Canadian Natural

Canadian Natural Resources Limited

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2018

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, production expenses, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands ("Horizon") operations and future expansions, the Athabasca Oil Sands Project ("AOSP"), Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the cost and timing of construction and future operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market, and the assumption of operations at processing facilities 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; 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 expenditures and production expenses); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

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

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

Management's Discussion and Analysis

This MD&A should be read in conjunction with the unaudited interim consolidated financial statements for the three and six months ended June 30, 2018 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2017.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the three and six months ended June 30, 2018 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 from operations; funds flow from operations and 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 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 from operations and funds flow from operations are reconciled to net earnings, 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 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 six months ended June 30, 2018 in relation to the comparable periods in 2017 and the first quarter of 2018. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2017, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated August 1, 2018.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Product sales	**$ 6,389**	$ 5,735	$ 4,127	**$ 12,124**	$ 8,119
Crude oil and NGLs	**$ 6,071**	$ 5,303	$ 3,645	**$ 11,374**	$ 7,104
Natural gas	**$ 318**	$ 432	$ 482	**$ 750**	$ 1,015
Net earnings	**$ 982**	$ 583	$ 1,072	**$ 1,565**	$ 1,317
Per common share – basic	**$ 0.80**	$ 0.48	$ 0.93	**$ 1.28**	$ 1.16
– diluted	**$ 0.80**	$ 0.47	$ 0.93	**$ 1.27**	$ 1.16
Adjusted net earnings from operations (1)	**$ 1,279**	$ 885	$ 332	**$ 2,164**	$ 609
Per common share – basic	**$ 1.05**	$ 0.72	$ 0.29	**$ 1.77**	$ 0.54
– diluted	**$ 1.04**	$ 0.71	$ 0.29	**$ 1.76**	$ 0.54
Funds flow from operations (2)	**$ 2,706**	$ 2,323	$ 1,726	**$ 5,029**	$ 3,365
Per common share – basic	**$ 2.20**	$ 1.90	$ 1.50	**$ 4.10**	$ 2.97
– diluted	**$ 2.19**	$ 1.89	$ 1.49	**$ 4.08**	$ 2.95
Net capital expenditures	**$ 974**	$ 1,103	$ 13,046	**$ 2,077**	$ 13,892

(1) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings as presented in the Company's consolidated Statements of Earnings, adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings from Operations" presented in this MD&A, presents the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings 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 as presented in the Company's consolidated Statements of Earnings, adjusted for certain non-cash items. 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" 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 from Operations

($ millions)	Three Months Ended Jun 30 2018	Three Months Ended Mar 31 2018	Three Months Ended Jun 30 2017	Six Months Ended Jun 30 2018	Six Months Ended Jun 30 2017
Net earnings	***$ 982***	*$ 583*	*$ 1,072*	***$ 1,565***	*$ 1,317*
Share-based compensation, net of tax (1)	***175***	*(88)*	*(104)*	***87***	*(77)*
Unrealized risk management (gain) loss, net of tax (2)	***(11)***	*(31)*	*2*	***(42)***	*(29)*
Unrealized foreign exchange loss (gain), net of tax (3)	***178***	*162*	*(355)*	***340***	*(415)*
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax (4)	**—**	*146*	—	***146***	—
Loss (gain) from investments, net of tax (5) (6)	***38***	*113*	*(27)*	***151***	*69*
Gain on acquisition, disposition and revaluation of properties, net of tax (7)	***(83)***	—	*(256)*	***(83)***	*(256)*
Adjusted net earnings from operations	***$ 1,279***	*$ 885*	*$ 332*	***$ 2,164***	*$ 609*

(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 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. The amounts ultimately realized may be materially different than those amounts reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil, natural gas and foreign exchange.

(3) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, partially offset by the impact of cross currency swaps, and are recognized in net earnings.

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

(5) The Company's investment in the 50% owned North West Redwater Partnership ("Redwater Partnership") is accounted for using the equity method of accounting. Included in the non-cash loss (gain) from investments is the Company's pro rata share of the Redwater Partnership's accounting loss (gain) for the period.

(6) The Company's investments in PrairieSky Royalty Ltd. ("PrairieSky") and Inter Pipeline Ltd. ("Inter Pipeline") have been accounted for at fair value through profit and loss and are remeasured each period with changes in fair value recognized in net earnings.

(7) During the second quarter of 2018, the Company recorded a pre-tax gain of $120 million ($72 million after-tax) on the acquisition of the remaining interest at Ninian and a pre-tax gain of $19 million ($11 million after-tax) relating to the revaluation of the Company's previously held interest at Ninian. During the second quarter of 2017, the Company recorded a pre and after-tax gain of $230 million on the acquisition of a direct and indirect 70% interest in AOSP and other assets from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), and a pre-tax gain of $35 million ($26 million after-tax) on the disposition of certain exploration and evaluation assets in the North America segment.

Funds Flow from Operations, as Reconciled to Net Earnings

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Net earnings	***$ 982***	*$ 583*	*$ 1,072*	***$ 1,565***	*$ 1,317*
Non-cash items:					
Depletion, depreciation and amortization	***1,270***	*1,257*	*1,210*	***2,527***	*2,509*
Share-based compensation	***175***	*(88)*	*(104)*	***87***	*(77)*
Asset retirement obligation accretion	***47***	*46*	*39*	***93***	*75*
Unrealized risk management gain	***(8)***	*(33)*	*(6)*	***(41)***	*(46)*
Unrealized foreign exchange loss (gain)	***178***	*162*	*(355)*	***340***	*(415)*
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax	**—**	*146*	—	***146***	—
Loss (gain) from investments	***38***	*113*	*(27)*	***151***	*69*
Deferred income tax expense	***163***	*137*	*162*	***300***	*198*
Gain on acquisition, disposition and revaluation of properties	***(139)***	—	*(265)*	***(139)***	*(265)*
Funds flow from operations	***$ 2,706***	*$ 2,323*	*$ 1,726*	***$ 5,029***	*$ 3,365*

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

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Cash flows from operating activities	***$ 2,613***	*$ 2,469*	*$ 1,631*	***$ 5,082***	*$ 3,302*
Net change in non-cash working capital	***57***	*(235)*	*(39)*	***(178)***	*(90)*
Abandonment expenditures	***50***	*90*	*105*	***140***	*146*
Other	***(14)***	*(1)*	*29*	***(15)***	*7*
Funds flow from operations	***$ 2,706***	*$ 2,323*	*$ 1,726*	***$ 5,029***	*$ 3,365*

SUMMARY OF CONSOLIDATED NET EARNINGS AND FUNDS FLOW FROM OPERATIONS

Net earnings for the six months ended June 30, 2018 were $1,565 million compared with net earnings of $1,317 million for the six months ended June 30, 2017. Net earnings for the six months ended June 30, 2018 included net after-tax expenses of $599 million compared with net after-tax income of $708 million for the six months ended June 30, 2017 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of realized foreign exchange losses on repayments of long-term debt, loss from investments, and gain on acquisition, disposition and revaluation of properties. Excluding these items, adjusted net earnings from operations for the six months ended June 30, 2018 were $2,164 million compared with adjusted net earnings of $609 million for the six months ended June 30, 2017.

Net earnings for the second quarter of 2018 were $982 million compared with net earnings of $1,072 million for the second quarter of 2017 and net earnings of $583 million for the first quarter of 2018. Net earnings for the second quarter of 2018 included net after-tax expenses of $297 million compared with net after-tax income of $740 million for the second quarter of 2017 and net after-tax expenses of $302 million for the first quarter of 2018 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of realized foreign exchange losses on repayment of long-term debt, loss (gain) from investments, and gain on acquisition, disposition and revaluation of properties. Excluding these items, adjusted net earnings from operations for the second quarter of 2018 were $1,279 million compared with adjusted net earnings of $332 million for the second quarter of 2017 and adjusted net earnings of $885 million for the first quarter of 2018.

The increase in adjusted net earnings for the three and six months ended June 30, 2018 from the three and six months ended June 30, 2017 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 3 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 in the Oil Sands Mining and Upgrading segment;
- 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 increase in adjusted net earnings for the second quarter of 2018 from the first quarter of 2018 was primarily due to:

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

partially offset by:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment, due to the planned maintenance activities at Horizon and AOSP;
- lower natural gas netbacks in the Exploration and Production segments; and
- higher depletion, depreciation and amortization.

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

Funds flow from operations for the six months ended June 30, 2018 was $5,029 million compared with $3,365 million for the six months ended June 30, 2017. Funds flow from operations for the second quarter of 2018 was $2,706 million compared with $1,726 million for the second quarter of 2017 and $2,323 million for the first quarter of 2018. 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, as well as due to the impact of fluctuations in cash taxes.

Total production before royalties for the second quarter of 2018 increased 15% to 1,050,376 BOE/d from 913,171 BOE/d for the second quarter of 2017 and decreased 7% from 1,123,546 BOE/d for the first quarter of 2018.

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)		**Jun 30 2018**		Mar 31 2018		Dec 31 2017		Sep 30 2017
Product sales [(1)]	**$**	**6,389**	$	5,735	$	5,516	$	4,725
Crude oil and NGLs	**$**	**6,071**	$	5,303	$	5,098	$	4,320
Natural gas	**$**	**318**	$	432	$	418	$	405
Net earnings (loss)	**$**	**982**	$	583	$	396	$	684
Net earnings (loss) per common share								
– basic	**$**	**0.80**	$	0.48	$	0.32	$	0.56
– diluted	**$**	**0.80**	$	0.47	$	0.32	$	0.56

($ millions, except per common share amounts)		Jun 30 2017		Mar 31 2017		Dec 31 2016		Sep 30 2016
Product sales [(1)]	$	4,127	$	3,992	$	3,672	$	2,477
Crude oil and NGLs	$	3,645	$	3,459	$	3,193	$	2,106
Natural gas	$	482	$	533	$	479	$	371
Net earnings (loss)	$	1,072	$	245	$	566	$	(326)
Net earnings (loss) per common share								
– basic	$	0.93	$	0.22	$	0.51	$	(0.29)
– diluted	$	0.93	$	0.22	$	0.51	$	(0.29)

(1) Comparative figures for product sales in 2016 are reported in accordance with the Company's presentation prior to adoption of IFRS 15 on January 1, 2018. There were no changes to reported net earnings or retained earnings as a result of adopting IFRS 15.

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

- **Crude oil pricing** – Fluctuating global supply/demand including crude oil production levels from the Organization of the Petroleum Exporting Countries ("OPEC") and its impact on world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the Western Canadian Select ("WCS") Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America and the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the North Sea and Offshore Africa.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, third party pipeline maintenance and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, fluctuations in the Company's drilling program in North America, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, new production from Horizon Phase 2B and Phase 3, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, shut-in production due to low commodity prices, and the impact of the drilling program in the International segments. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's allocation of capital to higher return crude oil projects, natural decline rates, fluctuating capacity at a third party processing facility, shut-in production due to third party pipeline restrictions and related pricing impacts, shut-in production due to low commodity prices, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production, 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 and pitstops in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, fluctuations in depletion, depreciation and amortization expense in the North Sea due to the cessation of production at the Ninian North platform in the second quarter of 2017, and the impact of turnarounds at Horizon.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses were also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense include statutory tax rate and other legislative changes substantively enacted in the various periods.
- **Gains on acquisition, disposition and revaluation of properties and gains/losses on investments** – Fluctuations due to the recognition of gains on the acquisition of AOSP and other assets, the acquisition, disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity loss (gain) in Redwater Partnership.

BUSINESS ENVIRONMENT

(Average for the period)	Three Months Ended **Jun 30 2018**	Three Months Ended Mar 31 2018	Three Months Ended Jun 30 2017	Six Months Ended **Jun 30 2018**	Six Months Ended Jun 30 2017
WTI benchmark price (US$/bbl)	**$ 67.90**	$ 62.89	$ 48.29	**$ 65.41**	$ 50.07
Dated Brent benchmark price (US$/bbl)	**$ 74.51**	$ 66.99	$ 50.24	**$ 70.77**	$ 52.14
WCS heavy differential from WTI (US$/bbl)	**$ 19.24**	$ 24.27	$ 11.11	**$ 21.74**	$ 12.84
SCO price (US$/bbl)	**$ 67.27**	$ 61.45	$ 49.83	**$ 64.38**	$ 50.63
Condensate benchmark price (US$/bbl)	**$ 68.85**	$ 63.12	$ 48.44	**$ 66.00**	$ 50.31
NYMEX benchmark price (US$/MMBtu)	**$ 2.80**	$ 2.98	$ 3.18	**$ 2.89**	$ 3.25
AECO benchmark price (C$/GJ)	**$ 0.97**	$ 1.75	$ 2.63	**$ 1.36**	$ 2.71
US/Canadian dollar average exchange rate (US$)	**$ 0.7746**	$ 0.7905	$ 0.7436	**$ 0.7824**	$ 0.7495

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

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$65.41 per bbl for the six months ended June 30, 2018, an increase of 31% from US$50.07 per bbl for the six months ended June 30, 2017. WTI averaged US$67.90 per bbl for the second quarter of 2018, an increase of 41% from US $48.29 per bbl for the second quarter of 2017, and an increase of 8% from US$62.89 per bbl for the first quarter of 2018.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$70.77 per bbl for the six months ended June 30, 2018, an increase of 36% from US$52.14 per bbl for the six months ended June 30, 2017. Brent averaged US$74.51 per bbl for the second quarter of 2018, an increase of 48% from US$50.24 per bbl for the second quarter of 2017, and an increase of 11% from US$66.99 per bbl for the first quarter of 2018.

WTI and Brent pricing for the three and six months ended June 30, 2018 has increased from the comparable periods due to declines in global crude oil inventories, together with larger than anticipated increases in global demand for crude oil.

The WCS heavy differential averaged US$21.74 per bbl for the six months ended June 30, 2018, an increase of 69% from US$12.84 per bbl for the six months ended June 30, 2017. The WCS heavy differential averaged US$19.24 per bbl for the second quarter of 2018, an increase of 73% from US$11.11 per bbl for the second quarter of 2017, and a decrease of 21% from US$24.27 per bbl for the first quarter of 2018. The widening of the WCS heavy differential for the three and six months ended June 30, 2018 from the comparable periods in 2017 reflected changes in transportation logistics and the impact of the third party pipeline outage in the fourth quarter of 2017. The narrowing of the differential for the second quarter of 2018 compared with the first quarter of 2018 reflected seasonal supply and demand factors.

The SCO price averaged US$64.38 per bbl for the six months ended June 30, 2018, an increase of 27% from US$50.63 per bbl for the six months ended June 30, 2017. The SCO price averaged US$67.27 per bbl for the second quarter of 2018, an increase of 35% from US$49.83 per bbl for the second quarter of 2017, and an increase of 9% from US$61.45 per bbl for the first quarter of 2018. The increase in SCO pricing for the three and six months ended June 30, 2018 from the comparable periods was primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.89 per MMBtu for the six months ended June 30, 2018, a decrease of 11% from US$3.25 per MMBtu for the six months ended June 30, 2017. NYMEX natural gas prices averaged US$2.80 per MMBtu for the second quarter of 2018, a decrease of 12% from US$3.18 per MMBtu for the second quarter of 2017, and a decrease of 6% from US$2.98 per MMBtu for the first quarter of 2018.

AECO natural gas prices averaged $1.36 per GJ for the six months ended June 30, 2018, a decrease of 50% from $2.71 per GJ for the six months ended June 30, 2017. AECO natural gas prices averaged $0.97 per GJ for the second quarter of 2018, a decrease of 63% from $2.63 per GJ for the second quarter of 2017, and a decrease of 45% from $1.75 per GJ for the first quarter of 2018.

The decrease in natural gas prices for the three and six months ended June 30, 2018 from the comparable periods in 2017 continued to reflect third party pipeline constraints limiting flow of natural gas to export markets as well as increased natural gas production in the basin. The decrease in natural gas prices for the second quarter of 2018 compared with the first quarter of 2018 reflected the third party pipeline constraints as well as seasonal demand factors.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**343,538**	357,460	332,802	**350,460**	346,308
North America – Oil Sands Mining and Upgrading [1]	**407,704**	456,076	257,541	**431,756**	225,196
North Sea	**24,456**	21,584	26,304	**23,028**	24,682
Offshore Africa	**18,201**	19,438	20,480	**18,816**	21,542
	793,899	854,558	637,127	**824,060**	617,728
Natural gas (MMcf/d)					
North America	**1,485**	1,547	1,603	**1,515**	1,607
North Sea	**30**	37	37	**34**	37
Offshore Africa	**24**	30	16	**27**	20
	1,539	1,614	1,656	**1,576**	1,664
Total barrels of oil equivalent (BOE/d)	**1,050,376**	1,123,546	913,171	**1,086,757**	895,139
Product mix					
Light and medium crude oil and NGLs	**13%**	12%	15%	**12%**	15%
Pelican Lake heavy crude oil	**6%**	6%	5%	**6%**	5%
Primary heavy crude oil	**8%**	8%	10%	**8%**	10%
Bitumen (thermal oil)	**10%**	10%	12%	**10%**	13%
Synthetic crude oil	**39%**	40%	28%	**40%**	26%
Natural gas	**24%**	24%	30%	**24%**	31%
Percentage of gross revenue [1] [2] (excluding Midstream revenue)					
Crude oil and NGLs	**95%**	92%	88%	**94%**	87%
Natural gas	**5%**	8%	12%	**6%**	13%

(1) Second quarter 2018 SCO production before royalties excludes 3,026 bbl/d of SCO consumed internally as diesel (first quarter 2018 – 3,224 bbl/d; second quarter 2017 – 438 bbl/d; six months ended June 30, 2018 – 3,125 bbl/d; six months ended June 30, 2017 – 433 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**293,080**	310,783	291,716	**301,883**	302,334
North America – Oil Sands Mining and Upgrading	**385,986**	443,606	251,623	**414,171**	220,575
North Sea	**24,411**	21,521	26,246	**22,974**	24,632
Offshore Africa	**16,502**	18,652	19,231	**17,571**	20,461
	719,979	794,562	588,816	**756,599**	568,002
Natural gas (MMcf/d)					
North America	**1,407**	1,473	1,528	**1,439**	1,515
North Sea	**30**	37	37	**34**	37
Offshore Africa	**20**	27	15	**23**	18
	1,457	1,537	1,580	**1,496**	1,570
Total barrels of oil equivalent (BOE/d)	**962,742**	1,050,702	852,170	**1,006,012**	829,733

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 six months ended June 30, 2018 increased 33% to 824,060 bbl/d from 617,728 bbl/d for the six months ended June 30, 2017. Crude oil and NGLs production for the second quarter of 2018 of 793,899 bbl/d increased 25% from 637,127 bbl/d for the second quarter of 2017, and decreased 7% from 854,558 bbl/d in the first quarter of 2018. The increase in crude oil and NGLs production for the three and six months ended June 30, 2018 from the comparable periods in 2017 was primarily due to acquisitions completed in 2017 and the impact of Phase 3 production at Horizon. The decrease in production for the second quarter of 2018 from the first quarter of 2018 primarily reflected planned maintenance activities at Horizon, AOSP and various thermal oil facilities, together with the impact of proactive measures taken to delay completion and ramp up of new wells in thermal and heavy oil.

Second quarter 2018 crude oil and NGLs production was within the Company's previously issued guidance of 773,000 to 821,000 bbl/d. Third quarter 2018 crude oil and NGLs production guidance is targeted to average between 771,000 and 819,000 bbl/d.

Natural gas production for the six months ended June 30, 2018 decreased 5% to 1,576 MMcf/d from 1,664 MMcf/d for the six months ended June 30, 2017. Natural gas production for the second quarter of 2018 averaged 1,539 MMcf/d, a decrease of 7% from 1,656 MMcf/d for the second quarter of 2017, and a decrease of 5% from 1,614 MMcf/d for the first quarter of 2018. As a result of low natural gas prices, the Company shut in 27 MMcf/d of production in the second quarter of 2018. Natural gas production continued to reflect processing constraints at a third party facility, where the Company averaged less than 80 MMcf/d for the second quarter of 2018. Subject to regulatory approval, the Company targets to take over operations at the facility in the latter half of 2018 and is evaluating the reinstatement of the facility's processing capacity.

Second quarter 2018 natural gas production was within the Company's previously issued guidance of 1,515 to 1,565 MMcf/d. Third quarter 2018 natural gas production guidance is targeted to average between 1,535 and 1,565 MMcf/d. Annual 2018 natural gas production guidance is now targeted to average between 1,550 and 1,600 MMcf/d.

North America - Exploration and Production

North America crude oil and NGLs production for the six months ended June 30, 2018 averaged 350,460 bbl/d, comparable with 346,308 bbl/d for the six months ended June 30, 2017. North America crude oil and NGLs production for the second quarter of 2018 increased 3% to 343,538 bbl/d from 332,802 bbl/d for the second quarter of 2017, and decreased 4% from 357,460 bbl/d for the first quarter of 2018. The increase in crude oil and NGLs production for the second quarter of 2018 from the second quarter of 2017 was due to acquisitions completed in 2017. The decrease in production for the second quarter of 2018 from the first quarter of 2018 primarily reflected the curtailment of 7,450 bbl/d during the second quarter as a result of widening differentials as well as planned maintenance activities at various thermal oil facilities, together with the impact of proactive measures taken to delay completion and ramp up of new wells in thermal and heavy oil.

Operating performance at the Pelican Lake tertiary recovery project continued to be strong following the acquisition completed in 2017, leading to production of 63,914 bbl/d in the second quarter of 2018 compared with 46,932 bbl/d in the second quarter of 2017 and 63,274 bbl/d in the first quarter of 2018.

Overall thermal oil production for the second quarter of 2018 averaged 104,907 bbl/d compared with 105,719 bbl/d for the second quarter of 2017 and 111,851 bbl/d for the first quarter of 2018. Second quarter 2018 thermal oil production was within the Company's previously issued guidance of 103,000 to 109,000 bbl/d. Third quarter 2018 thermal oil production guidance is targeted to average between 106,000 and 112,000 bbl/d.

Second quarter 2018 crude oil and NGLs production, including thermal oil, was within the Company's previously issued guidance of 339,000 to 353,000 bbl/d. Third quarter 2018 crude oil and NGLs production guidance, including thermal oil, is targeted to average between 354,000 and 368,000 bbl/d.

Natural gas production for the six months ended June 30, 2018 decreased 6% to 1,515 MMcf/d from 1,607 MMcf/d for the six months ended June 30, 2017. Natural gas production for the second quarter of 2018 averaged 1,485 MMcf/d, a decrease of 7% from 1,603 MMcf/d for the second quarter of 2017, and a decrease of 4% from 1,547 MMcf/d in the first quarter of 2018. As a result of low natural gas prices, the Company shut in 27 MMcf/d of production in the second quarter of 2018. Natural gas production continued to reflect processing constraints at a third party facility, where the Company averaged less than 80 MMcf/d for the second quarter of 2018.

North America – Oil Sands Mining and Upgrading

SCO production for the six months ended June 30, 2018 of 431,756 bbl/d increased 92% from 225,196 bbl/d for the six months ended June 30, 2017. SCO production for the second quarter of 2018 increased 58% to average 407,704 bbl/d from 257,541 bbl/d for the second quarter of 2017 and decreased 11% from 456,076 bbl/d for the first quarter of 2018. The increase in production for the three and six months ended June 30, 2018 from the comparable periods in 2017 primarily reflected production from the acquisition of AOSP and the impact of Phase 3 production at Horizon. As expected, production decreased for the second quarter of 2018 from the first quarter of 2018, primarily reflecting planned maintenance activities at Horizon and AOSP.

Second quarter 2018 SCO production was within the Company's previously issued guidance of 393,000 to 423,000 bbl/d. Third quarter 2018 SCO production guidance is targeted to average between 374,000 and 404,000 bbl/d, reflecting the impact of a planned turnaround at Horizon.

North Sea

North Sea crude oil production for the six months ended June 30, 2018 decreased 7% to 23,028 bbl/d from 24,682 bbl/d for the six months ended June 30, 2017. North Sea crude oil production for the second quarter of 2018 decreased 7% to 24,456 bbl/d from 26,304 bbl/d for the second quarter of 2017 and increased 13% from 21,584 bbl/d in the first quarter of 2018. The decrease in production for the three and six months ended June 30, 2018 from the comparable periods in 2017 primarily reflected the impact of the shut-in of the Ninian North platform in May 2017 and natural field declines, partially offset by new wells at Tiffany and Ninian. The increase in production for the second quarter of 2018 from the first quarter of 2018 was primarily due to new wells at Tiffany and Ninian.

Offshore Africa

Offshore Africa crude oil production for the six months ended June 30, 2018 decreased 13% to 18,816 bbl/d from 21,542 bbl/d for the six months ended June 30, 2017. Offshore Africa crude oil production for the second quarter of 2018 decreased 11% to 18,201 bbl/d from 20,480 bbl/d for the second quarter of 2017 and decreased 6% from 19,438 bbl/d in the first quarter of 2018. The decrease in production for the three and six months ended June 30, 2018 from the comparable periods primarily reflected planned maintenance activities completed during the second quarter of 2018, as well as natural field declines.

International Guidance

Second quarter 2018 International crude oil production of 42,657 bbl/d was within the Company's previously issued guidance of 41,000 to 45,000 bbl/d. Third quarter 2018 International crude oil production guidance is targeted to average between 43,000 and 47,000 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)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017
North Sea	**297,217**	506,589	528,705
Offshore Africa	**1,466,074**	1,141,282	1,510,446
	1,763,291	1,647,871	2,039,151

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 61.14**	$ 43.06	$ 47.12	**$ 52.32**	$ 47.08
Transportation	**3.30**	3.10	3.06	**3.20**	2.78
Realized sales price, net of transportation	**57.84**	39.96	44.06	**49.12**	44.30
Royalties	**7.56**	4.87	4.83	**6.25**	4.86
Production expense	**15.64**	15.70	15.51	**15.67**	14.92
Netback	**$ 34.64**	$ 19.39	$ 23.72	**$ 27.20**	$ 24.52
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 1.95**	$ 2.74	$ 2.97	**$ 2.35**	$ 3.11
Transportation	**0.51**	0.51	0.34	**0.50**	0.39
Realized sales price, net of transportation	**1.44**	2.23	2.63	**1.85**	2.72
Royalties	**0.08**	0.10	0.12	**0.09**	0.15
Production expense	**1.39**	1.41	1.25	**1.40**	1.26
Netback (3)	**$ (0.03)**	$ 0.72	$ 1.26	**$ 0.36**	$ 1.31
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 41.63**	$ 32.02	$ 33.94	**$ 36.86**	$ 34.99
Transportation	**3.20**	3.05	2.67	**3.13**	2.62
Realized sales price, net of transportation	**38.43**	28.97	31.27	**33.73**	32.37
Royalties	**4.75**	3.10	3.09	**3.93**	3.24
Production expense	**12.75**	12.68	12.11	**12.71**	11.89
Netback	**$ 20.93**	$ 13.19	$ 16.07	**$ 17.09**	$ 17.24

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

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

(3) Natural gas netbacks exclude netbacks derived from the sale of NGLs. Combining natural gas and NGLs, the netback for the three months ended June 30, 2018 was $0.60/Mcfe (three months ended March 31, 2018 - $1.19/Mcfe, three months ended June 30, 2017 - $1.49/Mcfe).

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 56.95**	$ 40.66	$ 44.78	**$ 48.82**	$ 44.47
North Sea	**$ 93.49**	$ 79.35	$ 64.37	**$ 88.36**	$ 67.49
Offshore Africa	**$ 102.57**	$ 78.85	$ 69.93	**$ 94.17**	$ 65.25
Company average	**$ 61.14**	$ 43.06	$ 47.12	**$ 52.32**	$ 47.08
Natural gas ($/Mcf) (1) (2)					
North America	**$ 1.69**	$ 2.44	$ 2.84	**$ 2.07**	$ 2.96
North Sea	**$ 10.32**	$ 11.67	$ 6.89	**$ 11.06**	$ 7.78
Offshore Africa	**$ 7.37**	$ 6.95	$ 6.84	**$ 7.14**	$ 6.49
Company average	**$ 1.95**	$ 2.74	$ 2.97	**$ 2.35**	$ 3.11
Company average ($/BOE) (1) (2)	**$ 41.63**	$ 32.02	$ 33.94	**$ 36.86**	$ 34.99

(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 10% to $48.82 per bbl for the six months ended June 30, 2018 from $44.47 per bbl for the six months ended June 30, 2017. North America realized crude oil prices averaged $56.95 per bbl for the second quarter of 2018, an increase of 27% compared with $44.78 per bbl for the second quarter of 2017, and an increase of 40% compared with $40.66 per bbl for the first quarter of 2018. The increase in realized crude oil prices for the three and six months ended June 30, 2018 from the comparable periods was primarily due to higher WTI benchmark pricing, partially offset by the widening of the WCS heavy differential. The Company continues to focus on its crude oil blending marketing strategy and in the second quarter of 2018 contributed approximately 183,100 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 30% to average $2.07 per Mcf for the six months ended June 30, 2018 from $2.96 per Mcf for the six months ended June 30, 2017. North America realized natural gas prices decreased 40% to average $1.69 per Mcf for the second quarter of 2018 compared with $2.84 per Mcf for the second quarter of 2017, and decreased 31% compared with $2.44 per Mcf for the first quarter of 2018. The decrease in realized natural gas prices for the three and six months ended June 30, 2018 from the comparable periods primarily reflected third party pipeline constraints limiting flow of natural gas to export markets.

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

(Quarterly Average)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 62.06**	$ 53.48	$ 46.44
Pelican Lake heavy crude oil ($/bbl)	**$ 60.49**	$ 41.63	$ 47.64
Primary heavy crude oil ($/bbl)	**$ 56.33**	$ 36.85	$ 45.92
Bitumen (thermal oil) ($/bbl)	**$ 51.04**	$ 32.22	$ 41.15
Natural gas ($/Mcf)	**$ 1.69**	$ 2.44	$ 2.84

(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 31% to average $88.36 per bbl for the six months ended June 30, 2018 from $67.49 per bbl for the six months ended June 30, 2017. North Sea realized crude oil prices increased 45% to average $93.49 per bbl for the second quarter of 2018 from $64.37 per bbl for the second quarter of 2017 and increased 18% from $79.35 per bbl for the first quarter of 2018. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three and six months ended June 30, 2018 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 44% to average $94.17 per bbl for the six months ended June 30, 2018 from $65.25 per bbl for the six months ended June 30, 2017. Offshore Africa realized crude oil prices increased 47% to average $102.57 per bbl for the second quarter of 2018 from $69.93 per bbl for the second quarter of 2017 and increased 30% from $78.85 per bbl for the first quarter of 2018. 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 six months ended June 30, 2018 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 8.03**	$ 5.11	$ 5.19	**$ 6.57**	$ 5.32
North Sea	**$ 0.17**	$ 0.23	$ 0.14	**$ 0.19**	$ 0.13
Offshore Africa	**$ 9.58**	$ 3.19	$ 4.26	**$ 7.32**	$ 3.23
Company average	**$ 7.56**	$ 4.87	$ 4.83	**$ 6.25**	$ 4.86
Natural gas ($/Mcf) [(1)]					
North America	**$ 0.06**	$ 0.09	$ 0.12	**$ 0.08**	$ 0.15
Offshore Africa	**$ 1.17**	$ 0.87	$ 0.51	**$ 1.00**	$ 0.58
Company average	**$ 0.08**	$ 0.10	$ 0.12	**$ 0.09**	$ 0.15
Company average ($/BOE) [(1)]	**$ 4.75**	$ 3.10	$ 3.09	**$ 3.93**	$ 3.24

(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 six months ended June 30, 2018 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS heavy differential.

Crude oil and NGLs royalties averaged approximately 14% of product sales for the six months ended June 30, 2018 compared with 13% of product sales for the six months ended June 30, 2017. Crude oil and NGLs royalties averaged approximately 15% of product sales for the second quarter of 2018 compared with 13% for the second quarter of 2017 and 14% for the first quarter of 2018. The increase in royalties for the three and six months ended June 30, 2018 from the comparable periods was primarily due to higher realized crude oil prices. North America crude oil and NGLs royalties per bbl are anticipated to average 12.5% to 14.5% of product sales for 2018.

Natural gas royalties averaged approximately 5% of product sales for the six months ended June 30, 2018 compared with 6% of product sales for the six months ended June 30, 2017. Natural gas royalties averaged approximately 5% of product sales for the second quarter of 2018 compared with 5% for the second quarter of 2017 and 5% for the first quarter of 2018. The decrease in natural gas royalties for the six months ended June 30, 2018 from the six months ended June 30, 2017 primarily reflected lower realized natural gas prices. North America natural gas royalties are anticipated to average 4% to 6% of product sales for 2018.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 9% for the six months ended June 30, 2018, compared with 5% of product sales for the six months ended June 30, 2017. Royalty rates as a percentage of product sales averaged approximately 10% for the second quarter of 2018, reflecting a lifting at Espoir, compared with 6% of product sales for the second quarter of 2017 and 6% for the first quarter of 2018. Royalties as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields. Offshore Africa royalty rates are anticipated to average 7% to 9% of product sales for 2018.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 13.78**	$ 14.15	$ 13.74	**$ 13.96**	$ 12.96
North Sea	**$ 35.12**	$ 43.39	$ 28.86	**$ 38.12**	$ 33.28
Offshore Africa	**$ 24.78**	$ 30.99	$ 32.39	**$ 26.98**	$ 24.27
Company average	**$ 15.64**	$ 15.70	$ 15.51	**$ 15.67**	$ 14.92
Natural gas ($/Mcf) (1)					
North America	**$ 1.28**	$ 1.31	$ 1.17	**$ 1.29**	$ 1.19
North Sea	**$ 5.81**	$ 4.67	$ 3.40	**$ 5.18**	$ 3.23
Offshore Africa	**$ 3.00**	$ 2.44	$ 3.88	**$ 2.69**	$ 3.66
Company average	**$ 1.39**	$ 1.41	$ 1.25	**$ 1.40**	$ 1.26
Company average ($/BOE) (1)	**$ 12.75**	$ 12.68	$ 12.11	**$ 12.71**	$ 11.89

(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 six months ended June 30, 2018 increased 8% to $13.96 per bbl from $12.96 per bbl for the six months ended June 30, 2017. North America crude oil and NGLs production expense for the second quarter of 2018 of $13.78 per bbl was comparable with $13.74 per bbl in the second quarter of 2017 and decreased 3% from $14.15 per bbl for the first quarter of 2018, reflecting the Company's focus on cost control and achieving efficiencies on acquired assets and across the entire asset base. The increase in crude oil and NGLs production expense per barrel for the six months ended June 30, 2018 from the six months ended June 30, 2017 primarily reflected increased energy and carbon tax costs along with the impact of proactive measures taken to delay completion and ramp up of new wells in thermal and heavy oil, resulting in lower production volumes in these areas relative to mainly fixed expenses. The decrease per barrel for the second quarter of 2018 from the first quarter of 2018 reflected lower fuel and other service costs in the Company's thermal areas notwithstanding lower volumes on a relatively fixed cost base and increased carbon tax costs. North America crude oil and NGLs production expense is anticipated to average $11.50 to $13.50 per bbl for 2018.

North America natural gas production expense for the six months ended June 30, 2018 averaged $1.29 per Mcf, an increase of 8% from $1.19 per Mcf for the six months ended June 30, 2017. North America natural gas production expense for the second quarter of 2018 increased 9% to $1.28 per Mcf from $1.17 per Mcf for the second quarter of 2017 and decreased 2% from $1.31 per Mcf for the first quarter of 2018. The increase in natural gas production expense for the three and six months ended June 30, 2018 from the comparable periods in 2017 reflected the impact of lower volumes on a relatively fixed cost base as a result of proactive measures taken to shut in natural gas production due to low natural gas pricing and address processing reliability issues. The Company continues to focus on cost control and achieving efficiencies on acquired assets and across the entire asset base. North America natural gas production expense is now anticipated to average $1.20 to $1.28 per Mcf for 2018.

North Sea

North Sea crude oil production expense for the six months ended June 30, 2018 increased 15% to $38.12 per bbl from $33.28 per bbl for the six months ended June 30, 2017. North Sea crude oil production expense for the second quarter of 2018 increased 22% to $35.12 per bbl from $28.86 per bbl for the second quarter of 2017 and decreased 19% from $43.39 per bbl in the first quarter of 2018. The increase in crude oil production expense for the three and six months ended June 30, 2018 from the comparable periods in 2017 primarily reflected recoveries realized in the second quarter of 2017, as well as the impact of lower volumes on a relatively fixed cost base. The decrease in production expense for the second quarter of 2018 from the first quarter of 2018 primarily reflected the impact of higher volumes on a relatively fixed cost base and the timing of liftings from various fields that have different cost structures, partially offset by higher fuel costs. Production expense is also impacted by fluctuations in the Canadian dollar. North Sea crude oil production expense is anticipated to average $36.00 to $39.00 per bbl for 2018.

Offshore Africa

Crude oil production expense for the Baobab and Espoir fields in Côte d'Ivoire for the six months ended June 30, 2018 was $14.17 per bbl, while total crude oil production expense for the Offshore Africa segment, including the Olowi field in Gabon, was $26.98 per bbl. Production expense for the second quarter of 2018 relating to Côte d'Ivoire was $16.39 per bbl, while total crude oil production expense for the Offshore Africa segment, including the Olowi field in Gabon, was $24.78 per bbl. Total Offshore Africa crude oil production expense for the three and six months ended June 30, 2018 primarily reflected the timing of liftings from various fields, including the Olowi field, that have different cost structures, fluctuating production volumes on a relatively fixed cost base, planned maintenance activities, and fluctuations in the Canadian dollar. On a standalone basis, Offshore Africa production expense related to Côte d'Ivoire is anticipated to average $11.00 to $13.00 per bbl for 2018.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Expense	**$ 894**	$ 850	$ 971	**$ 1,744**	$ 2,073
$/BOE [(1)]	**$ 15.20**	$ 14.66	$ 16.38	**$ 14.93**	$ 17.05

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

Depletion, depreciation and amortization per BOE for the six months ended June 30, 2018 decreased 12% to $14.93 per BOE from $17.05 per BOE for the six months ended June 30, 2017. Depletion, depreciation and amortization expense per BOE for the second quarter of 2018 decreased 7% to $15.20 per BOE from $16.38 per BOE for the second quarter of 2017 and increased 4% from $14.66 per BOE for the first quarter of 2018.

The decrease in depletion, depreciation and amortization expense per BOE for the three and six months ended June 30, 2018 from the comparable periods in 2017 was primarily due to additional depletion, depreciation and amortization expense in 2017 related to the abandonment of the Ninian North platform in the North Sea. The increase for the second quarter of 2018 from the first quarter of 2018 reflected increased sales volumes in the International segments, which have higher associated depletion rates.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Expense	**$ 32**	$ 31	$ 29	**$ 63**	$ 57
$/BOE [(1)]	**$ 0.53**	$ 0.53	$ 0.48	**$ 0.53**	$ 0.47

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

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

Asset retirement obligation accretion expense for the six months ended June 30, 2018 increased 13% to $0.53 per BOE from $0.47 per BOE for the six months ended June 30, 2017. Asset retirement obligation accretion expense for the second quarter of 2018 increased 10% to $0.53 per BOE from $0.48 per BOE for the second quarter of 2017, and was comparable with $0.53 per BOE for the first quarter of 2018.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on reliable and efficient operations. The Oil Sands Mining and Upgrading segment achieved production averaging 407,704 bbl/d during the second quarter of 2018, reflecting planned maintenance activities and pitstops during the quarter. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability of operations, cash production costs averaged $22.94 per bbl during the quarter.

Oil Sands operations continued to be strong following the planned maintenance activities at Horizon and AOSP during the second quarter of 2018. Turnaround activities planned for the third quarter of 2018 at Horizon have been reflected in third quarter guidance.

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

	Three Months Ended			Six Months Ended	
($/bbl) [(1)]	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
SCO realized sales price [(2)]	**$ 80.17**	$ 71.61	$ 63.39	**$ 75.70**	$ 65.25
Bitumen value for royalty purposes [(3)]	**$ 49.10**	$ 31.48	$ 39.99	**$ 39.94**	$ 38.37
Bitumen royalties [(4)]	**$ 4.25**	$ 1.98	$ 1.38	**$ 3.06**	$ 1.28
Transportation	**$ 1.63**	$ 1.54	$ 1.32	**$ 1.59**	$ 1.26

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

(2) Net of blending and feedstock costs.

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

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

The realized SCO sales price for the Oil Sands Mining and Upgrading segment averaged $75.70 per bbl for the six months ended June 30, 2018, an increase of 16% from $65.25 per bbl for the six months ended June 30, 2017. For the second quarter of 2018, the realized sales price increased 26% to $80.17 per bbl from $63.39 per bbl for the second quarter of 2017 and increased 12% from $71.61 per bbl for the first quarter of 2018. The increase in realized sales prices for the three and six months ended June 30, 2018 from the comparable periods primarily reflected WTI benchmark pricing.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Cash production costs, excluding natural gas costs	**$ 834**	$ 835	$ 515	**$ 1,669**	$ 854
Natural gas costs	**21**	38	38	**59**	71
Cash production costs	**$ 855**	$ 873	$ 553	**$ 1,728**	$ 925

	Three Months Ended			Six Months Ended	
($/bbl) [1]	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Cash production costs, excluding natural gas costs	**$ 22.37**	$ 20.45	$ 21.85	**$ 21.36**	$ 21.12
Natural gas costs	**0.57**	0.92	1.59	**0.76**	1.75
Cash production costs	**$ 22.94**	$ 21.37	$ 23.44	**$ 22.12**	$ 22.87
Sales (bbl/d)	**409,603**	453,850	259,033	**431,604**	223,353

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

Cash production costs for the six months ended June 30, 2018 decreased 3% to $22.12 per bbl from $22.87 per bbl for the six months ended June 30, 2017. Cash production costs for the second quarter of 2018 averaged $22.94 per bbl, a decrease of 2% from $23.44 per bbl for the second quarter of 2017 and an increase of 7% from $21.37 per bbl for the first quarter of 2018. The decrease in cash production costs per barrel for the three and six months ended June 30, 2018 from the comparable periods in 2017 primarily reflected the Company's continuous focus on cost control and efficiencies and high utilization rates and reliability, as well as additional capacity from Phase 3 production at Horizon and the acquisition of AOSP. The increase for the second quarter of 2018 from the first quarter of 2018 primarily reflected lower production volumes due to planned maintenance activities at Horizon and AOSP.

For 2018, Oil Sands Mining and Upgrading cash production costs, including turnaround costs, are anticipated to average $20.50 to $24.50 per bbl.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Six Months Ended	
($ millions, except per bbl amounts)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Expense	**$ 372**	$ 404	$ 237	**$ 776**	$ 432
$/bbl [1]	**$ 9.99**	$ 9.88	$ 10.05	**$ 9.93**	$ 10.69

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

Depletion, depreciation and amortization expense per barrel for the Oil Sands Mining and Upgrading segment for the six months ended June 30, 2018 decreased 7% to $9.93 per bbl from $10.69 per bbl for the six months ended June 30, 2017. Depletion, depreciation and amortization expense per barrel for the second quarter of 2018 of $9.99 per bbl was comparable with $10.05 per bbl for the second quarter of 2017 and $9.88 per bbl for the first quarter of 2018.

The decrease in depletion, depreciation and amortization expense per barrel for the six months ended June 30, 2018 from the six months ended June 30, 2017 was 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			Six Months Ended	
($ millions, except per bbl amounts)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Expense	**$ 15**	$ 15	$ 10	**$ 30**	$ 18
$/bbl (1)	**$ 0.41**	$ 0.38	$ 0.42	**$ 0.39**	$ 0.44

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

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

Asset retirement obligation accretion expense per bbl for the six months ended June 30, 2018 decreased 11% to $0.39 per bbl from $0.44 per bbl for the six months ended June 30, 2017 due to higher sales volumes. Asset retirement obligation accretion expense of $0.41 per bbl for the second quarter of 2018 decreased 2% from $0.42 per bbl for the second quarter of 2017 and increased 8% from $0.38 per bbl for the first quarter of 2018, primarily due to lower sales volumes in the second quarter of 2018 compared to the first quarter of 2018.

MIDSTREAM

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Revenue	**$ 25**	$ 27	$ 23	**$ 52**	$ 48
Production expense	**6**	5	4	**11**	8
Midstream cash flow	**19**	22	19	**41**	40
Depreciation	**4**	3	2	**7**	4
Equity loss (gain) on investment	**2**	1	(10)	**3**	(12)
Segment earnings before taxes	**$ 13**	$ 18	$ 27	**$ 31**	$ 48

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

The facility capital cost ("FCC") budget for the Project is currently estimated to be $9,700 million with project completion targeted for the fourth quarter of 2018. Productivity challenges during construction have continued to result in upward budgetary pressures. During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. To June 30, 2018, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $124 million, for a Company total of $563 million. Any additional subordinated debt financing is not expected to be significant.

As per the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, which currently consists of interest and fees, with principal repayments beginning in 2020. The Company is unconditionally obligated to pay the service toll of the syndicated credit facility and bonds over the tolling period of 30 years.

As at June 30, 2018, Redwater Partnership had additional borrowings of $2,366 million under its secured $3,500 million syndicated credit facility. During the first quarter of 2018, Redwater Partnership extended $2,000 million of the $3,500 million revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended Jun 30 2018	Mar 31 2018	Jun 30 2017	Six Months Ended Jun 30 2018	Jun 30 2017
Expense	**$ 76**	$ 81	$ 75	**$ 157**	$ 162
$/BOE (1)	**$ 0.79**	$ 0.82	$ 0.90	**$ 0.81**	$ 1.00

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

Administration expense per BOE for the six months ended June 30, 2018 decreased 19% to $0.81 per BOE from $1.00 per BOE for the six months ended June 30, 2017. Administration expense for the second quarter of 2018 of $0.79 per BOE decreased 12% from $0.90 per BOE for the second quarter of 2017 and decreased 4% from $0.82 per BOE for the first quarter of 2018. Administration expense per BOE decreased for the three and six months ended June 30, 2018 from the comparable periods in 2017 primarily due to higher sales volumes. The decrease in the second quarter of 2018 from the first quarter of 2018 was primarily due to higher overhead recoveries.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Jun 30 2018	Mar 31 2018	Jun 30 2017	Six Months Ended Jun 30 2018	Jun 30 2017
Expense (recovery)	**$ 175**	$ (88)	$ (104)	**$ 87**	$ (77)

The Company's Stock Option Plan provides current employees with the right to receive common shares or a cash payment in exchange for stock options surrendered.

The Company recorded an $87 million share-based compensation expense for the six months ended June 30, 2018, primarily as a result of remeasurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period and changes in the Company's share price. Included within share-based compensation expense for the six months ended June 30, 2018 was $6 million related to performance share units granted to certain executive employees (June 30, 2017 – $1 million). For the six months ended June 30, 2018, the Company charged $9 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (June 30, 2017 – $18 million costs recovered).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended Jun 30 2018	Mar 31 2018	Jun 30 2017	Six Months Ended Jun 30 2018	Jun 30 2017
Expense, gross	**$ 207**	$ 205	$ 166	**$ 412**	$ 322
Less: capitalized interest	**17**	15	21	**32**	43
Expense, net	**$ 190**	$ 190	$ 145	**$ 380**	$ 279
$/BOE (1)	**$ 1.99**	$ 1.92	$ 1.74	**$ 1.95**	$ 1.72
Average effective interest rate	**3.9%**	3.8%	3.9%	**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 six months ended June 30, 2018 increased from the comparable periods in 2017 primarily due to the impact of higher average debt levels as a result of acquisitions completed in 2017. Capitalized interest of $32 million for the six months ended June 30, 2018 was primarily related to Kirby North and residual project activities at Horizon.

Net interest and other financing expense per BOE for the six months ended June 30, 2018 increased 13% to $1.95 per BOE from $1.72 per BOE for the six months ended June 30, 2017. Net interest and other financing expense per BOE for the second quarter of 2018 increased 14% to $1.99 per BOE from $1.74 per BOE for the second quarter of 2017 and increased 4% from $1.92 per BOE for the first quarter of 2018. The increase for the three and six months ended June 30, 2018 from the comparable periods was primarily due to higher average debt levels as a result of acquisitions completed in 2017 and lower capitalized interest related to the completion of Horizon Phase 3. The increase for the second quarter of 2018 from the first quarter of 2018 was primarily due to lower sales volumes.

The Company's average effective interest rate for the three and six months ended June 30, 2018 was consistent with the comparable periods.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil and NGLs financial instruments	**$ —**	$ —	$ (17)	**$ —**	$ (18)
Natural gas financial instruments	**(3)**	—	(1)	**(3)**	(1)
Foreign currency contracts	**(24)**	(19)	5	**(43)**	(6)
Realized gain	**(27)**	(19)	(13)	**(46)**	(25)
Crude oil and NGLs financial instruments	**—**	—	(30)	**—**	(73)
Natural gas financial instruments	**16**	—	(1)	**16**	(9)
Foreign currency contracts	**(24)**	(33)	25	**(57)**	36
Unrealized gain	**(8)**	(33)	(6)	**(41)**	(46)
Net gain	**$ (35)**	$ (52)	$ (19)	**$ (87)**	$ (71)

During the six months ended June 30, 2018, net realized risk management gains were primarily related to the settlement of foreign currency contracts and natural gas AECO swaps. The Company recorded a net unrealized gain of $41 million ($42 million after-tax) on its risk management activities for the six months ended June 30, 2018, including an unrealized gain of $8 million ($11 million after-tax) for the second quarter of 2018 (March 31, 2018 – unrealized gain of $33 million, $31 million after-tax; June 30, 2017 – unrealized gain of $6 million, $2 million loss after-tax).

Further details related to outstanding derivative financial instruments at June 30, 2018 are disclosed in note 16 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Net realized (gain) loss	**$ (7)**	$ 116	$ 8	**$ 109**	$ 12
Net unrealized loss (gain)	**178**	162	(355)	**340**	(415)
Net loss (gain) (1)	**$ 171**	$ 278	$ (347)	**$ 449**	$ (403)

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

The net realized foreign exchange loss for the six months ended June 30, 2018 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes. The net unrealized foreign exchange loss for the six months ended June 30, 2018 was primarily related to the impact of the weakening Canadian dollar with respect to outstanding US dollar debt, partially offset by the reversal of the net unrealized foreign exchange loss on the repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (three months ended June 30, 2018 – unrealized gain of $25 million, March 31, 2018 – unrealized gain of $40 million, June 30, 2017 – unrealized loss of $208 million; six months ended June 30, 2018 – unrealized gain of $65 million, June 30, 2017 – unrealized loss of $231 million). The US/Canadian dollar exchange rate at June 30, 2018 was US$0.7609 (March 31, 2018 – US$0.7751, June 30, 2017 – US $0.7703).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
North America [1]	**$ 247**	$ 150	$ (47)	**$ 397**	$ (9)
North Sea	**7**	1	30	**8**	36
Offshore Africa	**16**	5	7	**21**	14
PRT recovery – North Sea	**(16)**	(4)	(72)	**(20)**	(73)
Other taxes	**3**	2	3	**5**	6
Current income tax expense (recovery)	**257**	154	(79)	**411**	(26)
Deferred corporate income tax expense	**156**	127	110	**283**	138
Deferred PRT expense – North Sea	**7**	10	52	**17**	60
Deferred income tax expense	**163**	137	162	**300**	198
	$ 420	$ 291	$ 83	**$ 711**	$ 172
Effective income tax rate on adjusted net earnings from operations [2]	**23%**	24%	20%	**23%**	20%

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

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

The effective income tax rate for the three and six months ended June 30, 2018 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings.

The current PRT recovery in the North Sea for the three and six months ended June 30, 2018 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the Murchison and Ninian North platforms.

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

For 2018, the Company expects to recognize current income tax expenses ranging from $600 million to $700 million in Canada and $nil to $30 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Jun 30 2018	Three Months Ended Mar 31 2018	Three Months Ended Jun 30 2017	Six Months Ended Jun 30 2018	Six Months Ended Jun 30 2017
Exploration and Evaluation					
Net expenditures [2] [3] [4]	**$ 8**	$ 56	$ 30	**$ 64**	$ 67
Property, Plant and Equipment					
Net property acquisitions [2] [3] [4]	**(70)**	162	371	**92**	380
Well drilling, completion and equipping	**350**	321	208	**671**	548
Production and related facilities	**308**	264	194	**572**	361
Capitalized interest and other [5]	**25**	23	21	**48**	42
Net expenditures	**613**	770	794	**1,383**	1,331
Total Exploration and Production	**621**	826	824	**1,447**	1,398
Oil Sands Mining and Upgrading					
Project costs [6]	**63**	66	182	**129**	321
Sustaining capital	**152**	105	85	**257**	152
Turnaround costs	**46**	13	10	**59**	11
Acquisitions of Exploration and Evaluation assets [2] [4]	**—**	—	219	**—**	219
Net property acquisitions [2] [4]	**—**	—	11,604	**—**	11,604
Capitalized interest and other [5]	**30**	(5)	(3)	**25**	17
Total Oil Sands Mining and Upgrading	**291**	179	12,097	**470**	12,324
Midstream	**5**	4	1	**9**	2
Abandonments [7]	**50**	90	105	**140**	146
Head office	**7**	4	19	**11**	22
Total net capital expenditures	**$ 974**	$ 1,103	$ 13,046	**$ 2,077**	$ 13,892
By segment					
North America [2] [3] [4]	**$ 568**	$ 772	$ 765	**$ 1,340**	$ 1,285
North Sea [3]	**3**	35	41	**38**	76
Offshore Africa	**50**	19	18	**69**	37
Oil Sands Mining and Upgrading [4]	**291**	179	12,097	**470**	12,324
Midstream	**5**	4	1	**9**	2
Abandonments [7]	**50**	90	105	**140**	146
Head office	**7**	4	19	**11**	22
Total	**$ 974**	$ 1,103	$ 13,046	**$ 2,077**	$ 13,892

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

(2) Includes business combinations.

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

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

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

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

(7) 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 six months ended June 30, 2018 were $2,077 million compared with $13,892 million for the six months ended June 30, 2017. Net capital expenditures for the second quarter of 2018 were $974 million, compared with $13,046 million for the second quarter of 2017 and $1,103 million for the first quarter of 2018. Net capital expenditures for the three and six months ended June 30, 2018 included the acquisition of the remaining interest at the Ninian field in the North Sea for net proceeds received of $73 million. The Company recognized a pre-tax gain of $120 million ($72 million after-tax) on the acquisition and a pre-tax revaluation gain of $19 million ($11 million after-tax) relating to its previously held interest.

Oil Sands Mining and Upgrading

At Horizon, the Phase 2/3 expansion program is essentially complete with residual scope remaining related to Mature Fine Tailings and mine basal water.

Drilling Activity

	Three Months Ended			Six Months Ended	
(number of net wells)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Net successful natural gas wells	**4**	5	5	**9**	16
Net successful crude oil wells [(1)]	**81**	122	61	**203**	216
Dry wells	**—**	2	2	**2**	3
Stratigraphic test / service wells	**27**	450	6	**477**	232
Total	**112**	579	74	**691**	467
Success rate (excluding stratigraphic test / service wells)	**100%**	98%	97%	**99%**	99%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 69% of the total net capital expenditures for the six months ended June 30, 2018 compared with approximately 9% for the six months ended June 30, 2017.

During the second quarter of 2018, the Company targeted 4 net natural gas wells in Northeast British Columbia. The Company also targeted 79 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 39 primary heavy crude oil wells, 11 Pelican Lake heavy crude oil wells, 21 bitumen (thermal oil) wells and 4 light crude oil wells were drilled. Another 4 wells targeting light crude oil were drilled outside the Northern Plains region.

North Sea

During the second quarter of 2018, the Company completed two gross production wells (1.9 on a net basis) in the North Sea (six months ended June 30, 2018 – three gross production wells (2.9 on a net basis)). In the third quarter of 2018, the Company is targeting to drill one gross injection well and one gross production well, completing the North Sea drilling program.

Offshore Africa

During the second quarter of 2018, the Company commenced drilling operations at Baobab. The Company is targeting three gross production wells and two gross injection wells for the drilling program.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Jun 30 2018**	Mar 31 2018	Dec 31 2017	Jun 30 2017
Working capital [(1)]	**$ 942**	$ 702	$ 513	$ 876
Long-term debt [(2) (3)]	**$ 21,397**	$ 21,978	$ 22,458	$ 23,276
Less: cash and cash equivalents	**182**	152	137	50
Long-term debt, net	**$ 21,215**	$ 21,826	$ 22,321	$ 23,226
Share capital	**$ 9,405**	$ 9,264	$ 9,109	$ 8,771
Retained earnings	**22,994**	22,785	22,612	22,203
Accumulated other comprehensive income (loss)	**12**	(23)	(68)	12
Shareholders' equity	**$ 32,411**	$ 32,026	$ 31,653	$ 30,986
Debt to book capitalization [(3) (4)]	**39.6%**	40.5%	41.4%	42.8%
Debt to market capitalization [(3) (5)]	**26.7%**	30.5%	28.9%	33.8%
After-tax return on average common shareholders' equity [(6)]	**8.3%**	8.7%	8.0%	5.7%
After-tax return on average capital employed [(3) (7)]	**5.9%**	6.0%	5.6%	4.2%

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

(2) Includes the current portion of long-term debt.

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

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

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

(6) Calculated as net earnings for the twelve month trailing period; as a percentage of average common shareholders' equity for the period.

(7) Calculated as net earnings 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 June 30, 2018, 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, 2017. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated funds flow from operations supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy. On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring funds flow from operations, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- For the six months ended June 30, 2018, the Company utilized funds flow from operations to facilitate net repayment of bank credit facilities and US dollar debt securities of $2,096 million, excluding the impact of foreign exchange on debt balances, including:
    - repayment and cancellation of the $125 million non-revolving credit facility;
    - repayment and cancellation of $150 million of the $3,000 million non-revolving term loan facility; and
    - repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes.
- Additionally, the Company utilized available liquidity to settle the deferred payment to Marathon Oil Corporation for $481 million, resulting in total net repayments of debt of $1,615 million.
- Reviewing the Company's borrowing capacity:
    - During the second quarter of 2018, the Company extended the $2,425 million revolving syndicated credit facility originally due June 2020 to June 2022. Each of the $2,425 million revolving facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.
    - During the second quarter of 2018, the Company extended the $2,200 million non-revolving credit facility originally due October 2019 to October 2020. Borrowings under the $2,200 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at June 30, 2018, the $2,200 million facility was fully drawn.
    - Borrowings under the $750 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at June 30, 2018, the $750 million facility was fully drawn.
    - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US $2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.
    - In July 2017, the Company filed base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, which expires in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default.

At June 30, 2018, the Company had in place revolving bank credit facilities of $4,976 million, of which $4,602 million was available, resulting in liquidity of $4,784 million, including cash and cash equivalents. Additionally, the Company had in place fully drawn term credit facilities of $5,800 million. This excludes certain other dedicated credit facilities supporting letters of credit.

At June 30, 2018, the Company had total US dollar denominated debt with a carrying amount of $14,316 million (US $10,895 million), before transaction costs and original issue discounts. This included $5,641 million (US$4,295 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$3,245 million). The fixed repayment amount of these hedging instruments is $5,397 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $244 million to $14,072 million as at June 30, 2018.

Net long-term debt was $21,215 million at June 30, 2018, resulting in a debt to book capitalization ratio of 39.6% (December 31, 2017 – 41.4%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when 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.

Further details related to the Company's long-term debt at June 30, 2018 are discussed in note 9 of the Company's unaudited interim consolidated financial statements.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. At June 30, 2018, 300,000 GJ/d of currently forecasted natural gas volumes were hedged using AECO swaps for July 2018 to October 2018. Further details related to the Company's commodity derivative financial instruments outstanding at June 30, 2018 are discussed in note 16 of the Company's unaudited interim consolidated financial statements.

Share Capital

As at June 30, 2018, there were 1,220,871,000 common shares outstanding (December 31, 2017 – 1,222,769,000 common shares) and 48,462,000 stock options outstanding. As at July 31, 2018, the Company had 1,221,306,000 common shares outstanding and 46,920,000 stock options outstanding.

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

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

For the six months ended June 30, 2018, the Company purchased for cancellation 10,140,127 common shares at a weighted average price of $43.52 per common share for a total cost of $441 million. Retained earnings were reduced by $363 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2018, the Company purchased 722,600 common shares at a weighted average price of $46.95 per common share for a total cost of $34 million.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at June 30, 2018:

($ millions)	Remaining 2018	2019	2020	2021	2022	Thereafter
Product transportation and pipeline	$ 344	$ 610	$ 561	$ 541	$ 474	$ 3,892
North West Redwater Partnership debt service toll (1)	$ 46	$ 79	$ 126	$ 157	$ 158	$ 3,015
Offshore equipment operating leases	$ 91	$ 94	$ 70	$ 68	$ 7	$ —
Long-term debt (2)	$ 327	$ 1,150	$ 6,843	$ 1,412	$ 1,000	$ 10,796
Interest and other financing expense (3)	$ 419	$ 828	$ 737	$ 596	$ 543	$ 5,629
Office leases	$ 22	$ 42	$ 43	$ 40	$ 31	$ 121
Other	$ 61	$ 44	$ 39	$ 36	$ 39	$ 365

(1) *As per the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, which currently consists of interest and fees, with principal repayments beginning in 2020. Included in the service toll is $1,340 million of interest payable over the 30 year tolling period.*

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

(3) *Interest and other financing payments were estimated based upon applicable interest and foreign exchange rates as at June 30, 2018.*

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

CHANGES IN ACCOUNTING POLICIES

For the impact of new accounting standards, refer to the audited consolidated financial statements for the year ended December 31, 2017 and the unaudited interim consolidated financial statements for the three and six months ended June 30, 2018.

ACCOUNTING POLICIES ISSUED BUT NOT YET APPLIED

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaces IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and requires the recognition of right-of-use assets and lease liabilities on the balance sheet. An exemption is available for mineral leases and for certain short-term leases and low-value assets, and these leases are not required to be recognized on the balance sheet. The new standard is effective January 1, 2019 and is required to be applied retrospectively, with a policy alternative of restating comparative prior periods or recognizing the cumulative adjustment in opening retained earnings at the date of adoption. The Company is in the process of reviewing its various lease agreements and business processes as a result of the new standard. The adoption of IFRS 16 may have a significant impact on the Company's financial statements.

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, 2017.