Canadian Natural Resources Limited

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE MONTHS AND YEAR ENDED DECEMBER 31, 2016

Forward-Looking Statements

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

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

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; 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 and year ended December 31, 2016 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2015.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company’s unaudited interim consolidated financial statements for the period ended December 31, 2016 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.

The following discussion and analysis refers primarily to the Company’s financial results for the three months and year ended December 31, 2016 in relation to the comparable periods in 2015 and the third 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, 2015, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated March 1, 2017.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Dec 31 2016**	Sep 30 2016	Dec 31 2015	Year Ended **Dec 31 2016**	Dec 31 2015
Product sales	**$ 3,672**	$ 2,477	$ 2,963	**$ 11,098**	$ 13,167
Net earnings (loss)	**$ 566**	$ (326)	$ 131	**$ (204)**	$ (637)
Per common share – basic	**$ 0.51**	$ (0.29)	$ 0.12	**$ (0.19)**	$ (0.58)
– diluted	**$ 0.51**	$ (0.29)	$ 0.12	**$ (0.19)**	$ (0.58)
Adjusted net earnings (loss) from operations (1)	**$ 439**	$ (355)	$ (49)	**$ (669)**	$ 263
Per common share – basic	**$ 0.40**	$ (0.32)	$ (0.04)	**$ (0.61)**	$ 0.24
– diluted	**$ 0.40**	$ (0.32)	$ (0.04)	**$ (0.61)**	$ 0.24
Funds flow from operations (2)	**$ 1,677**	$ 1,021	$ 1,379	**$ 4,293**	$ 5,785
Per common share – basic	**$ 1.52**	$ 0.93	$ 1.26	**$ 3.90**	$ 5.29
– diluted	**$ 1.50**	$ 0.92	$ 1.26	**$ 3.89**	$ 5.28
Net capital expenditures	**$ 411**	$ 1,185	$ (96)	**$ 3,794**	$ 3,853

(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 Dec 31 2016	Sep 30 2016	Dec 31 2015	Year Ended Dec 31 2016	Dec 31 2015
Net earnings (loss) as reported	**$ 566**	$ (326)	$ 131	**$ (204)**	$ (637)
Share-based compensation, net of tax (1)	**42**	74	56	**355**	(46)
Unrealized risk management (gain) loss, net of tax (2)	**(7)**	11	128	**21**	275
Unrealized foreign exchange loss (gain), net of tax (3)	**162**	39	170	**(93)**	858
(Gain) loss from investments, net of tax (4)(5)	**(106)**	(46)	23	**(299)**	55
Gain on disposition of properties and corporate acquisitions and dispositions, net of tax (6)	**(218)**	—	(627)	**(241)**	(663)
Derecognition of exploration and evaluation assets, net of tax (7)	**—**	—	70	**13**	70
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (8)	**—**	(107)	—	**(221)**	351
Adjusted net earnings (loss) from operations	**$ 439**	$ (355)	$ (49)	**$ (669)**	$ 263

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

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

(6) During the 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. During the fourth quarter of 2015, the Company recorded a pre-tax gain of $690 million ($627 million after-tax) related to the disposition of a number of North America royalty income assets. During the third quarter of 2015, the Company recorded a pre-tax gain of $49 million ($36 million after-tax) related to the disposition of a number of North America crude oil and natural gas properties.

(7) In connection with the Company's notice of withdrawal from Block CI-12 in Côte d'Ivoire, Offshore Africa in the second quarter of 2016, the Company derecognized $18 million ($13 million after-tax) of exploration and evaluation assets through depletion, depreciation and amortization expense. In connection with the Company's notice of withdrawal from Block CI-514 in Côte d'Ivoire, Offshore Africa in the fourth quarter of 2015, the Company derecognized $96 million ($70 million after-tax) of exploration and evaluation assets through depletion, depreciation and amortization expense.

(8) In the third quarter of 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. During the first quarter of 2016, the UK government enacted tax rate reductions relating to Petroleum Revenue Tax ("PRT"), resulting in a decrease in the Company's net deferred income tax liability of $114 million. During the second quarter of 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015 resulting in an increase in the Company's deferred corporate income tax liability of $579 million. During the first quarter of 2015, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and PRT, and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in the Company's net deferred income tax liability of $228 million.

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

($ millions)	Three Months Ended **Dec 31 2016**	 Sep 30 2016	 Dec 31 2015	Year Ended **Dec 31 2016**	 Dec 31 2015
Net earnings (loss)	***$ 566***	*$ (326)*	*$ 131*	***$ (204)***	*$ (637)*
Non-cash items:					
Depletion, depreciation and amortization	***1,249***	*1,216*	*1,472*	***4,858***	*5,483*
Share-based compensation	***42***	*74*	*56*	***355***	*(46)*
Asset retirement obligation accretion	***35***	*36*	*43*	***142***	*173*
Unrealized risk management (gain) loss	***(7)***	*10*	*174*	***25***	*374*
Unrealized foreign exchange loss (gain)	***162***	*39*	*170*	***(93)***	*858*
(Gain) loss from investments	***(106)***	*(46)*	*23*	***(299)***	*55*
Deferred income tax (recovery) expense	***(46)***	*18*	*(33)*	***(241)***	*231*
Gain on disposition of properties and corporate acquisitions and dispositions	***(218)***	—	*(690)*	***(250)***	*(739)*
Current income tax on disposition of properties	**—**	—	*33*	**—**	*33*
Funds flow from operations	***$ 1,677***	*$ 1,021*	*$ 1,379*	***$ 4,293***	*$ 5,785*

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

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

($ millions)	Three Months Ended **Dec 31 2016**	 Sep 30 2016	 Dec 31 2015	Year Ended **Dec 31 2016**	 Dec 31 2015
Cash flows from operating activities	***$ 1,255***	*$ 899*	*$ 1,485*	***$ 3,452***	*$ 5,632*
Net change in non-cash working capital	***317***	*14*	*(314)*	***542***	*(239)*
Abandonment expenditures	***35***	*122*	*105*	***267***	*370*
Other	***70***	*(14)*	*103*	***32***	*22*
Funds flow from operations	***$ 1,677***	*$ 1,021*	*$ 1,379*	***$ 4,293***	*$ 5,785*

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

The net loss for the year ended December 31, 2016 was $204 million compared with a net loss of $637 million for the year ended December 31, 2015. The net loss for the year ended December 31, 2016 included net after-tax income of $465 million compared with net after-tax expenses of $900 million for the year ended December 31, 2015 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, (gain) loss from investments, gain on disposition of properties and corporate acquisitions and dispositions, derecognition of exploration and evaluation assets and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, the adjusted net loss from operations for the year ended December 31, 2016 was $669 million compared with adjusted net earnings of $263 million for the year ended December 31, 2015.

Net earnings for the fourth quarter of 2016 were $566 million compared with net earnings of $131 million for the fourth quarter of 2015 and a net loss of $326 million for the third quarter of 2016. Net earnings for the fourth quarter of 2016 included net after-tax income of $127 million compared with net after-tax income of $180 million for the fourth quarter of 2015 and net after-tax income of $29 million for the third quarter of 2016 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, (gain) loss from investments, gains on disposition of properties and corporate acquisitions and dispositions, derecognition of exploration and evaluation assets and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2016 were $439 million compared with an adjusted net loss of $49 million for the fourth quarter of 2015 and an adjusted net loss of $355 million for the third quarter of 2016.

The decrease in adjusted net earnings (loss) for the year ended December 31, 2016 from the year ended December 31, 2015 was primarily due to:

- lower crude oil and NGLs sales volumes in the North America segment;
- lower natural gas netbacks in the Exploration and Production segments;
- lower crude oil and NGLs netbacks in the North America segment; and
- lower realized risk management gains;

partially offset by:

- higher crude oil and NGLs sales volumes in the Offshore Africa segment; and
- the weakening of the Canadian dollar.

The increase in adjusted net earnings (loss) for the fourth quarter of 2016 from the fourth quarter of 2015 and the third 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 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 (loss) and are discussed in detail in the relevant sections of this MD&A.

Funds flow from operations for the year ended December 31, 2016 was $4,293 million compared with $5,785 million for the year ended December 31, 2015. Funds flow from operations for the fourth quarter of 2016 was $1,677 million compared with $1,379 million for the fourth quarter of 2015 and $1,021 million for the third 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 and depletion, depreciation and amortization.

Total production before royalties for the fourth quarter of 2016 of 859,577 BOE/d was comparable to 855,800 BOE/d for the fourth quarter of 2015 and increased 17% from 735,212 BOE/d for the third 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)		**Dec 31 2016**		Sep 30 2016		Jun 30 2016		Mar 31 2016
Product sales	**$**	**3,672**	$	2,477	$	2,686	$	2,263
Net earnings (loss)	**$**	**566**	$	(326)	$	(339)	$	(105)
Net earnings (loss) per common share								
– basic	**$**	**0.51**	$	(0.29)	$	(0.31)	$	(0.10)
– diluted	**$**	**0.51**	$	(0.29)	$	(0.31)	$	(0.10)
($ millions, except per common share amounts)		Dec 31 2015		Sep 30 2015		Jun 30 2015		Mar 31 2015
Product sales	$	2,963	$	3,316	$	3,662	$	3,226
Net earnings (loss)	$	131	$	(111)	$	(405)	$	(252)
Net earnings (loss) per common share								
– basic	$	0.12	$	(0.10)	$	(0.37)	$	(0.23)
– diluted	$	0.12	$	(0.10)	$	(0.37)	$	(0.23)

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 an outage 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, 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 investments** – Fluctuations due to the recognition of gains on disposition of properties in the various periods and fair value changes in the investment in PrairieSky and Inter Pipeline shares.

BUSINESS ENVIRONMENT

	Three Months Ended						Year Ended			
		Dec 31 2016		Sep 30 2016		Dec 31 2015		**Dec 31 2016**		Dec 31 2015
WTI benchmark price (US$/bbl)	**$**	**49.33**	$	44.94	$	42.17	**$**	**43.37**	$	48.76
Dated Brent benchmark price (US$/bbl)	**$**	**50.27**	$	45.76	$	43.59	**$**	**43.96**	$	52.40
WCS blend differential from WTI (US$/bbl)	**$**	**14.59**	$	13.49	$	14.48	**$**	**13.91**	$	13.51
WCS blend differential from WTI (%)		**30%**		30%		34%		**32%**		28%
SCO price (US$/bbl)	**$**	**48.91**	$	45.63	$	42.77	**$**	**43.94**	$	48.59
Condensate benchmark price (US$/bbl)	**$**	**48.37**	$	43.05	$	41.67	**$**	**42.51**	$	47.34
NYMEX benchmark price (US$/MMBtu)	**$**	**2.99**	$	2.81	$	2.28	**$**	**2.45**	$	2.67
AECO benchmark price (C$/GJ)	**$**	**2.67**	$	2.08	$	2.51	**$**	**1.98**	$	2.62
US/Canadian dollar average exchange rate (US$)	**$**	**0.7496**	$	0.7663	$	0.7489	**$**	**0.7548**	$	0.7820

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 three months and year ended December 31, 2016, 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$43.37 per bbl for the year ended December 31, 2016, a decrease of 11% from US$48.76 per bbl for the year ended December 31, 2015. WTI averaged US$49.33 per bbl for the fourth quarter of 2016, an increase of 17% from US$42.17 per bbl for the fourth quarter of 2015, and an increase of 10% from $44.94 per bbl for the third 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$43.96 per bbl for the year ended December 31, 2016, a decrease of 16% from US$52.40 per bbl for the year ended December 31, 2015. Brent averaged US$50.27 per bbl for the fourth quarter of 2016, an increase of 15% from US$43.59 per bbl for the fourth quarter of 2015, and an increase of 10% from $45.76 per bbl for the third quarter of 2016.

WTI and Brent pricing for the three months and year ended December 31, 2016 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 fourth quarter pricing from comparable quarters.

The WCS Heavy Differential averaged 32% for the year ended December 31, 2016, compared with 28% for the year ended December 31, 2015. The WCS Heavy Differential averaged 30% for the fourth quarter of 2016 compared with 34% for the fourth quarter of 2015 and 30% for the third quarter of 2016. Fluctuations in the WCS Heavy Differential reflected seasonal demand, changes in transportation logistics, and refinery utilization and shutdowns.

The SCO price averaged US$43.94 per bbl for the year ended December 31, 2016, a decrease of 10% from US$48.59 per bbl for the year ended December 31, 2015. The SCO price averaged US$48.91 per bbl for the fourth quarter of 2016, an increase of 14% from $42.77 per bbl for the fourth quarter of 2015, and an increase of 7% from US$45.63 per bbl for the third quarter of 2016. The fluctuations in SCO pricing for the three months and year ended December 31, 2016 from the comparable periods were primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.45 per MMBtu for the year ended December 31, 2016, a decrease of 8% from US$2.67 per MMBtu for the year ended December 31, 2015. NYMEX natural gas prices averaged US$2.99 per MMBtu for the fourth quarter of 2016, an increase of 31% from $2.28 per MMBtu for the fourth quarter of 2015, and an increase of 6% from US$2.81 per MMBtu for the third quarter of 2016.

AECO natural gas prices averaged $1.98 per GJ for the year ended December 31, 2016, a decrease of 24% from $2.62 per GJ for the year ended December 31, 2015. AECO natural gas prices averaged $2.67 per GJ for the fourth quarter of 2016, an increase of 6% from $2.51 per GJ for the fourth quarter of 2015, and an increase of 28% from $2.08 per GJ for the third quarter of 2016.

The decrease in natural gas prices for 2016 compared with 2015 was primarily due to warmer than normal winter temperatures in the first quarter of 2016. US natural gas inventories were at near record high levels at the end of the 2015/2016 winter season, which resulted in weaker prices during storage injection.

The increase in natural gas prices in the fourth quarter of 2016 compared with the third quarter of 2016 and the fourth quarter of 2015 was primarily due to lower US natural gas production. Reduced supply resulted in natural gas storage inventories returning to historically normal levels by the end of 2016.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**361,348**	343,779	395,008	**350,958**	399,982
North America – Oil Sands Mining and Upgrading (1)	**178,063**	67,586	129,050	**123,265**	122,911
North Sea	**24,085**	23,450	23,110	**23,554**	22,216
Offshore Africa	**21,689**	26,171	24,832	**26,096**	19,079
	585,185	460,986	572,000	**523,873**	564,188
Natural gas (MMcf/d)					
North America	**1,578**	1,567	1,635	**1,622**	1,663
North Sea	**44**	50	36	**38**	36
Offshore Africa	**24**	28	32	**31**	27
	1,646	1,645	1,703	**1,691**	1,726
Total barrels of oil equivalent (BOE/d)	**859,577**	735,212	855,800	**805,782**	851,901
Product mix					
Light and medium crude oil and NGLs	**15%**	19%	16%	**17%**	16%
Pelican Lake heavy crude oil	**6%**	7%	6%	**6%**	6%
Primary heavy crude oil	**11%**	14%	14%	**13%**	15%
Bitumen (thermal oil)	**15%**	14%	16%	**14%**	15%
Synthetic crude oil (1)	**21%**	9%	15%	**15%**	14%
Natural gas	**32%**	37%	33%	**35%**	34%
Percentage of gross revenue (1) (2) (excluding Midstream revenue)					
Crude oil and NGLs	**85%**	83%	82%	**85%**	82%
Natural gas	**15%**	17%	18%	**15%**	18%

(1) Fourth quarter 2016 SCO production before royalties excludes 1,619 bbl/d of SCO consumed internally as diesel (third quarter 2016 – 1,464 bbl/d; fourth quarter 2015 – 2,337 bbl/d; year ended December 31, 2016 - 1,966 bbl/d; year ended December 31, 2015 - 2,122 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**315,090**	305,189	345,027	**311,059**	350,451
North America – Oil Sands Mining and Upgrading	**175,860**	67,008	127,968	**122,258**	121,208
North Sea	**24,034**	23,404	23,054	**23,497**	22,164
Offshore Africa	**20,730**	25,061	23,620	**24,995**	18,209
	535,714	420,662	519,669	**481,809**	512,032
Natural gas (MMcf/d)					
North America	**1,480**	1,497	1,568	**1,559**	1,606
North Sea	**44**	50	36	**38**	36
Offshore Africa	**23**	27	30	**30**	25
	1,547	1,574	1,634	**1,627**	1,667
Total barrels of oil equivalent (BOE/d)	**793,483**	682,944	792,083	**752,974**	789,799

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), SCO and natural gas.

Crude oil and NGLs production for the year ended December 31, 2016 decreased 7% to 523,873 bbl/d from 564,188 bbl/d for the year ended December 31, 2015. Crude oil and NGL production for the fourth quarter of 2016 of 585,185 bbl/d increased by 2% from 572,000 bbl/d for the fourth quarter of 2015, and increased by 27% from 460,986 bbl/d in the third quarter of 2016. The decrease in crude oil and NGL production for the year ended December 31, 2016 from 2015 was primarily due to lower drilling activity and natural field declines in North America, partially offset by increased production in the International segments. The increase in crude oil and NGLs production for the fourth quarter of 2016 from the fourth quarter of 2015 and the third 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.

Annual 2016 crude oil and NGLs production was within the Company's previously issued guidance of 514,000 to 563,000 bbl/d of crude oil and NGLs. For 2017, annual production guidance is targeted to average between 550,000 and 590,000 bbl/d of crude oil and NGLs. First quarter 2017 production guidance is targeted to average between 591,000 and 615,000 bbl/d of crude oil and NGLs.

Natural gas production for the year ended December 31, 2016 decreased 2% to 1,691 MMcf/d from 1,726 MMcf/d for the year ended December 31, 2015. Natural gas production for the fourth quarter of 2016 of 1,646 MMcf/d decreased 3% from 1,703 MMcf/d for the fourth quarter of 2015, and was comparable with the third quarter of 2016. Natural gas production for the three months and year ended December 31, 2016 decreased from the comparable periods in 2015 as a result of flood damage to a third party gathering system and facility in June 2016, together with the delay in the repair and reinstatement of full processing capacity. Due to the delay, the Company only averaged 76 MMcf/d of net sales volumes through the facility during the fourth quarter of 2016 compared to the Company's operated sales capacity of approximately 176 MMcf/d. Accordingly, fourth quarter 2016 production was approximately 100 MMcf/d less than it otherwise would have been had the facility been in full operation. Additionally, during the fourth quarter of 2016, third party pipeline transportation restrictions were 45 MMcf/d. On an annual basis, North America natural gas production volumes were impacted by approximately 70 MMcf/d due to the third party gathering system and facility outage and 31 MMcf/d due to third party transportation restrictions. The Company's sales volumes at the third party facility have increased subsequent to year end.

Annual 2016 natural gas production was below the Company's previously issued guidance of 1,705 to 1,735 MMcf/d of natural gas. Annual natural gas production guidance for 2017 is targeted to average between 1,700 and 1,760 MMcf/d. First quarter 2017 natural gas production guidance is targeted to average between 1,700 and 1,740 MMcf/d, an increase of approximately 74 MMcf/d compared to the fourth quarter of 2016 volumes at the midpoint of guidance.

North America – Exploration and Production

North America crude oil and NGLs production for the year ended December 31, 2016 decreased 12% to average 350,958 bbl/d from 399,982 bbl/d for the year ended December 31, 2015. North America crude oil and NGLs production for the fourth quarter of 2016 decreased 9% to 361,348 bbl/d from 395,008 bbl/d for the fourth quarter of 2015, and increased 5% from 343,779 bbl/d for the third quarter of 2016. The fluctuations in production for the three months and year ended December 31, 2016 from comparable periods primarily reflected lower drilling activity, natural field declines and the cyclic nature of thermal oil production at Primrose. Annual 2016 production of crude oil and NGLs was within the Company's previously issued guidance of 345,000 to 375,000 bbl/d. Annual production guidance for 2017 is targeted to average between 337,000 and 357,000 bbl/d of crude oil and NGLs. First quarter 2017 production guidance is targeted to average between 356,000 and 368,000 bbl/d of crude oil and NGLs.

Natural gas production for the year ended December 31, 2016 decreased 2% to average 1,622 MMcf/d from 1,663 MMcf/d for the year ended December 31, 2015. Natural gas production for the fourth quarter of 2016 decreased 3% to 1,578 MMcf/d from 1,635 MMcf/d for the fourth quarter of 2015, and was comparable with the third quarter of 2016. Natural gas production for the three months and year ended December 31, 2016 decreased from the comparable periods in 2015 as a result of flood damage to a third party gathering system and facility in June 2016, together with the delay in the repair and reinstatement of full processing capacity. Due to the delay, the Company only averaged 76 MMcf/d of net sales volumes through the facility during the fourth quarter of 2016 compared to the Company's operated sales capacity of approximately 176 MMcf/d. Accordingly, fourth quarter 2016 production was approximately 100 MMcf/d less than it otherwise would have been had the facility been in full operation. Additionally, during the fourth quarter of 2016, third party pipeline transportation restrictions were 45 MMcf/d. On an annual basis, North America natural gas production volumes were impacted by approximately 70 MMcf/d due to the third party gathering system and facility outage and 31 MMcf/d due to third party transportation restrictions. The Company's sales volumes at the third party facility have increased subsequent to year end.

North America – Oil Sands Mining and Upgrading

SCO production for the year ended December 31, 2016 of 123,265 bbl/d was comparable with 122,911 bbl/d for the year ended December 31, 2015. SCO production for the fourth quarter of 2016 increased 38% to average a record 178,063 bbl/d compared with 129,050 bbl/d for the fourth quarter of 2015 and increased 163% from 67,586 bbl/d for the third quarter of 2016. The increase in production for the fourth quarter of 2016 from the comparable periods primarily reflected new Phase 2B production following the completion of the planned major turnaround in the third quarter of 2016.

Annual 2016 production of SCO was within the Company’s previously issued guidance of 120,000 to 132,000 bbl/d. Annual production guidance for 2017 is targeted to average between 170,000 and 184,000 bbl/d of SCO, including the impact of planned tie-ins and turnarounds. First quarter 2017 production guidance is targeted to average between 192,000 and 200,000 bbl/d.

North Sea

North Sea crude oil production for the year ended December 31, 2016 increased 6% to 23,554 bbl/d from 22,216 bbl/d for the year ended December 31, 2015. North Sea crude oil production for the fourth quarter of 2016 increased 4% to 24,085 bbl/d from 23,110 bbl/d for the fourth quarter of 2015 and increased 3% from 23,450 bbl/d for the third quarter of 2016. The increase in production for the three months and year ended December 31, 2016 from comparable periods was due to successful production optimization, more than offsetting natural field declines.

Offshore Africa

Offshore Africa crude oil production for the year ended December 31, 2016 increased 37% to 26,096 bbl/d from 19,079 bbl/d for the year ended December 31, 2015. Offshore Africa crude oil production for the fourth quarter of 2016 decreased 13% to 21,689 bbl/d from 24,832 bbl/d for the fourth quarter of 2015, and decreased 17% from 26,171 bbl/d for the third quarter of 2016. Production volumes increased for the year ended December 31, 2016 from the comparable period in 2015, reflecting the impact of additional wells coming on stream at the Espoir and Baobab fields during 2015 and 2016, partially offset by natural field declines and unplanned downtime. The decrease in the fourth quarter of 2016 from the fourth quarter of 2015 and the third quarter of 2016 primarily reflected natural field declines and planned and unplanned production downtime.

International Guidance

Annual International crude oil production was within the Company's previously issued guidance of 49,000 to 56,000 bbl/d. Annual production guidance for 2017 is targeted to average between 43,000 and 49,000 bbl/d of crude oil. First quarter 2017 production guidance is targeted to average between 43,000 and 47,000 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)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015
North Sea	**987,316**	940,089	835,806
Offshore Africa	**1,126,999**	1,587,341	1,271,170
	2,114,315	2,527,430	2,106,976

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 45.00**	$ 39.66	$ 33.90	**$ 36.93**	$ 41.13
Transportation	**2.70**	2.51	2.61	**2.61**	2.60
Realized sales price, net of transportation	**42.30**	37.15	31.29	**34.32**	38.53
Royalties	**4.62**	3.48	3.49	**3.40**	4.30
Production expense	**14.28**	13.85	14.26	**14.10**	15.74
Netback	**$ 23.40**	$ 19.82	$ 13.54	**$ 16.82**	$ 18.49
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 3.14**	$ 2.44	$ 2.96	**$ 2.32**	$ 3.16
Transportation	**0.34**	0.40	0.38	**0.33**	0.38
Realized sales price, net of transportation	**2.80**	2.04	2.58	**1.99**	2.78
Royalties	**0.17**	0.09	0.10	**0.09**	0.10
Production expense	**1.15**	1.08	1.22	**1.18**	1.34
Netback	**$ 1.48**	$ 0.87	$ 1.26	**$ 0.72**	$ 1.34
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 34.54**	$ 29.39	$ 27.79	**$ 27.58**	$ 32.60
Transportation	**2.46**	2.51	2.59	**2.44**	2.56
Realized sales price, net of transportation	**32.08**	26.88	25.20	**25.14**	30.04
Royalties	**3.16**	2.27	2.38	**2.21**	2.85
Production expense	**11.34**	10.83	11.55	**11.18**	12.70
Netback	**$ 17.58**	$ 13.78	$ 11.27	**$ 11.75**	$ 14.49

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

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 42.56**	$ 36.84	$ 31.51	**$ 34.31**	$ 38.96
North Sea	**$ 63.68**	$ 60.00	$ 57.50	**$ 55.91**	$ 65.13
Offshore Africa	**$ 61.29**	$ 58.30	$ 53.37	**$ 54.96**	$ 63.13
Company average	**$ 45.00**	$ 39.66	$ 33.90	**$ 36.93**	$ 41.13
Natural gas ($/Mcf) (1) (2)					
North America	**$ 2.97**	$ 2.30	$ 2.73	**$ 2.15**	$ 2.91
North Sea	**$ 7.75**	$ 5.27	$ 9.53	**$ 6.62**	$ 9.66
Offshore Africa	**$ 5.75**	$ 5.39	$ 7.63	**$ 6.13**	$ 9.53
Company average	**$ 3.14**	$ 2.44	$ 2.96	**$ 2.32**	$ 3.16
Company average ($/BOE) (1) (2)	**$ 34.54**	$ 29.39	$ 27.79	**$ 27.58**	$ 32.60

(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 decreased 12% to $34.31 per bbl for the year ended December 31, 2016 from $38.96 per bbl for the year ended December 31, 2015. North America realized crude oil prices averaged $42.56 per bbl for the fourth quarter of 2016, an increase of 35% compared with $31.51 per bbl for the fourth quarter of 2015 and an increase of 16% compared with $36.84 per bbl for the third quarter of 2016. The fluctuations in realized crude oil prices for the three months and year ended December 31, 2016 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 fourth quarter of 2016, contributed approximately 214,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 26% to average $2.15 per Mcf for the year ended December 31, 2016 from $2.91 per Mcf for the year ended December 31, 2015. North America realized natural gas prices increased 9% to average $2.97 per Mcf for the fourth quarter of 2016 compared with $2.73 per Mcf for the fourth quarter of 2015, and increased 29% compared with $2.30 per Mcf for the third quarter of 2016. The decrease in natural gas prices per Mcf for the year ended December 31, 2016 from the comparable period in 2015 was primarily due to warmer than normal winter temperatures in the first quarter of 2016. US natural gas inventories were at near record high levels at the end of the 2015/2016 winter season, which resulted in weaker prices during storage injection.

The increase in realized natural gas prices for the fourth quarter of 2016 compared with the fourth quarter of 2015 and third quarter of 2016 was primarily due to lower US natural gas production. Reduced supply resulted in natural gas storage inventories returning to historically normal levels by the end of 2016.

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

(Quarterly Average)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 45.05**	$ 38.16	$ 36.45
Pelican Lake heavy crude oil ($/bbl)	**$ 43.96**	$ 37.57	$ 33.25
Primary heavy crude oil ($/bbl)	**$ 43.89**	$ 38.52	$ 31.14
Bitumen (thermal oil) ($/bbl)	**$ 39.39**	$ 33.68	$ 27.92
Natural gas ($/Mcf)	**$ 2.97**	$ 2.30	$ 2.73

(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 decreased 14% to average $55.91 per bbl for the year ended December 31, 2016 from $65.13 per bbl for the year ended December 31, 2015. North Sea realized crude oil prices increased 11% to average $63.68 per bbl for the fourth quarter of 2016 from $57.50 per bbl for the fourth quarter of 2015 and increased 6% from $60.00 per bbl for the third 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 three months and year ended December 31, 2016 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 decreased 13% to average $54.96 per bbl for the year ended December 31, 2016 from $63.13 per bbl for the year ended December 31, 2015. Offshore Africa realized crude oil prices increased 15% to average $61.29 per bbl for the fourth quarter of 2016 from $53.37 per bbl for the fourth quarter of 2015 and increased 5% from $58.30 per bbl for the third 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 three months and year ended December 31, 2016 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 5.05**	$ 3.81	$ 3.71	**$ 3.69**	$ 4.57
North Sea	**$ 0.13**	$ 0.12	$ 0.14	**$ 0.13**	$ 0.14
Offshore Africa	**$ 2.71**	$ 2.47	$ 2.61	**$ 2.31**	$ 2.87
Company average	**$ 4.62**	$ 3.48	$ 3.49	**$ 3.40**	$ 4.30
Natural gas ($/Mcf) (1)					
North America	**$ 0.17**	$ 0.09	$ 0.10	**$ 0.08**	$ 0.09
Offshore Africa	**$ 0.29**	$ 0.24	$ 0.44	**$ 0.28**	$ 0.46
Company average	**$ 0.17**	$ 0.09	$ 0.10	**$ 0.09**	$ 0.10
Company average ($/BOE) (1)	**$ 3.16**	$ 2.27	$ 2.38	**$ 2.21**	$ 2.85

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

North America

North America crude oil and natural gas royalties for the three months and year ended December 31, 2016 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 12% of product sales for the year ended December 31, 2016 compared with 13% of product sales for the year ended December 31, 2015. Crude oil and NGLs royalties averaged approximately 13% of product sales for the fourth quarter of 2016 compared with 13% for the fourth quarter of 2015 and 11% for the third quarter of 2016. The decrease in royalties for the year ended December 31, 2016 from the comparable period in 2015 was primarily due to lower realized crude oil prices during 2016. The increase for the fourth quarter of 2016 from the third quarter of 2016 reflected 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 4% of product sales for the year ended December 31, 2016 compared with 4% of product sales for the year ended December 31, 2015. Natural gas royalties averaged approximately 6% of product sales for the fourth quarter of 2016 compared with 4% for the fourth quarter of 2015 and 4% for the third quarter of 2016. The increase in natural gas royalties in the fourth quarter of 2016 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 4% for the year ended December 31, 2016, compared with 5% of product sales for the year ended December 31, 2015. Royalty rates as a percentage of product sales averaged approximately 4% for the fourth quarter of 2016, compared with 5% of product sales for the fourth quarter of 2015 and 4% for the third 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			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 12.13**	$ 11.69	$ 11.45	**$ 11.89**	$ 12.51
North Sea	**$ 41.66**	$ 39.41	$ 56.97	**$ 42.47**	$ 63.67
Offshore Africa	**$ 19.05**	$ 16.32	$ 26.08	**$ 18.48**	$ 33.32
Company average	**$ 14.28**	$ 13.85	$ 14.26	**$ 14.10**	$ 15.74
Natural gas ($/Mcf) (1)					
North America	**$ 1.07**	$ 1.04	$ 1.17	**$ 1.12**	$ 1.27
North Sea	**$ 3.36**	$ 2.15	$ 3.27	**$ 3.09**	$ 4.41
Offshore Africa	**$ 2.68**	$ 1.68	$ 1.55	**$ 1.79**	$ 1.76
Company average	**$ 1.15**	$ 1.08	$ 1.22	**$ 1.18**	$ 1.34
Company average ($/BOE) (1)	**$ 11.34**	$ 10.83	$ 11.55	**$ 11.18**	$ 12.70

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

North America

North America crude oil and NGLs production expense for the year ended December 31, 2016 decreased 5% to $11.89 per bbl from $12.51 per bbl for the year ended December 31, 2015. North America crude oil and NGLs production expense for the fourth quarter of 2016 of $12.13 per bbl increased 6% from $11.45 per bbl in the fourth quarter of 2015 and increased 4% from $11.69 per bbl for the third 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, together with lower industry service costs. As a result, crude oil and NGLs production expenses for 2016 were near the midpoint of annual guidance of $11.25 to $12.25 per bbl. The increase in production costs for the fourth quarter of 2016 from the fourth quarter of 2015 was primarily due to lower sales volumes. The increase from the third quarter of 2016 was primarily due to higher natural gas costs in the Company's thermal areas due to seasonality. 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 year ended December 31, 2016 decreased 12% to $1.12 per Mcf from $1.27 per Mcf for the year ended December 31, 2015. North America natural gas production expense for the fourth quarter of 2016 decreased 9% to $1.07 per Mcf from $1.17 per Mcf for the fourth quarter of 2015 and increased 3% from $1.04 per Mcf for the third quarter of 2016. Consistent with crude oil and NGLs production costs, the Company continues to successfully reduce its natural gas production costs and achieve efficiencies across the asset base, through focused cost and production optimization, together with lower industry service costs. As a result, natural gas production expenses for 2016 were below the midpoint of annual guidance of $1.05 to $1.25 per Mcf. The increase in production costs for the fourth quarter of 2016 from the third 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 year ended December 31, 2016 decreased 33% to $42.47 per bbl from $63.67 per bbl for the year ended December 31, 2015. North Sea crude oil production expense for the fourth quarter of 2016 decreased 27% to $41.66 per bbl from $56.97 per bbl for the fourth quarter of 2015 and increased 6% from $39.41 per bbl in the third quarter of 2016.The Company continues to successfully reduce its production costs and achieve efficiencies through focused cost and production optimization, together with lower industry service costs. As a result, crude oil and NGLs production expenses for 2016 were below the midpoint of annual guidance of $40.50 to $46.50 per bbl. The decrease in production expense in 2016 compared with the prior year also reflected fluctuations in the Canadian dollar and the weakening of the UK pound sterling. The increase in production expense in the fourth quarter of 2016 from the third quarter of 2016 primarily reflected the impact of seasonality. North Sea crude oil production expense guidance is anticipated to average $33.00 to $36.00 per bbl for 2017.

Offshore Africa

Offshore Africa oil production expense for the year ended December 31, 2016 decreased 45% to $18.48 per bbl from $33.32 per bbl for the year ended December 31, 2015. Offshore Africa crude oil production expense for the fourth quarter of 2016 decreased 27% to average $19.05 per bbl from $26.08 per bbl for the fourth quarter of 2015 and increased 17% from $16.32 per bbl in the third quarter of 2016. The fluctuations in production expense for the three months and year ended December 31, 2016 from the comparable periods were primarily due to 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. Offshore Africa production expense guidance is anticipated to average $10.50 to $12.50 per bbl for 2017.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Expense	**$ 1,049**	$ 1,031	$ 1,330	**$ 4,185**	$ 4,909
$/BOE (1)	**$ 16.71**	$ 16.84	$ 19.95	**$ 16.79**	$ 18.50

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

The decrease in depletion, depreciation and amortization expense for the three months and year ended December 31, 2016 from the comparable periods in 2015 was primarily due to lower sales volumes and depletion rates in North America. Depletion, depreciation and amortization expense for the fourth quarter of 2016 increased from the third quarter of 2016 primarily due to additional depletion in the North Sea related to the planned abandonment of the Ninian North platform in 2017.

Depletion, depreciation and amortization on a per barrel basis for the year ended December 31, 2016 decreased 9% to $16.79 per BOE from $18.50 per BOE for the year ended December 31, 2015. Depletion, depreciation and amortization expense on a per barrel basis for the fourth quarter of 2016 decreased 16% to $16.71 per BOE from $19.95 per BOE for the fourth quarter of 2015 and was comparable with the third quarter of 2016. The decrease in depletion, depreciation and amortization expense per BOE for the three months and year ended December 31, 2016 from comparable periods in 2015 was primarily due to a lower depletable base in North America in 2016 and the derecognition of exploration and evaluation assets in Block CI-514 in Offshore Africa in the fourth quarter of 2015, partially offset by the impact of additional depletion in the North Sea in the fourth quarter of 2016 related to the planned abandonment of the Ninian North platform in 2017.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Expense	**$ 28**	$ 28	$ 35	**$ 113**	$ 142
$/BOE (1)	**$ 0.45**	$ 0.46	$ 0.54	**$ 0.45**	$ 0.54

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

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

Asset retirement obligation accretion expense for the year ended December 31, 2016 decreased 17% to $0.45 per BOE from $0.54 per BOE for the year ended December 31, 2015. Asset retirement obligation accretion expense for the fourth quarter of 2016 decreased 17% to $0.45 per BOE from $0.54 per BOE for the fourth quarter of 2015, and was comparable with the third quarter of 2016.

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 fourth quarter of 2016 averaging 178,063 bbl/d following the completion of the major turnaround and the successful tie-in of Phase 2B during the third quarter. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, together with additional Phase 2B capacity and lower industry service costs, cash production costs averaging $22.53 per bbl were achieved in the fourth quarter.

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

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

	Three Months Ended			Year Ended	
($/bbl) (1)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
SCO sales price	**$ 64.51**	$ 58.61	$ 57.49	**$ 58.59**	$ 61.39
Bitumen value for royalty purposes (2)	**$ 35.92**	$ 30.16	$ 24.37	**$ 27.57**	$ 32.14
Bitumen royalties (3)	**$ 0.88**	$ 0.62	$ 0.99	**$ 0.54**	$ 1.08
Transportation	**$ 1.22**	$ 3.40	$ 1.66	**$ 1.77**	$ 1.81

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

(2) Calculated as the quarterly and annual 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 $58.59 per bbl for the year ended December 31, 2016, a decrease of 5% compared with $61.39 per bbl for the year ended December 31, 2015. Realized SCO sales prices averaged $64.51 per bbl for the fourth quarter of 2016, an increase of 12% compared with $57.49 per bbl for the fourth quarter of 2015 and an increase of 10% compared with $58.61 per bbl for the third quarter of 2016. The fluctuations in SCO pricing for the three months and year ended December 31, 2016 from comparable periods were primarily due to changes in WTI benchmark pricing and the impact of industry wide planned and unplanned upgrader outages.

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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Cash production costs	**$ 376**	$ 326	$ 344	**$ 1,292**	$ 1,332
Less: costs incurred during turnaround periods	**—**	(151)	—	**(151)**	(45)
Adjusted cash production costs	**$ 376**	$ 175	$ 344	**$ 1,141**	$ 1,287
Adjusted cash production costs, excluding natural gas costs	**$ 336**	$ 161	$ 326	**$ 1,057**	$ 1,212
Adjusted natural gas costs	**40**	14	18	**84**	75
Adjusted cash production costs	**$ 376**	$ 175	$ 344	**$ 1,141**	$ 1,287

	Three Months Ended			Year Ended	
($/bbl) (1)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Adjusted cash production costs, excluding natural gas costs	**$ 20.17**	$ 24.92	$ 27.10	**$ 23.36**	$ 26.95
Natural gas costs	**2.36**	2.13	1.46	**1.84**	1.66
Adjusted cash production costs	**$ 22.53**	$ 27.05	$ 28.56	**$ 25.20**	$ 28.61
Sales (bbl/d)	**181,523**	70,005	130,990	**123,652**	123,231

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

Adjusted cash production costs for the year ended December 31, 2016 decreased 12% to $25.20 per bbl from $28.61 per bbl for the year ended December 31, 2015. Adjusted cash production costs for the fourth quarter of 2016 averaged $22.53 per bbl, a decrease of 21% from $28.56 per bbl for the fourth quarter of 2015 and a decrease of 17% from $27.05 per bbl for the third quarter of 2016. The decrease in adjusted cash production costs on a per barrel basis for the three months and year ended December 31, 2016 from comparable periods primarily reflected the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, additional Phase 2B capacity and lower industry service costs. Cash production costs for 2016, including turnaround costs, were within the Company's previously issued guidance of $27.00 to $30.00 per bbl. For 2017, cash production costs are now 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			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Depletion, depreciation and amortization	**$ 198**	$ 182	$ 139	**$ 662**	$ 562
Less: depreciation incurred during turnaround period	**—**	(99)	—	**(99)**	(5)
Adjusted depletion, depreciation and amortization	**$ 198**	$ 83	$ 139	**$ 563**	$ 557
$/bbl	**$ 11.84**	$ 12.96	$ 11.48	**$ 12.43**	$ 12.37

Adjusted depletion, depreciation and amortization expense on a per barrel basis for the year ended December 31, 2016 was comparable with the year ended December 31, 2015. Depletion, depreciation and amortization expense on a per barrel basis for the fourth quarter of 2016 increased 3% to $11.84 per bbl from $11.48 per bbl for the fourth quarter of 2015 and decreased 9% from $12.96 per bbl for the third quarter of 2016.

Adjusted depletion, depreciation and amortization expense per barrel for the three months and year ended December 31, 2016 fluctuated from comparable periods primarily due to the impact of assets depreciated on a straight line basis and the timing of minor asset derecognitions.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Expense	**$ 7**	$ 8	$ 8	**$ 29**	$ 31
$/bbl (1)	**$ 0.44**	$ 1.13	$ 0.64	**$ 0.64**	$ 0.69

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

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

Asset retirement obligation accretion expense for the year ended December 31, 2016 decreased 7% to $0.64 per bbl from $0.69 per bbl for the year ended December 31, 2015. Asset retirement obligation accretion expense of $0.44 per bbl for the fourth quarter of 2016 decreased 31% from $0.64 per bbl the fourth quarter of 2015 and decreased 61% from $1.13 per bbl for the third quarter of 2016, primarily due to fluctuations in sales volumes.

MIDSTREAM

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Revenue	**$ 26**	$ 31	$ 33	**$ 114**	$ 136
Production expense	**5**	7	7	**25**	32
Midstream cash flow	**21**	24	26	**89**	104
Depreciation	**2**	3	3	**11**	12
Equity loss (gain) on investments	**12**	4	12	**(7)**	44
Gain on corporate disposition	**(218)**	—	—	**(218)**	—
Segment earnings before taxes	**$ 225**	$ 17	$ 11	**$ 303**	$ 48

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%. During 2016, the Company and APMC each provided $99 million of subordinated debt. To date, each party has provided $324 million of subordinated debt, together with accrued interest thereon of $61 million for a Company total of $385 million. Should final Project costs exceed the sanction cost estimate of $8,500 million, the Company and APMC have agreed, each with a 50% interest, to provide additional subordinated debt as required to reflect an agreed debt to equity ratio 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.

During the second quarter of 2016, Redwater Partnership issued $500 million of 4.15% series H senior secured bonds due June 2033, $500 million of 4.35% series I senior secured bonds due January 2039, and $200 million of senior secured bonds through the reopening of its previously issued 4.75% series G senior secured bonds due June 2037. During the first quarter of 2016, Redwater Partnership issued $550 million of 4.25% series F senior secured bonds due June 2029, and $300 million of 4.75% series G senior secured bonds due June 2037.

As at December 31, 2016, Redwater Partnership had additional borrowings of $1,581 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			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Expense	**$ 86**	$ 82	$ 93	**$ 345**	$ 390
$/BOE (1)	**$ 1.08**	$ 1.21	$ 1.18	**$ 1.17**	$ 1.26

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

Administration expense on a per BOE basis for the year ended December 31, 2016 decreased 7% to $1.17 per BOE from $1.26 per BOE for the year ended December 31, 2015. Administration expense for the fourth quarter of 2016 of $1.08 per BOE decreased 8% from $1.18 per BOE for the fourth quarter of 2015 and decreased 11% from $1.21 per BOE for the third quarter of 2016. Administration expense per BOE decreased for the year ended December 31, 2016 from the comparable period in 2015 primarily due to lower staffing and general corporate costs.

SHARE-BASED COMPENSATION

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Expense (Recovery)	**$ 42**	$ 74	$ 56	**$ 355**	$ (46)

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 $355 million share-based compensation expense for the year ended December 31, 2016, 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 year ended December 31, 2016, the Company capitalized $67 million of share-based compensation costs to property, plant and equipment in the Oil Sands Mining and Upgrading segment (December 31, 2015 – $10 million costs recovered).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts and interest rates)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Expense, gross	**$ 153**	$ 157	$ 133	**$ 616**	$ 566
Less: capitalized interest	**38**	67	60	**233**	244
Expense, net	**$ 115**	$ 90	$ 73	**$ 383**	$ 322
$/BOE (1)	**$ 1.43**	$ 1.34	$ 0.93	**$ 1.30**	$ 1.04
Average effective interest rate	**3.8%**	3.8%	3.8%	**3.9%**	3.9%

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

Gross interest and other financing expense for the three months and year ended December 31, 2016 increased from the comparable periods in 2015 primarily due to the impact of higher average debt levels. Capitalized interest of $233 million for the year ended December 31, 2016 was primarily related to the Horizon Phase 2/3 expansion.

Net interest and other financing expense for the year ended December 31, 2016 increased 25% to $1.30 per BOE from $1.04 per BOE for the year ended December 31, 2015. Net interest and other financing expense on a per BOE basis for the fourth quarter of 2016 increased 54% to $1.43 per BOE from $0.93 per BOE for the fourth quarter of 2015 and increased 7% from $1.34 per BOE for the third quarter of 2016. The increase for the year ended December 31, 2016 from the comparable period in 2015 was primarily due to higher average debt levels and lower sales volumes.

The increase for the fourth quarter of 2016 from the fourth quarter of 2015 and the third 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 three months and year ended December 31, 2016 were consistent with the comparable periods.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Crude oil and NGLs financial instruments	**$ —**	$ —	$ (218)	**$ —**	$ (599)
Foreign currency contracts	**(14)**	(23)	(37)	**8**	(244)
Realized (gain) loss	**(14)**	(23)	(255)	**8**	(843)
Crude oil and NGLs financial instruments	**—**	—	189	**—**	394
Natural gas financial instruments	**8**	(2)	—	**6**	—
Foreign currency contracts	**(15)**	12	(15)	**19**	(20)
Unrealized (gain) loss	**(7)**	10	174	**25**	374
Net (gain) loss	**$ (21)**	$ (13)	$ (81)	**$ 33**	$ (469)

During the year ended December 31, 2016, net realized risk management losses were related to the settlement of foreign currency contracts. The Company recorded a net unrealized loss of $25 million ($21 million after-tax) on its risk management activities for the year ended December 31, 2016, including an unrealized gain of $7 million ($7 million after-tax) for the fourth quarter of 2016 (September 30, 2016 - unrealized loss of $10 million; $11 million after-tax; December 31, 2015 – unrealized loss of $174 million; $128 million after-tax).

Complete details related to outstanding derivative financial instruments at December 31, 2016 are disclosed in note 14 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Net realized (gain) loss	**$ (2)**	$ 12	$ (5)	**$ 38**	$ (97)
Net unrealized loss (gain)	**162**	39	170	**(93)**	858
Net loss (gain) [(1)]	**$ 160**	$ 51	$ 165	**$ (55)**	$ 761

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

The net realized foreign exchange loss for the year ended December 31, 2016 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for the year ended December 31, 2016 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (three months ended December 31, 2016 – unrealized gain of $67 million, September 30, 2016 – unrealized loss of $23 million, December 31, 2015 – unrealized gain of $129 million; year ended December 31, 2016 - unrealized loss of $295 million, December 31, 2015 - unrealized gain of $649 million). The US/Canadian dollar exchange rate at December 31, 2016 was US$0.7448 (September 30, 2016 – US$0.7624, December 31, 2015 – US$0.7225).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Dec 31 2016	Sep 30 2016	Dec 31 2015	Year Ended Dec 31 2016	Dec 31 2015
North America [1]	**$ (22)**	$ (168)	$ (66)	**$ (377)**	$ 86
North Sea	**—**	(43)	(18)	**(74)**	(117)
Offshore Africa	**5**	5	5	**22**	17
PRT recovery – North Sea	**(35)**	(77)	(71)	**(198)**	(258)
Other taxes	**3**	2	2	**9**	11
Current income tax recovery	**(49)**	(281)	(148)	**(618)**	(261)
Deferred corporate income tax (recovery) expense	**(55)**	(32)	(1)	**(106)**	216
Deferred PRT expense (recovery) – North Sea	**9**	50	(32)	**(135)**	15
Deferred income tax (recovery) expense	**(46)**	18	(33)	**(241)**	231
	(95)	(263)	(181)	**(859)**	(30)
Income tax rate and other legislative changes [2]	**—**	107	—	**221**	(351)
	$ (95)	$ (156)	$ (181)	**$ (638)**	$ (381)
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**20%**	27%	59%	**45%**	61%

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

(2) During the third quarter of 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. During the first quarter of 2016 the UK government enacted tax rate reductions relating to PRT, resulting in a decrease in the Company's net deferred income tax liability of $114 million. During the second quarter of 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015 resulting in an increase in the Company's deferred corporate income tax liability of $579 million. During the first quarter of 2015, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and the PRT, and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in the Company's net deferred income tax liability of $228 million.

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

The effective income tax rate for the three months and year ended December 31, 2016 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 and year 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 three months and year ended December 31, 2016 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the Murchison platform.

In September 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million.

In March 2016, the UK government enacted legislation to reduce the PRT rate from 35% to 0% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to 2015 and prior taxation years for PRT purposes are still recoverable at a PRT rate of 50%. As a result of these income tax rate changes, the Company's deferred PRT liability was reduced by $228 million and the deferred corporate income tax liability was increased by $114 million.

In June 2015,the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015 resulting in an increase in the Company's deferred corporate income tax liability of $579 million.

In March 2015, the UK government enacted legislation that reduced the supplementary charge on oil and gas profits from 32% to 20% effective January 1, 2015. In addition, the legislation reduced the PRT rate from 50% to 35% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to prior taxation years for PRT purposes were still recoverable at the previous tax rate of 50%. The legislation also replaced the existing Brownfield Allowance with a new Investment Allowance on qualifying capital expenditures, effective April 1, 2015. The new Investment Allowance is deductible for supplementary charge purposes, subject to certain restrictions. As a result of the new income tax changes, the Company's deferred corporate income tax liability was reduced by $217 million and the deferred PRT liability was reduced by $11 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 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)

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Exploration and Evaluation					
Net expenditures (proceeds) (2) (3)	**$ 4**	$ —	$ (885)	**$ (6)**	$ (805)
Property, Plant and Equipment					
Net property acquisitions (2) (3) (4)	**1**	17	(443)	**159**	(451)
Well drilling, completion and equipping	**200**	186	237	**712**	965
Production and related facilities	**50**	104	154	**369**	908
Capitalized interest and other (5)	**26**	20	26	**91**	102
Net expenditures	**277**	327	(26)	**1,331**	1,524
Total Exploration and Production	**281**	327	(911)	**1,325**	719
Oil Sands Mining and Upgrading					
Horizon Phases 2/3 construction costs	**515**	400	578	**1,920**	2,187
Sustaining capital	**76**	151	55	**379**	301
Turnaround costs	**(3)**	103	5	**135**	18
Capitalized interest and other (5)	**40**	77	68	**284**	224
Total Oil Sands Mining and Upgrading	**628**	731	706	**2,718**	2,730
Midstream (6)	**(537)**	2	2	**(533)**	8
Abandonments (7)	**35**	122	105	**267**	370
Head office	**4**	3	2	**17**	26
Total net capital expenditures	**$ 411**	$ 1,185	$ (96)	**$ 3,794**	$ 3,853
By segment					
North America (2) (3) (4)	**$ 221**	$ 259	$ (1,126)	**$ 1,048**	$ (119)
North Sea	**37**	63	34	**126**	230
Offshore Africa	**23**	5	181	**151**	608
Oil Sands Mining and Upgrading	**628**	731	706	**2,718**	2,730
Midstream(6)	**(537)**	2	2	**(533)**	8
Abandonments (7)	**35**	122	105	**267**	370
Head office	**4**	3	2	**17**	26
Total	**$ 411**	$ 1,185	$ (96)	**$ 3,794**	$ 3,853

(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) The above noted figures in the fourth quarter of 2015 include non-cash share consideration of $985 million received from PrairieSky on the disposition of royalty income assets and the impact of other pre-tax gains on the sale of other properties totaling $49 million recognized in 2015.

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

(6) 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.

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

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

Net capital expenditures for the year ended December 31, 2016 were $3,794 million compared with $3,853 million for the year ended December 31, 2015. Net capital expenditures for the fourth quarter of 2016 were $411 million compared with net proceeds of $96 million for the fourth quarter of 2015 and net expenditures of $1,185 million for the third quarter of 2016.

Net capital expenditures for the three months and year ended December 31, 2016 included the disposition of the Company's ownership interest in the Cold Lake Pipeline in the Midstream segment. Total net consideration on the disposition 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 Ltd. ("Inter Pipeline") with a value of $29.57 per common share, determined as of the closing date.

On December 15, 2016 the Company announced its 2017 Capital Budget. The 2017 budget reflects a continued focus on proactive capital allocation and lowering overall operating and capital cost structures, and is targeted at $3,890 million.

Drilling Activity

	Three Months Ended			Year Ended	
(number of wells)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015	**Dec 31 2016**	Dec 31 2015
Net successful natural gas wells	**4**	—	4	**9**	19
Net successful crude oil wells [(1)]	**81**	85	2	**174**	115
Dry wells	**3**	4	—	**7**	6
Stratigraphic test / service wells	**62**	6	73	**268**	166
Total	**150**	95	79	**458**	306
Success rate (excluding stratigraphic test / service wells)	**97%**	96%	100%	**96%**	96%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 20% of the total net capital expenditures for the year ended December 31, 2016 compared with approximately 1% for the year ended December 31, 2015.

During the fourth quarter of 2016, the Company targeted 4 net natural gas wells, including 3 wells in Northeast British Columbia and 1 well in Northwest Alberta. The Company also targeted 83 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 69 primary heavy crude oil wells, 2 Pelican Lake heavy crude oil wells and 8 bitumen (thermal oil) wells were drilled. Another 4 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for the fourth quarter of 2016 averaged approximately 129,300 bbl/d compared with approximately 135,100 bbl/d for the fourth quarter of 2015 and approximately 103,500 bbl/d for the third quarter of 2016. Production volumes in the fourth quarter of 2016 reflected the cyclic nature of thermal oil production at Primrose and were within guidance.

Operating performance at the Pelican Lake tertiary recovery project continued to be strong, leading to average production of approximately 47,500 bbl/d in the fourth quarter of 2016 compared with 49,300 bbl/d in the fourth quarter of 2015 and 47,600 bbl/d in the third quarter of 2016.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the fourth quarter of 2016 focused on the commissioning of the hydrogen unit, hydrotreater unit, vacuum distillation and diluent recovery unit, sour water concentrator, tank farms, tailings re-handling plant, froth treatment, froth tank, tailings transfer pumphouses and pipelines, extraction plant, ore preparation plants, and superpot. Phase 3 work also continued with engineering, procurement and construction related to tailings retrofit, combined hydrotreater and sulphur recovery units.

During the turnaround in the third quarter, the Company successfully completed the tie-in of major components as planned. The construction, commissioning and operational teams at Horizon worked together to execute a safe and effective start-up of the Phase 2B expansion. The Horizon Phase 3 expansion, which is targeted to add 80,000 bbl/d of SCO production is on schedule and targeted for commissioning and startup in the fourth quarter of 2017.

North Sea

During the fourth quarter of 2016, the Company drilled 1 gross well (0.9 net well) at Ninian.

Due to the Company's continued focus on proactive capital allocation and lowering overall operating and capital cost structures, the Company plans to commence abandonment of the Ninian North platform in 2017. Abandonment activities at Ninian North have been reflected in 2017 guidance.

Offshore Africa

During the second quarter of 2016, the Company demobilized the drilling rigs at Baobab and Espoir. No additional drilling activity occurred for the remainder of 2016.

LIQUIDITY AND CAPITAL RESOURCES

	Three Months Ended		
($ millions, except ratios)	**Dec 31 2016**	Sep 30 2016	Dec 31 2015
Working capital [(1)]	**$ 1,056**	$ 489	$ 1,193
Long-term debt [(2) (3)]	**$ 16,805**	$ 17,292	$ 16,794
Share capital	**$ 4,671**	$ 4,367	$ 4,541
Retained earnings	**21,526**	21,237	22,765
Accumulated other comprehensive income	**70**	40	75
Shareholders' equity	**$ 26,267**	$ 25,644	$ 27,381
Debt to book capitalization [(3) (4)]	**39%**	40%	38%
Debt to market capitalization [(3) (5)]	**26%**	27%	34%
After-tax return on average common shareholders' equity [(6)]	**(1%)**	(2%)	(2%)
After-tax return on average capital employed [(3) (7)]	**0%**	(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 December 31, 2016, 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, 2015. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated funds flow from operations supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring funds flow from operations, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. In response to the current commodity price environment, the Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing the Company's borrowing capacity:
    - During the third quarter of 2016, the Company issued $1,000 million of 3.31% medium-term notes due February 2022. After issuing these securities, 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.
    - In October 2015, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in 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.
    - During the first quarter of 2016, the Company prepaid $250 million of the previously outstanding $1,000 million non-revolving term credit facility and extended the maturity date to February 2019 from January 2017. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at December 31, 2016, the $750 million facility was fully drawn. During the first quarter of 2016, the Company also entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn at December 31, 2016. Borrowings under this facility 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.

During the third quarter of 2016, the Company repaid US$250 million of 6.00% notes.

During the first quarter of 2016, the Company repaid US$500 million of three-month LIBOR plus 0.375% notes.

At December 31, 2016, the Company had in place bank credit facilities of $7,350 million, of which approximately $3,043 million, net of commercial paper issuances of $336 million, was available for general corporate purposes.

At December 31, 2016, the Company had total US dollar denominated debt with a carrying amount of $10,612 million (US$7,905 million), excluding transaction costs. This included $4,437 million (US$3,305 million) hedged by way of cross currency swaps (US$2,150 million) and foreign currency forwards (US$1,155 million). The fixed repayment amount of these hedging instruments is $3,975 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $462 million to $10,150 million as at December 31, 2016.

Long-term debt was $16,805 million at December 31, 2016, resulting in a debt to book capitalization ratio of 39% (December 31, 2015 – 38%); 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 December 31, 2016 are discussed in note 7 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 December 31, 2016, 50,000 GJ/d of currently forecasted natural gas volumes were hedged using AECO swaps for January 2017 to October 2017. Subsequent to year end, 50,000 bbl/d of currently forecasted crude oil volumes were hedged using WTI collars for February 2017 to December 2017 and 17,500 bbl/d of currently forecasted crude oil volumes were hedged using WTI collars for March 2017 to December 2017. Further details related to the Company's commodity derivative financial instruments at December 31, 2016 are discussed in note 14 of the Company's unaudited interim consolidated financial statements.

Share Capital

As at December 31, 2016, there were 1,110,952,000 common shares outstanding (December 31, 2015 – 1,094,668,000 common shares) and 58,299,000 stock options outstanding. As at February 28, 2017, the Company had 1,112,581,000 common shares outstanding and 55,957,000 stock options outstanding.

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

During the second quarter of 2016, the Company completed the net distribution of approximately 21.8 million PrairieSky common shares to the shareholders of record of the Company as at June 3, 2016, completing the previously announced Plan of Arrangement. The distribution was recognized as a return of capital of $546 million. Subsequent to the distribution, the Company's ownership interest in PrairieSky was less than 10% of the issued and outstanding common shares of PrairieSky.

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 commencing 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 December 31, 2016:

($ millions)	2017	2018	2019	2020	2021	Thereafter
Product transportation and pipeline	$ 441	$ 404	$ 306	$ 300	$ 258	$ 2,337
Offshore equipment operating leases and offshore drilling	$ 166	$ 105	$ 59	$ 34	$ 33	$ 9
Long-term debt (1) (2)	$ 1,813	$ 2,841	$ 2,705	$ 1,768	$ 671	$ 7,072
Interest and other financing expense (3)	$ 626	$ 539	$ 475	$ 434	$ 395	$ 4,126
Office leases	$ 44	$ 43	$ 43	$ 43	$ 40	$ 154
Other	$ 53	$ 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 December 31, 2016.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of Horizon Phase 3. 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, 2015 and the unaudited interim financial statements for the year ended December 31, 2016.

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, 2015.