Canadian Natural

FIRST QUARTER REPORT

THREE MONTHS ENDED MARCH 31, 2017 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2017 FIRST QUARTER RESULTS

Commenting on the first quarter 2017 results, Steve Laut, President of Canadian Natural stated, “The strength of our well balanced and diverse portfolio, combined with Canadian Natural’s ability to effectively and efficiently execute, delivered a strong first quarter for the Company. Funds flow from operations were strong in the quarter, exceeding capital expenditures by approximately $800 million, and as a direct result, contributed to over $500 million of debt reduction in the quarter, strengthening our balance sheet quickly.

Execution continues at Horizon with strong production following the ramp up of Phase 2B. Expansion volumes drove 9% growth in our crude oil production volumes and 4% growth on an overall BOE basis when compared with the first quarter of 2016, impressive results given natural gas volumes were once again impacted by third party facility reliability issues. Furthermore at Horizon, record low operating costs of just over $22.00/bbl of SCO were achieved, another strong result. The Phase 3 expansion continues to be on schedule and costs are on track. Phase 3 is targeted to add an additional 80,000 bbl/d of SCO in only six months, the next step in our transition to a long-life, low decline asset base."

Canadian Natural’s Chief Financial Officer, Corey Bieber, continued, "Our financial performance was strong during the first quarter. The Company achieved net earnings of $245 million as production increased by 2% from the fourth quarter of 2016, with benchmark crude oil prices stabilizing in the US$50 region in the quarter. Funds flow from operations for the Company in the quarter was also robust at $1.64 billion. This translates to free cash flow, after capital expenditures and dividends requirements, of roughly $515 million, further translating to a reduction in absolute debt levels of $500 million. Commensurate with this debt reduction, available liquidity to the Company increased by approximately $500 million to $3.5 billion from the $3.0 billion available at the end of 2016."

QUARTERLY HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Mar 31 2017	Dec 31 2016	Mar 31 2016
Net earnings (loss)	**$ 245**	$ 566	$ (105)
Per common share – basic	**$ 0.22**	$ 0.51	$ (0.10)
– diluted	**$ 0.22**	$ 0.51	$ (0.10)
Adjusted net earnings (loss) from operations (1)	**$ 277**	$ 439	$ (543)
Per common share – basic	**$ 0.25**	$ 0.40	$ (0.50)
– diluted	**$ 0.25**	$ 0.40	$ (0.50)
Funds flow from operations (2)	**$ 1,639**	$ 1,677	$ 657
Per common share – basic	**$ 1.47**	$ 1.52	$ 0.60
– diluted	**$ 1.46**	$ 1.50	$ 0.60
Net capital expenditures	**$ 846**	$ 411	$ 1,040
Daily production, before royalties			
Natural gas (MMcf/d)	**1,673**	1,646	1,786
Crude oil and NGLs (bbl/d)	**598,113**	585,185	546,927
Equivalent production (BOE/d) (3)	**876,907**	859,577	844,531

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").

(2) Funds flow from operations (formally cash flow from operations) is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and debt repayment. The derivation of this measure is discussed in the MD&A.

(3) 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.

- Canadian Natural generated funds flow from operations of $1,639 million in Q1/17, an increase of almost $1.0 billion from $657 million in Q1/16 and comparable with $1,677 million in Q4/16. The increase from Q1/16 primarily reflects higher synthetic crude oil ("SCO") sales volumes and realized prices from the Company's North America Oil Sands Mining and Upgrading ("Horizon"), higher North America E&P crude oil and NGL netbacks and higher natural gas netbacks.
  - The Company generated significant free cash flow of approximately $800 million in Q1/17 after net capital expenditures. After capital expenditures and quarterly dividend requirements, approximately $515 million of free cash flow was realized in the quarter, which was largely used to reduce the Company's debt levels.
- For Q1/17, the Company had net earnings of $245 million compared to net earnings of $566 million in Q4/16 and a net loss of $105 million in Q1/16. The adjusted net earnings from operations was $277 million in Q1/17 compared to adjusted net earnings of $439 million in Q4/16 and an adjusted net loss of $543 million in Q1/16.
- Canadian Natural's corporate crude oil and NGLs production volumes averaged 598,113 bbl/d representing a 9% increase from Q1/16 levels. Crude oil and NGL production volume increases were primarily due to the successful ramp up of the Horizon Phase 2B expansion.
- The Company's corporate production volumes averaged 876,907 BOE/d in Q1/17, representing a 4% increase from Q1/16 levels, despite 3rd party natural gas facility outages experienced in the quarter.

- At Horizon, Canadian Natural's world class oil sands mining and upgrading operations, record quarterly production volumes were achieved for the second consecutive quarter. In Q1/17 production reached 192,491 bbl/d of SCO, within the Company's previously issued guidance, representing increases of 8% and 50% over Q4/16 and Q1/16 levels respectively.
  - Through safe, steady and reliable operations and a strong focus on continuous improvement, the Company realized record low quarterly average operating costs of $22.08/bbl of SCO in Q1/17, representing 2% and 17% reductions from Q4/16 and Q1/16 levels respectively.
  - During Q1/17, Canadian Natural continued to advance the Horizon Phase 3 expansion toward completion with project capital expenditures of $139 million in the quarter. The next component of the Company's transition to a long-life, low decline asset base is progressing as planned, reaching 92% physical completion as at March 31, 2017. Targeted project capital in 2017 is $1.05 billion, with start-up of Phase 3 targeted for Q4/17. This phase is targeted to add incremental production capacity of 80,000 bbl/d of SCO, which will result in a further step change towards lower operating costs for Horizon.
  - The previously announced debottleneck option at Horizon continues to move forward, with a target to be executed during the Q3/17 turnaround. The scope and impact on production capacity of the debottleneck will be determined once the full engineering evaluation is completed in late Q2/17. The engineering evaluation primarily involves the fractionation tower which includes quantifying all product yields of naphtha, distillate, gas oil, natural gas and coke from the output of the coker unit on an optimized throughput basis. Concurrently, a process review of the flow dynamics to determine pump and vessel capacities throughout the upgrader is ongoing. A decision on final scope, capital requirements and impact on production capacity is scheduled for late Q2/17, as the Company continues to fully define the debottleneck and optimize production capability.
- As previously announced on March 9, 2017 Canadian Natural has entered into agreements, subject to regulatory approvals, to acquire 70% of the Athabasca Oil Sands Project ("AOSP"), including 70% of the Muskeg River Mine, Jackpine Mine, Scotford upgrader, Quest Carbon Capture and Storage as well as additional working interests in other producing and non-producing oil sands leases. Additionally, the Company acquired 100% working interest in the Peace River operations, the Cliffdale heavy oil field and other oil sands leases. The acquisitions do not include any interest in the 100% Shell owned Scotford refinery or chemical plants.
  - Pre-closing activities and regulatory processes related to the transaction are proceeding as planned with closing targeted for Q2/17.
- Thermal in situ operations were strong in Q1/17, with production averaging 128,372 bbl/d, representing a 9% increase from Q1/16 levels and within the Company's previously issued quarterly guidance.
  - Kirby South, the Company's Steam Assisted Gravity Drainage ("SAGD") project, continues to operate near facility capacity, resulting in production of 37,311 bbl/d in Q1/17, an increase of 8% over Q1/16 levels. Including energy costs, operating costs of $9.12/bbl were achieved in the quarter, representing a 13% decrease from Q1/16 levels, supported by a strong Steam to Oil Ratio ("SOR") of 2.7.
  - Primrose production results of 91,061 bbl/d in Q1/17 were strong, up 9% over Q1/16 levels. Including energy costs, operating costs of $12.55/bbl were realized in Q1/17.
    - Strong results from the Company's low pressure steamflood at Primrose continue to be achieved, with March 2017 production under steamflood averaging approximately 31,000 bbl/d.
- Pelican Lake polymer flood production remained relatively constant at 46,617 bbl/d in Q1/17, a decrease of 2% from both Q4/16 and Q1/16 levels due to natural declines and planned downtime to conduct wellbore cleanouts to improve polymer flood conformance. Operations continued to be optimized in the quarter, resulting in industry leading operating costs of $6.37/bbl in Q1/17, a 3% and 8% decrease from Q4/16 and Q1/16 levels respectively.
- Primary heavy crude oil production averaged 94,803 bbl/d in Q1/17. As a result of the Company's proactive decision to reduce its primary heavy crude oil drilling program in 2015 and the first half of 2016, production volumes have declined 2% from Q4/16 levels. Canadian Natural is the industry leading primary heavy crude oil producer and continues to focus on operations optimization, realizing quarterly operating costs of $14.55/bbl in Q1/17, comparable to Q4/16 levels.

- North America light crude oil and NGL quarterly production averaged 90,171 bbl/d, a 3% increase from Q4/16 and comparable to Q1/16 levels. Strong quarterly operating costs of $13.72/bbl were realized in Q1/17, a 3% decrease from Q4/16 levels.

- Within the Company's North America natural gas assets, operations continued to be optimized during the quarter. Q1/17 production was 1,613 MMcf/d with operating costs of $1.20/Mcf. Production was lower than expected in the quarter due to the unexpected 3rd party natural gas facility outages, which negatively impacted production by approximately 70 MMcf/d in the quarter.

  - Operating costs in Canadian Natural's key natural gas areas in the Deep Basin and Montney continued to be top tier at $0.42/Mcfe and $0.25/Mcfe respectively in Q1/17.

- Canadian Natural maintains significant financial stability and liquidity represented in part by committed bank credit facilities. As at March 31, 2017, the Company had in place bank credit facilities of $7.4 billion, of which $3.5 billion was available, an increase of approximately $500 million from December 31, 2016 availability.

- Balance sheet strength continues to be a focus of the Company, with debt to book capitalization of 38% at March 31, 2017, within the Company's targeted operating range.

- Canadian Natural declared a quarterly cash dividend on common shares of C$0.275 per share payable on July 1, 2017.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

Canadian Natural has a balanced and diverse portfolio of assets, primarily Canadian-based, with international exposure in the UK sector of the North Sea and Offshore Africa. Canadian Natural's production is well balanced between light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen and SCO (herein collectively referred to as "crude oil"), natural gas and NGLs. This balance provides optionality for capital investments, facilitating improved value for the Company's shareholders.

Underpinning this asset base is long-life, low decline production from Horizon Oil Sands mining and upgrading, thermal in situ oil sands and Pelican Lake heavy crude oil assets. The combination of low decline, low reserve replacement costs, and effective and efficient operations means these assets provide substantial and sustainable cash flow throughout the commodity price cycle.

Augmenting this, Canadian Natural maintains a substantial inventory of low capital exposure projects within its conventional asset base. These projects can be executed quickly, and, with the right economic conditions, can provide excellent returns and maximize value for shareholders. Supporting these projects is the Company's undeveloped land base which enables large, repeatable drilling programs; programs that can be optimized over time. Additionally, by owning and operating most of the related infrastructure, Canadian Natural is able to control a major component of its operating cost and minimize production commitments. Low capital exposure projects can typically be easily stopped or started depending upon success, market conditions, or corporate needs.

Canadian Natural's balanced portfolio, built with both long-life, low decline assets and low capital exposure assets, enables effective capital allocation, production growth and value creation.

Drilling Activity

	Three Months Ended Mar 31			
	2017		2016	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**164**	**155**	11	8
Natural gas	**11**	**11**	5	4
Dry	**1**	**1**	-	-
Subtotal	**176**	**167**	16	12
Stratigraphic test / service wells	**226**	**226**	199	199
Total	**402**	**393**	215	211
Success rate (excluding stratigraphic test / service wells)	**-**	**99%**	-	100%

- The Company's total Q1/17 North America E&P crude oil and natural gas drilling program of 167 net wells, excluding strat/service wells, was a significant increase from the 12 net wells drilled in Q1/16. The change in drilling reflects the flexibility of Canadian Natural's resource development program and the Company's disciplined capital allocation process.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands and Horizon Oil Sands

	Three Months Ended		
	Mar 31 2017	Dec 31 2016	Mar 31 2016
Crude oil and NGLs production (bbl/d)	**231,591**	232,019	251,943
Net wells targeting crude oil	**147**	75	7
Net successful wells drilled	**147**	72	7
Success rate	**100%**	96%	100%

- Quarterly production volumes of North America crude oil and NGLs averaged 231,591 bbl/d in Q1/17, within quarterly corporate guidance and comparable to Q4/16 levels. Q1/17 production volumes represent a decrease of 8% from Q1/16 levels as a result of limited drilling activity in 2016.
- Pelican Lake polymer flood production remained relatively constant at 46,617 bbl/d in Q1/17, a decrease of 2% from both Q4/16 and Q1/16 levels due to natural declines and planned downtime to conduct wellbore cleanouts to improve polymer flood conformance. Operations continued to be optimized in the quarter, resulting in industry leading operating costs of $6.37/bbl in Q1/17, a 3% and 8% decrease from Q4/16 and Q1/16 levels respectively.
  - Late in Q1/17 the Company successfully drilled 2 net wells at Pelican Lake, with first production coming on stream in early Q2/17. Initial production rates are strong, averaging 270 bbl/d per well.
- Primary heavy crude oil production averaged 94,803 bbl/d in Q1/17. As a result of the Company's proactive decision to reduce its primary heavy crude oil drilling program in 2015 and the first half of 2016, production volumes have declined 2% from Q4/16 levels. Canadian Natural is the industry leading primary heavy crude oil producer and continues to focus on operations optimization, realizing quarterly operating costs of $14.55/bbl in Q1/17, comparable to Q4/16 levels.
  - In Q1/17 the Company successfully drilled 122 net primary heavy crude oil wells with strong initial production and targeted rates averaging 65 bbl/d per well.
- North America light crude oil and NGL quarterly production averaged 90,171 bbl/d, a 3% increase from Q4/16 and comparable to Q1/16 levels. Strong quarterly operating costs of $13.72/bbl were realized in Q1/17, a 3% decrease from Q4/16 levels.
  - In Q1/17 the Company successfully drilled 23 net light crude oil wells.
    - Highlights of the drilling program were 9 net wells in Manitoba and SE Saskatchewan, successfully completed with strong initial production results of approximately 110 bbl/d per well, above targeted rates.
    - Additionally, 7 net wells were successfully drilled in Southern Alberta with initial production rates of approximately 125 bbl/d per well, positive results.
- The Company’s 2017 North America E&P crude oil and NGL annual production guidance remains unchanged and is targeted to range from 232,000 bbl/d - 242,000 bbl/d.

Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2017	Dec 31 2016	Mar 31 2016
Bitumen production (bbl/d)	**128,372**	129,329	118,044
Net wells targeting bitumen	**8**	8	-
Net successful wells drilled	**8**	8	-
Success rate	**100%**	100%	-

- Thermal in situ operations were strong in Q1/17, with production averaging 128,372 bbl/d, representing a 9% increase from Q1/16 levels and within the Company's previously issued quarterly guidance.
- Primrose production results of 91,061 bbl/d in Q1/17 were strong, up 9% over Q1/16 levels. Including energy costs, operating costs of $12.55/bbl were realized in Q1/17.
  - Strong results from the Company's low pressure steamflood at Primrose continue to be achieved, with March 2017 production under steamflood averaging approximately 31,000 bbl/d.
- Kirby South continues to operate near facility capacity, resulting in production of 37,311 bbl/d in Q1/17, an increase of 8% over Q1/16 levels. Including energy costs, operating costs of $9.12/bbl were achieved in the quarter, representing a 13% decrease from Q1/16 levels, supported by a strong SOR of 2.7.
- Planned turnarounds are being completed at both Primrose and Kirby South plants in Q2/17. Primrose is targeted to be restricted for 35 days relating to the processing facilities and an additional 26 days relating to the steam generation plants. Kirby South is targeted to be down for 21 days. All production volume impacts are reflected in the Company's quarterly and annual guidance.
- In Q1/17 the Company successfully targeted and drilled 8 net thermal in situ SAGD wells, which are targeted to come on production late in Q2/17.
- The Company's 2017 thermal in situ annual production guidance remains unchanged and is targeted to range from 105,000 bbl/d - 115,000 bbl/d.

Natural Gas

	Three Months Ended		
	Mar 31 2017	Dec 31 2016	Mar 31 2016
Natural gas production (MMcf/d)	**1,613**	1,578	1,722
Net wells targeting natural gas	**12**	4	4
Net successful wells drilled	**11**	4	4
Success rate	**92%**	100%	100%

- North America natural gas volumes averaged 1,613 MMcf/d in Q1/17, a decrease of 6% from Q1/16 levels and an increase of 2% from Q4/16 levels. Production was lower than expected due to the unexpected 3rd party natural gas facility outages, which negatively impacted production by approximately 70 MMcf/d in the quarter. The 3rd party is targeting to reinstate the plant to full capability in June 2017.
  - The Company's North America natural gas operations achieved operating costs of $1.20/Mcf in Q1/17.
  - Operating costs in Canadian Natural's key natural gas areas in the Deep Basin and Montney continued to be top tier at $0.42/Mcfe and $0.25/Mcfe respectively in Q1/17.
  - In Q1/17 the Company successfully drilled 11 net natural gas wells.
    - At Septimus, the Company's liquids rich Montney play, 4 net natural gas wells were successfully drilled and brought on production keeping the plant at full capacity (approximately 150 MMcf/d and 7,700 bbl/d of liquids). Production results for the new wells were strong, with per well natural gas and NGL volumes currently averaging approximately 9 MMcf/d and 450 bbl/d, respectively.
    - In the Deep Basin, 2 net wells were successfully drilled in the Bilbo area and are providing strong results. Current per well natural gas and NGL production is averaging approximately 14 MMcf/d and 500 bbl/d, respectively.
    - Additionally, performance has been positive at the Company's liquid rich Montney play at Gold Creek where 2 net wells were successfully drilled. Current per well NGL and natural gas production is averaging approximately 850 bbl/d and 4 MMcf/d, respectively.
- The Company's 2017 total natural gas annual production guidance remains unchanged and is targeted to range from 1,700 MMcf/d - 1,760 MMcf/d.

International Exploration and Production

	Three Months Ended		
	Mar 31 2017	Dec 31 2016	Mar 31 2016
Crude oil production (bbl/d)			
North Sea	**23,042**	24,085	23,317
Offshore Africa	**22,616**	21,689	25,714
Natural gas production (MMcf/d)			
North Sea	**37**	44	29
Offshore Africa	**23**	24	35
Net wells targeting crude oil	**-**	0.9	1.2
Net successful wells drilled	**-**	0.9	1.2
Success rate	**-**	100%	100%

- International E&P quarterly crude oil production volumes were within the Company's production guidance and averaged 45,658 bbl/d in Q1/17.
  - In the North Sea, the Company's continued focus on production enhancements, increased reliability and water flood optimization, resulted in average production volumes of 23,042 bbl/d in Q1/17, a decrease of 1% from Q1/16 and 4% from Q4/16 levels. North Sea quarterly crude oil operating costs decreased to $36.86/bbl, representing reductions of 23% and 12% from Q1/16 and Q4/16 levels respectively.
    - The Company's drilling program in the North Sea in the quarter consisted 1 gross injector well, 0.9 on a net basis. Additionally, subsequent to quarter end, 1 gross production well, 0.9 net, was successfully completed. Current net production from the drilling program, consisting of 1.7 net production wells is strong, averaging approximately 3,500 bbl/d.
    - The Company is targeting to begin the decommissioning and abandonment of the Ninian North platform in June 2017.
  - Offshore Africa production volumes averaged 22,616 bbl/d in Q1/17, a 4% increase over Q4/16 levels. Crude oil operating costs of $18.54/bbl were realized in Q1/17, representing a 3% reduction from Q4/16 levels.
    - Cote d'Ivoire ("CDI") crude oil production expense in Q1/17 averaged $9.10/bbl. CDI production expense for Q1/17 was below the Company's previously issued annual guidance of $10.50/bbl to $12.50/bbl which anticipated cessation of production from Gabon.
- The Company's 2017 International E&P annual production guidance remains unchanged and is targeted to range from 43,000 bbl/d - 49,000 bbl/d.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended		
	Mar 31 2017	Dec 31 2016	Mar 31 2016
Synthetic crude oil production (bbl/d) (1)	**192,491**	178,063	127,909

(1) The Company produces diesel for internal use at Horizon. First quarter 2017 SCO production before royalties excludes 428 bbl/d of SCO consumed internally as diesel (fourth quarter 2016 – 1,619 bbl/d; first quarter 2016 – 2,562 bbl/d).

- At Horizon, Canadian Natural's world class oil sands mining and upgrading operations, record quarterly production volumes were achieved for the second consecutive quarter. In Q1/17 production reached 192,491 bbl/d of SCO, within the Company's previously issued guidance, representing increases of 8% and 50% over Q4/16 and Q1/16 levels respectively.

- Through safe, steady and reliable operations and a strong focus on continuous improvement, the Company realized record low quarterly average operating costs of $22.08/bbl of SCO in Q1/17, representing 2% and 17% reductions from Q4/16 and Q1/16 levels respectively.

- January and February 2017 were strong production months reaching approximately 195,000 bbl/d and 202,600 bbl/d of SCO respectively, as the Company worked to optimize the Horizon Phase 2B expansion. In March 2017 the Company performed unplanned maintenance on the Phase 1 diluent recovery unit and the repairs were completed in 9 days, as a result March 2017 production averaged approximately 180,500 bbl/d of SCO, strong results given the downtime.

- Subsequent to quarter end, the previously announced planned maintenance activities on the Phase 2B diluent recovery systems began in April 2017 restricting production for 19 days in the month. As a result, April 2017 average production was approximately 165,000 bbl/d of SCO with full production capacity reinstated late in the month with current production rates of approximately 205,000 bbl/d of SCO.

- During Q1/17, Canadian Natural continued to advance the Horizon Phase 3 expansion toward completion with project capital expenditures of $139 million in the quarter. The next component of the Company's transition to a long-life, low decline asset base is progressing as planned, reaching 92% physical completion as at March 31, 2017. Targeted project capital in 2017 is $1.05 billion, with start-up of Phase 3 targeted for Q4/17. This phase is targeted to add incremental production capacity of 80,000 bbl/d of SCO, which will result in a further step change towards lower operating costs at this world class asset.

- The previously announced debottleneck option at Horizon continues to move forward, with a target to be executed during the Q3/17 turnaround. The scope and impact on production capacity of the debottleneck will be determined once the full engineering evaluation is completed in late Q2/17. The engineering evaluation primarily involves the fractionation tower which includes quantifying all product yields of naphtha, distillate, gas oil, natural gas and coke from the output of the coker unit on an optimized throughput basis. Concurrently, a process review of the flow dynamics to determine pump and vessel capacities throughout the upgrader is ongoing. A decision on final scope, capital requirements and impact on production capacity is scheduled for late Q2/17, as the Company continues to fully define the debottleneck and optimize production capability.

▪ Directive 85 (formerly Directive 74) of the Horizon expansion remains on track and was 69% physically complete as at March 31, 2017. This project includes research into tailings management and investments in technological advancements to advance the cessation of the use of traditional tailings ponds.

▪ The Company's 2017 Horizon annual production guidance remains unchanged and is targeted to range from 170,000 bbl/d - 184,000 bbl/d of SCO.

MARKETING

	Three Months Ended		
	Mar 31 2017	Dec 31 2016	Mar 31 2016
Crude oil and NGL pricing			
WTI benchmark price (US$/bbl) (1)	**$ 51.86**	$ 49.33	$ 33.51
WCS blend differential from WTI (%) (2)	**28%**	30%	42%
SCO price (US$/bbl)	**$ 51.45**	$ 48.91	$ 33.77
Condensate benchmark pricing (US$/bbl)	**$ 52.21**	$ 48.37	$ 34.45
Average realized pricing before risk management (C$/bbl) (3)	**$ 47.05**	$ 45.00	$ 23.31
Natural gas pricing			
AECO benchmark price (C$/GJ)	**$ 2.79**	$ 2.67	$ 2.00
Average realized pricing before risk management (C$/Mcf)	**$ 3.25**	$ 3.14	$ 2.23

(1) West Texas Intermediate ("WTI").
(2) Western Canadian Select ("WCS").
(3) Average crude oil and NGL pricing excludes SCO. Pricing is net of blending costs and excluding risk management activities.

- WTI averaged US$51.86/bbl for Q1/17, an increase of 55% from US$33.51/bbl in Q1/16, and an increase of 5% from $49.33/bbl in Q4/16.
- Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US $54.05/bbl for Q1/17, an increase of 59% from US$33.92/bbl in Q1/16, and an increase of 8% from $50.27/bbl in Q4/16.
- WTI and Brent pricing for Q1/17 continued to reflect volatility in supply and demand factors and geopolitical events. The OPEC decision in November 2016 to implement a production cut effective January 1, 2017 followed by additional production cuts by certain non-OPEC countries contributed to an increase in first quarter pricing from comparable quarters.
- The WCS Heavy Differential averaged $14.58/bbl in Q1/17, consistent with comparable periods. The WCS Heavy Differential reflects US Gulf Coast pricing, adjusted for transportation costs.
- Canadian Natural contributed approximately 194,000 bbl/d of its heavy crude oil stream to the WCS blend in Q1/17. The Company remains the largest contributor to the WCS blend, accounting for 44% of the total blend.
- The SCO price averaged US$51.45/bbl in Q1/17, an increase of 52% from $33.77/bbl in Q1/16, and an increase of 5% from US$48.91/bbl in Q4/16. The fluctuations in SCO pricing in Q1/17 from the comparable periods were primarily due to changes in WTI benchmark pricing.
- AECO natural gas prices averaged $2.79/GJ in Q1/17, an increase of 40% from $2.00/GJ in Q1/16, and an increase of 4% from $2.67/GJ in Q4/16. The increase in natural gas prices in Q1/17 compared with Q1/16 and Q4/16 reflected the rebalancing of natural gas storage inventory to historically normal levels, primarily due to reduced drilling activity in 2016 resulting in lower US natural gas production. Additionally, pricing during Q1/17 reflected colder weather in the 2016/2017 winter season as compared with the previous year.
- The North West Redwater refinery, upon completion, will strengthen the Company's position by providing a competitive return on investment and by adding 50,000 bbl/d of bitumen conversion capacity in Alberta which will help reduce pricing volatility in all Western Canadian heavy crude oil. The Company has a 50% interest in the North West Redwater Partnership. For project updates, please refer to: https://nwrsturgeonrefinery.com/whats-happening/news/.

FINANCIAL REVIEW

The Company continues to implement proven strategies and its disciplined approach to capital allocation. As a result, the financial position of Canadian Natural remains strong. Canadian Natural's cash flow generation, credit facilities, US commercial paper program, diverse asset base and related flexible capital expenditure programs all support a flexible financial position and provide the appropriate financial resources for the near-, mid- and long-term.

- The Company's strategy is to maintain a diverse portfolio balanced across various commodity types. The Company achieved production of 876,907 BOE/d in Q1/17, with approximately 97% of total production located in G7 countries.

- The Company generated significant free cash flow of approximately $800 million in Q1/17 after net capital expenditures. After capital expenditures and quarterly dividend requirements, approximately $515 million of free cash flow was realized in the quarter, which was largely used to reduce the Company's debt levels.

- Canadian Natural maintains significant financial stability and liquidity represented in part by committed bank credit facilities. As at March 31, 2017, the Company had in place bank credit facilities of $7.4 billion, of which $3.5 billion was available, an increase of approximately $500 million from December 31, 2016 availability.

- Balance sheet strength continues to be a focus of the Company, with debt to book capitalization of 38% at March 31, 2017, within the Company's targeted operating range.

- In addition to its strong cash flow and access to debt capital markets, Canadian Natural has additional financial levers at its disposal to effectively manage its liquidity. As at March 31, 2017, these financial levers include the Company's third party investments of approximately $815 million.

- At March 31, 2017, 50,000 GJ/d of natural gas volumes were hedged using AECO swaps for April 2017 to October 2017. Additionally, 67,000 bbl/d of crude oil volumes were hedged for April 2017 through December 2017 using WTI costless collars with a floor of US$50. For full hedging disclosure please see the Company's website.

- Canadian Natural declared a quarterly cash dividend on common shares of C$0.275 per share payable on July 1, 2017.

OUTLOOK

The Company's outlook and guidance excludes production volumes and capital associated with the AOSP acquisition announced on March 9, 2017. The transaction is targeted to close in Q2/17.

The Company forecasts annual 2017 production levels to average between 550,000 and 590,000 bbl/d of crude oil and NGLs and between 1,700 and 1,760 MMcf/d of natural gas, before royalties. Q2/17 production guidance before royalties is forecast to average between 544,000 and 570,000 bbl/d of crude oil and NGLs and between 1,675 and 1,730 MMcf/d of natural gas. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company’s website at www.cnrl.com.

Canadian Natural's annual 2017 capital expenditures are targeted to be approximately $3.9 billion.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

Forward-Looking Statements

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

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

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

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

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

Management's Discussion and Analysis

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

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

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

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

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

FINANCIAL HIGHLIGHTS

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

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

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

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

Adjusted Net Earnings (Loss) from Operations

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

partially offset by:

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

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

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

partially offset by:

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

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

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

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

SUMMARY OF QUARTERLY RESULTS

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

($ millions, except per common share amounts)		**Mar 31 2017**		Dec 31 2016		Sep 30 2016		Jun 30 2016
Product sales	**$**	**3,872**	$	3,672	$	2,477	$	2,686
Net earnings (loss)	**$**	**245**	$	566	$	(326)	$	(339)
Net earnings (loss) per common share								
– basic	**$**	**0.22**	$	0.51	$	(0.29)	$	(0.31)
– diluted	**$**	**0.22**	$	0.51	$	(0.29)	$	(0.31)

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

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

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

BUSINESS ENVIRONMENT

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

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Dated Brent ("Brent") indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are highly sensitive to fluctuations in foreign exchange rates. For the first quarter of 2017, realized prices continued to be supported by the weaker Canadian dollar, as the Canadian dollar sales price the Company received for its crude oil and natural gas sales is based on US dollar denominated benchmarks.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$51.86 per bbl for the first quarter of 2017, an increase of 55% from US$33.51 per bbl for the first quarter of 2016, and an increase of 5% from US$49.33 per bbl for the fourth quarter of 2016.

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

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

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

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

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

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

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

DAILY PRODUCTION, before royalties

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

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

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

DAILY PRODUCTION, net of royalties

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

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

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

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

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

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

North America – Exploration and Production

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

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

North America – Oil Sands Mining and Upgrading

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

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

North Sea

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

Offshore Africa

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

International Guidance

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

International Crude Oil Inventory Volumes

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

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

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

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

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

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

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

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

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

North America

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

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

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

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

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

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

North Sea

North Sea realized crude oil prices increased 55% to average $70.03 per bbl for the first quarter of 2017 from $45.04 per bbl for the first quarter of 2016 and increased 10% from $63.68 per bbl for the fourth quarter of 2016. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the first quarter of 2017 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 44% to average $61.95 per bbl for the first quarter of 2017 from $42.99 per bbl for the first quarter of 2016 and were comparable with the fourth quarter of 2016. Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the first quarter of 2017 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

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

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

North America

North America crude oil and natural gas royalties for the first quarter of 2017 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential.

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

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

Offshore Africa

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

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

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

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

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

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

North America

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

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

North Sea

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

Offshore Africa

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

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

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

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

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

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)	Three Months Ended **Mar 31 2017**	Dec 31 2016	Mar 31 2016
Expense	**$ 28**	$ 28	$ 29
$/BOE (1)	**$ 0.45**	$ 0.45	$ 0.45

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

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

Asset retirement obligation accretion expense for the first quarter of 2017 on a per BOE basis was consistent with comparable periods.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

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

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

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

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

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

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

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

Realized SCO sales prices averaged $67.85 per bbl for the first quarter of 2017, an increase of 46% compared with $46.63 per bbl for the first quarter of 2016 and an increase of 5% compared with $64.51 per bbl for the fourth quarter of 2016. The increase in SCO pricing for the first quarter of 2017 from comparable periods were primarily due to changes in WTI benchmark pricing.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 15 to the Company's unaudited interim consolidated financial statements.

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

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

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

Cash production costs for the first quarter of 2017 averaged $22.08 per bbl, a decrease of 17% from $26.55 per bbl for the first quarter of 2016 and a decrease of 2% from $22.53 per bbl for the fourth quarter of 2016. The decrease in cash production costs on a per barrel basis for the first quarter of 2017 from comparable periods primarily reflected the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, together with additional Phase 2B capacity. For 2017, cash production costs are anticipated to average $24.00 to $27.00 per bbl, including turnaround costs.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

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

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

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

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

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

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

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

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

MIDSTREAM

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

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

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

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

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

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

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

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

ADMINISTRATION EXPENSE

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

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

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

SHARE-BASED COMPENSATION

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

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

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

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended		
($ millions, except per BOE amounts and interest rates)	**Mar 31 2017**	Dec 31 2016	Mar 31 2016
Expense, gross	**$ 156**	$ 153	$ 153
Less: capitalized interest	**22**	38	61
Expense, net	**$ 134**	$ 115	$ 92
$/BOE (1)	**$ 1.70**	$ 1.43	$ 1.22
Average effective interest rate	**3.9%**	3.8%	3.9%

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

Gross interest and other financing expense was consistent with comparable periods. Capitalized interest of $22 million for the first quarter of 2017 was primarily related to the Horizon Phase 3 expansion.

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

RISK MANAGEMENT ACTIVITIES

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

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

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

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

FOREIGN EXCHANGE

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

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

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

INCOME TAXES

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

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

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

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

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

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

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

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

NET CAPITAL EXPENDITURES [1]

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

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values and other fair value adjustments, and include non-cash transfers of property, plant and equipment to inventory due to change in use.

(2) Includes Business Combinations.

(3) Includes proceeds from the Company's disposition of properties.

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

(5) The above noted figures in the fourth quarter of 2016 include non-cash share consideration of $190 million received from Inter Pipeline on the disposition of Midstream assets.

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

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

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

Drilling Activity

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

(1) Includes bitumen wells.

North America

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

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

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

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

Oil Sands Mining and Upgrading

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

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

North Sea

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

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

Proposed Acquisitions of Interests in the Athabasca Oil Sands Project

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

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

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

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

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

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

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

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

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

- Monitoring funds flow from operations, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. In response to the current commodity price environment, the Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing the Company's borrowing capacity:
    - The Company has $2,000 million remaining on its base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
    - The Company has US$3,000 million remaining on its base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
    - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US $2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under the US commercial paper program.
    - As at March 31, 2017, the $750 million and $125 million facilities were each fully drawn. Borrowings under the $750 million and $125 million non-revolving credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place to minimize the impact in the event of a default.

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

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

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

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

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

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

Share Capital

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

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

On March 1, 2017 the Board of Directors approved the Company's application for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 27,814,309 common shares, over a 12 month period. The Company targets the Normal Course Issuer Bid to commence in May 2017, upon receipt of applicable regulatory and other approvals.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at March 31, 2017:

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

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

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

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

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

CHANGES IN ACCOUNTING POLICIES

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2016.

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	**Mar 31 2017**	Dec 31 2016
ASSETS			
Current assets			
Cash and cash equivalents		**$ 19**	$ 17
Accounts receivable		**1,390**	1,434
Current income taxes		**741**	851
Inventory		**658**	689
Prepaids and other		**239**	149
Investments	4	**815**	913
Current portion of other long-term assets	5	**280**	283
		4,142	4,336
Exploration and evaluation assets	2	**2,383**	2,382
Property, plant and equipment	3	**50,417**	50,910
Other long-term assets	5	**998**	1,020
		$ 57,940	$ 58,648
LIABILITIES			
Current liabilities			
Accounts payable		**$ 541**	$ 595
Accrued liabilities		**1,947**	2,222
Current portion of long-term debt	6	**3,129**	1,812
Current portion of other long-term liabilities	7	**432**	463
		6,049	5,092
Long-term debt	6	**13,175**	14,993
Other long-term liabilities	7	**3,235**	3,223
Deferred income taxes		**9,104**	9,073
		31,563	32,381
SHAREHOLDERS' EQUITY			
Share capital	9	**4,869**	4,671
Retained earnings		**21,465**	21,526
Accumulated other comprehensive income	10	**43**	70
		26,377	26,267
		$ 57,940	$ 58,648

Commitments and contingencies (note 14).

Approved by the Board of Directors on May 3, 2017.

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Mar 31 2017	Mar 31 2016
Product sales		$ **3,872**	$ 2,263
Less: royalties		**(230)**	(85)
Revenue		**3,642**	2,178
Expenses			
Production		**1,102**	1,022
Transportation and blending		**642**	510
Depletion, depreciation and amortization	3	**1,299**	1,219
Administration		**87**	86
Share-based compensation	7	**27**	117
Asset retirement obligation accretion	7	**36**	36
Interest and other financing expense		**134**	92
Risk management activities	13	**(52)**	70
Foreign exchange gain		**(56)**	(315)
Gain on disposition of properties		**—**	(32)
Loss (gain) from investments	4, 5	**89**	(159)
		3,308	2,646
Earnings (loss) before taxes		**334**	(468)
Current income tax expense (recovery)	8	**53**	(192)
Deferred income tax expense (recovery)	8	**36**	(171)
Net earnings (loss)		$ **245**	$ (105)
Net earnings (loss) per common share			
Basic	12	$ **0.22**	$ (0.10)
Diluted	12	$ **0.22**	$ (0.10)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended Mar 31 2017	Mar 31 2016
Net earnings (loss)	$ **245**	$ (105)
Items that may be reclassified subsequently to net earnings (loss)		
Net change in derivative financial instruments designated as cash flow hedges		
Unrealized loss during the period, net of taxes of $nil (2016 – $3 million)	**(1)**	(24)
Reclassification to net earnings (loss), net of taxes of $1 million (2016 – $2 million)	**(7)**	10
	(8)	(14)
Foreign currency translation adjustment		
Translation of net investment	**(19)**	(49)
Other comprehensive loss, net of taxes	**(27)**	(63)
Comprehensive income (loss)	$ **218**	$ (168)

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Mar 31 2017**	 Mar 31 2016
Share capital	9		
Balance – beginning of period		**$ 4,671**	$ 4,541
Issued upon exercise of stock options		**160**	30
Previously recognized liability on stock options exercised for common shares		**38**	5
Balance – end of period		**4,869**	4,576
Retained earnings			
Balance – beginning of period		**21,526**	22,765
Net earnings (loss)		**245**	(105)
Dividends on common shares	9	**(306)**	(252)
Balance – end of period		**21,465**	22,408
Accumulated other comprehensive income	10		
Balance – beginning of period		**70**	75
Other comprehensive loss, net of taxes		**(27)**	(63)
Balance – end of period		**43**	12
Shareholders' equity		**$ 26,377**	$ 26,996

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Mar 31 2017**	Mar 31 2016
Operating activities			
Net earnings (loss)		**$ 245**	$ (105)
Non-cash items			
Depletion, depreciation and amortization		**1,299**	1,219
Share-based compensation		**27**	117
Asset retirement obligation accretion		**36**	36
Unrealized risk management (gain) loss		**(40)**	74
Unrealized foreign exchange gain		**(60)**	(334)
Loss (gain) from investments	4, 5	**96**	(147)
Deferred income tax expense (recovery)		**36**	(171)
Gain on disposition of properties		**—**	(32)
Other		**22**	19
Abandonment expenditures		**(41)**	(74)
Net change in non-cash working capital		**51**	(21)
		1,671	581
Financing activities			
(Repayment) issue of bank credit facilities and commercial paper, net	6	**(428)**	1,130
Repayment of US dollar debt securities		**—**	(555)
Issue of common shares on exercise of stock options		**160**	30
Dividends on common shares		**(277)**	—
		(545)	605
Investing activities			
Net (expenditures) proceeds on exploration and evaluation assets		**(37)**	30
Net expenditures on property, plant and equipment		**(768)**	(996)
Investment in other long-term assets		**—**	(99)
Net change in non-cash working capital		**(319)**	(175)
		(1,124)	(1,240)
Increase (decrease) in cash and cash equivalents		**2**	(54)
Cash and cash equivalents – beginning of period		**17**	69
Cash and cash equivalents – end of period		**$ 19**	$ 15
Interest paid, net		**$ 199**	$ 182
Income taxes received		**$ (65)**	$ (117)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts in millions of Canadian dollars, unless otherwise stated, unaudited)

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire, Gabon, and South Africa in Offshore Africa.

The Horizon Oil Sands Mining and Upgrading segment ("Horizon") produces synthetic crude oil through bitumen mining and upgrading operations.

Within Western Canada, the Company maintains certain midstream activities that include pipeline operations, an electricity co-generation system and an investment in the North West Redwater Partnership ("Redwater Partnership"), a general partnership formed in the Province of Alberta.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2100, 855 - 2 Street S.W., Calgary, Alberta, Canada.

These interim consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34, "Interim Financial Reporting", following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2016. These interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2016.

2. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2016	$ 2,306	$ —	$ 76	$ —	$ 2,382
Additions	**33**	**—**	**4**	**—**	**37**
Transfers to property, plant and equipment	**(36)**	**—**	**—**	**—**	**(36)**
At March 31, 2017	**$ 2,303**	**$ —**	**$ 80**	**$ —**	**$ 2,383**

3. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2016	$ 61,647	$ 7,380	$ 5,132	$ 27,038	$ 234	$ 395	$ 101,826
Additions	**491**	**35**	**15**	**227**	**1**	**3**	**772**
Transfers from E&E assets	**36**	**—**	**—**	**—**	**—**	**—**	**36**
Disposals/derecognitions	**(100)**	**—**	**—**	**(14)**	**—**	**—**	**(114)**
Foreign exchange adjustments and other	**—**	**(57)**	**(40)**	**—**	**—**	**—**	**(97)**
At March 31, 2017	**$ 62,074**	**$ 7,358**	**$ 5,107**	**$ 27,251**	**$ 235**	**$ 398**	**$ 102,423**
Accumulated depletion and depreciation							
At December 31, 2016	$ 38,311	$ 5,584	$ 3,797	$ 2,828	$ 115	$ 281	$ 50,916
Expense	**793**	**245**	**58**	**195**	**2**	**6**	**1,299**
Disposals/derecognitions	**(100)**	**—**	**—**	**(14)**	**—**	**—**	**(114)**
Foreign exchange adjustments and other	**(2)**	**(67)**	**(34)**	**8**	**—**	**—**	**(95)**
At March 31, 2017	**$ 39,002**	**$ 5,762**	**$ 3,821**	**$ 3,017**	**$ 117**	**$ 287**	**$ 52,006**
Net book value							
- at March 31, 2017	**$ 23,072**	**$ 1,596**	**$ 1,286**	**$ 24,234**	**$ 118**	**$ 111**	**$ 50,417**
- at December 31, 2016	$ 23,336	$ 1,796	$ 1,335	$ 24,210	$ 119	$ 114	$ 50,910

Project costs not subject to depletion and depreciation	Mar 31 2017	Dec 31 2016
Kirby Thermal Oil Sands – North	**$ 862**	$ 846

During the three months ended March 31, 2017, the Company acquired a number of producing crude oil and natural gas properties in the North America Exploration and Production segment for net cash consideration of $9 million. These transactions were accounted for using the acquisition method of accounting. No net deferred income tax liabilities or pre-tax gains were recognized on these acquisitions.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. For the three months ended March 31, 2017, pre-tax interest of $22 million (March 31, 2016 – $61 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (March 31, 2016 – 3.9%).

On March 9, 2017, the Company announced that it had entered into agreements to acquire 70% of the Athabasca Oil Sands Project, as well as additional working interests in certain other producing and non-producing oil and gas properties, for preliminary total consideration of approximately $12.7 billion, comprised of cash of approximately $8.7 billion and 97,560,975 common shares of the Company, with an estimated value of approximately $4 billion as at the announcement date. The transaction is expected to close in mid-2017, subject to receipt of all required consents and regulatory and other approvals.

4. INVESTMENTS

As at March 31, 2017, the Company had the following investments:

		Mar 31 2017		Dec 31 2016
Investment in PrairieSky Royalty Ltd.	**$**	**635**	$	723
Investment in Inter Pipeline Ltd.		**180**		190
	$	**815**	$	913

Investment in PrairieSky Royalty Ltd.

The Company's investment of 22.6 million common shares of PrairieSky Royalty Ltd. ("PrairieSky") does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at March 31, 2017, the Company's investment in PrairieSky was classified as a current asset.

The loss (gain) from the investment in PrairieSky was comprised as follows:

	Three Months Ended			
		Mar 31 2017		Mar 31 2016
Fair value loss (gain) from PrairieSky	**$**	**88**	$	(121)
Dividend income from PrairieSky		**(4)**		(12)
	$	**84**	$	(133)

Investment in Inter Pipeline Ltd.

The Company's investment of 6.4 million common shares of Inter Pipeline Ltd. ("Inter Pipeline") does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at March 31, 2017, the Company's investment in Inter Pipeline was classified as a current asset.

The loss from the investment in Inter Pipeline was comprised as follows:

	Three Months Ended			
		Mar 31 2017		Mar 31 2016
Fair value loss from Inter Pipeline	**$**	**10**	$	—
Dividend income from Inter Pipeline		**(3)**		—
	$	**7**	$	—

5. OTHER LONG-TERM ASSETS

		Mar 31 2017		Dec 31 2016
Investment in North West Redwater Partnership	**$**	**263**	$	261
North West Redwater Partnership subordinated debt (1)		**394**		385
Risk Management (note 13)		**484**		489
Other		**137**		168
		1,278		1,303
Less: current portion		**280**		283
	$	**998**	$	1,020

(1) Includes accrued interest.

Investment in North West Redwater Partnership

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

During 2013, the Company along with APMC, committed each to provide funding up to $350 million by each party by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. To date, each party has provided $324 million of subordinated debt, together with accrued interest thereon of $70 million for a Company total of $394 million. In 2014, the Partnership set the facility capital cost ("FCC") budget at $8,500 million, which was increased by approximately 4% to the current estimate of $8,900 million. The Company and APMC have agreed, each with a 50% interest, to provide additional subordinated debt as required for Project costs in excess of the FCC of $8,500 million to reflect an agreed debt to equity ratio of 80/20 and, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion which is currently targeted for mid-2018. The Company's share of any additional subordinated debt financing resulting from the increase in the FCC in excess of $8,500 million is not expected to be significant.

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

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

During the three months ended March 31, 2017, the Company recognized an equity gain from Redwater Partnership of $2 million (March 31, 2016 – gain of $26 million).

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.

6. LONG-TERM DEBT

	Mar 31 2017	Dec 31 2016
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ 2,341**	$ 2,758
Medium-term notes	**3,500**	3,500
	5,841	6,258
US dollar denominated debt, unsecured		
Bank credit facilities (March 31, 2017 - US$902 million; December 31, 2016 - US$905 million)	**1,200**	1,213
Commercial paper (March 31, 2017 - US$250 million; December 31, 2016 - US$250 million)	**333**	336
US dollar debt securities (March 31, 2017 - US$6,750 million; December 31, 2016 - US$6,750 million)	**8,992**	9,063
	10,525	10,612
Long-term debt before transaction costs and original issue discounts, net	**16,366**	16,870
Less: original issue discounts, net (1)	**(10)**	(10)
transaction costs (1) (2)	**(52)**	(55)
	16,304	16,805
Less: current portion of commercial paper	**333**	336
current portion of other long-term debt (1) (2)	**2,796**	1,476
	$ 13,175	$ 14,993

(1) The Company has included unamortized original issue discounts and premiums, and directly attributable transaction costs in the carrying amount of the outstanding debt.

(2) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.

Bank Credit Facilities and Commercial Paper

As at March 31, 2017, the Company had in place bank credit facilities of $7,350 million available for general corporate purposes, comprised of:

- a $100 million demand credit facility;
- a $1,500 million non-revolving term credit facility maturing April 2018;
- a $750 million non-revolving term credit facility maturing February 2019;
- a $125 million non-revolving term credit facility maturing February 2019;
- a $2,425 million revolving syndicated credit facility maturing June 2019;
- a $2,425 million revolving syndicated credit facility maturing June 2020; and
- a £15 million demand credit facility related to the Company's North Sea operations.

Each of the $2,425 million revolving facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.

Borrowings under the $750 million and $125 million non-revolving credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at March 31, 2017, the $750 million and $125 million facilities were each fully drawn.

Borrowings under the $1,500 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans. As at March 31, 2017, the $1,500 million facility was fully drawn.

The Company's borrowings under its US commercial paper program are authorized up to a maximum US$2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at March 31, 2017 was 2.0% (March 31, 2016 – 2.0%), and on total long-term debt outstanding for the three months ended March 31, 2017 was 3.9% (March 31, 2016 – 3.9%).

At March 31, 2017, letters of credit and guarantees aggregating $825 million, including letters of credit of $567 million related to the proposed acquisition of the Athabasca Oil Sands Project, a $39 million financial guarantee related to Horizon and $110 million of letters of credit related to North Sea operations, were outstanding. The letters of credit are supported by dedicated credit facilities.

Medium-Term Notes

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.

US Dollar Debt Securities

The Company has US$3,000 million remaining on its base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

7. OTHER LONG-TERM LIABILITIES

		Mar 31 2017		Dec 31 2016
Asset retirement obligations	**$**	**3,234**	$	3,243
Share-based compensation		**417**		426
Other		**16**		17
		3,667		3,686
Less: current portion		**432**		463
	$	**3,235**	$	3,223

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 5.2% (December 31, 2016 – 5.2%). Reconciliations of the discounted asset retirement obligations were as follows:

		Mar 31 2017		Dec 31 2016
Balance – beginning of period	**$**	**3,243**	$	2,950
Liabilities incurred		**4**		3
Liabilities acquired, net		**—**		30
Liabilities settled		**(41)**		(267)
Asset retirement obligation accretion		**36**		142
Revision of cost, inflation rates and timing estimates		**—**		(68)
Change in discount rate		**—**		493
Foreign exchange adjustments		**(8)**		(40)
Balance – end of period		**3,234**		3,243
Less: current portion		**93**		95
	$	**3,141**	$	3,148

Share-Based Compensation

As the Company's Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered, a liability for potential cash settlements is recognized. The current portion represents the maximum amount of the liability payable within the next twelve month period if all vested stock options are surrendered for cash settlement.

		Mar 31 2017		Dec 31 2016
Balance – beginning of period	**$**	**426**	$	128
Share-based compensation expense		**27**		355
Cash payment for stock options surrendered		**(1)**		(7)
Transferred to common shares		**(38)**		(117)
Capitalized to Oil Sands Mining and Upgrading		**3**		67
Balance – end of period		**417**		426
Less: current portion		**339**		368
	$	**78**	$	58

8. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended	
Expense (recovery)	**Mar 31 2017**	Mar 31 2016
Current corporate income tax – North America	**$ 38**	$ (119)
Current corporate income tax – North Sea	**6**	(23)
Current corporate income tax – Offshore Africa	**7**	4
Current PRT [(1)] – North Sea	**(1)**	(55)
Other taxes	**3**	1
Current income tax	**53**	(192)
Deferred corporate income tax	**28**	33
Deferred PRT [(1)] – North Sea	**8**	(204)
Deferred income tax	**36**	(171)
Income tax	**$ 89**	$ (363)

(1) Petroleum Revenue Tax.

9. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Three Months Ended Mar 31, 2017	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,110,952**	**$ 4,671**
Issued upon exercise of stock options	**4,654**	**160**
Previously recognized liability on stock options exercised for common shares	**—**	**38**
Balance – end of period	**1,115,606**	**$ 4,869**

Dividend Policy

The Company has paid regular quarterly dividends in each year since 2001. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 1, 2017, the Board of Directors declared a quarterly dividend of $0.275 per common share, an increase from the previous quarterly dividend of $0.25 per common share.

Normal Course Issuer Bid

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. For the three months ended March 31, 2017, the Company did not purchase any common shares for cancellation.

Stock Options

The following table summarizes information relating to stock options outstanding at March 31, 2017:

	Three Months Ended Mar 31, 2017	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of period	**58,299**	**$ 34.22**
Granted	**2,893**	**$ 42.14**
Surrendered for cash settlement	**(188)**	**$ 35.62**
Exercised for common shares	**(4,654)**	**$ 34.44**
Forfeited	**(1,609)**	**$ 38.92**
Outstanding – end of period	**54,741**	**$ 34.48**
Exercisable – end of period	**16,162**	**$ 33.15**

The Option Plan is a "rolling 9%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 9% of the common shares outstanding from time to time.

10. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of accumulated other comprehensive income, net of taxes, were as follows:

	Mar 31 2017	Mar 31 2016
Derivative financial instruments designated as cash flow hedges	**$ 19**	$ 44
Foreign currency translation adjustment	**24**	(32)
	$ 43	$ 12

11. CAPITAL DISCLOSURES

The Company does not have any externally imposed regulatory capital requirements for managing capital. The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined at each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. 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 cash flow from operating activities is greater than current investment activities. At March 31, 2017, the ratio was within the target range at 38%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS and this financial measure may not be comparable to similar measures presented by other companies. Further, there are no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

	Mar 31 2017	Dec 31 2016
Long-term debt (1)	**$ 16,304**	$ 16,805
Total shareholders' equity	**$ 26,377**	$ 26,267
Debt to book capitalization	**38%**	39%

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

12. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended			
		Mar 31 2017		Mar 31 2016
Weighted average common shares outstanding – basic (thousands of shares)		**1,112,939**		1,094,915
Effect of dilutive stock options (thousands of shares)		**8,337**		—
Weighted average common shares outstanding – diluted (thousands of shares)		**1,121,276**		1,094,915
Net earnings (loss)	**$**	**245**	$	(105)
Net earnings (loss) per common share – basic	**$**	**0.22**	$	(0.10)
– diluted	**$**	**0.22**	$	(0.10)

13. FINANCIAL INSTRUMENTS

The carrying amounts of the Company's financial instruments by category were as follows:

	Mar 31, 2017				
Asset (liability)	**Financial assets at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 1,390**	**$ —**	**$ —**	**$ —**	**$ 1,390**
Investments	**—**	**815**	**—**	**—**	**815**
Other long-term assets	**394**	**42**	**442**	**—**	**878**
Accounts payable	**—**	**—**	**—**	**(541)**	**(541)**
Accrued liabilities	**—**	**—**	**—**	**(1,947)**	**(1,947)**
Long-term debt (1)	**—**	**—**	**—**	**(16,304)**	**(16,304)**
	$ 1,784	**$ 857**	**$ 442**	**$ (18,792)**	**$ (15,709)**

	Dec 31, 2016				
Asset (liability)	Financial assets at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 1,434	$ —	$ —	$ —	$ 1,434
Investments	—	913	—	—	913
Other long-term assets	385	4	485	—	874
Accounts payable	—	—	—	(595)	(595)
Accrued liabilities	—	—	—	(2,222)	(2,222)
Long-term debt (1)	—	—	—	(16,805)	(16,805)
	$ 1,819	$ 917	$ 485	$ (19,622)	$ (16,401)

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

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt. The fair values of the Company's recurring other long-term assets and fixed rate long-term debt are outlined below:

	Mar 31, 2017			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3**
Investments (3)	**$ 815**	**$ 815**	**$ —**	**$ —**
Other long-term assets (4)	**$ 878**	**$ —**	**$ 484**	**$ 394**
Fixed rate long-term debt (5) (6)	**$ (12,430)**	**$ (13,249)**	**$ —**	**$ —**

	Dec 31, 2016			
	Carrying amount	Fair value		
Asset (liability) (1) (2)		Level 1	Level 2	Level 3
Investments (3)	$ 913	$ 913	$ —	$ —
Other long-term assets (4)	$ 874	$ —	$ 489	$ 385
Fixed rate long-term debt (5) (6)	$ (12,498)	$ (13,217)	$ —	$ —

(1) Excludes financial assets and liabilities where the carrying amount approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities).

(2) There were no transfers between Level 1, 2 and 3 financial instruments.

(3) The fair value of the investments are based on quoted market prices.

(4) The fair value of Redwater Partnership subordinated debt is based on the present value of future cash receipts.

(5) The fair value of fixed rate long-term debt has been determined based on quoted market prices.

(6) Includes the current portion of fixed rate long-term debt.

The following provides a summary of the carrying amounts of derivative financial instruments held and a reconciliation to the Company's consolidated balance sheets.

Asset (liability)	**Mar 31 2017**	Dec 31 2016
Derivatives held for trading		
Foreign currency forward contracts	**$ (3)**	$ 10
Crude oil price collars	**43**	—
Natural gas AECO swaps	**2**	(6)
Cash flow hedges		
Foreign currency forward contracts	**2**	16
Cross currency swaps	**440**	469
	$ 484	$ 489
Included within:		
Current portion of other long-term assets	**$ 233**	$ 222
Other long-term assets	**251**	267
	$ 484	$ 489

For the three months ended March 31, 2017, the Company recognized a gain of $2 million (year ended December 31, 2016 – gain of $7 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair value of derivative financial instruments in Level 2 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications. Level 2 fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs as applicable, including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

Risk Management

The Company periodically uses derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The changes in estimated fair values of derivative financial instruments included in the risk management asset were recognized in the financial statements as follows:

Asset (liability)		**Mar 31 2017**		Dec 31 2016
Balance – beginning of period	**$**	**489**	$	854
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**40**		(25)
Foreign exchange		**(36)**		(304)
Other comprehensive loss		**(9)**		(36)
Balance – end of period		**484**		489
Less: current portion		**233**		222
	$	**251**	$	267

Net (gains) losses from risk management activities were as follows:

	Three Months Ended			
		Mar 31 2017		Mar 31 2016
Net realized risk management gain	**$**	**(12)**	$	(4)
Net unrealized risk management (gain) loss		**(40)**		74
	$	**(52)**	$	70

Financial Risk Factors

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At March 31, 2017, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts

	Remaining term			Volume	Weighted average price			Index
Crude Oil								
Price collars	Apr 2017	-	Dec 2017	67,500 bbl/d	US$50.00	-	US$60.10	WTI
Natural Gas								
AECO swaps	Apr 2017	-	Oct 2017	50,000 GJ/d			$2.80	AECO

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At March 31, 2017, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt, commercial paper and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At March 31, 2017, the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Apr 2017	—	May 2017	US$1,100	1.170	5.70%	5.10%
	Apr 2017	—	Nov 2021	US$500	1.022	3.45%	3.96%
	Apr 2017	—	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments were designated as hedges at March 31, 2017 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at March 31, 2017, the Company had US$2,039 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$1,152 million designated as cash flow hedges.

b) Credit Risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At March 31, 2017, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. At March 31, 2017, the Company had net risk management assets of $488 million with specific counterparties related to derivative financial instruments (December 31, 2016 – $489 million).

The carrying amount of financial assets approximates the maximum credit exposure.

c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

The maturity dates for financial liabilities were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 541	$ —	$ —	$ —
Accrued liabilities	$ 1,947	$ —	$ —	$ —
Long-term debt [(1)]	$ 3,130	$ 2,370	$ 4,837	$ 6,029

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

14. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	Remaining 2017	2018	2019	2020	2021	Thereafter
Product transportation and pipeline	$ 349	$ 450	$ 327	$ 311	$ 260	$ 2,317
Offshore equipment operating leases and offshore drilling	$ 174	$ 192	$ 98	$ 74	$ 73	$ 8
Office leases	$ 32	$ 43	$ 43	$ 42	$ 40	$ 152
Other	$ 41	$ 2	$ 2	$ 2	$ 2	$ 35

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

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.

15. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America Three Months Ended Mar 31		North Sea Three Months Ended Mar 31		Offshore Africa Three Months Ended Mar 31		Total Exploration and Production Three Months Ended Mar 31	
	2017	2016	**2017**	2016	**2017**	2016	**2017**	2016
Segmented product sales	**2,366**	1,512	**219**	121	**140**	100	**2,725**	1,733
Less: royalties	**(204)**	(79)	**—**	—	**(7)**	(5)	**(211)**	(84)
Segmented revenue	**2,162**	1,433	**219**	121	**133**	95	**2,514**	1,649
Segmented expenses								
Production	**571**	567	**110**	120	**46**	34	**727**	721
Transportation and blending	**632**	493	**11**	10	**—**	1	**643**	504
Depletion, depreciation and amortization	**799**	897	**245**	111	**58**	61	**1,102**	1,069
Asset retirement obligation accretion	**19**	17	**7**	9	**2**	3	**28**	29
Realized risk management activities	**(12)**	(4)	**—**	—	**—**	—	**(12)**	(4)
Gain on disposition of properties	**—**	(32)	**—**	—	**—**	—	**—**	(32)
Loss (gain) from investments	**91**	(133)	**—**	—	**—**	—	**91**	(133)
Total segmented expenses	**2,100**	1,805	**373**	250	**106**	99	**2,579**	2,154
Segmented earnings (loss) before the following	**62**	(372)	**(154)**	(129)	**27**	(4)	**(65)**	(505)
Non–segmented expenses								
Administration								
Share-based compensation								
Interest and other financing expense								
Unrealized risk management activities								
Foreign exchange gain								
Total non–segmented expenses								
Earnings (loss) before taxes								
Current income tax expense (recovery)								
Deferred income tax expense (recovery)								
Net earnings (loss)								

(millions of Canadian dollars, unaudited)	**Oil Sands Mining and Upgrading** Three Months Ended Mar 31		**Midstream** Three Months Ended Mar 31		**Inter–segment elimination and other** Three Months Ended Mar 31		**Total** Three Months Ended Mar 31	
	2017	2016	**2017**	2016	**2017**	2016	**2017**	2016
Segmented product sales	**1,145**	524	**25**	26	**(23)**	(20)	**3,872**	2,263
Less: royalties	**(19)**	(1)	**—**	—	**—**	—	**(230)**	(85)
Segmented revenue	**1,126**	523	**25**	26	**(23)**	(20)	**3,642**	2,178
Segmented expenses								
Production	**372**	297	**4**	6	**(1)**	(2)	**1,102**	1,022
Transportation and blending	**20**	23	**—**	—	**(21)**	(17)	**642**	510
Depletion, depreciation and amortization	**195**	147	**2**	3	**—**	—	**1,299**	1,219
Asset retirement obligation accretion	**8**	7	**—**	—	**—**	—	**36**	36
Realized risk management activities	**—**	—	**—**	—	**—**	—	**(12)**	(4)
Gain on disposition of properties	**—**	—	**—**	—	**—**	—	**—**	(32)
Loss (gain) from investments	**—**	—	**(2)**	(26)	**—**	—	**89**	(159)
Total segmented expenses	**595**	474	**4**	(17)	**(22)**	(19)	**3,156**	2,592
Segmented earnings (loss) before the following	**531**	49	**21**	43	**(1)**	(1)	**486**	(414)
Non–segmented expenses								
Administration							**87**	86
Share-based compensation							**27**	117
Interest and other financing expense							**134**	92
Unrealized risk management activities							**(40)**	74
Foreign exchange gain							**(56)**	(315)
Total non–segmented expenses							**152**	54
Earnings (loss) before taxes							**334**	(468)
Current income tax expense (recovery)							**53**	(192)
Deferred income tax expense (recovery)							**36**	(171)
Net earnings (loss)							**245**	(105)

Capital Expenditures [1]

	Three Months Ended					
	Mar 31, 2017			Mar 31, 2016		
	Net expenditures (proceeds)	**Non-cash and fair value changes [2]**	**Capitalized costs**	Net expenditures (proceeds)	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [3]	**$ 33**	**$ (36)**	**$ (3)**	$ (3)	$ (48)	$ (51)
North Sea	**—**	**—**	**—**	—	—	—
Offshore Africa	**4**	**—**	**4**	5	—	5
	$ 37	**$ (36)**	**$ 1**	$ 2	$ (48)	$ (46)
Property, plant and equipment						
Exploration and Production						
North America	**$ 487**	**$ (60)**	**$ 427**	$ 284	$ (35)	$ 249
North Sea	**35**	**—**	**35**	16	—	16
Offshore Africa	**15**	**—**	**15**	104	—	104
	537	**(60)**	**477**	404	(35)	369
Oil Sands Mining and Upgrading [4]	**227**	**(14)**	**213**	585	(15)	570
Midstream	**1**	**—**	**1**	1	—	1
Head office	**3**	**—**	**3**	6	—	6
	$ 768	**$ (74)**	**$ 694**	$ 996	$ (50)	$ 946

(1) This table provides a reconciliation of capitalized costs including derecognitions and does not include the impact of foreign exchange adjustments.

(2) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, transfers of property, plant and equipment to inventory due to change in use, and other fair value adjustments.

(3) The above noted figures for 2016 do not include the impact of a pre-tax gain of $32 million on the disposition of exploration and evaluation assets.

(4) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest and share-based compensation.

Segmented Assets

	Mar 31 2017	Dec 31 2016
Exploration and Production		
North America	**$ 28,444**	$ 28,892
North Sea	**1,976**	2,269
Offshore Africa	**1,509**	1,580
Other	**62**	29
Oil Sands Mining and Upgrading	**24,927**	24,852
Midstream	**911**	912
Head office	**111**	114
	$ 57,940	$ 58,648

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated October 2015. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended March 31, 2017:	
Interest coverage (times)	
Net earnings [(1)]	0.4x
Funds flow from operations [(2)]	8.8x

(1) Net earnings plus income taxes and interest expense excluding current and deferred PRT expense and other taxes; divided by the sum of interest expense and capitalized interest.

(2) Funds flow from operations plus current income taxes and interest expense excluding current PRT expense and other taxes; divided by the sum of interest expense and capitalized interest.

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Stock Listing

Toronto Stock Exchange
Trading Symbol - CNQ

New York Stock Exchange
Trading Symbol - CNQ

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

Investor Relations

Telephone: (403) 514-7777
Email: ir@cnrl.com

CANADIAN NATURAL RESOURCES LIMITED
2100, 855 - 2nd Street S.W., Calgary, Alberta T2P 4J8
Telephone: (403) 517-6700 Facsimile: (403) 517-7350
Website: www.cnrl.com
Printed in Canada