017.

Adjusted depletion, depreciation and amortization expense per barrel for the three months and year ended December 31, 2017 decreased from the comparable periods in 2016 primarily due to the impact of AOSP, which has a lower depletion rate. The increase for the fourth quarter of 2017 from the third quarter of 2017 primarily reflected the impact of assets depreciated on a straight line basis.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Expense	**$ 15**	$ 15	$ 7	**$ 48**	$ 29
$/bbl [(1)]	**$ 0.53**	$ 0.45	$ 0.44	**$ 0.47**	$ 0.64

(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. The increase in asset retirement obligation accretion expense in 2017 reflected the acquisition of AOSP.

Asset retirement obligation accretion expense on a per bbl basis for the year ended December 31, 2017 decreased 27% to $0.47 per bbl from $0.64 per bbl for the year ended December 31, 2016 due to higher sales volumes in 2017. Asset retirement obligation accretion expense of $0.53 per bbl for the fourth quarter of 2017 increased 20% from $0.44 per bbl for the fourth quarter of 2016 and increased 18% from $0.45 per bbl for the third quarter of 2017, primarily due to lower sales volumes in the fourth quarter of 2017.

MIDSTREAM

($ millions)	Three Months Ended Dec 31 2017	Sep 30 2017	Dec 31 2016	Year Ended Dec 31 2017	Dec 31 2016
Revenue	**$ 28**	$ 26	$ 26	**$ 102**	$ 114
Production expense	**4**	4	5	**16**	25
Midstream cash flow	**24**	22	21	**86**	89
Depreciation	**3**	2	2	**9**	11
Equity loss (gain) on investments	**1**	(20)	12	**(31)**	(7)
Gain on disposition and revaluation of properties (1)	**—**	(114)	(218)	**(114)**	(218)
Segment earnings before taxes	**$ 20**	$ 154	$ 225	**$ 222**	$ 303

(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. During the fourth quarter of 2016, the Company disposed of its interest in the Cold Lake Pipeline including $321 million of property, plant and equipment, for total net consideration of $539 million, resulting in a pre-tax gain of $218 million.

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 $9,500 million with project completion targeted for third quarter 2018. Productivity challenges during construction have continued to result in upward budgetary pressures that may result in a further increase in FCC of up to 2%. During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. To December 31, 2017, each party has provided $411 million of subordinated debt, together with accrued interest thereon of $99 million, for a Company total of $510 million. Any additional subordinated debt financing is not expected to be significant.

Under its processing agreement, beginning on the earlier of the commercial operations date of the refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

During the second quarter of 2017, Redwater Partnership issued $750 million of 2.80% series J senior secured bonds due June 2027 and $750 million of 3.65% series K senior secured bonds due June 2035.

As at December 31, 2017, Redwater Partnership had additional borrowings of $1,870 million under its secured $3,500 million syndicated credit facility, maturing June 2018. Subsequent to December 31, 2017, 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

($ millions, except per BOE amounts)	Three Months Ended Dec 31 2017	Sep 30 2017	Dec 31 2016	Year Ended Dec 31 2017	Dec 31 2016
Expense	**$ 84**	$ 73	$ 86	**$ 319**	$ 345
$/BOE (1)	**$ 0.90**	$ 0.75	$ 1.08	**$ 0.91**	$ 1.17

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

Administration expense on a per BOE basis for the year ended December 31, 2017 decreased 22% to $0.91 per BOE from $1.17 per BOE for the year ended December 31, 2016. Administration expense for the fourth quarter of 2017 of $0.90 per BOE decreased 17% from $1.08 per BOE for the fourth quarter of 2016 and increased 20% from $0.75 per BOE for the third quarter of 2017. Administration expense per BOE decreased for the three months and year ended December 31, 2017 from the comparable periods in 2016 primarily due to higher overhead recoveries and higher sales volumes. The increase in the fourth quarter of 2017 from the third quarter of 2017 was primarily due to higher staffing and general corporate costs, together with lower sales volumes.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Dec 31 2017	Sep 30 2017	Dec 31 2016	Year Ended Dec 31 2017	Dec 31 2016
Expense	**$ 97**	$ 114	$ 42	**$ 134**	$ 355

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 a $134 million share-based compensation expense for the year ended December 31, 2017, 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 share-based compensation expense for the year ended December 31, 2017 was approximately $5 million related to performance share units granted to certain executive employees (December 31, 2016 – $nil). For the year ended December 31, 2017, the Company charged $14 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (December 31, 2016 – $67 million).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended Dec 31 2017	Sep 30 2017	Dec 31 2016	Year Ended Dec 31 2017	Dec 31 2016
Expense, gross	**$ 187**	$ 204	$ 153	**$ 713**	$ 616
Less: capitalized interest	**18**	21	38	**82**	233
Expense, net	**$ 169**	$ 183	$ 115	**$ 631**	$ 383
$/BOE (1)	**$ 1.81**	$ 1.90	$ 1.43	**$ 1.79**	$ 1.30
Average effective interest rate	**3.7%**	3.7%	3.8%	**3.8%**	3.9%

(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, 2017 increased from the comparable periods in 2016 primarily due to the impact of higher average debt levels as a result of acquisitions completed in 2017. The decrease for the fourth quarter of 2017 from the third quarter of 2017 was primarily due to the impact of interest on tax recoveries realized in the fourth quarter of 2017. Capitalized interest of $82 million for the year ended December 31, 2017 was related to the Horizon Phase 3 expansion and the Kirby North project.

Net interest and other financing expense on a per BOE basis for the year ended December 31, 2017 increased 38% to $1.79 per BOE from $1.30 per BOE for the year ended December 31, 2016. Net interest and other financing expense on a per BOE basis for the fourth quarter of 2017 increased 27% to $1.81 per BOE from $1.43 per BOE for the fourth quarter of 2016 and decreased 5% from $1.90 per BOE for the third quarter of 2017. The increase on an absolute and per BOE basis for the three months and year ended December 31, 2017 from the comparable periods in 2016 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 2B and Phase 3. The decrease for the fourth quarter of 2017 from the third quarter of 2017 was primarily due to the impact of interest on tax recoveries in North America, partially offset by lower sales volumes.

The Company's average effective interest rate for the three months and year ended December 31, 2017 was consistent with the comparable periods.

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 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs financial instruments	**$ —**	$ (14)	$ —	**$ (32)**	$ —
Natural gas financial instruments	**(2)**	(4)	—	**(7)**	—
Foreign currency contracts	**(71)**	114	(14)	**37**	8
Realized (gain) loss	**(73)**	96	(14)	**(2)**	8
Crude oil and NGLs financial instruments	**7**	66	—	**—**	—
Natural gas financial instruments	**2**	1	8	**(6)**	6
Foreign currency contracts	**66**	(59)	(15)	**43**	19
Unrealized loss (gain)	**75**	8	(7)	**37**	25
Net loss (gain)	**$ 2**	$ 104	$ (21)	**$ 35**	$ 33

During the year ended December 31, 2017, net realized risk management gains were primarily related to the settlement of crude oil price collars and natural gas AECO swaps, offset by the settlement of foreign currency contracts. The Company recorded a net unrealized loss of $37 million ($33 million after-tax) on its risk management activities for the year ended December 31, 2017, including an unrealized loss of $75 million ($68 million after-tax) for the fourth quarter of 2017 (September 30, 2017 – unrealized loss of $8 million, $6 million gain after-tax; December 31, 2016 – unrealized gain of $7 million, $7 million after-tax).

Further details related to outstanding derivative financial instruments at December 31, 2017 are disclosed in note 15 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Net realized (gain) loss	**$ (15)**	$ 37	$ (2)	**$ 34**	$ 38
Net unrealized (gain) loss	**(2)**	(404)	162	**(821)**	(93)
Net (gain) loss [(1)]	**$ (17)**	$ (367)	$ 160	**$ (787)**	$ (55)

(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, 2017 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for the year ended December 31, 2017 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized (gain) loss for each of the periods presented included the impact of cross currency swaps (three months ended December 31, 2017 – unrealized gain of $1 million, September 30, 2017 – unrealized loss of $50 million, December 31, 2016 – unrealized gain of $67 million; year ended December 31, 2017 – unrealized loss of $280 million, December 31, 2016 – unrealized loss of $295 million). The US/Canadian dollar exchange rate at December 31, 2017 was US$0.7988 (September 30, 2017 – US$0.7994, December 31, 2016 – US$0.7448).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended			Year Ended	
	Dec 31 2017	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
North America [(1)]	**$ (93)**	$ (43)	$ (22)	**$ (145)**	$ (377)
North Sea	**10**	11	—	**57**	(74)
Offshore Africa	**17**	14	5	**45**	22
PRT recovery – North Sea	**(25)**	(34)	(35)	**(132)**	(198)
Other taxes	**3**	2	3	**11**	9
Current income tax recovery	**(88)**	(50)	(49)	**(164)**	(618)
Deferred corporate income tax expense (recovery)	**307**	141	(55)	**586**	(106)
Deferred PRT (recovery) expense – North Sea	**(13)**	7	9	**54**	(135)
Deferred income tax expense (recovery)	**294**	148	(46)	**640**	(241)
	206	98	(95)	**476**	(859)
Income tax rate and other legislative changes [(2)]	**(10)**	—	—	**(10)**	221
	$ 196	$ 98	$ (95)	**$ 466**	$ (638)
Effective income tax rate on adjusted net earnings (loss) from operations [(3)]	**32%**	32%	20%	**27%**	45%

(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. During the third quarter of 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. During the first quarter of 2016 the UK government enacted tax rate reductions relating to PRT, resulting in a decrease in the Company's net deferred income tax liability of $114 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, 2017 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 (loss) 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 three months and year ended December 31, 2017 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the Murchison and Ninian North platforms.

In October 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.

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 2018, the Company expects to recognize current income tax expense ranging from $300 million to $400 million in Canada and recoveries of $nil to $40 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Dec 31 2017	Sep 30 2017	Dec 31 2016	Year Ended Dec 31 2017	Dec 31 2016
Exploration and Evaluation					
Net expenditures (proceeds) [2] [3] [4]	**$ 16**	$ 66	$ 4	**$ 149**	$ (6)
Property, Plant and Equipment					
Net property acquisitions [2] [3] [4]	**19**	820	1	**1,219**	159
Well drilling, completion and equipping	**212**	241	200	**1,001**	712
Production and related facilities	**258**	241	50	**860**	369
Capitalized interest and other [5]	**27**	22	26	**91**	91
Net expenditures	**516**	1,324	277	**3,171**	1,331
Total Exploration and Production	**532**	1,390	281	**3,320**	1,325
Horizon Oil Sands Mining and Upgrading					
Horizon Phases 2/3 construction costs	**248**	252	515	**821**	1,920
Sustaining capital	**125**	150	76	**419**	379
Turnaround costs	**65**	73	(3)	**149**	135
Capitalized interest and other [5]	**26**	33	40	**76**	284
Total Horizon Oil Sands Mining and Upgrading	**464**	508	628	**1,465**	2,718
Athabasca Oil Sands Project					
Acquisitions of Exploration and Evaluation assets [2] [4]	**—**	—	—	**219**	—
Net property acquisitions [2] [4]	**—**	—	—	**11,604**	—
Sustaining capital	**89**	45	—	**142**	—
Turnaround costs	**4**	2	—	**6**	—
Total Athabasca Oil Sands Project	**93**	47	—	**11,971**	—
Total Oil Sands Mining and Upgrading	**557**	555	628	**13,436**	2,718
Midstream	**2**	76	(537)	**80**	(533)
Abandonments [6]	**63**	65	35	**274**	267
Head office	**(11)**	8	4	**19**	17
Total net capital expenditures	**$ 1,143**	$ 2,094	$ 411	**$ 17,129**	$ 3,794
By segment					
North America [2] [3] [4]	**$ 444**	$ 1,327	$ 221	**$ 3,056**	$ 1,048
North Sea	**52**	32	37	**160**	126
Offshore Africa	**36**	31	23	**104**	151
Oil Sands Mining and Upgrading [4]	**557**	555	628	**13,436**	2,718
Midstream	**2**	76	(537)	**80**	(533)
Abandonments [6]	**63**	65	35	**274**	267
Head office	**(11)**	8	4	**19**	17
Total	**$ 1,143**	$ 2,094	$ 411	**$ 17,129**	$ 3,794

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values and other 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 Company's disposition of properties.

(4) In the second quarter of 2017, total purchase consideration for the acquisition of interests in AOSP of $12,157 million includes $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) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

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, 2017 were $17,129 million compared with $3,794 million for the year ended December 31, 2016. Net capital expenditures for the fourth quarter of 2017 were $1,143 million, compared with $411 million for the fourth quarter of 2016 and $2,094 million for the third quarter of 2017.

Included in net capital expenditures for the year ended December 31, 2017 was $12,157 million related to the acquisition of AOSP and other assets in the second quarter of 2017 and $921 million related to the acquisition of assets in the Greater Pelican Lake region and other miscellaneous assets in the third quarter of 2017.

On November 7, 2017 the Company announced its 2018 Capital Budget. The budget reflects the Company's transition to a long life low decline asset base with a focus on reliability across the asset base and the continued integration and optimization of acquired assets in 2017. The 2018 budget is targeted at approximately $4,300 million.

Drilling Activity

	Three Months Ended			Year Ended	
(number of net wells)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Net successful natural gas wells	**2**	3	4	**21**	9
Net successful crude oil wells [(1)]	**125**	154	81	**495**	174
Dry wells	**3**	1	3	**7**	7
Stratigraphic test / service wells	**51**	6	62	**289**	268
Total	**181**	164	150	**812**	458
Success rate (excluding stratigraphic test / service wells)	**98%**	99%	97%	**99%**	96%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 19% of the total net capital expenditures for the year ended December 31, 2017 compared with approximately 20% for the year ended December 31, 2016.

During the fourth quarter of 2017, the Company targeted 2 net natural gas wells in Northwest Alberta. The Company also targeted 128 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 118 primary heavy crude oil wells and 5 bitumen (thermal oil) wells were drilled. Another 5 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for the fourth quarter of 2017 averaged approximately 124,100 bbl/d compared with approximately 129,300 bbl/d for the fourth quarter of 2016 and approximately 122,400 bbl/d for the third quarter of 2017. Fourth quarter thermal oil production was within the Company's previously issued guidance.

Pelican Lake production for the fourth quarter of 2017 averaged approximately 65,700 bbl/d compared with 47,500 bbl/d in the fourth quarter of 2016 and 47,600 bbl/d in the third quarter of 2017. Production volumes in the fourth quarter of 2017 reflected the impact of acquisitions in the third quarter of 2017.

Horizon Oil Sands Mining and Upgrading

During the fourth quarter of 2017, Horizon Phase 3 expansion work was completed on schedule and within budget. Phase 3 activities included the expansion tie-in and commissioning of the production plant.

North Sea

During the fourth quarter of 2017, the Company continued to progress the abandonment of the Murchison and Ninian North platforms. Abandonment activities are currently on schedule and within budget.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Dec 31 2017**		Sep 30 2017		Dec 31 2016
Working capital [1]	**$**	**513**	$	205	$	1,056
Long-term debt [2] [3]	**$**	**22,458**	$	22,921	$	16,805
Less: cash and cash equivalents		**137**		312		17
Long-term debt, net	**$**	**22,321**	$	22,609	$	16,788
Share capital	**$**	**9,109**	$	8,844	$	4,671
Retained earnings		**22,612**		22,552		21,526
Accumulated other comprehensive (loss) income		**(68)**		(57)		70
Shareholders' equity	**$**	**31,653**	$	31,339	$	26,267
Debt to book capitalization [3] [4]		**41%**		42%		39%
Debt to market capitalization [3] [5]		**29%**		31%		26%
After-tax return on average common shareholders' equity [6]		**8%**		9%		(1%)
After-tax return on average capital employed [3] [7]		**6%**		6%		0%

(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 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 period.

At December 31, 2017, the Company’s capital resources consisted primarily of funds flow from operations, available bank credit facilities and access to debt capital markets. Funds flow from operations 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, 2016. 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 funds flow from operations 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 funds flow from operations, 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;
- Utilizing funds flow from operations to facilitate debt reduction. Subsequent to December 31, 2017, the Company:
  - extended the fully drawn $750 million non-revolving credit facility originally due February 2019 to February 2021 and fully repaid and cancelled the $125 million non-revolving credit facility;
  - repaid and cancelled $150 million of the $3,000 million non-revolving term loan facility; and
  - repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.
- Reviewing the Company's borrowing capacity:
  - During the second quarter of 2017, the Company extended $2,095 million of the $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021. The remaining $330 million outstanding under this facility continues under the previous terms and matures in June 2019. The other $2,425 million revolving credit facility matures in June 2020. The revolving credit facilities are 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 would be repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar or US dollar bankers’ acceptances, or LIBOR, US base rate or Canadian prime loans.
  - During the second quarter of 2017, the $1,500 million non-revolving term credit facility was increased to $2,200 million and the maturity date was extended to October 2019 from April 2018. Borrowings under the $2,200 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar or US dollar bankers’ acceptances, or LIBOR, US base rate or Canadian prime loans. As at December 31, 2017, the $2,200 million facility was fully drawn.
  - In addition to the credit facilities described above, during the second quarter of 2017, the Company entered into a $3,000 million non-revolving term loan facility to finance the acquisition of AOSP and other assets. This facility matures in May 2020 and is subject to annual amortization of 5% of the original balance. Borrowings under the term loan facility may be made by way of pricing referenced to Canadian dollar or US dollar bankers’ acceptances, or LIBOR, US base rate or Canadian prime loans. The facility also supports a US$375 million letter of credit relating to the deferred purchase consideration payable to Marathon in March 2018. As at December 31, 2017, the $3,000 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.
  - During the second quarter of 2017, the Company issued $900 million of 2.05% medium-term notes due June 2020, $600 million of 3.42% medium-term notes due December 2026 and $300 million of 4.85% medium-term notes due May 2047. Proceeds from the securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires 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.

- During the second quarter of 2017, the Company repaid US$1,100 million of 5.70% notes. In addition, the Company issued US$1,000 million of 2.95% notes due January 2023, US$1,250 million of 3.85% notes due June 2027 and US$750 million of 4.95% notes due June 2047. Proceeds from the debt securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires 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.

At December 31, 2017, the Company had in place bank credit facilities of $11,050 million, of which approximately $4,112 million was available, resulting in liquidity of $4,249 million, including cash and cash equivalents. This excludes certain other dedicated credit facilities supporting letters of credit.

At December 31, 2017, the Company had total US dollar denominated debt with a carrying amount of $13,753 million (US$10,989 million), before transaction costs and original issue discounts. This included $4,239 million (US$3,389 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$2,339 million). The fixed repayment amount of these hedging instruments is $4,150 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $89 million to $13,664 million as at December 31, 2017.

Net long-term debt was $22,321 million at December 31, 2017, resulting in a debt to book capitalization ratio of 41% (December 31, 2016 – 39%); 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 funds flow from operations is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. In connection with the acquisition of AOSP and other assets, the Company arranged acquisition financing of $1.8 billion of medium-term notes in Canada, US$3 billion of long-term notes in the United States and a $3 billion term loan facility. See note 8 in the unaudited interim consolidated financial statements.

Further details related to the Company's long-term debt at December 31, 2017 are discussed in note 8 to the Company's unaudited interim consolidated financial statements.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. At February 28, 2018 the Company had no commodity derivative financial instruments outstanding.

Share Capital

As at December 31, 2017, there were 1,222,769,000 common shares outstanding (December 31, 2016 – 1,110,952,000 common shares) and 56,036,000 stock options outstanding. As at February 27, 2018, the Company had 1,225,805,000 common shares outstanding and 54,701,000 stock options outstanding.

On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to $0.335 per common share, beginning with the dividend payable on April 1, 2018. On March 1, 2017, the Board of Directors approved an increase in the quarterly dividend to $0.275 per common share, beginning with the dividend payable on April 1, 2017. On November 2, 2016, the Board of Directors approved an increase in the quarterly dividend to $0.25 per common share (previous quarterly dividend rate of $0.23 per common share), beginning with the dividend payable on January 1, 2017. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On May 16, 2017, 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 27,931,135 common shares, over a 12 month period commencing May 23, 2017 and ending May 22, 2018. For the year ended December 31, 2017, the Company did not purchase any common shares for cancellation.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. In connection with the acquisition of AOSP and other assets, the Company also assumed certain pipeline and other commitments. The following table summarizes the Company's commitments as at December 31, 2017:

($ millions)	2018	2019	2020	2021	2022	Thereafter
Product transportation and pipeline	$ 680	$ 584	$ 526	$ 482	$ 422	$ 3,868
Offshore equipment operating leases	$ 181	$ 92	$ 70	$ 68	$ 8	$ —
Long-term debt (1)	$ 2,027	$ 4,228	$ 4,231	$ 760	$ 1,000	$ 10,351
Interest and other financing expense (2)	$ 842	$ 755	$ 638	$ 561	$ 513	$ 5,384
Office leases	$ 43	$ 42	$ 42	$ 39	$ 30	$ 118
Other (3)	$ 87	$ 41	$ 40	$ 39	$ 43	$ 333

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

(2) Interest and other financing payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2017.

(3) In addition to the amounts disclosed above, beginning on the earlier of the commercial operations date of the Redwater refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

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, 2016 and the unaudited interim consolidated financial statements for the three months and year ended December 31, 2017.

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, 2016.