Canadian Natural Resources Limited

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE MONTHS ENDED MARCH 31, 2017

MANAGEMENT'S DISCUSSION AND ANALYSIS

Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitute forward-looking statements. Disclosure regarding the anticipated closing of the proposed acquisitions of interests in the Athabasca Oil Sands Project, as well as additional working interests in certain other producing and non-producing oil and gas properties, described herein as the "proposed acquisitions of interests in the Athabasca Oil Sands Project", and plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansions, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the construction and future operations of the North West Redwater bitumen upgrader and refinery, and construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

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

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

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

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management’s estimates or opinions change.

Management’s Discussion and Analysis

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

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company’s unaudited interim consolidated financial statements for the period ended March 31, 2017 and this MD&A have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board. This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings (loss) from operations, funds flow from operations (previously referred to as cash flow from operations), and adjusted cash production costs. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings (loss) and cash flows from operating activities, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings (loss) from operations and funds flow from operations are reconciled to net earnings (loss), as determined in accordance with IFRS, in the “Financial Highlights” section of this MD&A. The non-GAAP measure funds flow from operations is also reconciled to cash flows from operating activities in this section. The derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the “Operating Highlights – Oil Sands Mining and Upgrading” section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the “Liquidity and Capital Resources” section of this MD&A.

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

Production volumes and per unit statistics are presented throughout this MD&A on a “before royalty” or “gross” basis, and realized prices are net of blending costs and exclude the effect of risk management activities. Production on an “after royalty” or “net” basis is also presented for information purposes only. Further, results from operations for the three months ended March 31, 2017 and all guidance amounts presented in this MD&A exclude the impact of the proposed acquisitions of interests in the Athabasca Oil Sands Project.

The following discussion and analysis refers primarily to the Company’s financial results for the three months ended March 31, 2017 in relation to the first quarter of 2016 and the fourth quarter of 2016. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2016, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated May 3, 2017.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended		
	Mar 31 2017	Dec 31 2016	Mar 31 2016
Product sales	**$ 3,872**	$ 3,672	$ 2,263
Net earnings (loss)	**$ 245**	$ 566	$ (105)
Per common share – basic	**$ 0.22**	$ 0.51	$ (0.10)
– diluted	**$ 0.22**	$ 0.51	$ (0.10)
Adjusted net earnings (loss) from operations (1)	**$ 277**	$ 439	$ (543)
Per common share – basic	**$ 0.25**	$ 0.40	$ (0.50)
– diluted	**$ 0.25**	$ 0.40	$ (0.50)
Funds flow from operations (2)	**$ 1,639**	$ 1,677	$ 657
Per common share – basic	**$ 1.47**	$ 1.52	$ 0.60
– diluted	**$ 1.46**	$ 1.50	$ 0.60
Net capital expenditures	**$ 846**	$ 411	$ 1,040

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

(2) Funds flow from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for certain non-cash items and current income tax on disposition of properties. The Company evaluates its performance based on funds flow from operations. The Company considers funds flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Funds Flow from Operations, as Reconciled to Net Earnings (Loss) " presented in this MD&A, includes certain non-cash items that are disclosed in the Company's financial results as presented in the Company's consolidated Statements of Cash Flows. Funds flow from operations may not be comparable to similar measures presented by other companies.

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

Adjusted Net Earnings (Loss) from Operations

($ millions)	Three Months Ended Mar 31 2017	Dec 31 2016	Mar 31 2016
Net earnings (loss) as reported	**$ 245**	$ 566	$ (105)
Share-based compensation, net of tax [(1)]	**27**	42	117
Unrealized risk management (gain) loss, net of tax [(2)]	**(31)**	(7)	63
Unrealized foreign exchange (gain) loss, net of tax [(3)]	**(60)**	162	(334)
Loss (gain) from investments, net of tax [(4)(5)]	**96**	(106)	(147)
Gain on disposition of properties and corporate dispositions, net of tax [(6)]	**—**	(218)	(23)
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities [(7)]	**—**	—	(114)
Adjusted net earnings (loss) from operations	**$ 277**	$ 439	$ (543)

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

(2) Derivative financial instruments are recorded at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings (loss). The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil, natural gas and foreign exchange.

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

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

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

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

(7) During the first quarter of 2016, the UK government enacted tax rate reductions relating to Petroleum Revenue Tax ("PRT"), resulting in a decrease in the Company's net deferred income tax liability of $114 million.

Funds Flow from Operations, as Reconciled to Net Earnings (Loss)[(1)]

($ millions)	Three Months Ended Mar 31 2017	Dec 31 2016	Mar 31 2016
Net earnings (loss)	**$ 245**	$ 566	$ (105)
Non-cash items:			
Depletion, depreciation and amortization	**1,299**	1,249	1,219
Share-based compensation	**27**	42	117
Asset retirement obligation accretion	**36**	35	36
Unrealized risk management (gain) loss	**(40)**	(7)	74
Unrealized foreign exchange (gain) loss	**(60)**	162	(334)
Loss (gain) from investments	**96**	(106)	(147)
Deferred income tax expense (recovery)	**36**	(46)	(171)
Gain on disposition of properties and corporate dispositions	**—**	(218)	(32)
Funds flow from operations	**$ 1,639**	$ 1,677	$ 657

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

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

	Three Months Ended		
($ millions)	**Mar 31 2017**	Dec 31 2016	Mar 31 2016
Cash flows from operating activities	***$ 1,671***	*$ 1,255*	*$ 581*
Net change in non-cash working capital	***(51)***	*317*	*21*
Abandonment expenditures	***41***	*35*	*74*
Other	***(22)***	*70*	*(19)*
Funds flow from operations	***$ 1,639***	*$ 1,677*	*$ 657*

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

Net earnings for the first quarter of 2017 were $245 million compared with a net loss of $105 million for the first quarter of 2016 and net earnings of $566 million for the fourth quarter of 2016. Net earnings for the first quarter of 2017 included net after-tax expenses of $32 million compared with net after-tax income of $438 million for the first quarter of 2016 and net after-tax income of $127 million for the fourth quarter of 2016 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, loss (gain) from investments, gains on disposition of properties and corporate dispositions 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 2017 were $277 million compared with an adjusted net loss of $543 million for the first quarter of 2016 and adjusted net earnings of $439 million for the fourth quarter of 2016.

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

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

partially offset by:

- lower crude oil and NGLs and natural gas production in the Exploration and Production segments.

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

- lower current income tax recoveries; and
- lower natural gas netbacks in the Exploration and Production segments;

partially offset by:

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

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

Funds flow from operations for the first quarter of 2017 was $1,639 million compared with $657 million for the first quarter of 2016 and $1,677 million for the fourth quarter of 2016. The fluctuations in funds flow from operations from the comparable periods were primarily due to the factors noted above relating to the fluctuations in adjusted net earnings (loss), as well as due to the impact of fluctuations in cash taxes.

Total production before royalties for the first quarter of 2017 increased 4% to 876,907 BOE/d from 844,531 BOE/d for the first quarter of 2016 and increased 2% from 859,577 BOE/d for the fourth quarter of 2016.

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 2017**		Dec 31 2016		Sep 30 2016		Jun 30 2016
Product sales	**$**	**3,872**	$	3,672	$	2,477	$	2,686
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)
($ millions, except per common share amounts)		Mar 31 2016		Dec 31 2015		Sep 30 2015		Jun 30 2015
Product sales	$	2,263	$	2,963	$	3,316	$	3,662
Net earnings (loss)	$	(105)	$	131	$	(111)	$	(405)
Net earnings (loss) per common share								
– basic	$	(0.10)	$	0.12	$	(0.10)	$	(0.37)
– diluted	$	(0.10)	$	0.12	$	(0.10)	$	(0.37)

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

- **Crude oil pricing** – The impact of shale oil production in North America, fluctuating global supply/demand including crude oil production levels from the Organization of the Petroleum Exporting Countries (“OPEC”) and its impact on world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of the WCS Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America and the impact of the differential between WTI and Brent benchmark pricing in the North Sea and Offshore Africa.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, 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, the reduction in the Company’s drilling program in North America, the impact and timing of acquisitions, the impact of turnarounds at Horizon, and the impact of the drilling program in Côte d’Ivoire in Offshore Africa. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.
- **Natural gas sales volumes** – Fluctuations in production due to the Company’s allocation of capital to higher return crude oil projects, natural decline rates, shut-in production due to third party pipeline restrictions and related pricing impacts and reliability issues at a third party processing facility, 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, turnarounds at Horizon and maintenance activities in the International segments.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company’s proved undeveloped reserves, fluctuations in international sales volumes subject to higher depletion rates, fluctuations in depletion, depreciation and amortization expense in the North Sea due to the planned cessation of production at the Ninian North platform, and the impact of turnarounds at Horizon.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company’s share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company’s risk management activities.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense include statutory tax rate and other legislative changes substantively enacted in the various periods.
- **Gains on disposition of properties and gains/losses on investments** – Fluctuations due to the recognition of gains on disposition of properties in the various periods and fair value changes in the investments in PrairieSky and Inter Pipeline shares.

BUSINESS ENVIRONMENT

	Three Months Ended		
	Mar 31 2017	Dec 31 2016	Mar 31 2016
WTI benchmark price (US$/bbl)	**$ 51.86**	$ 49.33	$ 33.51
Dated Brent benchmark price (US$/bbl)	**$ 54.05**	$ 50.27	$ 33.92
WCS blend differential from WTI (US$/bbl)	**$ 14.58**	$ 14.59	$ 14.24
SCO price (US$/bbl)	**$ 51.45**	$ 48.91	$ 33.77
Condensate benchmark price (US$/bbl)	**$ 52.21**	$ 48.37	$ 34.45
NYMEX benchmark price (US$/MMBtu)	**$ 3.31**	$ 2.99	$ 2.04
AECO benchmark price (C$/GJ)	**$ 2.79**	$ 2.67	$ 2.00
US/Canadian dollar average exchange rate (US$)	**$ 0.7554**	$ 0.7496	$ 0.7282

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Dated Brent ("Brent") indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are highly sensitive to fluctuations in foreign exchange rates. For the first quarter of 2017, realized prices continued to be supported by the weaker 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$51.86 per bbl for the first quarter of 2017, an increase of 55% from US$33.51 per bbl for the first quarter of 2016, and an increase of 5% from US$49.33 per bbl for the fourth quarter of 2016.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$54.05 per bbl for the first quarter of 2017, an increase of 59% from US$33.92 per bbl for the first quarter of 2016, and an increase of 8% from US$50.27 per bbl for the fourth quarter of 2016.

WTI and Brent pricing for the first quarter of 2017 continued to reflect volatility in supply and demand factors and geopolitical events. The OPEC decision in November 2016 to implement a production cut effective January 1, 2017 followed by additional production cuts by certain non-OPEC countries contributed to an increase in first quarter pricing from comparable quarters.

The WCS Heavy Differential averaged US$14.58 per bbl for the first quarter of 2017, consistent with comparable periods. The WCS Heavy Differential reflects US Gulf Coast pricing, adjusted for transportation costs.

The SCO price averaged US$51.45 per bbl for the first quarter of 2017, an increase of 52% from US$33.77 per bbl for the first quarter of 2016, and an increase of 5% from US$48.91 per bbl for the fourth quarter of 2016. The fluctuations in SCO pricing for the first quarter of 2017 from the comparable periods were primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US$3.31 per MMBtu for the first quarter of 2017, an increase of 62% from US$2.04 per MMBtu for the first quarter of 2016, and an increase of 11% from US$2.99 per MMBtu for the fourth quarter of 2016.

AECO natural gas prices averaged $2.79 per GJ for the first quarter of 2017, an increase of 40% from $2.00 per GJ for the first quarter of 2016, and an increase of 4% from $2.67 per GJ for the fourth quarter of 2016.

The increase in natural gas prices in the first quarter of 2017 compared with the first quarter of 2016 and the fourth quarter of 2016 reflected the rebalancing of natural gas storage inventory to historically normal levels, primarily due to reduced drilling activity in 2016, resulting in lower US natural gas production. Additionally, pricing during the first quarter of 2017 reflected colder weather in the 2016/2017 winter season as compared with the previous year.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2017	Dec 31 2016	Mar 31 2016
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**359,964**	361,348	369,987
North America – Oil Sands Mining and Upgrading (1)	**192,491**	178,063	127,909
North Sea	**23,042**	24,085	23,317
Offshore Africa	**22,616**	21,689	25,714
	598,113	585,185	546,927
Natural gas (MMcf/d)			
North America	**1,613**	1,578	1,722
North Sea	**37**	44	29
Offshore Africa	**23**	24	35
	1,673	1,646	1,786
Total barrels of oil equivalent (BOE/d)	**876,907**	859,577	844,531
Product mix			
Light and medium crude oil and NGLs	**15%**	15%	16%
Pelican Lake heavy crude oil	**5%**	6%	6%
Primary heavy crude oil	**11%**	11%	14%
Bitumen (thermal oil)	**15%**	15%	14%
Synthetic crude oil (1)	**22%**	21%	15%
Natural gas	**32%**	32%	35%
Percentage of gross revenue (1) (2) (excluding Midstream revenue)			
Crude oil and NGLs	**86%**	85%	79%
Natural gas	**14%**	15%	21%

(1) First quarter 2017 SCO production before royalties excludes 428 bbl/d of SCO consumed internally as diesel (fourth quarter 2016 – 1,619 bbl/d; first quarter 2016 – 2,562 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2017	Dec 31 2016	Mar 31 2016
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**313,070**	315,090	331,313
North America – Oil Sands Mining and Upgrading	**189,182**	175,860	127,571
North Sea	**23,001**	24,034	23,264
Offshore Africa	**21,702**	20,730	24,578
	546,955	535,714	506,726
Natural gas (MMcf/d)			
North America	**1,503**	1,480	1,654
North Sea	**37**	44	29
Offshore Africa	**21**	23	34
	1,561	1,547	1,717
Total barrels of oil equivalent (BOE/d)	**797,529**	793,483	792,939

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 2017 increased by 9% to average 598,113 bbl/d from 546,927 bbl/d for the first quarter of 2016, and increased by 2% from 585,185 bbl/d for the fourth quarter of 2016.The increase in crude oil and NGLs production for the first quarter of 2017 from the first quarter of 2016 and the fourth quarter of 2016 primarily reflected new Phase 2B production at Horizon following the completion of the planned major turnaround in the third quarter of 2016, as well as the impact of the cyclic nature of thermal production at Primrose.

First quarter production was within previously issued guidance of 591,000 and 615,000 bbl/d of crude oil and NGLs. Second quarter 2017 production guidance is targeted to average between 544,000 and 570,000 bbl/d of crude oil and NGLs.

Natural gas production for the first quarter of 2017 of 1,673 MMcf/d decreased 6% from 1,786 MMcf/d for the first quarter of 2016, and increased 2% from 1,646 MMcf/d for the fourth quarter of 2016. Natural gas production for the first quarter of 2017 decreased from the first quarter of 2016 primarily due to the impact of natural field declines as well as the impact of ongoing reliability issues at a third party facility, which reduced production by approximately 70 MMcf/d during the quarter. The increase from the fourth quarter of 2016 was primarily due to the partial reinstatement of volumes at the third party facility during the first quarter of 2017.

First quarter natural gas production was slightly below previously issued guidance of 1,700 to 1,740 MMcf/d as a result of the third party facility reliability issues. Second quarter 2017 natural gas production guidance is now targeted to average between 1,675 and 1,730 MMcf/d, reflecting the ongoing reliability issues at the third party facility. The third party is now targeting to have the facility reinstated to full capacity in June.

North America – Exploration and Production

North America crude oil and NGLs production for the first quarter of 2017 decreased 3% to 359,964 bbl/d from 369,987 bbl/d for the first quarter of 2016, and was comparable with the fourth quarter of 2016. The decrease in production for the first quarter of 2017 from the first quarter of 2016 primarily reflected natural field declines, partially offset by the cyclic nature of thermal oil production at Primrose and increased drilling activity in the first quarter of 2017. First quarter production was within previously issued guidance of 356,000 to 368,000 bbl/d of crude oil and NGLs. Second quarter 2017 production guidance is targeted to average between 318,000 and 332,000 bbl/d of crude oil and NGLs.

Natural gas production for the first quarter of 2017 decreased 6% to 1,613 MMcf/d from 1,722 MMcf/d for the first quarter of 2016, and increased 2% from 1,578 MMcf/d for the fourth quarter of 2016. Natural gas production for the first quarter of 2017 decreased from the first quarter of 2016 primarily due to the impact of natural field declines as well as the impact of ongoing reliability issues at a third party facility, which reduced production by approximately 70 MMcf/d during the quarter. The increase from the fourth quarter of 2016 was primarily due to the partial reinstatement of volumes at the third party facility during the first quarter of 2017.

North America – Oil Sands Mining and Upgrading

SCO production for the first quarter of 2017 increased 50% to average 192,491 bbl/d from 127,909 bbl/d for the first quarter of 2016 and increased 8% from 178,063 bbl/d for the fourth quarter of 2016. The increase in production for the first quarter of 2017 from the first quarter of 2016 and the fourth quarter of 2016 primarily reflected new Phase 2B production following the completion of the planned major turnaround in the third quarter of 2016.

First quarter SCO production was within previously issued guidance of 192,000 to 200,000 bbl/d. Second quarter 2017 production guidance is targeted to average between 180,000 and 188,000 bbl/d, reflecting previously announced planned maintenance activities during April 2017.

North Sea

North Sea crude oil production of 23,042 bbl/d for first quarter of 2017 was comparable with the first quarter of 2016 and decreased 4% from 24,085 bbl/d for the fourth quarter of 2016. The decrease in production for the first quarter of 2017 from the fourth quarter of 2016 was primarily due to natural field declines, partially offset by successful production optimization.

Offshore Africa

Offshore Africa crude oil production for the first quarter of 2017 decreased 12% to 22,616 bbl/d from 25,714 bbl/d for the first quarter of 2016, and increased 4% from 21,689 bbl/d for the fourth quarter of 2016. The decrease from the first quarter of 2016 was primarily due to natural field declines, partially offset by successful production optimization. The increase in the first quarter of 2017 from the fourth quarter of 2016 primarily reflected successful production optimization.

International Guidance

First quarter production was within previously issued guidance of 43,000 to 47,000 bbl/d. Second quarter 2017 production guidance is targeted to average between 46,000 and 50,000 bbl/d of crude oil.

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 2017**	Dec 31 2016	Mar 31 2016
North Sea	**339,457**	987,316	667,879
Offshore Africa	**1,102,137**	1,126,999	1,830,976
	1,441,594	2,114,315	2,498,855

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2017	Dec 31 2016	Mar 31 2016
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	**$ 47.05**	$ 45.00	$ 23.31
Transportation	**2.54**	2.70	2.46
Realized sales price, net of transportation	**44.51**	42.30	20.85
Royalties	**4.89**	4.62	1.90
Production expense	**14.37**	14.28	13.94
Netback	**$ 25.25**	$ 23.40	$ 5.01
Natural gas ($/Mcf) (1)			
Sales price (2)	**$ 3.25**	$ 3.14	$ 2.23
Transportation	**0.43**	0.34	0.28
Realized sales price, net of transportation	**2.82**	2.80	1.95
Royalties	**0.19**	0.17	0.07
Production expense	**1.28**	1.15	1.23
Netback	**$ 1.35**	$ 1.48	$ 0.65
Barrels of oil equivalent ($/BOE) (1)			
Sales price (2)	**$ 35.98**	$ 34.54	$ 19.37
Transportation	**2.57**	2.46	2.20
Realized sales price, net of transportation	**33.41**	32.08	17.17
Royalties	**3.38**	3.16	1.30
Production expense	**11.67**	11.34	11.19
Netback	**$ 18.36**	$ 17.58	$ 4.68

(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 2017	Dec 31 2016	Mar 31 2016
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 44.17**	$ 42.56	$ 20.77
North Sea	**$ 70.03**	$ 63.68	$ 45.04
Offshore Africa	**$ 61.95**	$ 61.29	$ 42.99
Company average	**$ 47.05**	$ 45.00	$ 23.31
Natural gas ($/Mcf) (1) (2)			
North America	**$ 3.08**	$ 2.97	$ 2.05
North Sea	**$ 8.68**	$ 7.75	$ 7.02
Offshore Africa	**$ 6.23**	$ 5.75	$ 7.13
Company average	**$ 3.25**	$ 3.14	$ 2.23
Company average ($/BOE) (1) (2)	**$ 35.98**	$ 34.54	$ 19.37

(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 $44.17 per bbl for the first quarter of 2017, an increase of 113% compared with $20.77 per bbl for the first quarter of 2016 and an increase of 4% compared with $42.56 per bbl for the fourth quarter of 2016. The fluctuations in realized crude oil prices for the first quarter of 2017 from the comparable periods were primarily due to WTI benchmark pricing. The Company continues to focus on its crude oil blending marketing strategy and in the first quarter of 2017, contributed approximately 192,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 50% to average $3.08 per Mcf for the first quarter of 2017 compared with $2.05 per Mcf for the first quarter of 2016, and increased 4% compared with $2.97 per Mcf for the fourth quarter of 2016. The increase in realized natural gas prices for the first quarter of 2017 compared with the first quarter of 2016 and fourth quarter of 2016 reflected the rebalancing of natural gas storage inventory to historically normal levels, primarily due to reduced drilling activity in 2016, resulting in lower US natural gas production. Additionally, pricing during the first quarter of 2017 reflected colder weather in the 2016/2017 winter season as compared with the previous year.

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

(Quarterly Average)	Mar 31 2017	Dec 31 2016	Mar 31 2016
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 47.10**	$ 45.05	$ 28.30
Pelican Lake heavy crude oil ($/bbl)	**$ 45.82**	$ 43.96	$ 21.76
Primary heavy crude oil ($/bbl)	**$ 45.22**	$ 43.89	$ 19.63
Bitumen (thermal oil) ($/bbl)	**$ 40.69**	$ 39.39	$ 15.72
Natural gas ($/Mcf)	**$ 3.08**	$ 2.97	$ 2.05

(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 55% to average $70.03 per bbl for the first quarter of 2017 from $45.04 per bbl for the first quarter of 2016 and increased 10% from $63.68 per bbl for the fourth quarter of 2016. 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 2017 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 44% to average $61.95 per bbl for the first quarter of 2017 from $42.99 per bbl for the first quarter of 2016 and were comparable with the fourth quarter of 2016. 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 2017 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2017	Dec 31 2016	Mar 31 2016
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 5.45**	$ 5.05	$ 2.03
North Sea	**$ 0.13**	$ 0.13	$ 0.10
Offshore Africa	**$ 2.50**	$ 2.71	$ 1.90
Company average	**$ 4.89**	$ 4.62	$ 1.90
Natural gas ($/Mcf) (1)			
North America	**$ 0.18**	$ 0.17	$ 0.07
Offshore Africa	**$ 0.63**	$ 0.29	$ 0.32
Company average	**$ 0.19**	$ 0.17	$ 0.07
Company average ($/BOE) (1)	**$ 3.38**	$ 3.16	$ 1.30

(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 2017 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 13% of product sales for the first quarter of 2017 compared with 11% for the first quarter of 2016 and 13% for the fourth quarter of 2016. The increase in royalties for the first quarter of 2017 from the first quarter of 2016 was primarily due to higher realized crude oil prices. North America crude oil and NGLs royalties per bbl are anticipated to average 13% to 14% of product sales for 2017.

Natural gas royalties averaged approximately 7% of product sales for the first quarter of 2017 compared with 4% for the first quarter of 2016 and 6% for the fourth quarter of 2016. The increase in natural gas royalties in the first quarter of 2017 from comparable periods primarily reflected higher realized natural gas prices. North America natural gas royalties are anticipated to average 6% to 8% of product sales for 2017.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 5% for the first quarter of 2017, compared with 4% of product sales for the first quarter of 2016 and 4% for the fourth quarter of 2016. Royalties as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields. Offshore Africa royalty rates are anticipated to average 7% to 9% of product sales for 2017.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2017	Dec 31 2016	Mar 31 2016
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 12.22**	$ 12.13	$ 11.46
North Sea	**$ 36.86**	$ 41.66	$ 47.69
Offshore Africa (2)	**$ 18.54**	$ 19.05	$ 17.07
Company average	**$ 14.37**	$ 14.28	$ 13.94
Natural gas ($/Mcf) (1)			
North America	**$ 1.20**	$ 1.07	$ 1.18
North Sea	**$ 3.07**	$ 3.36	$ 4.09
Offshore Africa	**$ 3.50**	$ 2.68	$ 1.29
Company average	**$ 1.28**	$ 1.15	$ 1.23
Company average ($/BOE) (1)	**$ 11.67**	$ 11.34	$ 11.19

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

(2) Offshore Africa production expense of $18.54 per bbl for the first quarter of 2017 was comprised of production expense of $9.10 per bbl relating to the Baobab and Espoir fields, Côte d'Ivoire and $9.44 per bbl relating to the Olowi field, Gabon.

North America

North America crude oil and NGLs production expense for the first quarter of 2017 of $12.22 per bbl increased 7% from $11.46 per bbl in the first quarter of 2016 and was comparable with the fourth quarter of 2016.The Company continues to successfully manage its production costs and achieve efficiencies across the asset base, through focused cost and production optimization. Production costs during the first quarter of 2017 as compared with the first quarter of 2016 reflected higher fuel costs in thermal production. North America crude oil and NGLs production expense is anticipated to average $11.50 to $13.50 per bbl for 2017.

North America natural gas production expense for the first quarter of 2017 of $1.20 per Mcf was comparable with the first quarter of 2016 and increased 12% from $1.07 per Mcf for the fourth quarter of 2016. Consistent with crude oil and NGLs production costs, the Company continues to successfully manage its natural gas production costs and achieve efficiencies across the asset base, through focused cost and production optimization. The increase in production costs for the first quarter of 2017 from the fourth quarter of 2016 primarily reflected the impact of seasonality. North America natural gas production expense guidance is anticipated to average $1.00 to $1.20 per Mcf for 2017.

North Sea

North Sea crude oil production expense for the first quarter of 2017 decreased 23% to $36.86 per bbl from $47.69 per bbl for the first quarter of 2016 and decreased 12% from $41.66 per bbl in the fourth quarter of 2016. The Company continues to successfully manage its production costs and achieve efficiencies through focused cost and production optimization. Fluctuations in production expense also reflected fluctuations in the Canadian dollar and the weakening of the UK pound sterling. North Sea crude oil production expense guidance is anticipated to average $33.00 to $36.00 per bbl for 2017.

Offshore Africa

Offshore Africa crude oil production expense of $18.54 per bbl for the first quarter of 2017 included production expense of $9.10 per bbl relating to the Baobab and Espoir fields in Côte d'Ivoire. Fluctuations in Offshore Africa crude oil production expense for the first quarter of 2017 from the comparable periods reflected the timing of liftings from various fields, which have different cost structures, fluctuating production volumes on a relatively fixed cost base and fluctuations in the Canadian dollar.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2017**	Dec 31 2016	Mar 31 2016
Expense	**$ 1,102**	$ 1,049	$ 1,069
$/BOE (1)	**$ 17.68**	$ 16.71	$ 16.60

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

Depletion, depreciation and amortization expense on a per barrel basis for the first quarter of 2017 increased 7% to $17.68 per BOE from $16.60 per BOE for the first quarter of 2016 and increased 6% from $16.71 per BOE for the fourth quarter of 2016. The increase in depletion, depreciation and amortization expense on a total and per BOE basis for the first quarter of 2017 from comparable periods reflected depletion of $151 million in the North Sea during the first quarter of 2017 related to the planned abandonment of the Ninian North platform, partially offset by a lower depletable base in North America.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2017**	Dec 31 2016	Mar 31 2016
Expense	**$ 28**	$ 28	$ 29
$/BOE (1)	**$ 0.45**	$ 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 2017 on a per BOE basis was consistent with comparable periods.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

The Company continues to focus on reliable and efficient operations. Horizon achieved record SCO production during the first quarter of 2017 averaging 192,491 bbl/d, exceeding plant nameplate capacity of 182,000 bbl/d, following the completion of the major turnaround and the successful tie-in of Phase 2B during the third quarter of 2016. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, together with additional Phase 2B capacity, cash production costs averaging $22.08 per bbl were achieved in the first quarter.

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

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

	Three Months Ended		
($/bbl) [1]	**Mar 31 2017**	Dec 31 2016	Mar 31 2016
SCO sales price	**$ 67.85**	$ 64.51	$ 46.63
Bitumen value for royalty purposes [2]	**$ 36.07**	$ 35.92	$ 11.29
Bitumen royalties [3]	**$ 1.14**	$ 0.88	$ 0.13
Transportation	**$ 1.17**	$ 1.22	$ 2.07

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

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

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

Realized SCO sales prices averaged $67.85 per bbl for the first quarter of 2017, an increase of 46% compared with $46.63 per bbl for the first quarter of 2016 and an increase of 5% compared with $64.51 per bbl for the fourth quarter of 2016. The increase in SCO pricing for the first quarter of 2017 from comparable periods were primarily due to changes in 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 15 to the Company's unaudited interim consolidated financial statements.

	Three Months Ended		
($ millions)	**Mar 31 2017**	Dec 31 2016	Mar 31 2016
Cash production costs, excluding natural gas costs	**$ 339**	$ 336	$ 282
Natural gas costs	**33**	40	15
Cash production costs	**$ 372**	$ 376	$ 297

	Three Months Ended		
($/bbl) [1]	**Mar 31 2017**	Dec 31 2016	Mar 31 2016
Cash production costs, excluding natural gas costs	**$ 20.11**	$ 20.17	$ 25.17
Natural gas costs	**1.97**	2.36	1.38
Cash production costs	**$ 22.08**	$ 22.53	$ 26.55
Sales (bbl/d)	**187,276**	181,523	123,047

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

Cash production costs for the first quarter of 2017 averaged $22.08 per bbl, a decrease of 17% from $26.55 per bbl for the first quarter of 2016 and a decrease of 2% from $22.53 per bbl for the fourth quarter of 2016. The decrease in cash production costs on a per barrel basis for the first quarter of 2017 from comparable periods primarily reflected the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, together with additional

Phase 2B capacity. For 2017, cash production costs are anticipated to average $24.00 to $27.00 per bbl, including turnaround costs.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($ millions, except per bbl amounts)	**Mar 31 2017**	Dec 31 2016	Mar 31 2016
Depletion, depreciation and amortization	**$ 195**	$ 198	$ 147
$/bbl	**$ 11.58**	$ 11.84	$ 13.11

Depletion, depreciation and amortization expense on a per barrel basis for the first quarter of 2017 decreased 12% to $11.58 per bbl from $13.11 per bbl for the first quarter of 2016 and decreased 2% from $11.84 per bbl for the fourth quarter of 2016.

Depletion, depreciation and amortization expense per barrel for the first quarter of 2017 was comparable with the fourth quarter of 2016 and decreased from the first quarter of 2016 primarily due to the impact of increased production volumes on assets depreciated on a straight line basis.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($ millions, except per bbl amounts)	**Mar 31 2017**	Dec 31 2016	Mar 31 2016
Expense	**$ 8**	$ 7	$ 7
$/bbl (1)	**$ 0.46**	$ 0.44	$ 0.65

(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 $0.46 per bbl for the first quarter of 2017 decreased 29% from $0.65 per bbl the first quarter of 2016 and increased 5% from $0.44 per bbl for the fourth quarter of 2016, primarily due to fluctuations in sales volumes.

MIDSTREAM

	Three Months Ended		
($ millions)	**Mar 31 2017**	Dec 31 2016	Mar 31 2016
Revenue	**$ 25**	$ 26	$ 26
Production expense	**4**	5	6
Midstream cash flow	**21**	21	20
Depreciation	**2**	2	3
Equity (gain) loss on investment	**(2)**	12	(26)
Gain on corporate disposition	**—**	(218)	—
Segment earnings before taxes	**$ 21**	$ 225	$ 43

On December 16, 2016, in the Midstream segment, the Company disposed of its interest in the Cold Lake Pipeline, including $321 million of property, plant and equipment for total net consideration of $539 million, resulting in a pre-tax gain of $218 million. Total net consideration was comprised of $349 million in cash, together with $190 million of non-cash share consideration of approximately 6.4 million common shares of Inter Pipeline with a value of $29.57 per common share, determined as of the closing date.

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

During 2013, the Company along with APMC, committed each to provide funding up to $350 million by each party by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. To date, each party has provided $324 million of subordinated debt, together with accrued interest thereon of $70 million for a Company total of $394 million. In 2014, the Partnership set the facility capital cost ("FCC") budget at $8,500 million, which was increased by approximately 4% to the current estimate of $8,900 million. A higher than expected USD/CAD exchange rate, scope changes, and productivity challenges during construction have resulted in upward budgetary pressures. The cumulative effect of these changes may result in a further increase in FCC of between 3% and 6%. Partially offsetting these FCC increases are lower than budgeted interest rates which the Partnership has been able to lock in to date.

The Company and APMC have agreed, each with a 50% interest, to provide additional subordinated debt as required for Project costs in excess of the FCC of $8,500 million to reflect an agreed debt to equity ratio of 80/20 and, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion which is currently targeted for mid-2018. The Company's share of any additional subordinated debt financing resulting from the increase in the FCC in excess of $8,500 million is not expected to be significant.

As at March 31, 2017, Redwater Partnership had additional borrowings of $2,044 million under its secured $3,500 million syndicated credit facility.

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

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

ADMINISTRATION EXPENSE

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2017**	Dec 31 2016	Mar 31 2016
Expense	**$ 87**	$ 86	$ 86
$/BOE (1)	**$ 1.10**	$ 1.08	$ 1.14

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

Administration expense for the first quarter of 2017 of $1.10 per BOE decreased 4% from $1.14 per BOE for the first quarter of 2016 and was comparable with $1.08 per BOE for the fourth quarter of 2016. Administration expense per BOE was consistent with comparable quarters due to the Company's continuous focus on cost control.

SHARE-BASED COMPENSATION

	Three Months Ended		
($ millions)	**Mar 31 2017**	Dec 31 2016	Mar 31 2016
Expense	**$ 27**	$ 42	$ 117

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

The Company recorded a $27 million share-based compensation expense for the first quarter of 2017, primarily as a result of remeasurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period and changes in the Company’s share price. For the first quarter of 2017, the Company capitalized $3 million of share-based compensation costs to property, plant and equipment in the Oil Sands Mining and Upgrading segment (March 31, 2016 – $23 million).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)		Three Months Ended **Mar 31 2017**		Dec 31 2016		Mar 31 2016
Expense, gross	**$**	**156**	$	153	$	153
Less: capitalized interest		**22**		38		61
Expense, net	**$**	**134**	$	115	$	92
$/BOE [(1)]	**$**	**1.70**	$	1.43	$	1.22
Average effective interest rate		**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 was consistent with comparable periods. Capitalized interest of $22 million for the first quarter of 2017 was primarily related to the Horizon Phase 3 expansion.

Net interest and other financing expense on a per BOE basis for the first quarter of 2017 increased 39% to $1.70 per BOE from $1.22 per BOE for the first quarter of 2016 and increased 19% from $1.43 per BOE for the fourth quarter of 2016. The increase for the first quarter of 2017 from the first quarter of 2016 and the fourth quarter of 2016 was primarily due to lower capitalized interest related to the completion of Horizon Phase 2B. The Company's average effective interest rates for the first quarter of 2017 was consistent with the comparable periods.

RISK MANAGEMENT ACTIVITIES

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

($ millions)		Three Months Ended **Mar 31 2017**		Dec 31 2016		Mar 31 2016
Crude oil and NGLs financial instruments	**$**	**(1)**	$	—	$	—
Natural gas financial instruments		**—**		—		—
Foreign currency contracts		**(11)**		(14)		(4)
Realized gain		**(12)**		(14)		(4)
Crude oil and NGLs financial instruments		**(43)**		—		—
Natural gas financial instruments		**(8)**		8		—
Foreign currency contracts		**11**		(15)		74
Unrealized (gain) loss		**(40)**		(7)		74
Net (gain) loss	**$**	**(52)**	$	(21)	$	70

During the first quarter of 2017, net realized risk management gains were related to the settlement of foreign currency contracts. The Company recorded a net unrealized gain of $40 million ($31 million after-tax) on its risk management activities for the first quarter of 2017 (December 31, 2016 - unrealized gain of $7 million; $7 million after-tax; March 31, 2016 – unrealized loss of $74 million; $63 million after-tax).

Complete details related to outstanding derivative financial instruments at March 31, 2017 are disclosed in note 13 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

($ millions)	Three Months Ended Mar 31 2017	Dec 31 2016	Mar 31 2016
Net realized loss (gain)	**$ 4**	$ (2)	$ 19
Net unrealized (gain) loss	**(60)**	162	(334)
Net (gain) loss (1)	**$ (56)**	$ 160	$ (315)

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

The net realized foreign exchange loss for the first quarter of 2017 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for the first quarter of 2017 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized (gain) loss for each of the periods presented included the impact of cross currency swaps (three months ended March 31, 2017 – unrealized loss of $23 million, December 31, 2016 – unrealized gain of $67 million, March 31, 2016 – unrealized loss of $348 million). The US/Canadian dollar exchange rate at March 31, 2017 was US$0.7506 (December 31, 2016 – US$0.7448, March 31, 2016 – US$0.7710).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Mar 31 2017	Dec 31 2016	Mar 31 2016
North America (1)	**$ 38**	$ (22)	$ (119)
North Sea	**6**	—	(23)
Offshore Africa	**7**	5	4
PRT recovery – North Sea	**(1)**	(35)	(55)
Other taxes	**3**	3	1
Current income tax expense (recovery)	**53**	(49)	(192)
Deferred corporate income tax expense (recovery)	**28**	(55)	33
Deferred PRT expense (recovery) – North Sea	**8**	9	(204)
Deferred income tax expense (recovery)	**36**	(46)	(171)
	89	(95)	(363)
Income tax rate and other legislative changes (2)	**—**	—	114
	$ 89	$ (95)	$ (249)
Effective income tax rate on adjusted net earnings (loss) from operations (3)	**20%**	20%	29%

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

(2) During the first quarter of 2016 the UK government enacted tax rate reductions relating to PRT, resulting in a decrease in the Company's net deferred income tax liability of $114 million.

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

The effective income tax rate for the first quarter of 2017 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income (loss) and tax rates in the countries in which the Company operates, in relation to net earnings (loss). In addition, the effective income tax rate for the three months ended December 31, 2016 also reflected the successful resolution of certain prior year tax matters.

The current corporation income tax and PRT recoveries in the North Sea in the first quarter of 2017 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the Murchison platform.

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

For 2017, the Company expects to recognize current income tax expense of $100 million to $150 million in Canada and $15 million to $35 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Mar 31 2017	Dec 31 2016	Mar 31 2016
Exploration and Evaluation			
Net expenditures (proceeds) [2] [3]	**$ 37**	$ 4	$ (30)
Property, Plant and Equipment			
Net property acquisitions [2] [3]	**9**	1	31
Well drilling, completion and equipping	**340**	200	228
Production and related facilities	**167**	50	121
Capitalized interest and other [4]	**21**	26	24
Net expenditures	**537**	277	404
Total Exploration and Production	**574**	281	374
Oil Sands Mining and Upgrading			
Horizon Phases 2/3 construction costs	**139**	515	422
Sustaining capital	**67**	76	76
Turnaround costs	**1**	(3)	6
Capitalized interest and other [4]	**20**	40	81
Total Oil Sands Mining and Upgrading	**227**	628	585
Midstream [5]	**1**	(537)	1
Abandonments [6]	**41**	35	74
Head office	**3**	4	6
Total net capital expenditures	**$ 846**	$ 411	$ 1,040
By segment			
North America [2] [3]	**$ 520**	$ 221	$ 249
North Sea	**35**	37	16
Offshore Africa	**19**	23	109
Oil Sands Mining and Upgrading	**227**	628	585
Midstream [5]	**1**	(537)	1
Abandonments [6]	**41**	35	74
Head office	**3**	4	6
Total	**$ 846**	$ 411	$ 1,040

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values and other fair value 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) The above noted figures in the fourth quarter of 2016 include non-cash share consideration of $190 million received from Inter Pipeline on the disposition of Midstream assets.

(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 2017 were $846 million compared with $1,040 million for the first quarter of 2016 and $411 million for the fourth quarter of 2016.

Drilling Activity

	Three Months Ended		
(number of wells)	**Mar 31 2017**	Dec 31 2016	Mar 31 2016
Net successful natural gas wells	**11**	4	4
Net successful crude oil wells (1)	**155**	81	8
Dry wells	**1**	3	—
Stratigraphic test / service wells	**226**	62	199
Total	**393**	150	211
Success rate (excluding stratigraphic test / service wells)	**99%**	97%	100%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 63% of the total net capital expenditures for the first quarter of 2017 compared with approximately 26% for the first quarter of 2016.

During the first quarter of 2017, the Company targeted 12 net natural gas wells, including 4 wells in Northeast British Columbia, 7 wells in Northwest Alberta and 1 well in Northern Plains. The Company also targeted 155 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 122 primary heavy crude oil wells, 2 Pelican Lake heavy crude oil wells, 1 light crude oil and 8 bitumen (thermal oil) wells were drilled. Another 22 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for the first quarter of 2017 averaged approximately 128,400 bbl/d compared with approximately 118,100 bbl/d for the first quarter of 2016 and approximately 129,300 bbl/d for the fourth quarter of 2016. Quarterly fluctuations in production volumes reflect the cyclic nature of thermal oil production at Primrose.

Operating performance at the Pelican Lake tertiary recovery project continued to be strong, leading to average production of approximately 46,600 bbl/d in the first quarter of 2017 compared with 47,600 bbl/d in the first quarter of 2016 and 47,500 bbl/d in the fourth quarter of 2016.

Oil Sands Mining and Upgrading

Horizon Phase 2 Plants are all commissioned and activity during the quarter focused on optimization of plant production. Phase 3 expansion work also continued with field construction of the combined hydrotreater and sulphur recovery units.

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

North Sea

During the first quarter of 2017, the Company completed one injection well (0.9 on a net basis) at Ninian. Subsequent to March 31, 2017, the Company completed one production well (0.9 on a net basis) at Ninian.

The Company targets to commence decommissioning activities at the Ninian North platform in the second quarter of 2017.

Proposed Acquisitions of Interests in the Athabasca Oil Sands Project

On March 9, 2017, the Company announced that it had entered into agreements to acquire 70% of the Athabasca Oil Sands Project, as well as additional working interests in certain other producing and non-producing oil and gas properties, for preliminary total consideration of approximately $12.7 billion, comprised of cash of approximately $8.7 billion and 97,560,975 common shares of the Company, with an estimated value of approximately $4 billion as at the announcement date. The transaction is expected to close in mid-2017, subject to receipt of all required consents and regulatory and other approvals, all of which are progressing in the normal course. In connection with the Company's proposed acquisitions of interests in the Athabasca Oil Sands Project, the Company has arranged fully committed acquisition financing of $9 billion comprised of a $3 billion term loan facility and up to $6 billion in bridge facility to bonds in US and Canadian debt capital markets.

Additional information regarding the proposed acquisitions of interests in the Athabasca Oil Sands Project is available in the Company's material change report dated March 20, 2017, available on SEDAR and EDGAR. The information in this MD&A relates to the Company's operations for the three months ended March 31, 2017 and does not reflect closing of the proposed acquisitions.

LIQUIDITY AND CAPITAL RESOURCES

	Three Months Ended		
($ millions, except ratios)	**Mar 31 2017**	Dec 31 2016	Mar 31 2016
Working capital (1)	**$ 1,222**	$ 1,056	$ 833
Long-term debt (2) (3)	**$ 16,304**	$ 16,805	$ 16,564
Share capital	**$ 4,869**	$ 4,671	$ 4,576
Retained earnings	**21,465**	21,526	22,408
Accumulated other comprehensive income	**43**	70	12
Shareholders' equity	**$ 26,377**	$ 26,267	$ 26,996
Debt to book capitalization (3) (4)	**38%**	39%	38%
Debt to market capitalization (3) (5)	**25%**	26%	30%
After-tax return on average common shareholders' equity (6)	**1%**	(1%)	(2)%
After-tax return on average capital employed (3) (7)	**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 current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.

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

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

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

At March 31, 2017, the Company's capital resources consisted primarily of funds flow from operations, available bank credit facilities and access to debt capital markets. Funds flow from operations and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2016. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated funds flow from operations supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy. On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring funds flow from operations, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. In response to the current commodity price environment, the Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing the Company's borrowing capacity:
    - The Company has $2,000 million remaining on its base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in November 2017. 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.
    - The Company has US$3,000 million remaining on its base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in November 2017. 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.
    - 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 the US commercial paper program.
    - As at March 31, 2017, the $750 million and $125 million facilities were each fully drawn. Borrowings under the $750 million and $125 million non-revolving credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.
- 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 to minimize the impact in the event of a default.

At March 31, 2017, the Company had in place bank credit facilities of $7,350 million, of which approximately $3,476 million, net of commercial paper issuances of $333 million, was available for general corporate purposes.

At March 31, 2017, the Company had total US dollar denominated debt with a carrying amount of $10,525 million (US $7,902 million), excluding transaction costs. This included $4,399 million (US$3,302 million) hedged by way of cross currency swaps (US$2,150 million) and foreign currency forwards (US$1,152 million). The fixed repayment amount of these hedging instruments is $3,973 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $425 million to $10,100 million as at March 31, 2017.

Long-term debt was $16,304 million at March 31, 2017, resulting in a debt to book capitalization ratio of 38% (December 31, 2016 – 39%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when funds flow from operations is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. In connection with the Company's proposed acquisitions of interests in the Athabasca Oil Sands Project, the Company has arranged fully committed acquisition financing of $9 billion comprised of a $3 billion term loan facility and up to $6 billion in bridge facility to bonds in US and Canadian debt capital markets. The terms and conditions of the $6 billion in bridge facility financing of the proposed acquisitions of interests in the Athabasca Oil Sands Project, including interest rates and tenor, are dependent upon market conditions at the time of issuance.

Upon completion of the proposed acquisitions of interests in Athabasca Oil Sands Project, the Company is targeting to maintain its debt to book capitalization metric within its targeted range of 25% to 45%, with 2017 exit debt to book capitalization of approximately 41% compared with 38% at March 31, 2017.

Further details related to the Company's long-term debt at March 31, 2017 are discussed in note 6 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedge policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. At March 31, 2017, 50,000 GJ/d of currently forecasted natural gas volumes were hedged using AECO swaps for April 2017 to October 2017, and 67,500 bbl/d of currently forecasted crude oil volumes were hedged using WTI collars for April 2017 to December 2017. Further details related to the Company's commodity derivative financial instruments at March 31, 2017 are discussed in note 13 of the Company's unaudited interim consolidated financial statements.

Share Capital

As at March 31, 2017, there were 1,115,606,000 common shares outstanding (December 31, 2016 – 1,110,952,000 common shares) and 54,741,000 stock options outstanding. As at May 2, 2017, the Company had 1,117,185,000 common shares outstanding and 53,000,000 stock options outstanding.

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

On March 1, 2017 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 27,814,309 common shares, over a 12 month period. The Company targets the Normal Course Issuer Bid to commence in May 2017, upon receipt of applicable regulatory and other approvals.

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, 2017:

($ millions)	Remaining 2017	2018	2019	2020	2021	Thereafter
Product transportation and pipeline	$ 349	$ 450	$ 327	$ 311	$ 260	$ 2,317
Offshore equipment operating leases and offshore drilling	$ 174	$ 192	$ 98	$ 74	$ 73	$ 8
Long-term debt (1) (2)	$ 1,798	$ 2,828	$ 2,369	$ 1,676	$ 666	$ 7,029
Interest and other financing expense (3)	$ 412	$ 530	$ 468	$ 431	$ 393	$ 4,095
Office leases	$ 32	$ 43	$ 43	$ 42	$ 40	$ 152
Other	$ 41	$ 2	$ 2	$ 2	$ 2	$ 35

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

(2) Included in the 2017 long-term debt repayment commitments, the Company had US$1,100 million of 5.70% debt securities due May 2017, hedged by way of a cross currency swap with a principal repayment amount fixed at $1,287 million.

(3) Interest and other financing expense amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at March 31, 2017.

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

CHANGES IN ACCOUNTING POLICIES

For the impact of new accounting standards, refer to the audited consolidated financial statements for the year ended December 31, 2016 and the unaudited interim financial statements for the three months ended March 31, 2017.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results 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, 2016.