Canadian Natural Resources Limited

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE MONTHS ENDED MARCH 31, 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"), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansions, the Athabasca Oil Sands Project ("AOSP"), Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the cost of construction and future operations of the North West Redwater bitumen upgrader and refinery, and construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and natural gas liquids ("NGLs") reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets; 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 report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company's estimates or opinions change.

Management’s Discussion and Analysis

This MD&A of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 31, 2018 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2017.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company’s unaudited interim consolidated financial statements for the period ended March 31, 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, adjusted cash production costs and adjusted depreciation, depletion and amortization. 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 derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the “Operating Highlights – Oil Sands Mining and Upgrading” section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the “Liquidity and Capital Resources” section of this MD&A.

A Barrel of Oil Equivalent (“BOE”) is derived by converting six thousand cubic feet (“Mcf”) of natural gas to one barrel (“bbl”) of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO.

Production volumes and per unit statistics are presented throughout this MD&A on a “before royalty” or “gross” basis, and realized prices are net of blending costs and exclude the effect of risk management activities. Production on an “after royalty” or “net” basis is also presented for information purposes only. Results from operations for the three months ended March 31, 2017 presented in this MD&A exclude the impact of the acquisition of interests in AOSP on May 31, 2017.

The following discussion and analysis refers primarily to the Company’s financial results for the three months ended March 31, 2018 in relation to the first quarter of 2017 and the fourth quarter of 2017. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2017, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated May 2, 2018.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Mar 31 2018**	 Dec 31 2017	 Mar 31 2017
Product sales	**$ 5,735**	$ 5,516	$ 3,992
Crude oil and NGLs	**$ 5,303**	$ 5,098	$ 3,459
Natural gas	**$ 432**	$ 418	$ 533
Net earnings	**$ 583**	$ 396	$ 245
Per common share – basic	**$ 0.48**	$ 0.32	$ 0.22
– diluted	**$ 0.47**	$ 0.32	$ 0.22
Adjusted net earnings from operations (1)	**$ 885**	$ 565	$ 277
Per common share – basic	**$ 0.72**	$ 0.46	$ 0.25
– diluted	**$ 0.71**	$ 0.46	$ 0.25
Funds flow from operations (2)	**$ 2,323**	$ 2,307	$ 1,639
Per common share – basic	**$ 1.90**	$ 1.89	$ 1.47
– diluted	**$ 1.89**	$ 1.88	$ 1.46
Net capital expenditures	**$ 1,103**	$ 1,143	$ 846

(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 and current income tax on disposition of properties. The Company evaluates its performance based on funds flow from operations. The Company considers funds flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Funds Flow from Operations, as Reconciled to Net Earnings" 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 Mar 31 2018	Dec 31 2017	Mar 31 2017
Net earnings	**$ 583**	$ 396	$ 245
Share-based compensation, net of tax (1)	**(88)**	97	27
Unrealized risk management (gain) loss, net of tax (2)	**(31)**	68	(31)
Unrealized foreign exchange loss (gain), net of tax (3)	**162**	(2)	(60)
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax (4)	**146**	—	—
Loss (gain) from investments, net of tax (5) (6)	**113**	(4)	96
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (7)	**—**	10	—
Adjusted net earnings from operations	**$ 885**	$ 565	$ 277

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

Funds Flow from Operations, as Reconciled to Net Earnings

($ millions)	Three Months Ended Mar 31 2018	Dec 31 2017	Mar 31 2017
Net earnings	**$ 583**	$ 396	$ 245
Non-cash items:			
Depletion, depreciation and amortization	**1,257**	1,406	1,299
Share-based compensation	**(88)**	97	27
Asset retirement obligation accretion	**46**	45	36
Unrealized risk management (gain) loss	**(33)**	75	(40)
Unrealized foreign exchange loss (gain)	**162**	(2)	(60)
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax	**146**	—	—
Loss (gain) from investments	**113**	(4)	96
Deferred income tax expense	**137**	294	36
Funds flow from operations	**$ 2,323**	$ 2,307	$ 1,639

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

	Three Months Ended		
($ millions)	**Mar 31 2018**	Dec 31 2017	Mar 31 2017
Cash flows from operating activities	***$ 2,469***	*$ 1,438*	*$ 1,671*
Net change in non-cash working capital	***(235)***	*709*	*(51)*
Abandonment expenditures	***90***	*63*	*41*
Other	***(1)***	*97*	*(22)*
Funds flow from operations	***$ 2,323***	*$ 2,307*	*$ 1,639*

SUMMARY OF CONSOLIDATED NET EARNINGS AND FUNDS FLOW FROM OPERATIONS

Net earnings for the first quarter of 2018 were $583 million compared with net earnings of $245 million for the first quarter of 2017 and net earnings of $396 million for the fourth quarter of 2017. Net earnings for the first quarter of 2018 included net after-tax expenses of $302 million compared with net after-tax expenses of $32 million for the first quarter of 2017 and net after-tax expenses of $169 million for the fourth quarter of 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 (gain) from investments and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the first quarter of 2018 were $885 million compared with adjusted net earnings of $277 million for the first quarter of 2017 and adjusted net earnings of $565 million for the fourth quarter of 2017.

The increase in adjusted net earnings for the first quarter of 2018 from the first quarter of 2017 was primarily due to:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment associated with both the acquisition of AOSP and new Phase 3 volumes at Horizon; and
- higher realized SCO prices in the Oil Sands Mining and Upgrading segment;

partially offset by:

- lower crude oil and NGLs and natural gas netbacks in the Exploration and Production segments;
- higher interest and other financing expense;
- lower crude oil and NGLs sales volumes in the Exploration and Production segments; and
- the strengthening of the Canadian dollar relative to the US dollar.

The increase in adjusted net earnings for the first quarter of 2018 from the fourth quarter of 2017 was primarily due to:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment associated with new Phase 3 volumes at Horizon; and
- lower depletion, depreciation and amortization;

partially offset by:

- lower crude oil and NGLs netbacks in the Exploration and Production segments;
- lower crude oil and NGLs sales volumes in the Exploration and Production segments; and
- lower realized risk management gains.

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 first quarter of 2018 was $2,323 million compared with $1,639 million for the first quarter of 2017 and $2,307 million for the fourth quarter of 2017. The fluctuations in funds flow from operations from the comparable periods were primarily due to the factors noted above relating to the fluctuations in adjusted net earnings, as well as due to the impact of fluctuations in cash taxes.

Total production before royalties for the first quarter of 2018 increased 28% to 1,123,546 BOE/d from 876,907 BOE/d for the first quarter of 2017 and increased 10% from 1,020,094 BOE/d for the fourth quarter of 2017.

SUMMARY OF QUARTERLY RESULTS

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

($ millions, except per common share amounts)	**Mar 31 2018**	Dec 31 2017	Sep 30 2017	Jun 30 2017
Product sales [1]	**$ 5,735**	$ 5,516	$ 4,725	$ 4,127
Crude oil and NGLs	**$ 5,303**	$ 5,098	$ 4,320	$ 3,645
Natural gas	**$ 432**	$ 418	$ 405	$ 482
Net earnings (loss)	**$ 583**	$ 396	$ 684	$ 1,072
Net earnings (loss) per common share				
– basic	**$ 0.48**	$ 0.32	$ 0.56	$ 0.93
– diluted	**$ 0.47**	$ 0.32	$ 0.56	$ 0.93
($ millions, except per common share amounts)	Mar 31 2017	Dec 31 2016	Sep 30 2016	Jun 30 2016
Product sales [1]	$ 3,992	$ 3,672	$ 2,477	$ 2,686
Crude oil and NGLs	$ 3,459	$ 3,193	$ 2,106	$ 2,456
Natural gas	$ 533	$ 479	$ 371	$ 230
Net earnings (loss)	$ 245	$ 566	$ (326)	$ (339)
Net earnings (loss) per common share				
– basic	$ 0.22	$ 0.51	$ (0.29)	$ (0.31)
– diluted	$ 0.22	$ 0.51	$ (0.29)	$ (0.31)

(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 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 Côte d’Ivoire in Offshore Africa. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.
- **Natural gas sales volumes** – Fluctuations in production due to the Company’s allocation of capital to higher return crude oil projects, natural decline rates, 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 disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity (gain) loss in Redwater Partnership.

BUSINESS ENVIRONMENT

(Average for the period)		Three Months Ended Mar 31 2018		Dec 31 2017		Mar 31 2017
WTI benchmark price (US$/bbl)	**$**	**62.89**	$	55.39	$	51.86
Dated Brent benchmark price (US$/bbl)	**$**	**66.99**	$	61.46	$	54.05
WCS heavy differential from WTI (US$/bbl)	**$**	**24.27**	$	12.28	$	14.58
SCO price (US$/bbl)	**$**	**61.45**	$	58.64	$	51.45
Condensate benchmark price (US$/bbl)	**$**	**63.12**	$	57.96	$	52.21
NYMEX benchmark price (US$/MMBtu)	**$**	**2.98**	$	2.94	$	3.31
AECO benchmark price (C$/GJ)	**$**	**1.75**	$	1.85	$	2.79
US/Canadian dollar average exchange rate (US$)	**$**	**0.7905**	$	0.7865	$	0.7554

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$62.89 per bbl for the first quarter of 2018, an increase of 21% from US$51.86 per bbl for the first quarter of 2017, and an increase of 14% from US$55.39 per bbl for the fourth quarter of 2017.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$66.99 per bbl for the first quarter of 2018, an increase of 24% from US$54.05 per bbl for the first quarter of 2017, and an increase of 9% from US$61.46 per bbl for the fourth quarter of 2017.

WTI and Brent pricing for the first quarter of 2018 has increased from the comparable periods due to declines in global crude oil surplus inventories as a result of OPEC's adherence to previously announced production cuts, together with larger than anticipated increases in global demand for crude oil.

The WCS Heavy Differential averaged US$24.27 per bbl for the first quarter of 2018, an increase of 66% from US$14.58 per bbl for the first quarter of 2017, and an increase of 98% from US$12.28 per bbl for the fourth quarter of 2017. The WCS Heavy Differential reflects US Gulf Coast pricing, adjusted for transportation costs. The widening of the differential for the first quarter of 2018 from the comparable periods primarily reflected increased heavy oil inventory in Western Canada due to a third party pipeline outage in the fourth quarter of 2017.

The SCO price averaged US$61.45 per bbl for the first quarter of 2018, an increase of 19% from US$51.45 per bbl for the first quarter of 2017, and an increase of 5% from US$58.64 per bbl for the fourth quarter of 2017. The increase in SCO pricing for the first quarter of 2018 from the comparable periods was primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.98 per MMBtu for the first quarter of 2018, a decrease of 10% from US$3.31 per MMBtu for the first quarter of 2017 and comparable with US$2.94 per MMBtu for the fourth quarter of 2017.

AECO natural gas prices averaged $1.75 per GJ for the first quarter of 2018, a decrease of 37% from $2.79 per GJ for the first quarter of 2017 and a decrease of 5% from $1.85 per GJ for the fourth quarter of 2017.

The decrease in AECO natural gas prices for the first quarter of 2018 from the comparable periods 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.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2018	Dec 31 2017	Mar 31 2017
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**357,460**	383,537	359,964
North America – Oil Sands Mining and Upgrading (1)	**456,076**	321,496	192,491
North Sea	**21,584**	19,548	23,042
Offshore Africa	**19,438**	19,519	22,616
	854,558	744,100	598,113
Natural gas (MMcf/d)			
North America	**1,547**	1,596	1,613
North Sea	**37**	37	37
Offshore Africa	**30**	23	23
	1,614	1,656	1,673
Total barrels of oil equivalent (BOE/d)	**1,123,546**	1,020,094	876,907
Product mix			
Light and medium crude oil and NGLs	**12%**	13%	15%
Pelican Lake heavy crude oil	**6%**	6%	5%
Primary heavy crude oil	**8%**	10%	11%
Bitumen (thermal oil)	**10%**	12%	15%
Synthetic crude oil (1)	**40%**	32%	22%
Natural gas	**24%**	27%	32%
Percentage of gross revenue (1) (2) (excluding Midstream revenue)			
Crude oil and NGLs	**92%**	92%	86%
Natural gas	**8%**	8%	14%

(1) First quarter 2018 SCO production before royalties excludes 3,224 bbl/d of SCO consumed internally as diesel (fourth quarter 2017 – 1,730 bbl/d; first quarter 2017 – 428 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2018	Dec 31 2017	Mar 31 2017
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**310,783**	333,698	313,070
North America – Oil Sands Mining and Upgrading	**443,606**	309,777	189,182
North Sea	**21,521**	19,518	23,001
Offshore Africa	**18,652**	17,885	21,702
	794,562	680,878	546,955
Natural gas (MMcf/d)			
North America	**1,473**	1,538	1,503
North Sea	**37**	37	37
Offshore Africa	**27**	20	21
	1,537	1,595	1,561
Total barrels of oil equivalent (BOE/d)	**1,050,702**	946,731	807,045

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 first quarter of 2018 increased by 43% to average 854,558 bbl/d from 598,113 bbl/d for the first quarter of 2017, and increased by 15% from 744,100 bbl/d for the fourth quarter of 2017.The increase in crude oil and NGLs production for the first quarter of 2018 from the first quarter of 2017 was due to acquisitions completed in 2017 and new Phase 3 production at Horizon. The increase in crude oil and NGLs production for the first quarter of 2018 from the fourth quarter of 2017 reflected the successful ramp-up of Phase 3 production at Horizon and strong production at AOSP, partially offset by changes in the timing of activities in thermal and heavy oil production, including delaying completion and ramp up of new wells at Kirby South and in heavy oil, together with proactive measures taken to curtail thermal and heavy oil production.

First quarter 2018 crude oil and NGLs production was above the mid point of the Company's previously issued guidance of 821,000 to 869,000 bbl/d. Second quarter 2018 crude oil and NGLs production guidance is targeted to average between 773,000 and 821,000 bbl/d.

Natural gas production for the first quarter of 2018 of 1,614 MMcf/d decreased 4% from 1,673 MMcf/d for the first quarter of 2017, and decreased 3% from 1,656 MMcf/d for the fourth quarter of 2017. The first quarter of 2018 reflected reduced natural gas activity, including the impact of shut-in natural gas production volumes of 14 MMcf/d as a result of low natural gas prices.

First quarter 2018 natural gas production was within the Company's previously issued guidance of 1,600 to 1,650 MMcf/d. Second quarter 2018 natural gas production guidance is targeted to average between 1,515 and 1,565 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production for the first quarter of 2018 of 357,460 bbl/d was comparable with 359,964 bbl/d for the first quarter of 2017, and decreased by 7% from 383,537 bbl/d for the fourth quarter of 2017. The decrease in crude oil and NGLs production for the first quarter of 2018 from the fourth quarter of 2017 was primarily due to changes in the timing of activities in thermal and heavy oil production, including delaying completion and ramp up of new wells at Kirby South and in heavy oil, together with proactive measures taken to curtail thermal and heavy oil production.

Operating performance at the Pelican Lake tertiary recovery project continued to be strong following the acquisition completed in 2017, leading to production of 63,274 bbl/d in the first quarter of 2018 compared with 46,617 bbl/d in the first quarter of 2017 and 65,654 bbl/d in the fourth quarter of 2017.

Overall thermal oil production for the first quarter of 2018 averaged 111,851 bbl/d compared with 128,372 bbl/d for the first quarter of 2017 and 124,121 bbl/d for the fourth quarter of 2017. First quarter 2018 thermal oil production was within the Company's previously issued guidance of 108,000 to 114,000 bbl/d. Second quarter 2018 thermal oil production is targeted to average between 103,000 and 109,000 bbl/d.

First quarter 2018 crude oil and NGLs production, including thermal oil, was within the Company's previously issued guidance of 348,000 to 362,000 bbl/d. Second quarter 2018 crude oil and NGLs production guidance, including thermal oil, is targeted to average between 339,000 and 353,000 bbl/d.

Natural gas production for the first quarter of 2018 decreased 4% to 1,547 MMcf/d from 1,613 MMcf/d for the first quarter of 2017, and decreased 3% from 1,596 MMcf/d for the fourth quarter of 2017. The first quarter of 2018 reflected reduced natural gas activity, including the impact of shut-in natural gas production volumes of 14 MMcf/d as a result of low natural gas prices.

North America – Oil Sands Mining and Upgrading

SCO production for the first quarter of 2018 increased 137% to average 456,076 bbl/d from 192,491 bbl/d for the first quarter of 2017 and increased 42% from 321,496 bbl/d for the fourth quarter of 2017. The increase in SCO production for the first quarter of 2018 from the first quarter of 2017 reflected new production from the acquisition of AOSP in May 2017 and new Phase 3 production at Horizon. The increase in SCO production for the first quarter of 2018 from the fourth quarter of 2017 primarily reflected the successful ramp-up of Phase 3 production at Horizon in the fourth quarter of 2017 and strong production at AOSP.

First quarter 2018 SCO production was above the mid point of the Company's previously issued guidance of 435,000 to 465,000 bbl/d. Second quarter 2018 SCO production guidance is targeted to average between 393,000 and 423,000 bbl/d.

North Sea

North Sea crude oil production for the first quarter of 2018 decreased 6% to 21,584 bbl/d from 23,042 bbl/d for the first quarter of 2017 and increased 10% from 19,548 bbl/d for the fourth quarter of 2017. The decrease in production for the first quarter of 2018 from the first quarter of 2017 was primarily due to the impact of the shut-in of the Ninian North platform in May 2017 and natural field declines, partially offset by new wells at Ninian South and production optimization. The increase in production for the first quarter of 2018 from the fourth quarter of 2017 was primarily due to production resuming following the temporary unplanned shut-ins of the Ninian South Platform as well as the Forties Pipeline System in December 2017, together with production optimization.

Offshore Africa

Offshore Africa crude oil production for the first quarter of 2018 decreased 14% to 19,438 bbl/d from 22,616 bbl/d for the first quarter of 2017, and was comparable with 19,519 bbl/d for the fourth quarter of 2017. The decrease in production for the first quarter of 2018 from the first quarter of 2017 primarily reflected natural field declines, partially offset by production optimization.

International Guidance

First quarter 2018 International crude oil production of 41,022 bbl/d was within the Company's previously issued guidance of 38,000 to 42,000 bbl/d. Second quarter 2018 crude oil production guidance is targeted to average between 41,000 and 45,000 bbl/d.

International Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. Revenue has not been recognized in the International business segments on crude oil volumes that were stored in various storage facilities or FPSOs, as follows:

(bbl)	**Mar 31 2018**	Dec 31 2017	Mar 31 2017
North Sea	**506,589**	—	339,457
Offshore Africa	**1,141,282**	121,936	1,102,137
	1,647,871	121,936	1,441,594

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2018	Dec 31 2017	Mar 31 2017
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	**$ 43.06**	$ 53.42	$ 47.05
Transportation	**3.10**	2.82	2.54
Realized sales price, net of transportation	**39.96**	50.60	44.51
Royalties	**4.87**	5.84	4.89
Production expense	**15.70**	15.03	14.37
Netback	**$ 19.39**	$ 29.73	$ 25.25
Natural gas ($/Mcf) (1)			
Sales price (2)	**$ 2.74**	$ 2.55	$ 3.25
Transportation	**0.51**	0.46	0.43
Realized sales price, net of transportation	**2.23**	2.09	2.82
Royalties	**0.10**	0.08	0.19
Production expense	**1.41**	1.33	1.28
Netback	**$ 0.72**	$ 0.68	$ 1.35
Barrels of oil equivalent ($/BOE) (1)			
Sales price (2)	**$ 32.02**	$ 38.78	$ 35.98
Transportation	**3.05**	2.86	2.57
Realized sales price, net of transportation	**28.97**	35.92	33.41
Royalties	**3.10**	3.75	3.38
Production expense	**12.68**	12.28	11.67
Netback	**$ 13.19**	$ 19.89	$ 18.36

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

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2018	Dec 31 2017	Mar 31 2017
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 40.66**	$ 50.51	$ 44.17
North Sea	**$ 79.35**	$ 76.71	$ 70.03
Offshore Africa	**$ 78.85**	$ 73.43	$ 61.95
Company average	**$ 43.06**	$ 53.42	$ 47.05
Natural gas ($/Mcf) (1) (2)			
North America	**$ 2.44**	$ 2.33	$ 3.08
North Sea	**$ 11.67**	$ 9.77	$ 8.68
Offshore Africa	**$ 6.95**	$ 6.73	$ 6.23
Company average	**$ 2.74**	$ 2.55	$ 3.25
Company average ($/BOE) (1) (2)	**$ 32.02**	$ 38.78	$ 35.98

(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 averaged $40.66 per bbl for the first quarter of 2018, a decrease of 8% compared with $44.17 per bbl for the first quarter of 2017 and a decrease of 20% compared with $50.51 per bbl for the fourth quarter of 2017. The decrease in realized crude oil prices for the first quarter of 2018 from the comparable periods primarily reflected the widening of the WCS Heavy Differential in the first quarter of 2018 and increased heavy oil inventory in Western Canada due to a third party pipeline outage in the fourth quarter of 2017. The Company continues to focus on its crude oil blending marketing strategy and in the first quarter of 2018, contributed approximately 175,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 21% to average $2.44 per Mcf for the first quarter of 2018 compared with $3.08 per Mcf for the first quarter of 2017, and increased 5% compared with $2.33 per Mcf for the fourth quarter of 2017. The decrease in realized natural gas prices for the first quarter of 2018 compared with the first quarter of 2017 reflected third party pipeline constraints limiting flow of natural gas to export markets as well as increased natural gas production in the basin. The increase in realized natural gas prices for the first quarter of 2018 compared with the fourth quarter of 2017 is primarily due to higher natural gas export sales volumes and prices.

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

(Quarterly average)	**Mar 31 2018**	Dec 31 2017	Mar 31 2017
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 53.48**	$ 54.09	$ 47.10
Pelican Lake heavy crude oil ($/bbl)	**$ 41.63**	$ 52.44	$ 45.82
Primary heavy crude oil ($/bbl)	**$ 36.85**	$ 50.71	$ 45.22
Bitumen (thermal oil) ($/bbl)	**$ 32.22**	$ 46.58	$ 40.69
Natural gas ($/Mcf)	**$ 2.44**	$ 2.33	$ 3.08

(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 13% to average $79.35 per bbl for the first quarter of 2018 from $70.03 per bbl for the first quarter of 2017 and increased 3% from $76.71 per bbl for the fourth quarter of 2017. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the first quarter of 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 27% to average $78.85 per bbl for the first quarter of 2018 from $61.95 per bbl for the first quarter of 2017 and increased 7% from $73.43 per bbl for the fourth quarter of 2017. Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the first quarter of 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		
	Mar 31 2018	Dec 31 2017	Mar 31 2017
Crude oil and NGLs ($/bbl) [1]			
North America	**$ 5.11**	$ 6.20	$ 5.45
North Sea	**$ 0.23**	$ 0.12	$ 0.13
Offshore Africa	**$ 3.19**	$ 6.15	$ 2.50
Company average	**$ 4.87**	$ 5.84	$ 4.89
Natural gas ($/Mcf) [1]			
North America	**$ 0.09**	$ 0.07	$ 0.18
Offshore Africa	**$ 0.87**	$ 0.84	$ 0.63
Company average	**$ 0.10**	$ 0.08	$ 0.19
Company average ($/BOE) [1]	**$ 3.10**	$ 3.75	$ 3.38

(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 first quarter of 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 first quarter of 2018 compared with 13% for the first quarter of 2017 and 13% for the fourth quarter of 2017. The increase in royalties for the first quarter of 2018 from the first quarter of 2017 primarily reflected the impact of higher 2018 thermal oil royalty rates and royalty adjustments. North America crude oil and NGLs royalties per bbl are now anticipated to average 12.5% to 14.5% of product sales for 2018.

Natural gas royalties averaged approximately 5% of product sales for the first quarter of 2018 compared with 7% for the first quarter of 2017 and 4% for the fourth quarter of 2017. The fluctuations in natural gas royalties primarily reflected prevailing natural gas prices in the periods presented. 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 6% for the first quarter of 2018, compared with 5% of product sales for the first quarter of 2017 and 9% for the fourth quarter of 2017. Royalties as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields. Offshore Africa royalty rates are anticipated to average 7% to 9% of product sales for 2018.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2018	Dec 31 2017	Mar 31 2017
Crude oil and NGLs ($/bbl) [1]			
North America	**$ 14.15**	$ 12.84	$ 12.22
North Sea	**$ 43.39**	$ 44.37	$ 36.86
Offshore Africa	**$ 30.99**	$ 17.96	$ 18.54
Company average	**$ 15.70**	$ 15.03	$ 14.37
Natural gas ($/Mcf) [1]			
North America	**$ 1.31**	$ 1.26	$ 1.20
North Sea	**$ 4.67**	$ 3.98	$ 3.07
Offshore Africa	**$ 2.44**	$ 2.26	$ 3.50
Company average	**$ 1.41**	$ 1.33	$ 1.28
Company average ($/BOE) [1]	**$ 12.68**	$ 12.28	$ 11.67

(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 first quarter of 2018 of $14.15 per bbl increased 16% from $12.22 per bbl for the first quarter of 2017 and increased 10% from $12.84 per bbl for the fourth quarter of 2017. The increase in production expense per barrel for the first quarter of 2018 from the comparable periods was primarily due to increased energy and carbon tax costs along with the impact of proactive measures taken to curtail thermal and heavy oil production volumes relative to mainly fixed expenses. The Company continues to focus on cost control and achieving efficiencies on acquired assets and across the entire asset base. 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 first quarter of 2018 of $1.31 per Mcf increased 9% from $1.20 per Mcf for the first quarter of 2017 and increased 4% from $1.26 per Mcf for the fourth quarter of 2017. The increase in production expense for the first quarter of 2018 from the comparable periods primarily reflected proactive measures taken to curtail natural gas production volumes and address processing reliability issues, together with the impact of seasonal conditions in the first quarter of 2018. 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 anticipated to average $1.00 to $1.20 per Mcf for 2018.

North Sea

North Sea crude oil production expense for the first quarter of 2018 increased 18% to $43.39 per bbl from $36.86 per bbl for the first quarter of 2017 and was comparable with $44.37 per bbl in the fourth quarter of 2017. The increase in production expense for the first quarter of 2018 from the first quarter of 2017 primarily reflected the strengthening of the UK pound sterling compared to the Canadian dollar. The decrease in production expense for the first quarter of 2018 from the fourth quarter of 2017 reflected the impact of temporary unplanned shut-ins in December 2017. 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 was $10.14 per bbl, while total crude oil production expense for the Offshore Africa segment, including the Olowi field in Gabon, was $30.99 per bbl. Total Offshore Africa crude oil production expense for the first quarter of 2018 from the comparable periods primarily reflected the timing of liftings from various fields, including the Olowi field, which have different cost structures, fluctuating production volumes on a relatively fixed cost base and fluctuations in the Canadian dollar.

On a standalone basis, Offshore Africa production expense 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		
($ millions, except per BOE amounts)	**Mar 31 2018**	Dec 31 2017	Mar 31 2017
Expense	**$ 850**	$ 939	$ 1,102
$/BOE (1)	**$ 14.66**	$ 14.46	$ 17.68

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

Depletion, depreciation and amortization expense per BOE for the first quarter of 2018 decreased 17% to $14.66 per BOE from $17.68 per BOE for the first quarter of 2017 and was comparable with $14.46 per BOE for the fourth quarter of 2017. The decrease in depletion, depreciation and amortization expense per BOE for the first quarter of 2018 from the first quarter of 2017 was due to additional depletion, depreciation and amortization expense in the first quarter of 2017 related to the abandonment of the Ninian North platform in the North Sea.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2018**	Dec 31 2017	Mar 31 2017
Expense	**$ 31**	$ 30	$ 28
$/BOE (1)	**$ 0.53**	$ 0.45	$ 0.45

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

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

Asset retirement obligation accretion expense for the first quarter of 2018 of $0.53 per BOE increased 18% from $0.45 per BOE for the first quarter of 2017 and the fourth quarter of 2017. The increase in asset retirement obligation accretion expense per BOE for the first quarter of 2018 from the comparable periods primarily reflected lower sales volumes during 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 during the first quarter of 2018 averaging 456,076 bbl/d. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability of operations, cash production costs averaged $21.37 per bbl during the quarter.

Operations at Horizon during the first quarter of 2018 were strong following the successful ramp-up of Phase 3 production upon completion of the major turnaround in the fourth quarter of 2017. AOSP also showed steady and reliable operations following the pitstops successfully completed at the Jackpine and Muskeg River Mines during the fourth quarter of 2017.

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

	Three Months Ended		
($/bbl) (1)	**Mar 31 2018**	Dec 31 2017	Mar 31 2017
SCO realized sales price (2)	**$ 71.61**	$ 70.85	$ 67.85
Bitumen value for royalty purposes (3)	**$ 31.48**	$ 44.78	$ 36.07
Bitumen royalties (4)	**$ 1.98**	$ 2.45	$ 1.14
Transportation	**$ 1.54**	$ 1.88	$ 1.17

(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 $71.61 per bbl for the first quarter of 2018, an increase of 6% compared with $67.85 per bbl for the first quarter of 2017 and comparable with $70.85 per bbl for the fourth quarter of 2017. The increase in realized sales prices for the first quarter of 2018 from the first quarter of 2017 primarily reflected WTI benchmark pricing, together with the impact of new AOSP SCO sales volumes.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 17 to the Company’s unaudited interim consolidated financial statements.

	Three Months Ended		
($ millions)	**Mar 31 2018**	Dec 31 2017	Mar 31 2017
Cash production costs	**$ 873**	$ 846	$ 372
Less: costs incurred during turnaround periods	**—**	(137)	—
Adjusted cash production costs	**$ 873**	$ 709	$ 372
Adjusted cash production costs, excluding natural gas costs	**$ 835**	$ 668	$ 339
Adjusted natural gas costs	**38**	41	33
Adjusted cash production costs	**$ 873**	$ 709	$ 372

	Three Months Ended		
($/bbl) (1)	**Mar 31 2018**	Dec 31 2017	Mar 31 2017
Adjusted cash production costs, excluding natural gas costs	**$ 20.45**	$ 23.56	$ 20.11
Adjusted natural gas costs	**0.92**	1.43	1.97
Adjusted cash production costs	**$ 21.37**	$ 24.99	$ 22.08
Sales (bbl/d)	**453,850**	308,067	187,276

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

Adjusted cash production costs for the first quarter of 2018 averaged $21.37 per bbl, a decrease of 3% from $22.08 per bbl for the first quarter of 2017 and a decrease of 14% from $24.99 per bbl for the fourth quarter of 2017. The decrease in adjusted cash production costs per barrel for the first quarter of 2018 from the first quarter of 2017 primarily reflected the Company's continuous focus on cost control and efficiencies and high utilization rates and reliability. The decrease in adjusted cash production costs per barrel for the first quarter of 2018 from the fourth quarter of 2017 primarily reflected additional capacity from new Phase 3 production at Horizon.

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

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($ millions, except per bbl amounts)	**Mar 31 2018**	Dec 31 2017	Mar 31 2017
Expense	**$ 404**	$ 464	$ 195
Less: depreciation incurred during turnaround period	**—**	(188)	—
Adjusted depletion, depreciation and amortization	**$ 404**	$ 276	$ 195
$/bbl (1)	**$ 9.88**	$ 9.75	$ 11.58

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

Adjusted depletion, depreciation and amortization expense per barrel for the first quarter of 2018 decreased 15% to $9.88 per bbl from $11.58 per bbl for the first quarter of 2017 and was comparable with $9.75 per bbl for the fourth quarter of 2017.

Adjusted depletion, depreciation and amortization expense per barrel for the first quarter of 2018 decreased from the first quarter of 2017 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		
($ millions, except per bbl amounts)	**Mar 31 2018**	Dec 31 2017	Mar 31 2017
Expense	**$ 15**	$ 15	$ 8
$/bbl (1)	**$ 0.38**	$ 0.53	$ 0.46

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

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

Asset retirement obligation accretion expense of $0.38 per bbl for the first quarter of 2018 decreased 17% from $0.46 per bbl for the first quarter of 2017 and decreased 28% from $0.53 per bbl for the fourth quarter of 2017, primarily due to higher sales volumes.

MIDSTREAM

($ millions)	Three Months Ended Mar 31 2018	Dec 31 2017	Mar 31 2017
Revenue	$ 27	$ 28	$ 25
Production expense	5	4	4
Midstream cash flow	22	24	21
Depreciation	3	3	2
Equity loss (gain) on investment	1	1	(2)
Segment earnings before taxes	$ 18	$ 20	$ 21

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 March 31, 2018, each party has provided $432 million of subordinated debt, together with accrued interest thereon of $111 million, for a Company total of $543 million. Any additional subordinated debt financing is not expected to be significant.

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

As at March 31, 2018, Redwater Partnership had additional borrowings of $2,112 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 Mar 31 2018	Dec 31 2017	Mar 31 2017
Expense	$ 81	$ 84	$ 87
$/BOE (1)	$ 0.82	$ 0.90	$ 1.10

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

Administration expense for the first quarter of 2018 of $0.82 per BOE decreased 25% from $1.10 per BOE for the first quarter of 2017 and decreased 9% from $0.90 per BOE for the fourth quarter of 2017. Administration expense per BOE decreased for the first quarter of 2018 from the comparable periods primarily due to higher overhead recoveries and higher sales volumes.

SHARE-BASED COMPENSATION

	Three Months Ended		
($ millions)	**Mar 31 2018**	Dec 31 2017	Mar 31 2017
(Recovery) expense	**$ (88)**	$ 97	$ 27

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 $88 million share-based compensation recovery for the first quarter of 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 recovery for the first quarter of 2018 was an expense of $1 million related to performance share units granted to certain executive employees (March 31, 2017 – $1 million). For the first quarter of 2018, the Company recovered $13 million of share-based compensation costs from the Oil Sands Mining and Upgrading segment (March 31, 2017 – $3 million costs charged).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended		
($ millions, except per BOE amounts and interest rates)	**Mar 31 2018**	Dec 31 2017	Mar 31 2017
Expense, gross	**$ 205**	$ 187	$ 156
Less: capitalized interest	**15**	18	22
Expense, net	**$ 190**	$ 169	$ 134
$/BOE (1)	**$ 1.92**	$ 1.81	$ 1.70
Average effective interest rate	**3.8%**	3.7%	3.9%

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

Gross interest and other financing expense for the first quarter of 2018 increased from the first quarter of 2017 primarily due to the impact of higher average debt levels as a result of acquisitions completed in 2017. Capitalized interest of $15 million for the first quarter of 2018 was primarily related to Kirby North and residual project activities at Horizon.

Net interest and other financing expense per BOE for the first quarter of 2018 increased 13% to $1.92 per BOE from $1.70 per BOE for the first quarter of 2017 and increased 6% from $1.81 per BOE for the fourth quarter of 2017. The increase for the first quarter of 2018 from the first quarter of 2017 was primarily due to higher average debt levels as a result of acquisitions completed in 2017 and lower capitalized interest related to the completion of Horizon Phase 3. The increase for the first quarter of 2018 from the fourth quarter of 2017 was primarily due to the impact of interest on PRT recoveries in the North Sea in the fourth quarter of 2017, as well as lower capitalized interest related to the completion of Horizon Phase 3.

The Company's average effective interest rate for the first quarter of 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		
($ millions)	**Mar 31 2018**	Dec 31 2017	Mar 31 2017
Crude oil and NGLs financial instruments	**$ —**	$ —	$ (1)
Natural gas financial instruments	**—**	(2)	—
Foreign currency contracts	**(19)**	(71)	(11)
Realized gain	**(19)**	(73)	(12)
Crude oil and NGLs financial instruments	**—**	7	(43)
Natural gas financial instruments	**—**	2	(8)
Foreign currency contracts	**(33)**	66	11
Unrealized (gain) loss	**(33)**	75	(40)
Net (gain) loss	**$ (52)**	$ 2	$ (52)

During the first quarter of 2018, net realized risk management gains were related to the settlement of foreign currency contracts. The Company recorded a net unrealized gain of $33 million ($31 million after-tax) on its risk management activities for the first quarter of 2018 (December 31, 2017 - unrealized loss of $75 million; $68 million after-tax; March 31, 2017 – unrealized gain of $40 million; $31 million after-tax).

Further details related to outstanding derivative financial instruments at March 31, 2018 are disclosed in note 15 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended		
($ millions)	**Mar 31 2018**	Dec 31 2017	Mar 31 2017
Net realized loss (gain)	**$ 116**	$ (15)	$ 4
Net unrealized loss (gain)	**162**	(2)	(60)
Net loss (gain) [1]	**$ 278**	$ (17)	$ (56)

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

The net realized foreign exchange loss for the first quarter of 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 first quarter of 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 March 31, 2018 – unrealized gain of $40 million, December 31, 2017 – unrealized gain of $1 million, March 31, 2017 – unrealized loss of $23 million). The US/Canadian dollar exchange rate at March 31, 2018 was US$0.7751 (December 31, 2017 – US$0.7988, March 31, 2017 – US$0.7506).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended **Mar 31 2018**	Dec 31 2017	Mar 31 2017
North America [1]	**$ 150**	$ (93)	$ 38
North Sea	**1**	10	6
Offshore Africa	**5**	17	7
PRT recovery – North Sea	**(4)**	(25)	(1)
Other taxes	**2**	3	3
Current income tax expense (recovery)	**154**	(88)	53
Deferred corporate income tax expense	**127**	307	28
Deferred PRT expense (recovery) – North Sea	**10**	(13)	8
Deferred income tax expense	**137**	294	36
	291	206	89
Income tax rate and other legislative changes [2]	**—**	(10)	—
	$ 291	$ 196	$ 89
Effective income tax rate on adjusted net earnings from operations [3]	**24%**	32%	20%

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

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

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

The effective income tax rate for the first quarter of 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 first quarter of 2018 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the Murchison and Ninian North platforms.

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

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

For 2018, the Company now 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 Mar 31 2018	Dec 31 2017	Mar 31 2017
Exploration and Evaluation			
Net expenditures (2) (3)	**$ 56**	$ 16	$ 37
Property, Plant and Equipment			
Net property acquisitions (2) (3)	**162**	19	9
Well drilling, completion and equipping	**321**	212	340
Production and related facilities	**264**	258	167
Capitalized interest and other (4)	**23**	27	21
Net expenditures	**770**	516	537
Total Exploration and Production	**826**	532	574
Oil Sands Mining and Upgrading			
Project costs (5)	**66**	248	139
Sustaining capital	**105**	214	67
Turnaround costs	**13**	69	1
Capitalized interest and other (4)	**(5)**	26	20
Total Oil Sands Mining and Upgrading	**179**	557	227
Midstream	**4**	2	1
Abandonments (6)	**90**	63	41
Head office	**4**	(11)	3
Total net capital expenditures	**$ 1,103**	$ 1,143	$ 846
By segment			
North America (2) (3)	**$ 772**	$ 444	$ 520
North Sea	**35**	52	35
Offshore Africa	**19**	36	19
Oil Sands Mining and Upgrading	**179**	557	227
Midstream	**4**	2	1
Abandonments (6)	**90**	63	41
Head office	**4**	(11)	3
Total	**$ 1,103**	$ 1,143	$ 846

(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 Company's disposition of properties.

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

(5) Includes Horizon Phases 2/3 construction costs.

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

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

Net capital expenditures for the first quarter of 2018 were $1,103 million compared with $846 million for the first quarter of 2017 and $1,143 million for the fourth quarter of 2017.

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 ("MFT") and mine basal water.

Drilling Activity

	Three Months Ended		
(number of wells)	**Mar 31 2018**	Dec 31 2017	Mar 31 2017
Net successful natural gas wells	**5**	2	11
Net successful crude oil wells [(1)]	**122**	125	155
Dry wells	**2**	3	1
Stratigraphic test / service wells	**450**	51	226
Total	**579**	181	393
Success rate (excluding stratigraphic test / service wells)	**98%**	98%	99%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 75% of the total net capital expenditures for the first quarter of 2018 compared with approximately 26% for the first quarter of 2017.

During the first quarter of 2018, the Company targeted 5 net natural gas wells, all in Northwest Alberta. The Company also targeted 123 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 64 primary heavy crude oil wells, 7 Pelican Lake heavy crude oil wells and 22 bitumen (thermal oil) wells were drilled. Another 30 wells targeting light crude oil were drilled outside the Northern Plains region.

North Sea

During the first quarter of 2018, the Company completed one production well (1.0 on a net basis) at Tiffany in the North Sea. The Company also continued to progress the abandonment of the Murchison and Ninian North platforms. The well plug and abandonment project at Ninian North was completed during the quarter, ahead of schedule and under the sanctioned budget.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		Mar 31 2018		Dec 31 2017		Mar 31 2017
Working capital [1]	**$**	**702**	$	513	$	1,222
Long-term debt [2] [3]	**$**	**21,978**	$	22,458	$	16,304
Less: cash and cash equivalents		**152**		137		19
Long-term debt, net	**$**	**21,826**	$	22,321	$	16,285
Share capital	**$**	**9,264**	$	9,109	$	4,869
Retained earnings		**22,785**		22,612		21,465
Accumulated other comprehensive income		**(23)**		(68)		43
Shareholders' equity	**$**	**32,026**	$	31,653	$	26,377
Debt to book capitalization [3] [4]		**40.5%**		41.4%		38.2%
Debt to market capitalization [3] [5]		**30.5%**		28.9%		25.2%
After-tax return on average common shareholders' equity [6]		**8.7%**		8.0%		0.6%
After-tax return on average capital employed [3] [7]		**6.0%**		5.6%		1.1%

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

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

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

(4) Calculated as 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 March 31, 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;
- During the first quarter of 2018, the Company utilized funds flow from operations to facilitate net repayment of bank credit facilities and US dollar debt securities of $1,336 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 $855 million.
- Reviewing the Company's borrowing capacity:
  - 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 March 31, 2018, the $2,200 million facility was fully drawn.
  - Borrowings under the $2,850 million non-revolving term loan 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 March 31, 2018, the $2,850 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 March 31, 2018, the $750 million facility was fully drawn.
  - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US $2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.
  - In July 2017, the Company filed base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, which 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 March 31, 2018, the Company had in place bank credit facilities of $10,777 million, of which approximately $3,835 million was available, resulting in liquidity of $3,987 million, including cash and cash equivalents. This excludes certain other dedicated credit facilities supporting letters of credit.

At March 31, 2018, the Company had total US dollar denominated debt with a carrying amount of $14,377 million (US$11,147 million), before transaction costs and original issue discounts. This included $5,863 million (US$4,547 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$3,497 million). The fixed repayment amount of these hedging instruments is $5,639 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $224 million to $14,153 million as at March 31, 2018.

Net long-term debt was $21,826 million at March 31, 2018, resulting in a debt to book capitalization ratio of 40.5% (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 March 31, 2018 are discussed in note 8 to the Company's unaudited interim consolidated financial statements.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. At March 31, 2018 the Company had no commodity derivative financial instruments outstanding.

Share Capital

As at March 31, 2018, there were 1,226,205,000 common shares outstanding (December 31, 2017 – 1,222,769,000 common shares) and 54,221,000 stock options outstanding. As at May 1, 2018, the Company had 1,228,025,000 common shares outstanding and 51,344,000 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 March 14, 2018, the Board of Directors approved the Company's application 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 5% of the issued and outstanding common shares of the Company, over a 12 month period commencing upon expiry of its current Normal Course Issuer Bid and upon receipt of applicable regulatory and other approvals.

The Company's Normal Course Issuer Bid previously announced in March 2017, to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 27,931,135 common shares of the Company, ends May 22, 2018. For the three months ended March 31, 2018, the Company did not purchase any common shares for cancellation. Subsequent to March 31, 2018, the Company purchased 700,000 common shares at a weighted average price of $41.95 per common share for a total cost of $29 million.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

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

($ millions)	Remaining 2018	2019	2020	2021	2022	Thereafter
Product transportation and pipeline	$ 512	$ 590	$ 546	$ 539	$ 474	$ 3,901
Offshore equipment operating leases	$ 129	$ 92	$ 69	$ 67	$ 7	$ —
Long-term debt (1)	$ 644	$ 3,382	$ 4,854	$ 1,607	$ 1,000	$ 10,624
Interest and other financing expense (2)	$ 620	$ 825	$ 690	$ 581	$ 526	$ 5,535
Office leases	$ 33	$ 42	$ 43	$ 40	$ 31	$ 121
Other (3)	$ 80	$ 43	$ 39	$ 36	$ 39	$ 365

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

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

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

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

CHANGES IN ACCOUNTING POLICIES

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

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