Canadian Natural Resources Limited

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 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, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the construction and future operations of the North West Redwater bitumen upgrader and refinery, and construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or 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 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 and nine months ended September 30, 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 September 30, 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 and nine months ended September 30, 2017 in relation to the comparable periods in 2016 and the second 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 November 1, 2017.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Sep 30 2017	Three Months Ended Jun 30 2017	Three Months Ended Sep 30 2016	Nine Months Ended Sep 30 2017	Nine Months Ended Sep 30 2016
Product sales	**$ 4,547**	$ 3,927	$ 2,477	**$ 12,346**	$ 7,426
Net earnings (loss)	**$ 684**	$ 1,072	$ (326)	**$ 2,001**	$ (770)
Per common share – basic	**$ 0.56**	$ 0.93	$ (0.29)	**$ 1.72**	$ (0.70)
– diluted	**$ 0.56**	$ 0.93	$ (0.29)	**$ 1.71**	$ (0.70)
Adjusted net earnings (loss) from operations (1)	**$ 229**	$ 332	$ (355)	**$ 838**	$ (1,108)
Per common share – basic	**$ 0.19**	$ 0.29	$ (0.32)	**$ 0.72**	$ (1.01)
– diluted	**$ 0.19**	$ 0.29	$ (0.32)	**$ 0.72**	$ (1.01)
Funds flow from operations (2)	**$ 1,675**	$ 1,726	$ 1,021	**$ 5,040**	$ 2,616
Per common share – basic	**$ 1.38**	$ 1.50	$ 0.93	**$ 4.34**	$ 2.38
– diluted	**$ 1.37**	$ 1.49	$ 0.92	**$ 4.32**	$ 2.38
Net capital expenditures	**$ 2,094**	$ 13,046	$ 1,185	**$ 15,986**	$ 3,383

(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" 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 **Sep 30 2017**	Three Months Ended Jun 30 2017	Three Months Ended Sep 30 2016	Nine Months Ended **Sep 30 2017**	Nine Months Ended Sep 30 2016
Net earnings (loss) as reported	***$ 684***	*$ 1,072*	*$ (326)*	***$ 2,001***	*$ (770)*
Share-based compensation, net of tax (1)	***114***	*(104)*	*74*	***37***	*313*
Unrealized risk management (gain) loss, net of tax (2)	***(6)***	*2*	*11*	***(35)***	*28*
Unrealized foreign exchange (gain) loss, net of tax (3)	***(404)***	*(355)*	*39*	***(819)***	*(255)*
Gain from investments, net of tax (4) (5)	***(76)***	*(27)*	*(46)*	***(7)***	*(193)*
Gain on acquisition, disposition and revaluation of properties, net of tax (6)	***(83)***	*(256)*	*—*	***(339)***	*(23)*
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)	***—***	*—*	*(107)*	***—***	*(221)*
Adjusted net earnings (loss) from operations	***$ 229***	*$ 332*	*$ (355)*	***$ 838***	*$ (1,108)*

(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 before 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 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 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) [(1)]

($ millions)	Three Months Ended Sep 30 2017	Jun 30 2017	Sep 30 2016	Nine Months Ended Sep 30 2017	Sep 30 2016
Net earnings (loss)	**$ 684**	$ 1,072	$ (326)	**$ 2,001**	$ (770)
Non-cash items:					
Depletion, depreciation and amortization	**1,271**	1,210	1,216	**3,780**	3,609
Share-based compensation	**114**	(104)	74	**37**	313
Asset retirement obligation accretion	**44**	39	36	**119**	107
Unrealized risk management loss (gain)	**8**	(6)	10	**(38)**	32
Unrealized foreign exchange (gain) loss	**(404)**	(355)	39	**(819)**	(255)
Gain from investments	**(76)**	(27)	(46)	**(7)**	(193)
Deferred income tax expense (recovery)	**148**	162	18	**346**	(195)
Gain on acquisition, disposition and revaluation of properties	**(114)**	(265)	—	**(379)**	(32)
Funds flow from operations	**$ 1,675**	$ 1,726	$ 1,021	**$ 5,040**	$ 2,616

(1) Funds flow from operations was previously referred to as cash flow from operations.

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

($ millions)	Three Months Ended Sep 30 2017	Jun 30 2017	Sep 30 2016	Nine Months Ended Sep 30 2017	Sep 30 2016
Cash flows from operating activities	**$ 2,522**	$ 1,631	$ 899	**$ 5,824**	$ 2,197
Net change in non-cash working capital	**(918)**	(39)	14	**(1,008)**	225
Abandonment expenditures	**65**	105	122	**211**	232
Other	**6**	29	(14)	**13**	(38)
Funds flow from operations	**$ 1,675**	$ 1,726	$ 1,021	**$ 5,040**	$ 2,616

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

Net earnings for the nine months ended September 30, 2017 were $2,001 million compared with a net loss of $770 million for the nine months ended September 30, 2016. Net earnings for the nine months ended September 30, 2017 included net after-tax income of $1,163 million compared with net after-tax income of $338 million for the nine months ended September 30, 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 nine months ended September 30, 2017 were $838 million compared with an adjusted net loss of $1,108 million for the nine months ended September 30, 2016.

Net earnings for the third quarter of 2017 were $684 million compared with a net loss of $326 million for the third quarter of 2016 and net earnings of $1,072 million for the second quarter of 2017. Net earnings for the third quarter of 2017 included net after-tax income of $455 million compared with net after-tax income of $29 million for the third quarter of 2016 and net after-tax income of $740 million for the second 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 third quarter of 2017 were $229 million compared with an adjusted net loss of $355 million for the third quarter of 2016 and adjusted net earnings of $332 million for the second quarter of 2017.

The increase in adjusted net earnings (loss) for the nine months ended September 30, 2017 from the nine months ended September 30, 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 Phase 2B sales volumes at Horizon;
- higher realized SCO prices in the Oil Sands Mining and Upgrading segment; and
- higher crude oil and NGLs netbacks in the Exploration and Production segments;

partially offset by:

- higher depletion, depreciation and amortization;
- higher realized risk management losses;
- 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 third quarter of 2017 from the third 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 Phase 2B sales volumes at Horizon;
- higher crude oil and NGLs netbacks in the Exploration and Production segments; and
- higher crude oil and NGLs sales volumes in the Exploration and Production segments;

partially offset by:

- higher realized risk management losses;
- lower natural gas netbacks in the North America Exploration and Production segment;
- higher interest and financing expense; and
- the strengthening of the Canadian dollar relative to the US dollar.

The decrease in adjusted net earnings for the third quarter of 2017 from the second quarter of 2017 was primarily due to:

- lower natural gas netbacks in the Exploration and Production segments;
- higher realized risk management losses;
- higher depletion, depreciation and amortization in the Oil Sands Mining and Upgrading segment;
- higher interest and financing expense; and
- the strengthening of the Canadian dollar relative to the US dollar;

partially offset by:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment; and
- higher crude oil and NGLs sales volumes in the Exploration and Production segments.

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 nine months ended September 30, 2017 was $5,040 million compared with $2,616 million for the nine months ended September 30, 2016. Funds flow from operations for the third quarter of 2017 was $1,675 million compared with $1,021 million for the third quarter of 2016 and $1,726 million for the second 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 third quarter of 2017 increased 41% to 1,036,499 BOE/d from 735,212 BOE/d for the third quarter of 2016 and increased 14% from 913,171 BOE/d for the second 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)	**Sep 30 2017**	Jun 30 2017	Mar 31 2017	Dec 31 2016
Product sales	**$ 4,547**	$ 3,927	$ 3,872	$ 3,672
Net earnings (loss)	**$ 684**	$ 1,072	$ 245	$ 566
Net earnings (loss) per common share				
– basic	**$ 0.56**	$ 0.93	$ 0.22	$ 0.51
– diluted	**$ 0.56**	$ 0.93	$ 0.22	$ 0.51

($ millions, except per common share amounts)	Sep 30 2016	Jun 30 2016	Mar 31 2016	Dec 31 2015
Product sales	$ 2,477	$ 2,686	$ 2,263	$ 2,963
Net earnings (loss)	$ (326)	$ (339)	$ (105)	$ 131
Net earnings (loss) per common share				
– basic	$ (0.29)	$ (0.31)	$ (0.10)	$ 0.12
– diluted	$ (0.29)	$ (0.31)	$ (0.10)	$ 0.12

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

- **Crude oil pricing** – The impact of shale oil production in North America, 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 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, increased production from Horizon Phase 2B, the impact of turnarounds at Horizon, 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 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 are 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 gains/losses 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, and fair value changes in the investments in PrairieSky and Inter Pipeline shares.

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
(Average for the period)	**Sep 30 2017**	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
WTI benchmark price (US$/bbl)	**$ 48.19**	$ 48.29	$ 44.94	**$ 49.43**	$ 41.37
Dated Brent benchmark price (US$/bbl)	**$ 51.76**	$ 50.24	$ 45.76	**$ 52.01**	$ 41.84
WCS blend differential from WTI (US$/bbl)	**$ 9.94**	$ 11.11	$ 13.49	**$ 11.86**	$ 13.68
SCO price (US$/bbl)	**$ 48.83**	$ 49.83	$ 45.63	**$ 50.03**	$ 42.27
Condensate benchmark price (US$/bbl)	**$ 47.96**	$ 48.44	$ 43.05	**$ 49.52**	$ 40.54
NYMEX benchmark price (US$/MMBtu)	**$ 3.00**	$ 3.18	$ 2.81	**$ 3.16**	$ 2.27
AECO benchmark price (C$/GJ)	**$ 1.94**	$ 2.63	$ 2.08	**$ 2.45**	$ 1.75
US/Canadian dollar average exchange rate (US$)	**$ 0.7983**	$ 0.7436	$ 0.7663	**$ 0.7649**	$ 0.7565

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$49.43 per bbl for the nine months ended September 30, 2017, an increase of 19% from US$41.37 per bbl for the nine months ended September 30, 2016. WTI averaged US$48.19 per bbl for the third quarter of 2017, an increase of 7% from US$44.94 per bbl for the third quarter of 2016, and comparable with the second 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$52.01 per bbl for the nine months ended September 30, 2017, an increase of 24% from US$41.84 per bbl for the nine months ended September 30, 2016. Brent averaged US$51.76 per bbl for the third quarter of 2017, an increase of 13% from US$45.76 per bbl for the third quarter of 2016, and an increase of 3% from US$50.24 per bbl for the second quarter of 2017.

WTI and Brent pricing for the three and nine months ended September 30, 2017 continued to reflect volatility in supply and demand factors and geopolitical events.

The WCS Heavy Differential averaged US$11.86 per bbl for the nine months ended September 30, 2017, a decrease of 13% from US$13.68 per bbl for the nine months ended September 30, 2016. The WCS Heavy Differential averaged US$9.94 per bbl for the third quarter of 2017, a decrease of 26% from US$13.49 per bbl for the third quarter of 2016, and a decrease of 11% from US$11.11 per bbl for the second quarter of 2017. The WCS Heavy Differential reflects US Gulf Coast pricing, adjusted for transportation costs. The narrowing of the differential for the third quarter of 2017 compared with the second quarter of 2017 also reflected seasonality.

The SCO price averaged US$50.03 per bbl for the nine months ended September 30, 2017, an increase of 18% from US$42.27 per bbl for the nine months ended September 30, 2016. The SCO price averaged US$48.83 per bbl for the third quarter of 2017, an increase of 7% from US$45.63 per bbl for the third quarter of 2016, and comparable with the second quarter of 2017. The fluctuations in SCO pricing for the three and nine months ended September 30, 2017 from the comparable periods were primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US$3.16 per MMBtu for the nine months ended September 30, 2017, an increase of 39% from US$2.27 per MMBtu for the nine months ended September 30, 2016. NYMEX natural gas prices averaged US$3.00 per MMBtu for the third quarter of 2017, an increase of 7% from US$2.81 per MMBtu for the third quarter of 2016, and a decrease of 6% from US$3.18 per MMBtu for the second quarter of 2017.

AECO natural gas prices averaged $2.45 per GJ for the nine months ended September 30, 2017, an increase of 40% from $1.75 per GJ for the nine months ended September 30, 2016. AECO natural gas prices averaged $1.94 per GJ for the third quarter of 2017, a decrease of 7% from $2.08 per GJ for the third quarter of 2016, and a decrease of 26% from $2.63 per GJ for the second quarter of 2017.

The increase in benchmark natural gas prices for the nine months ended September 30, 2017 compared with the comparable period in 2016 primarily reflected the rebalancing of natural gas storage inventory to historically normal levels and colder weather in the 2016/2017 winter season as compared with the previous year.

The decrease in AECO benchmark natural gas prices in the third quarter of 2017 compared with the third quarter of 2016 and second quarter of 2017 reflected third party pipeline maintenance, reducing flow capability of natural gas to discretionary storage and export markets.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2017	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**361,216**	332,802	343,779	**351,331**	347,469
Oil Sands Mining and Upgrading – Horizon (1)	**156,465**	190,837	67,586	**179,799**	104,865
Oil Sands Mining and Upgrading – AOSP	**197,900**	66,704	—	**88,926**	—
North Sea	**24,832**	26,304	23,450	**24,733**	23,376
Offshore Africa	**18,776**	20,480	26,171	**20,610**	27,576
	759,189	637,127	460,986	**665,399**	503,286
Natural gas (MMcf/d)					
North America	**1,593**	1,603	1,567	**1,602**	1,637
North Sea	**46**	37	50	**40**	36
Offshore Africa	**25**	16	28	**22**	34
	1,664	1,656	1,645	**1,664**	1,707
Total barrels of oil equivalent (BOE/d)	**1,036,499**	913,171	735,212	**942,776**	787,718
Product mix					
Light and medium crude oil and NGLs	**13%**	15%	19%	**14%**	18%
Pelican Lake heavy crude oil	**5%**	5%	7%	**5%**	6%
Primary heavy crude oil	**10%**	10%	14%	**10%**	14%
Bitumen (thermal oil)	**11%**	12%	14%	**13%**	13%
Synthetic crude oil	**34%**	28%	9%	**29%**	13%
Natural gas	**27%**	30%	37%	**29%**	36%
Percentage of gross revenue (1) (2) (excluding Midstream revenue)					
Crude oil and NGLs	**92%**	88%	83%	**89%**	85%
Natural gas	**8%**	12%	17%	**11%**	15%

(1) During the third quarter of 2017, no SCO production was consumed internally as diesel (second quarter 2017 – 438 bbl/d; third quarter 2016 – 1,464 bbl/d; nine months ended September 30, 2017 – 287 bbl/d; nine months ended September 30, 2016 – 2,083 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2017	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**310,497**	291,716	305,189	**305,084**	309,706
Oil Sands Mining and Upgrading – Horizon	**154,757**	187,315	67,008	**176,958**	104,261
Oil Sands Mining and Upgrading – AOSP	**190,310**	64,308	—	**85,570**	—
North Sea	**24,784**	26,246	23,404	**24,683**	23,316
Offshore Africa	**17,735**	19,231	25,061	**19,543**	26,428
	698,083	588,816	420,662	**611,838**	463,711
Natural gas (MMcf/d)					
North America	**1,543**	1,528	1,497	**1,525**	1,586
North Sea	**46**	37	50	**40**	36
Offshore Africa	**22**	15	27	**19**	32
	1,611	1,580	1,574	**1,584**	1,654
Total barrels of oil equivalent (BOE/d)	**966,528**	852,170	682,944	**875,831**	739,374

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 nine months ended September 30, 2017 increased 32% to 665,399 bbl/d from 503,286 bbl/d for the nine months ended September 30, 2016. Crude oil and NGLs production for the third quarter of 2017 of 759,189 bbl/d increased 65% from 460,986 bbl/d for the third quarter of 2016, and increased 19% from 637,127 bbl/d in the second quarter of 2017. The increase in crude oil and NGLs production for the three and nine months ended September 30, 2017 from the comparable periods was primarily due to the acquisition of AOSP and other assets on May 31, 2017, Phase 2B production, utilization of Phase 3 infrastructure and continued high reliability at Horizon, and strong thermal oil production, partially offset by the impact of the commencement of the planned major turnaround at Horizon in September 2017.

Third quarter 2017 crude oil and NGLs production was within the Company's previously issued guidance of 740,000 to 778,000 bbl/d. Fourth quarter 2017 crude oil and NGLs production guidance is targeted to average between 736,000 and 772,000 bbl/d. Annual crude oil and NGLs production guidance for 2017 is targeted to average between 663,000 and 717,000 bbl/d.

Natural gas production for the nine months ended September 30, 2017 decreased 3% to 1,664 MMcf/d from 1,707 MMcf/d for the nine months ended September 30, 2016. Natural gas production for the third quarter of 2017 averaged 1,664 MMcf/d, comparable with 1,645 MMcf/d for the third quarter of 2016 and 1,656 MMcf/d in the second quarter of 2017. The decrease in natural gas production for the nine months ended September 30, 2017 from the comparable period was primarily due to shut-in production volumes of approximately 27 MMcf/d related to low natural gas prices and 41 MMcf/d related to the impact of reliability issues at a third party facility. Natural gas production at the third party facility restarted at the end of July, with plant operations reinstated to near full capacity in the latter half of August, and for the month of September the plant was operating near full capacity.

Third quarter natural gas production was within the Company's previously issued guidance of 1,650 to 1,710 MMcf/d. Fourth quarter 2017 natural gas production guidance is targeted to average between 1,700 and 1,750 MMcf/d. Annual natural gas production guidance for 2017 is targeted to average between 1,655 and 1,705 MMcf/d.

North America - Exploration and Production

North America crude oil and NGLs production for the nine months ended September 30, 2017 averaged 351,331 bbl/d, comparable with 347,469 bbl/d for the nine months ended September 30, 2016. North America crude oil and NGLs production for the third quarter of 2017 increased 5% to 361,216 bbl/d from 343,779 bbl/d for the third quarter of 2016, and increased 9% from 332,802 bbl/d for the second quarter of 2017. The increase in production for the third quarter of 2017 from the third quarter of 2016 and the second quarter of 2017 was primarily due to strong thermal oil production due to the successful completion of planned turnarounds at the Primrose and Kirby South plants, increased heavy oil production due to higher drilling activity, and additional production volumes from the acquisition of the other assets on May 31, 2017.

Third quarter 2017 crude oil and NGLs production was within the Company's previously issued guidance of 358,000 to 372,000 bbl/d. Fourth quarter 2017 crude oil and NGLs production guidance is targeted to average between 377,000 and 391,000 bbl/d. Annual crude oil and NGLs production guidance for 2017 is targeted to average between 348,000 and 368,000 bbl/d.

Natural gas production for the nine months ended September 30, 2017 averaged 1,602 MMcf/d, comparable with 1,637 MMcf/d for the nine months ended September 30, 2016. Natural gas production for the third quarter of 2017 averaged 1,593 MMcf/d, comparable with 1,567 MMcf/d for the third quarter of 2016 and 1,603 MMcf/d in the second quarter of 2017. Natural gas production for the nine months ended September 30, 2017 reflected shut-in production volumes of approximately 27 MMcf/d related to low natural gas prices and 41 MMcf/d related to the impact of reliability issues at a third party facility. Natural gas production at the third party facility restarted at the end of July, with plant operations reinstated to near full capacity in the latter half of August, and for the month of September the plant was operating near full capacity.

Horizon

Horizon SCO production for the nine months ended September 30, 2017 of 179,799 bbl/d increased 71% from 104,865 bbl/d for the nine months ended September 30, 2016. Horizon SCO production for the third quarter of 2017 increased 132% to average 156,465 bbl/d from 67,586 bbl/d for the third quarter of 2016 and decreased 18% from 190,837 bbl/d for the second quarter of 2017. The increase in production for the three and nine months ended September 30, 2017 from the comparable periods in 2016 primarily reflected Phase 2B production at Horizon, the utilization of Phase 3 infrastructure and continued high reliability in the mining and upgrading operations. Third quarter production volumes reflected the impact of the planned major turnaround which commenced in September 2017.

Third quarter 2017 Horizon SCO production was within the Company’s previously issued guidance of 148,000 to 160,000 bbl/d. Fourth quarter 2017 Horizon SCO production guidance is targeted to average between 140,000 and 150,000 bbl/d, reflecting the impact of Phase 3 startup and the planned major turnaround which commenced in September 2017. Annual Horizon SCO production guidance for 2017 is targeted to average between 170,000 and 184,000 bbl/d.

Athabasca Oil Sands Project

AOSP SCO production for the third quarter of 2017 averaged 197,900 bbl/d, reflecting a full quarter of production for the Company's 70% interest in the project.

Third quarter 2017 AOSP SCO production was within the Company's previously issued guidance of 193,000 to 201,000 bbl/d. Fourth quarter 2017 AOSP SCO production guidance is targeted to average between 178,000 and 186,000 bbl/d, reflecting the impact of planned pitstops in the Albian mines for the fourth quarter. Annual AOSP SCO production guidance for 2017 is targeted to average between 102,000 and 116,000 bbl/d.

North Sea

North Sea crude oil production for the nine months ended September 30, 2017 increased 6% to 24,733 bbl/d from 23,376 bbl/d for the nine months ended September 30, 2016. North Sea crude oil production for the third quarter of 2017 increased 6% to 24,832 bbl/d from 23,450 bbl/d for the third quarter of 2016 and decreased 6% from 26,304 bbl/d for the second quarter of 2017. The increase in production for the three and nine months ended September 30, 2017 from comparable periods in 2016 was due to new wells at Ninian and successful production optimization, partially offset by the impact of the shut-in of the Ninian North platform in May 2017. The decrease in production for the third quarter of 2017 from the second quarter of 2017 primarily reflected the shut-in of the Ninian North platform in May 2017.

Offshore Africa

Offshore Africa crude oil production for the nine months ended September 30, 2017 decreased 25% to 20,610 bbl/d from 27,576 bbl/d for the nine months ended September 30, 2016. Offshore Africa crude oil production for the third quarter of 2017 decreased 28% to 18,776 bbl/d from 26,171 bbl/d for the third quarter of 2016 and decreased 8% from 20,480 bbl/d for the second quarter of 2017. The decrease in production for the three and nine months ended September 30, 2017 from comparable periods in 2016 primarily reflected natural field declines. The decrease for the third quarter of 2017 from the second quarter of 2017 primarily reflected the planned turnaround at Baobab during the third quarter of 2017 and natural field declines.

INTERNATIONAL GUIDANCE

Third quarter international crude oil production of 43,608 bbl/d was within the Company's previously issued guidance of 41,000 to 45,000 bbl/d. Fourth quarter 2017 international crude oil production guidance is targeted to average between 41,000 and 45,000 bbl/d. Annual international crude oil production guidance for 2017 is targeted to average between 43,000 and 49,000 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)	**Sep 30 2017**	Jun 30 2017	Sep 30 2016
North Sea	**506,748**	528,705	940,089
Offshore Africa	**639,622**	1,510,446	1,587,341
	1,146,370	2,039,151	2,527,430

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2017	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Crude oil and NGLs ($/bbl) [1]					
Sales price [2]	**$ 46.33**	$ 47.12	$ 39.66	**$ 46.82**	$ 34.14
Transportation	**2.81**	3.06	2.51	**2.79**	2.60
Realized sales price, net of transportation	**43.52**	44.06	37.15	**44.03**	31.54
Royalties	**5.33**	4.83	3.48	**5.03**	2.97
Production expense	**14.71**	15.51	13.85	**14.84**	14.03
Netback	**$ 23.48**	$ 23.72	$ 19.82	**$ 24.16**	$ 14.54
Natural gas ($/Mcf) [1]					
Sales price [2]	**$ 2.29**	$ 2.97	$ 2.44	**$ 2.83**	$ 2.06
Transportation	**0.33**	0.34	0.40	**0.37**	0.34
Realized sales price, net of transportation	**1.96**	2.63	2.04	**2.46**	1.72
Royalties	**0.07**	0.12	0.09	**0.12**	0.06
Production expense	**1.22**	1.25	1.08	**1.25**	1.18
Netback	**$ 0.67**	$ 1.26	$ 0.87	**$ 1.09**	$ 0.48
Barrels of oil equivalent ($/BOE) [1]					
Sales price [2]	**$ 33.27**	$ 33.94	$ 29.39	**$ 34.40**	$ 25.24
Transportation	**2.51**	2.67	2.51	**2.59**	2.44
Realized sales price, net of transportation	**30.76**	31.27	26.88	**31.81**	22.80
Royalties	**3.36**	3.09	2.27	**3.28**	1.89
Production expense	**11.73**	12.11	10.83	**11.83**	11.13
Netback	**$ 15.67**	$ 16.07	$ 13.78	**$ 16.70**	$ 9.78

(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			Nine Months Ended	
	Sep 30 2017	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 43.56**	$ 44.78	$ 36.84	**$ 44.16**	$ 31.45
North Sea	**$ 66.07**	$ 64.37	$ 60.00	**$ 67.04**	$ 53.23
Offshore Africa	**$ 64.14**	$ 69.93	$ 58.30	**$ 64.78**	$ 52.81
Company average	**$ 46.33**	$ 47.12	$ 39.66	**$ 46.82**	$ 34.14
Natural gas ($/Mcf) (1) (2)					
North America	**$ 2.07**	$ 2.84	$ 2.30	**$ 2.66**	$ 1.88
North Sea	**$ 7.73**	$ 6.89	$ 5.27	**$ 7.76**	$ 6.16
Offshore Africa	**$ 6.56**	$ 6.84	$ 5.39	**$ 6.52**	$ 6.23
Company average	**$ 2.29**	$ 2.97	$ 2.44	**$ 2.83**	$ 2.06
Company average ($/BOE) (1) (2)	**$ 33.27**	$ 33.94	$ 29.39	**$ 34.40**	$ 25.24

(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 40% to $44.16 per bbl for the nine months ended September 30, 2017 from $31.45 per bbl for the nine months ended September 30, 2016. North America realized crude oil prices averaged $43.56 per bbl for the third quarter of 2017, an increase of 18% compared with $36.84 per bbl for the third quarter of 2016 and a decrease of 3% compared with $44.78 per bbl for the second quarter of 2017. The increase in realized crude oil prices for the three and nine months ended September 30, 2017 from the comparable periods in 2016 was primarily due to higher WTI benchmark pricing and the narrowing of the heavy differential. The decrease in realized crude oil prices for the third quarter of 2017 from the second quarter of 2017 was primarily due to the strengthening of the Canadian dollar relative to the US dollar. The Company continues to focus on its crude oil blending marketing strategy and in the third quarter of 2017, contributed approximately 196,500 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 41% to average $2.66 per Mcf for the nine months ended September 30, 2017 from $1.88 per Mcf for the nine months ended September 30, 2016. North America realized natural gas prices decreased 10% to average $2.07 per Mcf for the third quarter of 2017 compared with $2.30 per Mcf for the third quarter of 2016, and decreased 27% compared with $2.84 per Mcf for the second quarter of 2017. The increase in natural gas prices per Mcf for the nine months ended September 30, 2017 from the comparable period in 2016 reflected the rebalancing of natural gas storage inventory to historically normal levels and colder weather in the 2016/2017 winter season as compared with the previous year.

The decrease in realized natural gas prices for the third quarter of 2017 compared with the third quarter of 2016 and second quarter of 2017 reflected third party pipeline maintenance reducing flow capability of natural gas to discretionary storage and export markets.

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

(Quarterly Average)	**Sep 30 2017**	Jun 30 2017	Sep 30 2016
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 43.27**	$ 46.44	$ 38.16
Pelican Lake heavy crude oil ($/bbl)	**$ 45.67**	$ 47.64	$ 37.57
Primary heavy crude oil ($/bbl)	**$ 45.55**	$ 45.92	$ 38.52
Bitumen (thermal oil) ($/bbl)	**$ 41.38**	$ 41.15	$ 33.68
Natural gas ($/Mcf)	**$ 2.07**	$ 2.84	$ 2.30

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

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

North Sea

North Sea realized crude oil prices increased 26% to average $67.04 per bbl for the nine months ended September 30, 2017 from $53.23 per bbl for the nine months ended September 30, 2016. North Sea realized crude oil prices increased 10% to average $66.07 per bbl for the third quarter of 2017 from $60.00 per bbl for the third quarter of 2016 and increased 3% from $64.37 per bbl for the second 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 and nine months ended September 30, 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 23% to average $64.78 per bbl for the nine months ended September 30, 2017 from $52.81 per bbl for the nine months ended September 30, 2016. Offshore Africa realized crude oil prices increased 10% to average $64.14 per bbl for the third quarter of 2017 from $58.30 per bbl for the third quarter of 2016 and decreased 8% from $69.93 per bbl for the second 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 and nine months ended September 30, 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			Nine Months Ended	
	Sep 30 2017	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 5.84**	$ 5.19	$ 3.81	**$ 5.50**	$ 3.22
North Sea	**$ 0.13**	$ 0.14	$ 0.12	**$ 0.13**	$ 0.13
Offshore Africa	**$ 3.56**	$ 4.26	$ 2.47	**$ 3.37**	$ 2.17
Company average	**$ 5.33**	$ 4.83	$ 3.48	**$ 5.03**	$ 2.97
Natural gas ($/Mcf) (1)					
North America	**$ 0.05**	$ 0.12	$ 0.09	**$ 0.12**	$ 0.06
Offshore Africa	**$ 0.95**	$ 0.51	$ 0.24	**$ 0.73**	$ 0.28
Company average	**$ 0.07**	$ 0.12	$ 0.09	**$ 0.12**	$ 0.06
Company average ($/BOE) (1)	**$ 3.36**	$ 3.09	$ 2.27	**$ 3.28**	$ 1.89

(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 and nine months ended September 30, 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 nine months ended September 30, 2017 compared with 11% of product sales for the nine months ended September 30, 2016. Crude oil and NGLs royalties averaged approximately 14% of product sales for the third quarter of 2017 compared with 11% for the third quarter of 2016 and 13% for the second quarter of 2017. The increase in royalties for the three and nine months ended September 30, 2017 from the comparable periods was primarily due to higher expected annualized crude oil prices. North America crude oil and NGLs royalties per bbl are anticipated to average 12% to 13% of product sales for 2017.

Natural gas royalties averaged approximately 5% of product sales for the nine months ended September 30, 2017 compared with 3% of product sales for the nine months ended September 30, 2016. Natural gas royalties averaged approximately 3% of product sales for the third quarter of 2017 compared with 4% for the third quarter of 2016 and 5% for the second quarter of 2017. The increase in natural gas royalties for the nine months ended September 30, 2017 from the comparable period in 2016 reflected higher realized natural gas prices. The decrease in natural gas royalties in the third quarter of 2017 from the third quarter of 2016 and second quarter of 2017 primarily reflected lower realized natural gas prices. North America natural gas royalties are anticipated to average 5% to 7% of product sales for 2017.

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 6% for the nine months ended September 30, 2017, compared with 4% of product sales for the nine months ended September 30, 2016. Royalty rates as a percentage of product sales averaged approximately 6% for the third quarter of 2017, compared with 4% of product sales for the third quarter of 2016 and 6% for the second 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 2017.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2017	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 12.10**	$ 13.74	$ 11.69	**$ 12.66**	$ 11.80
North Sea	**$ 35.72**	$ 28.86	$ 39.41	**$ 34.06**	$ 42.75
Offshore Africa	**$ 29.24**	$ 32.39	$ 16.32	**$ 26.39**	$ 18.29
Company average	**$ 14.71**	$ 15.51	$ 13.85	**$ 14.84**	$ 14.03
Natural gas ($/Mcf) (1)					
North America	**$ 1.15**	$ 1.17	$ 1.04	**$ 1.17**	$ 1.13
North Sea	**$ 3.09**	$ 3.40	$ 2.15	**$ 3.18**	$ 2.98
Offshore Africa	**$ 2.32**	$ 3.88	$ 1.68	**$ 3.13**	$ 1.58
Company average	**$ 1.22**	$ 1.25	$ 1.08	**$ 1.25**	$ 1.18
Company average ($/BOE) (1)	**$ 11.73**	$ 12.11	$ 10.83	**$ 11.83**	$ 11.13

(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 nine months ended September 30, 2017 increased 7% to $12.66 per bbl from $11.80 per bbl for the nine months ended September 30, 2016. North America crude oil and NGLs production expense for the third quarter of 2017 of $12.10 per bbl increased 4% from $11.69 per bbl in the third quarter of 2016 and decreased 12% from $13.74 per bbl for the second quarter of 2017. The Company continues to focus on cost control and achieving efficiencies across the asset base. Production expense per barrel for the nine months ended September 30, 2017 reflected higher maintenance activities. The decrease in production expense per barrel in the third quarter of 2017 from the second quarter of 2017 was primarily due to lower fuel costs in the Company's thermal areas. North America crude oil and NGLs production expense is anticipated to average $11.50 to $13.50 per bbl for 2017.

North America natural gas production expense for the nine months ended September 30, 2017 averaged $1.17 per Mcf, an increase of 4% from $1.13 per Mcf for the nine months ended September 30, 2016. North America natural gas production expense for the third quarter of 2017 increased 11% to $1.15 per Mcf from $1.04 per Mcf for the third quarter of 2016 and decreased 2% from $1.17 per Mcf for the second quarter of 2017. The Company continues to focus on cost control and achieving efficiencies across the asset base. North America natural gas production expense is anticipated to average $1.00 to $1.20 per Mcf for 2017.

North Sea

North Sea crude oil production expense for the nine months ended September 30, 2017 decreased 20% to $34.06 per bbl from $42.75 per bbl for the nine months ended September 30, 2016. North Sea crude oil production expense for the third quarter of 2017 decreased 9% to $35.72 per bbl from $39.41 per bbl for the third quarter of 2016 and increased 24% from $28.86 per bbl in the second quarter of 2017. The decrease for the three and nine months ended September 30, 2017 from the comparable periods in 2016 reflected the Company's continuous focus on cost control, efficiencies and production optimization. The increase in production expense in the third quarter of 2017 from the second quarter of 2017 primarily reflected the impact of one-time recoveries realized in the second quarter. Production expense also reflected fluctuations in the Canadian dollar and the UK pound sterling. North Sea crude oil production expense is anticipated to average $33.00 to $36.00 per bbl for 2017.

Offshore Africa

Offshore Africa crude oil production expense of $26.39 per bbl for the nine months ended September 30, 2017 included production expense of $12.49 per bbl relating to the Baobab and Espoir fields in Côte d'Ivoire. Production expense of $29.24 per bbl for the third quarter of 2017 included production expense of $12.51 per bbl relating to the Baobab and Espoir fields in Côte d'Ivoire. Total Offshore Africa crude oil production expense for the three and nine months ended September 30, 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, the planned turnaround at Baobab in the third quarter of 2017 and fluctuations in the Canadian dollar. Offshore Africa production expense related to Côte d'Ivoire is anticipated to average $10.50 to $12.50 per bbl for 2017.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2017**	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Expense	**$ 945**	$ 971	$ 1,031	**$ 3,018**	$ 3,136
$/BOE (1)	**$ 14.87**	$ 16.38	$ 16.84	**$ 16.30**	$ 16.82

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

Depletion, depreciation and amortization on a per barrel basis for the nine months ended September 30, 2017 decreased 3% to $16.30 per BOE from $16.82 per BOE for the nine months ended September 30, 2016. Depletion, depreciation and amortization expense on a per barrel basis for the third quarter of 2017 decreased 12% to $14.87 per BOE from $16.84 per BOE for the third quarter of 2016 and decreased 9% from $16.38 per BOE for the second quarter of 2017.

The decrease in depletion, depreciation and amortization expense on a per BOE basis for the nine months ended September 30, 2017 from the comparable period in 2016 was primarily due to a lower depletable base in North America, partially offset by additional depletion, depreciation and amortization of $225 million in the North Sea related to the abandonment of the Ninian North platform. The decrease for the three months ended September 30, 2017 from the comparable period in 2016 was primarily due to a lower depletable base in North America and the North Sea. The decrease from the second quarter of 2017 primarily reflected depletion of $74 million in the North Sea during the second quarter of 2017 related to the abandonment of the Ninian North platform.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2017**	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Expense	**$ 29**	$ 29	$ 28	**$ 86**	$ 85
$/BOE (1)	**$ 0.47**	$ 0.48	$ 0.46	**$ 0.47**	$ 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 nine months ended September 30, 2017 increased 4% to $0.47 per BOE from $0.45 per BOE for the nine months ended September 30, 2016. Asset retirement obligation accretion expense for the third quarter of 2017 increased 2% to $0.47 per BOE from $0.46 per BOE for the third quarter of 2016, and decreased 2% from $0.48 per BOE for the second 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 strengthens 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 third quarter of 2017 averaging 354,365 bbl/d following the addition of production volumes from the acquisition of and successful integration of the Company's interest in AOSP, partially offset by the impact of the planned major turnaround at Horizon which commenced September 2017.

Horizon Operations Update

Horizon achieved SCO production averaging 156,465 bbl/d during the third quarter of 2017, reflecting the planned major turnaround. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, together with additional production from Phase 2B and utilization of available Phase 3 infrastructure, adjusted cash production costs averaging $20.24 per bbl were achieved during the quarter.

The Horizon Phase 3 expansion, which is anticipated to add 80,000 bbl/d of SCO production, is on schedule and within cost, with commissioning and startup targeted in the fourth quarter of 2017 bringing total targeted plant capacity to 250,000 bbl/d.

AOSP Operations Update

AOSP SCO production averaged 197,900 bbl/d during the third quarter of 2017, reflecting a full quarter of production and high reliability of operations. Due to the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability of AOSP operations, cash production costs of $24.60 per bbl were achieved during the quarter.

The planned pit stops at both the Jackpine and Muskeg River Mines were successfully completed in the fourth quarter of 2017.

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

($/bbl) [1]	Three Months Ended Sep 30 2017	Jun 30 2017	Sep 30 2016	Nine Months Ended Sep 30 2017	Sep 30 2016
Sales Price [2] [3]	**$ 56.55**	$ 63.39	$ 58.61	**$ 61.33**	$ 55.13
Bitumen value for royalty purposes [4]	**$ 40.69**	$ 39.99	$ 30.16	**$ 39.45**	$ 22.89
Bitumen Royalties [5]	**$ 1.39**	$ 1.38	$ 0.62	**$ 1.33**	$ 0.34
Transportation	**$ 1.61**	$ 1.32	$ 3.40	**$ 1.42**	$ 2.09

(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 sales volumes.

The realized SCO sales price for the Oil Sands Mining and Upgrading segment averaged $61.33 per bbl for the nine months ended September 30, 2017, an increase of 11% from $55.13 per bbl for the nine months ended September 30, 2016. For the third quarter of 2017, the realized sales price decreased 4% to $56.55 per bbl from $58.61 per bbl for the third quarter of 2016 and decreased 11% from $63.39 per bbl for the second quarter of 2017. The fluctuations in realized sales prices for the three and nine months ended September 30, 2017 from the comparable periods primarily reflected WTI benchmark pricing, together with the impact of AOSP SCO sales volumes.

The realized SCO sales price for Horizon averaged $65.49 per bbl for the nine months ended September 30, 2017, an increase of 19% from $55.13 per bbl for the nine months ended September 30, 2016. For the third quarter of 2017, the realized sales price increased 4% to $60.84 per bbl from $58.61 per bbl for the third quarter of 2016 and decreased 9% from $67.04 per bbl for the second quarter of 2017.

The realized SCO sales price for AOSP averaged $53.24 per bbl for the three months ended September 30, 2017, an increase of 2% from $52.35 per bbl for the month of June 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			Nine Months Ended	
($ millions)	**Sep 30 2017**	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Cash production costs	**$ 829**	$ 553	$ 326	**$ 1,754**	$ 916
Less: costs incurred during turnaround periods	**(79)**	—	(151)	**(79)**	(151)
Adjusted cash production costs	**$ 750**	$ 553	$ 175	**$ 1,675**	$ 765
Adjusted cash production costs, excluding natural gas costs	**$ 717**	$ 515	$ 161	**$ 1,571**	$ 721
Adjusted natural gas costs	**33**	38	14	**104**	44
Adjusted cash production costs	**$ 750**	$ 553	$ 175	**$ 1,675**	$ 765

	Three Months Ended			Nine Months Ended	
($/bbl) (1)	**Sep 30 2017**	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Adjusted cash production costs, excluding natural gas costs	**$ 21.68**	$ 21.85	$ 24.92	**$ 21.37**	$ 25.22
Natural gas costs	**1.01**	1.59	2.13	**1.42**	1.55
Adjusted cash production costs	**$ 22.69**	$ 23.44	$ 27.05	**$ 22.79**	$ 26.77
Sales (bbl/d)	**359,748**	259,033	70,005	**269,317**	104,221

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

Adjusted cash production costs for the nine months ended September 30, 2017 decreased 15% to $22.79 per bbl from $26.77 per bbl for the nine months ended September 30, 2016. Adjusted cash production costs for the third quarter of 2017 averaged $22.69 per bbl, a decrease of 16% from $27.05 per bbl for the third quarter of 2016 and a 3% decrease from $23.44 per bbl for the second quarter of 2017. The decrease in adjusted cash production costs on a per barrel basis for the three and nine months ended September 30, 2017 from the comparable periods in 2016 primarily reflected the Company's continuous focus on cost control and efficiencies and high utilization rates and reliability, together with additional capacity from Phase 2B and Phase 3 infrastructure, partially offset by the impact of the acquisition of AOSP.

Horizon adjusted cash production costs for the nine months ended September 30, 2017 decreased 20% to $21.54 per bbl from $26.77 per bbl for the nine months ended September 30, 2016. Adjusted cash production costs for the third quarter of 2017 averaged $20.24 per bbl, a decrease of 25% from $27.05 per bbl for the third quarter of 2016 and an 8% decrease from $22.09 per bbl for the second quarter of 2017. For 2017, Horizon cash production costs are anticipated to average $24.00 to $27.00 per bbl, including turnaround costs.

AOSP cash production costs for the third quarter of 2017 averaged $24.60 per bbl, a decrease of 11% from $27.50 per bbl for the month of June 2017. For 2017, AOSP cash production costs are anticipated to average $27.00 to $31.00 per bbl.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2017**	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Expense	**$ 324**	$ 237	$ 182	**$ 756**	$ 464
Less: depreciation incurred during turnaround period	**(25)**	—	(99)	**(25)**	(99)
Adjusted depletion, depreciation and amortization	**$ 299**	$ 237	$ 83	**$ 731**	$ 365
$/bbl (1)	**$ 9.03**	$ 10.05	$ 12.96	**$ 9.94**	$ 12.77

(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 nine months ended September 30, 2017 decreased 22% to $9.94 per bbl from $12.77 per bbl for the nine months ended September 30, 2016. Adjusted depletion, depreciation and amortization expense on a per barrel basis for the third quarter of 2017 decreased 30% to $9.03 per bbl from $12.96 per bbl for the third quarter of 2016 and decreased 10% from $10.05 per bbl for the second quarter of 2017.

Adjusted depletion, depreciation and amortization expense per barrel for the three and nine months ended September 30, 2017 decreased from the comparable periods primarily due to the impact of AOSP, which has a lower depletion rate.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2017**	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Expense	**$ 15**	$ 10	$ 8	**$ 33**	$ 22
$/bbl (1)	**$ 0.45**	$ 0.42	$ 1.13	**$ 0.45**	$ 0.76

(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 nine months ended September 30, 2017 decreased 41% to $0.45 per bbl from $0.76 per bbl for the nine months ended September 30, 2016. Asset retirement obligation accretion expense of $0.45 per bbl for the third quarter of 2017 decreased 60% from $1.13 per bbl for the third quarter of 2016 and increased 7% from $0.42 per bbl for the second quarter of 2017, primarily due to higher overall sales volumes.

MIDSTREAM

($ millions)	Three Months Ended Sep 30 2017	Three Months Ended Jun 30 2017	Three Months Ended Sep 30 2016	Nine Months Ended Sep 30 2017	Nine Months Ended Sep 30 2016
Revenue	**$ 26**	$ 23	$ 31	**$ 74**	$ 88
Production expense	**4**	4	7	**12**	20
Midstream cash flow	**22**	19	24	**62**	68
Depreciation	**2**	2	3	**6**	9
Equity (gain) loss on investments	**(20)**	(10)	4	**(32)**	(19)
Gain on revaluation of properties [1]	**(114)**	—	—	**(114)**	—
Segment earnings before taxes	**$ 154**	$ 27	$ 17	**$ 202**	$ 78

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

The Company has a 50% interest in the Redwater Partnership. Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission (“APMC”), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

During 2013, the Company along with APMC, initially committed each to provide funding up to $350 million by each party by January 2016 in the form of subordinated debt bearing interest at prime plus 6%, based on a facility capital cost ("FCC") budget at $8,500 million, which was subsequently increased by approximately 11% to approximately $9,400 million. A higher than expected USD/CAD exchange rate, scope changes, and productivity challenges during construction have resulted in upward budgetary pressures. The cumulative effect of these changes may result in a further increase in FCC of 1% to 2%. Partially offsetting these FCC increases are lower than budgeted interest rates which the Redwater Partnership has been able to lock in to date.

The Company and APMC have agreed, each with a 50% interest, to provide additional subordinated debt as required for Project costs in excess of the FCC of $8,500 million to reflect an agreed debt to equity ratio of 80/20 and, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion, which is currently targeted for mid-2018. For the nine months ended September 30, 2017, the Company and APMC each contributed an additional $44 million. The Company's share of any additional subordinated debt financing resulting from the increase in the FCC in excess of $8,500 million is not expected to be significant. To September 30, 2017, each party has provided $368 million of subordinated debt, together with accrued interest thereon of $88 million, for a Company total of $456 million.

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 September 30, 2017, Redwater Partnership had additional borrowings of $1,351 million under its secured $3,500 million syndicated credit facility.

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.

Redwater Partnership has entered into various agreements related to the engineering, procurement and construction of the Project. These contracts can be cancelled by Redwater Partnership upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

ADMINISTRATION EXPENSE

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2017**	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Expense	**$ 73**	$ 75	$ 82	**$ 235**	$ 259
$/BOE (1)	**$ 0.75**	$ 0.90	$ 1.21	**$ 0.91**	$ 1.21

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

Administration expense on a per BOE basis for the nine months ended September 30, 2017 decreased 25% to $0.91 per BOE from $1.21 per BOE for the nine months ended September 30, 2016. Administration expense for the third quarter of 2017 of $0.75 per BOE decreased 38% from $1.21 per BOE for the third quarter of 2016 and decreased 17% from $0.90 per BOE for the second quarter of 2017. Administration expense per BOE decreased for the three and nine months ended September 30, 2017 from comparable periods primarily due to higher overhead recoveries and higher sales volumes.

SHARE-BASED COMPENSATION

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2017**	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Expense (Recovery)	**$ 114**	$ (104)	$ 74	**$ 37**	$ 313

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 $37 million share-based compensation expense for the nine months ended September 30, 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. For the nine months ended September 30, 2017, the Company charged $2 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (September 30, 2016 – $61 million costs charged).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts and interest rates)	**Sep 30 2017**	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Expense, gross	**$ 204**	$ 166	$ 157	**$ 526**	$ 463
Less: capitalized interest	**21**	21	67	**64**	195
Expense, net	**$ 183**	$ 145	$ 90	**$ 462**	$ 268
$/BOE (1)	**$ 1.90**	$ 1.74	$ 1.34	**$ 1.79**	$ 1.25
Average effective interest rate	**3.7%**	3.9%	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 and nine months ended September 30, 2017 increased from the comparable periods primarily due to the impact of higher average debt levels as a result of the acquisition of AOSP and other assets. Capitalized interest of $64 million for the nine months ended September 30, 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 nine months ended September 30, 2017 increased 43% to $1.79 per BOE from $1.25 per BOE for the nine months ended September 30, 2016. Net interest and other financing expense on a per BOE basis for the third quarter of 2017 increased 42% to $1.90 per BOE from $1.34 per BOE for the third quarter of 2016 and increased 9% from $1.74 per BOE for the second quarter of 2017. The increase for the three and nine months ended September 30, 2017 from the comparable periods in 2016 was primarily due to higher average debt levels as a result of the acquisition of AOSP and other assets, and lower capitalized interest related to the completion of Horizon Phase 2B.

The Company's average effective interest rate for the three and nine months ended September 30, 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.

($ millions)	Three Months Ended Sep 30 2017	Three Months Ended Jun 30 2017	Three Months Ended Sep 30 2016	Nine Months Ended Sep 30 2017	Nine Months Ended Sep 30 2016
Crude oil and NGLs financial instruments	**$ (14)**	$ (17)	$ —	**$ (32)**	$ —
Natural gas financial instruments	**(4)**	(1)	—	**(5)**	—
Foreign currency contracts	**114**	5	(23)	**108**	22
Realized loss (gain)	**96**	(13)	(23)	**71**	22
Crude oil and NGLs financial instruments	**66**	(30)	—	**(7)**	—
Natural gas financial instruments	**1**	(1)	(2)	**(8)**	(2)
Foreign currency contracts	**(59)**	25	12	**(23)**	34
Unrealized loss (gain)	**8**	(6)	10	**(38)**	32
Net loss (gain)	**$ 104**	$ (19)	$ (13)	**$ 33**	$ 54

During the nine months ended September 30, 2017, net realized risk management losses were primarily related to the settlement of foreign currency contracts, partially offset by the settlement of crude oil price collars. The Company recorded a net unrealized gain of $38 million ($35 million after-tax) on its risk management activities for the nine months ended September 30, 2017, including an unrealized loss of $8 million ($6 million gain after-tax) for the third quarter of 2017 (June 30, 2017 – unrealized gain of $6 million, $2 million loss after-tax; September 30, 2016 – unrealized loss of $10 million, $11 million after-tax).

Further details related to outstanding derivative financial instruments at September 30, 2017 are disclosed in note 15 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

($ millions)	Three Months Ended Sep 30 2017	Three Months Ended Jun 30 2017	Three Months Ended Sep 30 2016	Nine Months Ended Sep 30 2017	Nine Months Ended Sep 30 2016
Net realized loss	**$ 37**	$ 8	$ 12	**$ 49**	$ 40
Net unrealized (gain) loss	**(404)**	(355)	39	**(819)**	(255)
Net (gain) loss (1)	**$ (367)**	$ (347)	$ 51	**$ (770)**	$ (215)

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

The net realized foreign exchange loss for the nine months ended September 30, 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 nine months ended September 30, 2017 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized gain for each of the periods presented included the impact of cross currency swaps (three months ended September 30, 2017 – unrealized loss of $50 million, June 30, 2017 – unrealized loss of $208 million, September 30, 2016 – unrealized loss of $23 million; nine months ended September 30, 2017 – unrealized loss of $281 million, September 30, 2016 – unrealized loss of $362 million). The US/Canadian dollar exchange rate at September 30, 2017 was US$0.7994 (June 30, 2017 – US$0.7703, September 30, 2016 – US$0.7624).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended **Sep 30 2017**	Jun 30 2017	Sep 30 2016	Nine Months Ended **Sep 30 2017**	Sep 30 2016
North America [1]	**$ (43)**	$ (47)	$ (168)	**$ (52)**	$ (355)
North Sea	**11**	30	(43)	**47**	(74)
Offshore Africa	**14**	7	5	**28**	17
PRT recovery – North Sea	**(34)**	(72)	(77)	**(107)**	(163)
Other taxes	**2**	3	2	**8**	6
Current income tax recovery	**(50)**	(79)	(281)	**(76)**	(569)
Deferred corporate income tax expense (recovery)	**141**	110	(32)	**279**	(51)
Deferred PRT expense (recovery) – North Sea	**7**	52	50	**67**	(144)
Deferred income tax expense (recovery)	**148**	162	18	**346**	(195)
	98	83	(263)	**270**	(764)
Income tax rate and other legislative changes [2]	**—**	—	107	**—**	221
	$ 98	$ 83	$ (156)	**$ 270**	$ (543)
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**32%**	20%	27%	**24%**	30%

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

(2) 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 and nine months ended September 30, 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 and nine months ended September 30, 2017 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the Murchison and Ninian North platforms.

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

For 2017, the Company expects to recognize current income tax recoveries ranging from $50 million to $150 million in Canada and $20 million to $60 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Sep 30 2017	Jun 30 2017	Sep 30 2016	Nine Months Ended Sep 30 2017	Sep 30 2016
Exploration and Evaluation					
Net expenditures (proceeds) (2) (3) (4)	**$ 66**	$ 30	$ —	**$ 133**	$ (10)
Property, Plant and Equipment					
Net property acquisitions (2) (3) (4)	**820**	371	17	**1,200**	158
Well drilling, completion and equipping	**241**	208	186	**789**	512
Production and related facilities	**241**	194	104	**602**	319
Capitalized interest and other (5)	**22**	21	20	**64**	65
Net expenditures	**1,324**	794	327	**2,655**	1,054
Total Exploration and Production	**1,390**	824	327	**2,788**	1,044
Horizon Oil Sands Mining and Upgrading					
Horizon Phases 2/3 construction costs	**252**	182	400	**573**	1,405
Sustaining capital	**150**	77	151	**294**	303
Turnaround costs	**73**	10	103	**84**	138
Capitalized interest and other (5)	**33**	(3)	77	**50**	244
Total Horizon Oil Sands Mining and Upgrading	**508**	266	731	**1,001**	2,090
Athabasca Oil Sands Project					
Acquisitions of Exploration and Evaluation assets (2) (4)	**—**	219	—	**219**	—
Net property acquisitions (2) (4)	**—**	11,604	—	**11,604**	—
Sustaining capital	**45**	8	—	**53**	—
Turnaround costs	**2**	—	—	**2**	—
Total Athabasca Oil Sands Project	**47**	11,831	—	**11,878**	—
Total Oil Sands Mining and Upgrading	**555**	12,097	731	**12,879**	2,090
Midstream	**76**	1	2	**78**	4
Abandonments (6)	**65**	105	122	**211**	232
Head office	**8**	19	3	**30**	13
Total net capital expenditures	**$ 2,094**	$ 13,046	$ 1,185	**$ 15,986**	$ 3,383
By segment					
North America (2) (3) (4)	**$ 1,327**	$ 765	$ 259	**$ 2,612**	$ 827
North Sea	**32**	41	63	**108**	89
Offshore Africa	**31**	18	5	**68**	128
Oil Sands Mining and Upgrading (4)	**555**	12,097	731	**12,879**	2,090
Midstream	**76**	1	2	**78**	4
Abandonments (6)	**65**	105	122	**211**	232
Head office	**8**	19	3	**30**	13
Total	**$ 2,094**	$ 13,046	$ 1,185	**$ 15,986**	$ 3,383

(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) 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 nine months ended September 30, 2017 were $15,986 million compared with $3,383 million for the nine months ended September 30, 2016. Net capital expenditures for the third quarter of 2017 were $2,094 million, compared with $1,185 million for the third quarter of 2016 and $13,046 million for the second quarter of 2017.

Included in net capital expenditures for the nine months ended September 30, 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.

Drilling Activity

	Three Months Ended			Nine Months Ended	
(number of net wells)	**Sep 30 2017**	Jun 30 2017	Sep 30 2016	**Sep 30 2017**	Sep 30 2016
Net successful natural gas wells	**3**	5	—	**19**	5
Net successful crude oil wells (1)	**154**	61	85	**370**	93
Dry wells	**1**	2	4	**4**	4
Stratigraphic test / service wells	**6**	6	6	**238**	206
Total	**164**	74	95	**631**	308
Success rate (excluding stratigraphic test / service wells)	**99%**	97%	96%	**99%**	96%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 17% of the total net capital expenditures for the nine months ended September 30, 2017 compared with approximately 26% for the nine months ended September 30, 2016.

During the third quarter of 2017, the Company targeted 3 net natural gas wells in Northwest Alberta. The Company also targeted 155 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 136 primary heavy crude oil wells, 6 Pelican Lake heavy crude oil wells and 10 bitumen (thermal oil) wells were drilled. Another 3 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for the third quarter of 2017 averaged approximately 122,400 bbl/d compared with approximately 103,500 bbl/d for the third quarter of 2016 and approximately 105,700 bbl/d for the second quarter of 2017. Production volumes in the third quarter of 2017 primarily reflected strong thermal oil production following the successful turnarounds at Primrose and Kirby South plants in the second quarter of 2017 and added production volumes as a result of the acquisition of the other assets on May 31, 2017.

Pelican Lake production for the third quarter of 2017 averaged approximately 47,600 bbl/d, comparable with 47,600 bbl/d in the third quarter of 2016 and 46,900 bbl/d in the second quarter of 2017.

Horizon Oil Sands Mining and Upgrading

Horizon Phase 3 expansion work continued with field construction of the combined hydrotreater and sulphur recovery units and completion of all major tie-ins. Phase 3 expansion is on schedule and within cost, with commissioning and startup targeted in the fourth quarter of 2017.

North Sea

During the third quarter of 2017, the Company continued to progress the abandonment of the Murchison and Ninian North platforms.

Offshore Africa

During the third quarter of 2017, the Company successfully completed the 18 day turnaround at Baobab ahead of schedule.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Sep 30 2017**		Jun 30 2017		Dec 31 2016		Sep 30 2016
Working capital [1]	**$**	**205**	$	876	$	1,056	$	489
Long-term debt [2] [3]	**$**	**22,921**	$	23,276	$	16,805	$	17,292
Share capital	**$**	**8,844**	$	8,771	$	4,671	$	4,367
Retained earnings		**22,552**		22,203		21,526		21,237
Accumulated other comprehensive (loss) income		**(57)**		12		70		40
Shareholders' equity	**$**	**31,339**	$	30,986	$	26,267	$	25,644
Debt to book capitalization [3] [4]		**42%**		43%		39%		40%
Debt to market capitalization [3] [5]		**31%**		34%		26%		27%
After-tax return on average common shareholders' equity [6]		**9%**		6%		(1)%		(2)%
After-tax return on average capital employed [3] [7]		**6%**		4%		0%		(1)%

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

(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus 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 September 30, 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. In response to the current commodity price environment, the Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing the Company's borrowing capacity:
    - During 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 September 30, 2017, the $2,200 million facility was fully drawn.
    - Borrowings under the $750 million and $125 million non-revolving credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at September 30, 2017, the $750 million and $125 million facilities were each 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 September 30, 2017, the $3,000 million facility was fully drawn.
    - 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 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 condition 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 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 condition at the time of issuance.

  - 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.
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default.

As at September 30, 2017, the Company had in place bank credit facilities of $11,050 million, of which $3,636 million was available, resulting in liquidity of $3,948 million, including cash and cash equivalents. This excludes certain other dedicated credit facilities supporting letters of credit.

At September 30, 2017, the Company had total US dollar denominated debt with a carrying amount of $13,555 million (US$10,837 million), before transaction costs and original issue discounts. This included $4,047 million (US$3,237 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$2,187 million). The fixed repayment amount of these hedging instruments is $3,869 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $178 million to $13,377 million as at September 30, 2017.

Long-term debt was $22,921 million at September 30, 2017, resulting in a debt to book capitalization ratio of 42% (December 31, 2016 – 39%, September 30, 2016 – 40%); 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 September 30, 2017 are discussed in note 8 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedge policy reduces the risk of volatility in commodity prices and supports 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 September 30, 2017, 50,000 GJ/d of currently forecasted natural gas volumes were hedged using AECO swaps for October 2017 and 67,500 bbl/d of currently forecasted crude oil volumes were hedged using WTI collars for October 2017 to December 2017. Further details related to the Company's commodity derivative financial instruments at September 30, 2017 are discussed in note 15 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at September 30, 2017, there were 1,216,863,000 common shares outstanding (December 31, 2016 – 1,110,952,000 common shares) and 55,617,000 stock options outstanding. As at October 31, 2017, the Company had 1,218,140,000 common shares outstanding and 54,073,000 stock options outstanding.

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 nine months ended September 30, 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 September 30, 2017:

($ millions)	Remaining 2017	2018	2019	2020	2021	Thereafter
Product transportation and pipeline	$ 172	$ 648	$ 499	$ 476	$ 445	$ 4,065
Offshore equipment operating leases and offshore drilling	$ 54	$ 181	$ 92	$ 69	$ 68	$ 8
Long-term debt (1)	$ 625	$ 1,401	$ 4,280	$ 4,506	$ 910	$ 11,344
Interest and other financing expense (2)	$ 181	$ 815	$ 751	$ 638	$ 560	$ 5,893
Office leases	$ 12	$ 45	$ 43	$ 42	$ 40	$ 152
Other	$ 33	$ 45	$ 40	$ 39	$ 39	$ 359

(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 expense amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at September 30, 2017.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of Horizon and Kirby North. 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 and nine months ended September 30, 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 could 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.