Canadian Natural

THIRD QUARTER REPORT

NINE MONTHS ENDED SEPTEMBER 30, 2016 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2016 THIRD QUARTER RESULTS

Commenting on third quarter 2016 results, Steve Laut, President of Canadian Natural stated, “Canadian Natural's diverse and balanced asset portfolio delivered quarterly production volumes of 735,212 BOE/d that were within the Company's Q3/16 guidance. We continued our focus on lowering our cost structures, which helped to achieve the Company's cash flow from operations of $1.021 billion during the quarter.

The planned major turnaround at our Horizon Oil Sands Mining and Upgrading project was successfully completed in the third quarter of 2016 and tie-in of the 45,000 bbl/d of additional production from the Phase 2B expansion went as planned. Current production volumes at Horizon are approximately 175,000 bbl/d as we executed the Phase 2B expansion start-up in early October, slightly ahead of the targeted start-up date. We anticipate delivering targeted production rates in excess of 182,000 bbl/d of SCO being achieved imminently.

Also, the Company's Board of Directors has authorized Management to re-initiate the development of the Kirby North thermal project with engineering and procurement commencing in 2017, with a focus on finding opportunities to continue to reduce construction costs to completion. The project will add 40,000 bbl/d of targeted production volumes to Canadian Natural's thermal oil sands portfolio. Kirby North will be targeted to deliver first steam-in in 2019 with first oil targeted in 2020.

With the excellent progress of the Horizon expansion and the recommencement of Kirby North development, we are on track to deliver substantial and sustainable cash flow in the near-, mid- and long-term as we continue our transition to a longer-life, low decline asset base. As we go forward, Canadian Natural becomes a significantly more robust and sustainable company. Endorsing confidence in our ability to deliver the remaining elements of this transition, the Company’s Board of Directors increased the quarterly dividend on common shares by roughly 9% to 25 cents per quarter."

Canadian Natural’s Chief Financial Officer, Corey Bieber, continued, “During the quarter, our financial position remained resilient reflecting solid production and increased cash flow. Supplementing the Company's liquidity, we successfully completed a $1.0 billion bond issuance in August.

Canadian Natural has reached a significant milestone with the recent additional production and incremental cash flows associated with the Company's completion of Horizon Phase 2B, being a major addition to the Company's balanced asset portfolio. Coupled with lower Horizon project capital, our free cash flow profile significantly changes, making us more sustainable through the commodity price cycle. The targeted completion of the Horizon expansion to 250,000 bbl/d of SCO in 2017 will further increase our long-life, low decline asset profile. In addition, we have made great strides throughout the entire company in lowering overall costs to reflect the new commodity price paradigms and we continue to target new savings and innovation to augment our sustainability."

QUARTERLY HIGHLIGHTS

	Three Months Ended			Nine Months Ended	
($ millions, except per common share amounts)	**Sep 30 2016**	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Net earnings (loss)	**$ (326)**	$ (339)	$ (111)	**$ (770)**	$ (768)
Per common share – basic	**$ (0.29)**	$ (0.31)	$ (0.10)	**$ (0.70)**	$ (0.70)
– diluted	**$ (0.29)**	$ (0.31)	$ (0.10)	**$ (0.70)**	$ (0.70)
Adjusted net earnings (loss) from operations (1)	**$ (355)**	$ (210)	$ 113	**$ (1,108)**	$ 312
Per common share – basic	**$ (0.32)**	$ (0.19)	$ 0.10	**$ (1.01)**	$ 0.28
– diluted	**$ (0.32)**	$ (0.19)	$ 0.10	**$ (1.01)**	$ 0.28
Cash flow from operations (2)	**$ 1,021**	$ 938	$ 1,533	**$ 2,616**	$ 4,406
Per common share – basic	**$ 0.93**	$ 0.85	$ 1.40	**$ 2.38**	$ 4.03
– diluted	**$ 0.92**	$ 0.85	$ 1.40	**$ 2.38**	$ 4.02
Net capital expenditures	**$ 1,185**	$ 1,158	$ 1,240	**$ 3,383**	$ 3,949
Daily production, before royalties					
Natural gas (MMcf/d)	**1,645**	1,689	1,653	**1,707**	1,734
Crude oil and NGLs (bbl/d)	**460,986**	502,410	573,135	**503,286**	561,554
Equivalent production (BOE/d) (3)	**735,212**	783,988	848,701	**787,718**	850,587

(1) Adjusted net (loss) earnings 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) 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.

- The staged start-up of the Horizon Oil Sands ("Horizon") Phase 2B expansion is substantially complete with October Synthetic Crude Oil ("SCO") production volumes averaging approximately 161,000 bbl/d, a new monthly production record. Production rates are very strong with current production volumes of approximately 175,000 bbl/d of SCO and imminent ramp up to targeted production rates in excess of 182,000 bbl/d of SCO.

- For the first nine months of 2016, Horizon project capital costs totaled $1.405 billion, with total Horizon project capital now targeted to be approximately $1.920 billion in 2016 versus the Company's original 2016 budget range of $1.890 billion to $1.990 billion. In 2017, Horizon project capital costs are targeted to be approximately $1 billion for Phase 3 completion, which is targeted to add incremental production volumes of 80,000 bbl/d of SCO in Q4/17. The addition of Phase 3 will mark the completion of the Horizon expansion with targeted design capacity in excess of 250,000 bbl/d of SCO, and targeted operating costs below C$25.00/bbl (US$20.00/bbl).

- At September 30, 2016, the Horizon Phase 3 expansion reached 87% physical completion. Within the scope of work for the combined hydrotreater, all modules have been installed and module interconnections are well advanced. Phase 3 includes the addition of an ore preparation plant, extraction trains, the combined hydrotreater and a sulphur recovery unit. Phase 3 remains on schedule for targeted start-up in Q4/17.

- Canadian Natural realized cash flow from operations in Q3/16 of $1,021 million, an increase from $938 million in Q2/16 primarily reflecting the impact of higher natural gas netbacks, higher North America Exploration and Production ("E&P") crude oil and NGL sales volumes and lower cash tax expense. The decrease from $1,533 million in Q3/15 primarily reflects lower North America crude oil and NGL sales volumes, largely due to the planned turnaround activities completed at Horizon and Primrose, and lower commodity prices resulting in lower North America netbacks.

- For Q3/16, the Company had a net loss of $326 million compared to a net loss of $111 million in Q3/15 and net loss of $339 million in Q2/16. Adjusted net loss from operations was $355 million in Q3/16 compared to adjusted net earnings of $113 million in Q3/15 and an adjusted net loss of $210 million in Q2/16. Changes in adjusted net earnings primarily reflect the changes in cash flow from operations.

- Canadian Natural continues to realize excellent results from its commitment to effective and efficient operations, resulting in approximately $451 million of operating cost savings for the first nine months of 2016 over the same period in 2015.

- Canadian Natural's corporate production volumes averaged 735,212 BOE/d, as expected, in Q3/16, representing a 13% and 6% decrease from Q3/15 and Q2/16 levels respectively. As expected, Q3/16 corporate production volumes were lower than Q3/15 and Q2/16 levels primarily due to the planned turnaround activities completed at Horizon and Primrose during Q3/16.

  - Q3/16 primary heavy crude oil production averaged 102,484 bbl/d, expected decreases of 18% and 1% from Q3/15 and Q2/16 levels respectively. During the quarter, Canadian Natural increased its primary heavy crude oil drilling activity to 85 net wells, partially offsetting natural production declines.

  - At Pelican Lake, Canadian Natural's leading edge polymer flood, Q3/16 production volumes of 47,608 bbl/d were 6% lower than Q3/15 levels and relatively consistent with Q2/16 levels. Overall performance has been very good and notably, production volumes have been maintained despite the curtailment of drilling activity at Pelican Lake since Q4/14 due to capital allocation choices.

  - Thermal in situ quarterly production averaged 103,481 bbl/d in Q3/16, as expected, representing a decrease of 22% from Q3/15 and an increase of 11% from Q2/16. The increase in production volumes over Q2/16 levels is primarily due to strong steam flood performance at Primrose East and continued strong performance at Kirby South. The decrease in production volumes year-over-year reflects the normal impacts of Cyclical Steam Stimulation ("CSS") operations and the planned turnaround activities performed at Primrose during the third quarter of 2016. Notably, thermal production volumes have met expectations considering a significant reduction in drilling activity at Primrose due to capital allocation choices. Canadian Natural's thermal Q4/16 production guidance is targeted to range from 127,000 bbl/d to 133,000 bbl/d.

  - Total natural gas quarterly production volumes averaged 1,645 MMcf/d, within the targeted production guidance range for the quarter. As was previously announced, the third party plant and gathering system restrictions continued into the third quarter resulting in the shut-in of approximately 139 MMcf/d of Q3/16 natural gas volumes. Currently, the Company has approximately 106 MMcf/d of this shut-in production targeted to be reinstated in December 2016.

  - During the third quarter, the Company successfully completed major turnaround activities at the Horizon plant and tied in the major components of the Horizon Phase 2B expansion. Upon start-up of the plant, additional maintenance activities were identified primarily within the Coker unit, resulting in delayed production ramp-up to plant capacity by 7 days. The additional work was undertaken to ensure safe and reliable operations and to ensure a smooth Phase 2B start-up. Subsequently, strong and then record production volumes were achieved with September rates averaging approximately 148,000 bbl/d of SCO.

- As previously announced, the Company expanded its North America E&P crude oil drilling program for the second half of 2016. During Q3/16, drilling activity included 85 net primary heavy crude oil wells, 1 net bitumen well and 3 net wells targeting light crude oil.

- Canadian Natural has determined to re-initiate the development of its second thermal in situ oil sands Steam Assisted Gravity Drainage ("SAGD") project, Kirby North, with engineering and procurement to commence in 2017. Kirby North project capital spending in 2017 is targeted to be $28 million as the Company optimizes its execution strategies in order to continue the reduction in project capital costs. Approximately $700 million of project capital has been invested to-date at Kirby North and the remaining project costs are targeted to be approximately $650 million, more than $100 million less than originally expected. Canadian Natural targets first steam-in for 2019 and first oil in 2020 for Kirby North. The project will add 40,000 bbl/d of targeted production volumes to Canadian Natural's thermal oil sands portfolio.

- Continued cost savings achieved in the quarter on a per unit operating cost basis are detailed below.

Operating Costs (Canadian $)		**Q3/16**		Q3/15	**Year-over-Year Percent Change**
North America Light Crude Oil and NGLs ($/bbl)	**$**	**13.15**	$	14.37	**(8)%**
Pelican Lake Heavy Crude Oil ($/bbl)	**$**	**6.09**	$	6.64	**(8)%**
Primary Heavy Crude Oil ($/bbl)	**$**	**13.12**	$	13.81	**(5)%**
Horizon Oil Sands Mining and Upgrading ($/bbl)(1)	**$**	**27.05**	$	27.04	**—**
North Sea Light Crude Oil ($/bbl)	**$**	**39.41**	$	72.69	**(46)%**
Offshore Africa Light Crude Oil ($/bbl)	**$**	**16.32**	$	40.53	**(60)%**
North America Natural Gas ($/Mcf)	**$**	**1.04**	$	1.25	**(17)%**
Total Overall ($/BOE)(2)(3)	**$**	**12.37**	$	14.87	**(17)%**

(1) Horizon Q3/16 operating costs adjusted to reflect the impact of the Q3/16 planned maintenance turnaround.

(2) Total overall quarterly operating costs per BOE adjusted to reflect Horizon adjusted operating costs.

(3) Given the cyclical nature of Primrose operations, quarterly cost comparison year over year is not indicative of performance.

- Pelican Lake quarterly operating costs continue to be optimized to an industry leading level of $6.09/bbl in Q3/16, compared to $6.64/bbl in Q3/15 and $6.81/bbl in Q2/16.

- After normalizing for the planned turnaround in the quarter, Horizon quarterly adjusted operating costs averaged $27.05/bbl, comparable to Q3/15 costs of $27.04/bbl and to Q2/16 costs of $26.82/bbl. Horizon unadjusted operating costs averaged $50.57/bbl in Q3/16, as result of the completion of the planned major turnaround.

- Within the Company's North America natural gas operations, gains in process optimization continued to be made during the quarter. Q3/16 operating costs were $1.04/Mcf, a 17% and 11% decrease from Q3/15 and Q2/16 levels respectively. Q3/16 operating costs in Canadian Natural's key natural gas areas in the Deep Basin and Montney averaged $0.38/Mcfe and $0.25/Mcfe respectively.

- Offshore Africa crude oil operating costs significantly improved to $16.32/bbl in Q3/16 from $40.53/bbl in Q3/15 and from $20.13/bbl in Q2/16. The decrease in operating costs from Q3/15 reflects an increase in production volumes from wells added through the infill drilling program completed in Q1/16, timing of liftings from various fields and a focus on effective and efficient operations.

- As a result of capital allocation choices, there has been no drilling activity of production wells in the North Sea since Q4/14. However, due to the Company's continued focus on production enhancements, increased reliability and water flood optimization in the North Sea, production volumes averaged 23,450 bbl/d in Q3/16, increasing by 5% from Q3/15 levels and comparable to Q2/16 levels. North Sea quarterly crude oil operating costs averaged $39.41/bbl, representing excellent reductions of 46% and 3% from Q3/15 and Q2/16 levels respectively. In addition, effective January 1, 2016, the reduction of the Petroleum Revenue Tax rate from 35% to 0%, and more recently a decrease in the supplementary charge on oil and gas profits from 20% to 10%, represent favorable changes to the tax regime for assets in the North Sea. Due to these factors, the viability of reinvestment in the Company's North Sea asset base has improved.

- Canadian Natural maintains significant financial liquidity represented in part by committed bank credit facilities. As at September 30, 2016, the Company had in place bank credit facilities of approximately $7.4 billion, of which approximately $2.35 billion was undrawn and available. Balance sheet strength continues to be a focus of the Company with debt to book capitalization of 40% at September 30, 2016, within Canadian Natural's targeted operating range.

- On August 9, 2016, the Company successfully issued medium-term notes at 3.31% with a principal amount of $1.0 billion. The net proceeds were used to repay credit facilities, thereby generating additional liquidity for the Company.

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

- Canadian Natural declared a quarterly cash dividend on common shares of C$0.25 per share payable on January 1, 2017, increasing approximately 9% over the previous quarterly dividend. This is the sixteenth consecutive year of dividend increases since the Company first paid a dividend in 2001.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

Canadian Natural has a balanced and diverse portfolio of assets. 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 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

	Nine Months Ended Sep 30			
	2016		2015	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**99**	**93**	124	113
Natural gas	**6**	**5**	22	15
Dry	**4**	**4**	6	6
Subtotal	**109**	**102**	152	134
Stratigraphic test / service wells	**206**	**206**	130	93
Total	**315**	**308**	282	227
Success rate (excluding stratigraphic test / service wells)		**96%**		96%

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2016	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Crude oil and NGLs production (bbl/d)	**240,298**	235,468	264,709	**242,561**	273,609
Net wells targeting crude oil	**88**	—	67	**95**	111
Net successful wells drilled	**84**	—	63	**91**	105
Success rate	**95%**	—	94%	**96%**	95%

- In Q3/16, North America E&P crude oil and NGL production volumes averaged 240,298 bbl/d, as expected, within the Company's Q3/16 production guidance, decreasing by 9% from Q3/15 levels and increasing by 2% over Q2/16 levels.
- North America light crude oil and NGL quarterly production averaged 90,207 bbl/d in Q3/16, representing a 2% and 8% increase from Q3/15 and Q2/16 levels respectively. The increase in production volumes is primarily a result of a focus on production optimization and minor acquisitions completed in Q2/16.
- Quarterly production volumes from Pelican Lake operations averaged 47,608 bbl/d, representing a 6% decrease from Q3/15 and comparable to Q2/16 levels. Overall performance has been very good and notably, production volumes have been maintained despite the curtailment of drilling activity at Pelican Lake since Q4/14 due to capital allocation choices.
- Q3/16 primary heavy crude oil production averaged 102,484 bbl/d, expected decreases of 18% and 1% from Q3/15 and Q2/16 levels respectively. During the quarter, Canadian Natural increased its primary heavy crude oil drilling activity to 85 net wells, partially offsetting natural production declines within the asset base.
- Canadian Natural continued to reduce quarterly operating costs of its North America E&P crude oil and NGL products on a per unit basis in Q3/16 from Q3/15 levels.
  - North America light crude oil and NGL quarterly operating costs were reduced by 8%.
  - At Pelican Lake, industry leading operating costs of $6.09/bbl were achieved, representing an 8% decrease.
  - Continued operating cost reductions of 5% were realized within the primary heavy crude oil operations despite expected production declines.
- The Company’s North America E&P crude oil and NGL annual production guidance remains unchanged and is targeted to range from 235,000 bbl/d - 245,000 bbl/d in 2016.

Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2016	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Bitumen production (bbl/d)	**103,481**	93,213	133,183	**104,908**	128,048
Net wells targeting bitumen	**1**	—	—	**1**	3
Net successful wells drilled	**1**	—	—	**1**	3
Success rate	**100%**	—	—	**100%**	100%

- Thermal in situ quarterly production averaged 103,481 bbl/d in Q3/16, as expected, representing a decrease of 22% from Q3/15 and an increase of 11% from Q2/16. The increase in production volumes over Q2/16 levels is primarily due to strong steam flood performance at Primrose East and continued strong performance at Kirby South. The decrease in production volumes year-over-year reflects the normal impacts of CSS operations and the planned turnaround activities performed at Primrose during the third quarter of 2016. Notably, thermal production volumes have met expectations considering a significant reduction in drilling activity at Primrose due to capital allocation choices. Canadian Natural's thermal Q4/16 production guidance is targeted to range from 127,000 bbl/d to 133,000 bbl/d.
- Kirby South achieved quarterly volumes of 38,150 bbl/d, while operations continue to be optimized. Including energy costs, Q3/16 operating costs of $8.86/bbl represent a 18% reduction from Q3/15 and a 4% increase over Q2/16. The increase in quarterly operating costs over Q2/16 reflects an increase in fuel costs. Kirby South's Steam to Oil Ratio ("SOR") was 2.6 in the quarter.

- Canadian Natural has determined to re-initiate the development of its second thermal in situ oil sands SAGD project, Kirby North, with engineering and procurement to commence in 2017. Kirby North project capital spending in 2017 is targeted to be $28 million as the Company optimizes its execution strategies in order to continue the reduction in project capital costs. Approximately $700 million of project capital has been invested to-date at Kirby North and the remaining project costs are targeted to be approximately $650 million, more than $100 million less than originally expected. Canadian Natural targets first steam-in for 2019 and first oil in 2020 for Kirby North. The project will add 40,000 bbl/d of targeted production volumes to Canadian Natural's thermal oil sands portfolio.

- The Company’s thermal in situ oil sands annual production guidance remains unchanged and is targeted to range from 110,000 bbl/d - 130,000 bbl/d in 2016.

Natural Gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2016	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Natural gas production (MMcf/d)	**1,567**	1,620	1,592	**1,637**	1,673
Net wells targeting natural gas	**—**	1	4	**5**	15
Net successful wells drilled	**—**	1	4	**5**	15
Success rate	**—**	100%	100%	**100%**	100%

- North America natural gas quarterly production volumes averaged 1,567 MMcf/d in Q3/16, a decrease of 2% and 3% from both Q3/15 and Q2/16 levels respectively. As was previously announced, the third party plant and gathering system restrictions continued into the third quarter resulting in the shut-in of approximately 139 MMcf/d of Q3/16 natural gas volumes. Currently, the Company has approximately 106 MMcf/d of this shut-in production targeted to be reinstated in December 2016.

- Within the Company's North America natural gas operations, gains in process optimization continued to be made during the quarter. Q3/16 operating costs were $1.04/Mcf, a 17% and 11% decrease from Q3/15 and Q2/16 levels respectively. Q3/16 operating costs in Canadian Natural's key natural gas areas in the Deep Basin and Montney averaged $0.38/Mcfe and $0.25/Mcfe respectively.

- Operations at Septimus, Canadian Natural’s liquids-rich Montney natural gas play in British Columbia, continue to perform above expectations. Q3/16 Septimus sales volumes averaged 140 MMcf/d and associated liquids, with industry leading operating costs of $0.25/Mcfe.

- The Company’s total natural gas annual production guidance remains unchanged and is targeted to range from 1,705 MMcf/d to 1,735 MMcf/d in 2016.

International Exploration and Production

	Three Months Ended			Nine Months Ended	
	Sep 30 2016	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Crude oil production (bbl/d)					
North Sea	**23,450**	23,360	22,387	**23,376**	21,915
Offshore Africa	**26,171**	30,858	21,077	**27,576**	17,140
Natural gas production (MMcf/d)					
North Sea	**50**	30	35	**36**	36
Offshore Africa	**28**	39	26	**34**	25
Net wells targeting crude oil	**—**	—	2.6	**1.2**	4.6
Net successful wells drilled	**—**	—	2.6	**1.2**	4.6
Success rate	**—**	—	100%	**100%**	100%

- International E&P quarterly crude oil production volumes were within the Company's production guidance and averaged 49,621 bbl/d, representing a 14% increase over Q3/15 and an 8% decrease from Q2/16 levels. The year-over-year increase in production reflects the impact of the infill drilling program completed at Espoir and Baobab during 2015 and 2016, and substantial gains in production optimization attained in the North Sea, offsetting natural production declines. The decrease in production from Q2/16 to Q3/16 primarily reflects natural production declines and unplanned downtime at Espoir.

- As a result of capital allocation choices, there has been no drilling activity of production wells in the North Sea since Q4/14. However, due to the Company's continued focus on production enhancements, increased reliability and water flood optimization in the North Sea, production volumes averaged 23,450 bbl/d in Q3/16, increasing by 5% from Q3/15 levels and comparable to Q2/16 levels. North Sea quarterly crude oil operating costs averaged $39.41/bbl, representing excellent reductions of 46% and 3% from Q3/15 and Q2/16 levels respectively. In addition, effective January 1, 2016, the reduction of the Petroleum Revenue Tax rate from 35% to 0%, and more recently a decrease in the supplementary charge on oil and gas profits from 20% to 10%, represent favorable changes to the tax regime for assets in the North Sea. Due to these factors, the viability of reinvestment in the Company's North Sea asset base has improved.

- The Company's International E&P annual production guidance remains unchanged and is targeted to range from 49,000 bbl/d to 56,000 bbl/d in 2016.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Nine Months Ended	
	Sep 30 2016	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Synthetic crude oil production (bbl/d) (1)	**67,586**	119,511	131,779	**104,865**	120,842

(1) The Company produces diesel for internal use at Horizon. Third quarter 2016 SCO production before royalties excludes 1,464 bbl/d of SCO consumed internally as diesel (second quarter 2016 – 2,227 bbl/d; third quarter 2015 – 2,058 bbl/d; nine months ended September 30, 2016 – 2,083 bbl/d; nine months ended September 30, 2015 – 2,049 bbl/d).

- During the third quarter, the Company successfully completed major turnaround activities at the Horizon plant and tied in the major components of the Horizon Phase 2B expansion. Upon start-up of the plant, additional maintenance activities were identified primarily within the Coker unit, resulting in delayed production ramp-up to plant capacity by 7 days. The additional work was undertaken to ensure safe and reliable operations and to ensure a smooth Phase 2B start-up. Subsequently, strong and then record production volumes were achieved with September and October rates averaging approximately 148,000 bbl/d and 161,000 bbl/d respectively.

- The staged start-up of the Horizon Phase 2B expansion is substantially complete. Production rates are very strong with current production volumes of approximately 175,000 bbl/d of SCO and imminent ramp up to targeted production rates in excess of 182,000 bbl/d of SCO.
- After normalizing for the planned turnaround in the quarter, Horizon quarterly adjusted operating costs averaged $27.05/bbl, comparable to Q3/15 costs of $27.04/bbl and to Q2/16 costs of $26.82/bbl. Horizon unadjusted operating costs averaged $50.57/bbl in Q3/16, as result of the completion of the planned major turnaround.
- For the first nine months of 2016, Horizon project capital costs totaled $1.405 billion, with total Horizon project capital now targeted to be approximately $1.920 billion in 2016 versus the Company's original 2016 budget range of $1.890 billion to $1.990 billion. In 2017, Horizon project capital costs are targeted to be approximately $1 billion for Phase 3 completion, which is targeted to add incremental production volumes of 80,000 bbl/d of SCO in Q4/17. The addition of Phase 3 will mark the completion of the Horizon expansion with targeted design capacity in excess of 250,000 bbl/d of SCO, and targeted operating costs below C$25.00/bbl (US$20.00/bbl).
- At September 30, 2016, the Horizon Phase 3 expansion reached 87% physical completion. Within the scope of work for the combined hydrotreater, all modules have been installed and module interconnections are well advanced. Phase 3 includes the addition of an ore preparation plant, extraction trains, the combined hydrotreater and a sulphur recovery unit. Phase 3 remains on schedule for targeted start-up in Q4/17. Phase 3 is targeted to increase production capacity by 80,000 bbl/d in Q4/17 and will target significant operating cost savings for Horizon operations.
- Directive 85 (formerly Directive 74) of the Horizon expansion remains on track and was 65% physically complete as at September 30, 2016. This project includes research into tailings management and technological investment.
- Canadian Natural's Horizon annual production guidance remains unchanged and is targeted to range from 120,000 bbl/d to 132,000 bbl/d in 2016.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2016	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Crude oil and NGL pricing					
WTI benchmark price (US$/bbl) (1)	**$ 44.94**	$ 45.60	$46.44	$ 41.37	$ 50.98
WCS blend differential from WTI (%) (2)	**30%**	29%	28%	33%	26%
SCO price (US$/bbl)	**$ 45.63**	$ 47.39	$ 45.78	$ 42.27	$ 50.55
Condensate benchmark pricing (US$/bbl)	**$ 43.05**	$ 44.10	$ 44.20	$ 40.54	$ 49.25
Average realized pricing before risk management (C$/bbl) (3)	**$ 39.66**	$ 39.98	$ 41.55	$ 34.14	$ 43.58
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.08**	$ 1.18	$ 2.65	$ 1.75	$ 2.66
Average realized pricing before risk management (C$/Mcf)	**$ 2.44**	$ 1.50	$ 3.22	$ 2.06	$ 3.22

(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$44.94/bbl for Q3/16, a decrease of 3% from US$46.44/bbl from Q3/15 and comparable to US $45.60/bbl for Q2/16. WTI pricing for the nine months ended September 30, 2016 continued to reflect volatility in supply and demand factors and geopolitical events.
- In Q3/16, the WCS Heavy Differential averaged US$13.49/bbl (30%) compared with US$13.21/bbl (28%) and US $13.31/bbl (29%) in Q3/15 and Q2/16 respectively. Fluctuations in the WCS Heavy Differential reflect seasonal demand, changes in transportation logistics, and refinery utilization and shutdowns. As of October 17, 2016, the WCS Heavy Differential for the fourth quarter of 2016 is approximately US$14.16/bbl (28%).

- Canadian Natural contributed approximately 191,000 bbl/d of its heavy crude oil stream to the WCS blend in Q3/16. The Company remains the largest contributor to the WCS blend, accounting for 47% of the total blend.

- The SCO price averaged US$45.63/bbl for Q3/16, comparable to US$45.78/bbl for the Q3/15, and a decrease of 4% from US$47.39/bbl for Q2/16. The fluctuations in SCO pricing for Q3/16 from the comparable periods were primarily due to changes in WTI benchmark pricing.

- AECO natural gas prices averaged $2.08/GJ for Q3/16, a decrease of 22% from $2.65/GJ for Q3/15, and an increase of 76% from $1.18/GJ for Q2/16. The decrease in natural gas prices in Q3/16 compared with Q3/15 was primarily due to US natural gas inventories being at near record high levels at the end of the winter season. The increase from Q2/16 to Q3/16 was primarily due to reduced natural gas production growth, warm weather in the third quarter of 2016 and strong substitution of natural gas for coal in U.S. electricity generation.

- 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 735,212 BOE/d in Q3/16, with approximately 96% of total production located in G7 countries.

- Canadian Natural maintains significant financial liquidity represented in part by committed bank credit facilities. As at September 30, 2016, the Company had in place bank credit facilities of approximately $7.4 billion, of which approximately $2.35 billion was undrawn and available. Balance sheet strength continues to be a focus of the Company with debt to book capitalization of 40% at September 30, 2016, within Canadian Natural's targeted operating range.

- On August 9, 2016, the Company successfully issued medium-term notes at 3.31% with a principal amount of $1.0 billion. The net proceeds were used to repay credit facilities, thereby generating additional liquidity for the Company.

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

- 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 October 31, 2016, these financial levers include the Company's investment in PrairieSky with an approximate value of $660 million and cross currency swaps maturing after 2020 with an approximate value of $370 million. Additionally, the Company could monetize its third party royalty volumes of approximately 1,000 BOE/d.

- Canadian Natural declared a quarterly cash dividend on common shares of C$0.25 per share payable on January 1, 2017, increasing approximately 9% over the previous quarterly dividend. This is the sixteenth consecutive year of dividend increases since the Company first paid a dividend in 2001.

OUTLOOK

The Company forecasts annual 2016 production levels to average between 514,000 and 563,000 bbl/d of crude oil and NGLs and between 1,705 and 1,735 MMcf/d of natural gas, before royalties. Q4/16 production guidance before royalties is forecast to average between 575,000 and 599,000 bbl/d of crude oil and NGLs and between 1,690 and 1,720 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 2016 capital expenditures are targeted to be approximately $4.4 billion. This reflects increased operating capital at Horizon partly due to additional proactive maintenance completed during the Q3/16 turnaround to ensure safe and reliable operations and a smooth Phase 2B start-up. Additionally the Company targets increased capital activity in the Company's North America E&P business in the second half of 2016 and also targets an increase in the Company's net acquisition and dispositions in 2016. This additional capital has minimal impact on Q3/16 and Q4/16 production volumes, but will be reflected in 2017 production volumes.

This Page Left Intentionally Blank

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

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

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

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

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

Management's Discussion and Analysis

This MD&A of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the three and nine months ended September 30, 2016 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2015.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the period ended September 30, 2016 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings (loss) from operations, 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), 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 cash 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 derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

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

Production volumes and per unit statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of blending costs and exclude the effect of risk management activities. Production on an "after royalty" or "net" basis is also presented for information purposes only.

The following discussion and analysis refers primarily to the Company's financial results for the three and nine months ended September 30, 2016 in relation to the comparable periods in 2015 and the second quarter of 2016. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2015, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated November 2, 2016.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Sep 30 2016	Jun 30 2016	Sep 30 2015	Nine Months Ended Sep 30 2016	Sep 30 2015
Product sales	**$ 2,477**	$ 2,686	$ 3,316	**$ 7,426**	$ 10,204
Net earnings (loss)	**$ (326)**	$ (339)	$ (111)	**$ (770)**	$ (768)
Per common share – basic	**$ (0.29)**	$ (0.31)	$ (0.10)	**$ (0.70)**	$ (0.70)
– diluted	**$ (0.29)**	$ (0.31)	$ (0.10)	**$ (0.70)**	$ (0.70)
Adjusted net earnings (loss) from operations (1)	**$ (355)**	$ (210)	$ 113	**$ (1,108)**	$ 312
Per common share – basic	**$ (0.32)**	$ (0.19)	$ 0.10	**$ (1.01)**	$ 0.28
– diluted	**$ (0.32)**	$ (0.19)	$ 0.10	**$ (1.01)**	$ 0.28
Cash flow from operations (2)	**$ 1,021**	$ 938	$ 1,533	**$ 2,616**	$ 4,406
Per common share – basic	**$ 0.93**	$ 0.85	$ 1.40	**$ 2.38**	$ 4.03
– diluted	**$ 0.92**	$ 0.85	$ 1.40	**$ 2.38**	$ 4.02
Net capital expenditures	**$ 1,185**	$ 1,158	$ 1,240	**$ 3,383**	$ 3,949

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure that represents net 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) Cash flow from operations is a non-GAAP measure that represents net earnings (loss) adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. The Company considers cash 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 "Cash Flow from Operations" presents certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings (Loss) from Operations

($ millions)	Three Months Ended Sep 30 2016	Jun 30 2016	Sep 30 2015	Nine Months Ended Sep 30 2016	Sep 30 2015
Net earnings (loss) as reported	**$ (326)**	$ (339)	$ (111)	**$ (770)**	$ (768)
Share-based compensation, net of tax (1)	**74**	122	(87)	**313**	(102)
Unrealized risk management loss (gain), net of tax (2)	**11**	(46)	(24)	**28**	147
Unrealized foreign exchange loss (gain), net of tax (3)	**39**	40	351	**(255)**	688
(Gain) loss from investments, net of tax (4)(5)	**(46)**	—	20	**(193)**	32
Gain on disposition of properties, net of tax (6)	**—**	—	(36)	**(23)**	(36)
Derecognition of exploration and evaluation assets, net of tax (7)	**—**	13	—	**13**	—
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (8)	**(107)**	—	—	**(221)**	351
Adjusted net earnings (loss) from operations	**$ (355)**	$ (210)	$ 113	**$ (1,108)**	$ 312

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

(5) The Company's investment in PrairieSky Royalty Ltd. ("PrairieSky") has been accounted for at fair value through profit and loss and is remeasured each period with changes in fair value recognized in net earnings (loss).

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

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

Cash Flow from Operations

($ millions)	Three Months Ended Sep 30 2016	Jun 30 2016	Sep 30 2015	Nine Months Ended Sep 30 2016	Sep 30 2015
Net earnings (loss)	**$ (326)**	$ (339)	$ (111)	**$ (770)**	$ (768)
Non-cash items:					
Depletion, depreciation and amortization	**1,216**	1,174	1,376	**3,609**	4,011
Share-based compensation	**74**	122	(87)	**313**	(102)
Asset retirement obligation accretion	**36**	35	44	**107**	130
Unrealized risk management loss (gain)	**10**	(52)	(29)	**32**	200
Unrealized foreign exchange loss (gain)	**39**	40	351	**(255)**	688
(Gain) loss from investments	**(46)**	—	20	**(193)**	32
Deferred income tax expense (recovery)	**18**	(42)	18	**(195)**	264
Gain on disposition of properties	**—**	—	(49)	**(32)**	(49)
Cash flow from operations	**$ 1,021**	$ 938	$ 1,533	**$ 2,616**	$ 4,406

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

The net loss for the nine months ended September 30, 2016 was $770 million compared with a net loss of $768 million for the nine months ended September 30, 2015. The net loss for the nine months ended September 30, 2016 included net after-tax income of $338 million compared with expenses of $1,080 million for the nine months ended September 30, 2015 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, (gain) loss from investments, gain on disposition of properties, derecognition of exploration and evaluation assets and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, the adjusted net loss from operations for the nine months ended September 30, 2016 was $1,108 million compared with adjusted net earnings of $312 million for the nine months ended September 30, 2015.

The net loss for the third quarter of 2016 was $326 million compared with a net loss of $111 million for the third quarter of 2015 and a net loss of $339 million for the second quarter of 2016. The net loss for the third quarter of 2016 included net after-tax income of $29 million compared with net after-tax expenses of $224 million for the third quarter of 2015 and net after-tax expenses of $129 million for the second quarter of 2016 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, (gain) loss from investments, gain on disposition of properties, derecognition of exploration and evaluation assets and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, the adjusted net loss from operations for the third quarter of 2016 was $355 million compared with adjusted net earnings of $113 million for the third quarter of 2015 and an adjusted net loss of $210 million for the second quarter of 2016.

The decrease in adjusted net earnings (loss) for the three and nine months ended September 30, 2016 from the comparable periods in 2015 was primarily due to:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment as a result of the major turnaround in the third quarter of 2016;
- lower crude oil and NGLs sales volumes in the North America segment;
- lower natural gas netbacks in the Exploration and Production segments;
- lower crude oil and NGLs netbacks in the North America segment;
- higher depletion, depreciation and amortization in the Oil Sands Mining and Upgrading segment as a result of minor asset de-recognitions resulting from the major turnaround; and
- lower realized risk management gains.

partially offset by:

- higher crude oil and NGLs sales volumes in the Offshore Africa segment; and
- higher crude oil and NGLs netbacks in the International segments.

The increase in adjusted net loss for the third quarter of 2016 from the second quarter of 2016 was primarily due to:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower natural gas sales volumes in the North America segment; and
- higher depletion, depreciation and amortization in the Oil Sands Mining and Upgrading segment as a result of minor asset de-recognitions resulting from the major turnaround.

partially offset by:

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

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

Cash flow from operations for the nine months ended September 30, 2016 was $2,616 million compared with $4,406 million for the nine months ended September 30, 2015. Cash flow from operations for the third quarter of 2016 was $1,021 million compared with $1,533 million for the third quarter of 2015 and $938 million for the second quarter of 2016. The fluctuations in cash 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 cash taxes.

Total production before royalties for the third quarter of 2016 decreased 13% to 735,212 BOE/d from 848,701 BOE/d for the third quarter of 2015 and decreased 6% from 783,988 BOE/d for the second 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)		**Sep 30 2016**		Jun 30 2016		Mar 31 2016		Dec 31 2015
Product sales	**$**	**2,477**	$	2,686	$	2,263	$	2,963
Net earnings (loss)	**$**	**(326)**	$	(339)	$	(105)	$	131
Net earnings (loss) per common share								
– basic	**$**	**(0.29)**	$	(0.31)	$	(0.10)	$	0.12
– diluted	**$**	**(0.29)**	$	(0.31)	$	(0.10)	$	0.12
($ millions, except per common share amounts)		Sep 30 2015		Jun 30 2015		Mar 31 2015		Dec 31 2014
Product sales	$	3,316	$	3,662	$	3,226	$	4,850
Net earnings (loss)	$	(111)	$	(405)	$	(252)	$	1,198
Net earnings (loss) per common share								
– basic	$	(0.10)	$	(0.37)	$	(0.23)	$	1.10
– diluted	$	(0.10)	$	(0.37)	$	(0.23)	$	1.09

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 the Organization of the Petroleum Exporting Countries' ("OPEC") decision not to curtail crude oil production to offset the excess world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of the WCS Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America and the impact of the differential between WTI and Brent benchmark pricing in the North Sea and Offshore Africa.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, the reduction in the Company's drilling program in North America, the impact and timing of acquisitions, the impact of turnarounds at Horizon, and the impact of the drilling program in Côte d'Ivoire in Offshore Africa. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's allocation of capital to higher return crude oil projects, natural decline rates, shut-in production due to third party pipeline restrictions and related pricing impacts and an outage at a third party processing facility, shut-in production due to low commodity prices, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production, the impact of seasonal costs that are dependent on weather, cost optimizations across all segments, the impact and timing of acquisitions, turnarounds at Horizon and maintenance activities in the International segments.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in international sales volumes subject to higher depletion rates, and the impact of turnarounds at Horizon.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense include statutory tax rate and other legislative changes substantively enacted in the various periods.
- **Gains on disposition of properties and investments** – Fluctuations due to the recognition of gains on disposition of properties in the various periods and fair value changes in the investment in PrairieSky shares.

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
	Sep 30 2016	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
WTI benchmark price (US$/bbl)	**$ 44.94**	$ 45.60	$ 46.44	**$ 41.37**	$ 50.98
Dated Brent benchmark price (US$/bbl)	**$ 45.76**	$ 45.80	$ 50.39	**$ 41.84**	$ 55.37
WCS blend differential from WTI (US$/bbl)	**$ 13.49**	$ 13.31	$ 13.21	**$ 13.68**	$ 13.18
WCS blend differential from WTI (%)	**30%**	29%	28%	**33%**	26%
SCO price (US$/bbl)	**$ 45.63**	$ 47.39	$ 45.78	**$ 42.27**	$ 50.55
Condensate benchmark price (US$/bbl)	**$ 43.05**	$ 44.10	$ 44.20	**$ 40.54**	$ 49.25
NYMEX benchmark price (US$/MMBtu)	**$ 2.81**	$ 1.95	$ 2.77	**$ 2.27**	$ 2.80
AECO benchmark price (C$/GJ)	**$ 2.08**	$ 1.18	$ 2.65	**$ 1.75**	$ 2.66
US/Canadian dollar average exchange rate (US$)	**$ 0.7663**	$ 0.7761	$ 0.7640	**$ 0.7565**	$ 0.7936

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 third quarter of 2016, realized prices continued to be supported by the weaker Canadian dollar, as the Canadian dollar sales price the Company received for its crude oil and natural gas sales is based on US dollar denominated benchmarks.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$41.37 per bbl for the nine months ended September 30, 2016, a decrease of 19% from US$50.98 per bbl for the nine months ended September 30, 2015. WTI averaged US$44.94 per bbl for the third quarter of 2016, a decrease of 3% from US$46.44 per bbl for the third quarter of 2015, and comparable with the second 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$41.84 per bbl for the nine months ended September 30, 2016, a decrease of 24% from US$55.37 per bbl for the nine months ended September 30, 2015. Brent averaged US$45.76 per bbl for the third quarter of 2016, a decrease of 9% from US$50.39 per bbl for the third quarter of 2015, and comparable with the second quarter of 2016.

WTI and Brent pricing for the nine months ended September 30, 2016 continued to reflect volatility in supply and demand factors and geopolitical events.

The WCS Heavy Differential averaged 33% for the nine months ended September 30, 2016, compared with 26% for the nine months ended September 30, 2015. The WCS Heavy Differential averaged 30% for the third quarter of 2016 compared with 28% for the third quarter of 2015 and 29% for the second quarter of 2016. Fluctuations in the WCS Heavy Differential reflected seasonal demand, changes in transportation logistics, and refinery utilization and shutdowns.

The SCO price averaged US$42.27 per bbl for the nine months ended September 30, 2016, a decrease of 16% from US$50.55 per bbl for the nine months ended September 30, 2015. The SCO price averaged US$45.63 per bbl for the third quarter of 2016, comparable with the third quarter of 2015, and a decrease of 4% from US$47.39 per bbl for the second quarter of 2016. The fluctuations in SCO pricing for the three and nine months ended September 30, 2016 from the comparable periods were primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.27 per MMBtu for the nine months ended September 30, 2016, a decrease of 19% from US$2.80 per MMBtu for the nine months ended September 30, 2015. NYMEX natural gas prices averaged US$2.81 per MMBtu for the third quarter of 2016, comparable with the third quarter of 2015, and an increase of 44% from US$1.95 per MMBtu for the second quarter of 2016.

AECO natural gas prices averaged $1.75 per GJ for the nine months ended September 30, 2016, a decrease of 34% from $2.66 per GJ for the nine months ended September 30, 2015. AECO natural gas prices averaged $2.08 per GJ for the third quarter of 2016, a decrease of 22% from $2.65 per GJ for the third quarter of 2015, and an increase of 76% from $1.18 per GJ for the second quarter of 2016.

The decrease in natural gas prices for the nine months ended September 30, 2016 compared with the comparable period in 2015 was primarily due to warmer than normal winter temperatures in 2016. US natural gas inventories were at near record high levels at the end of the 2015/2016 winter season.

The increase in natural gas prices in the third quarter of 2016 compared with the second quarter of 2016 was primarily due to reduced natural gas production growth, warm weather in the third quarter of 2016 and strong substitution of gas for coal in U.S. electricity generation. While natural gas prices are anticipated to remain volatile in the near term, ongoing normalization of storage inventories is expected to continue to reduce pressure on natural gas pricing entering the 2016/2017 winter season.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2016	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**343,779**	328,681	397,892	**347,469**	401,657
North America – Oil Sands Mining and Upgrading (1)	**67,586**	119,511	131,779	**104,865**	120,842
North Sea	**23,450**	23,360	22,387	**23,376**	21,915
Offshore Africa	**26,171**	30,858	21,077	**27,576**	17,140
	460,986	502,410	573,135	**503,286**	561,554
Natural gas (MMcf/d)					
North America	**1,567**	1,620	1,592	**1,637**	1,673
North Sea	**50**	30	35	**36**	36
Offshore Africa	**28**	39	26	**34**	25
	1,645	1,689	1,653	**1,707**	1,734
Total barrels of oil equivalent (BOE/d)	**735,212**	783,988	848,701	**787,718**	850,587
Product mix					
Light and medium crude oil and NGLs	**19%**	18%	15%	**18%**	15%
Pelican Lake heavy crude oil	**7%**	6%	6%	**6%**	6%
Primary heavy crude oil	**14%**	13%	15%	**14%**	16%
Bitumen (thermal oil)	**14%**	12%	16%	**13%**	15%
Synthetic crude oil (1)	**9%**	15%	16%	**13%**	14%
Natural gas	**37%**	36%	32%	**36%**	34%
Percentage of gross revenue (1) (2) (excluding Midstream revenue)					
Crude oil and NGLs	**83%**	90%	83%	**85%**	83%
Natural gas	**17%**	10%	17%	**15%**	17%

(1) Third quarter 2016 SCO production before royalties excludes 1,464 bbl/d of SCO consumed internally as diesel (second quarter 2016 – 2,227 bbl/d; third quarter 2015 – 2,058 bbl/d; nine months ended September 30, 2016 - 2,083 bbl/d; nine months ended September 30, 2015 - 2,049 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2016	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**305,189**	292,666	350,444	**309,706**	352,278
North America – Oil Sands Mining and Upgrading	**67,008**	118,613	129,355	**104,261**	118,930
North Sea	**23,404**	23,279	22,325	**23,316**	21,865
Offshore Africa	**25,061**	29,658	20,145	**26,428**	16,386
	420,662	464,216	522,269	**463,711**	509,459
Natural gas (MMcf/d)					
North America	**1,497**	1,604	1,527	**1,586**	1,617
North Sea	**50**	30	35	**36**	36
Offshore Africa	**27**	37	25	**32**	24
	1,574	1,671	1,587	**1,654**	1,677
Total barrels of oil equivalent (BOE/d)	**682,944**	742,785	786,734	**739,374**	789,030

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 nine months ended September 30, 2016 decreased 10% to 503,286 bbl/d from 561,554 bbl/d for the nine months ended September 30, 2015. Crude oil and NGL production for the third quarter of 2016 of 460,986 bbl/d decreased by 20% from 573,135 bbl/d for the third quarter of 2015, and decreased 8% from 502,410 bbl/d for the second quarter of 2016. The decrease in crude oil and NGL production for the three and nine months ended September 30, 2016 from the comparable periods in 2015 was primarily due to lower drilling activity and natural field declines in North America and the completion of the major turnaround at Horizon in the third quarter of 2016. The decrease in crude oil and NGLs production for the third quarter of 2016 from the second quarter of 2016 primarily reflected lower production at Horizon due to the major turnaround in the third quarter of 2016, partially offset by higher thermal oil production.

Crude oil and NGLs production for the third quarter of 2016 was within the Company's previously issued guidance of 458,000 to 484,000 bbl/d.

For 2016, annual production guidance is targeted to average between 514,000 and 563,000 bbl/d of crude oil and NGLs. Fourth quarter 2016 production guidance is targeted to average between 575,000 and 599,000 bbl/d of crude oil and NGLs.

Natural gas production for the nine months ended September 30, 2016 decreased 2% to 1,707 MMcf/d from 1,734 MMcf/d for the nine months ended September 30, 2015. Natural gas production for the third quarter of 2016 of 1,645 MMcf/d was comparable with the third quarter of 2015, and decreased 3% from 1,689 MMcf/d for the second quarter of 2016. The decrease in natural gas production for the three and nine months ended September 30, 2016 from the comparable periods in 2015 primarily reflected lower production in North America due to the continued impact of the shut in of a third party processing facility and third party pipeline transportation restrictions. The decrease for the third quarter of 2016 compared with the second quarter of 2016 primarily reflected continued third party processing facility outages and third party pipeline transportation restrictions. During the third quarter the company averaged approximately 37 MMcf/d of net sales volumes through the third party processing facility. The third party facility is targeting to be at full capacity in December 2016, at which time the Company's operated sales capacity will increase to 176 MMcf/d.

Natural gas production for the third quarter of 2016 was within the Company's previously issued guidance of 1,645 to 1,685 MMcf/d. Annual production guidance is targeted to average between 1,705 and 1,735 MMcf/d. Fourth quarter 2016 production guidance is targeted to average between 1,690 and 1,720 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the nine months ended September 30, 2016 decreased 13% to average 347,469 bbl/d from 401,657 bbl/d for the nine months ended September 30, 2015. North America crude oil and NGLs production for the third quarter of 2016 decreased 14% to 343,779 bbl/d from 397,892 bbl/d for the third quarter of 2015, and increased 5% from 328,681 bbl/d for the second quarter of 2016. The decrease in production for the nine months ended September 30, 2016 from the comparable period in 2015 primarily reflected lower drilling activity, natural field declines, the cyclic nature of thermal oil production at Primrose, the temporary shut in of the Primrose East pipeline due to pipeline anomalies, as well as minor production disruptions at various fields in the second quarter of 2016. The decrease in production for the third quarter from the comparable period in 2015 was primarily due to lower drilling activity, natural field declines and the cyclic nature of thermal oil production at Primrose. The increase in production for the third quarter of 2016 from the second quarter of 2016 was primarily a result of the reinstatement of the Primrose East pipeline in late May 2016. Crude oil and NGLs production for the third quarter of 2016 was within the Company's previously issued guidance of 337,000 to 351,000 bbl/d. Fourth quarter 2016 production guidance is targeted to average between 359,000 and 371,000 bbl/d of crude oil and NGLs.

Natural gas production for the nine months ended September 30, 2016 decreased 2% to average 1,637 MMcf/d from 1,673 MMcf/d for the nine months ended September 30, 2015. Natural gas production for the third quarter of 2016 decreased 2% to 1,567 MMcf/d from 1,592 MMcf/d for the third quarter of 2015, and decreased 3% from 1,620 MMcf/d for the second quarter of 2016. The decrease in production for the three and nine months ended September 30, 2016 from the comparable periods in 2015 primarily reflected the continued impact of the shut in of a third party processing facility and third party pipeline transportation restrictions in both 2015 and 2016. The decrease for the third quarter of 2016 compared with the second quarter of 2016 primarily reflected continued third party processing facility outages and third party pipeline transportation restrictions. During the third quarter the company averaged approximately 37 MMcf/d of net sales volumes through the third party processing facility. The third party facility is targeting to be at full capacity in December 2016, at which time the Company's operated sales capacity will increase to 176 MMcf/d.

North America – Oil Sands Mining and Upgrading

SCO production for the nine months ended September 30, 2016 decreased 13% to 104,865 bbl/d from 120,842 bbl/d for the nine months ended September 30, 2015. SCO production for the third quarter of 2016 decreased 49% to average 67,586 bbl/d compared with 131,779 bbl/d for the third quarter of 2015 and decreased 43% from 119,511 bbl/d for the second quarter of 2016. The decrease in production for the three and nine months ended September 30, 2016 from the comparable periods reflected the completion of the major turnaround in the third quarter of 2016. During the turnaround, additional maintenance was required, primarily in the coker, delaying ramp up of operations. The Company achieved record SCO production in September of 148,049 bbl/d following the reinstatement of plant capacity in August.

Third quarter 2016 production of SCO was slightly below the Company's previously issued guidance of 72,000 to 80,000 bbl/d. Fourth quarter 2016 production guidance is targeted to average between 170,000 and 178,000 bbl/d.

North Sea

North Sea crude oil production for the nine months ended September 30, 2016 increased 7% to 23,376 bbl/d from 21,915 bbl/d for the nine months ended September 30, 2015. North Sea crude oil production for the third quarter of 2016 increased 5% to 23,450 bbl/d from 22,387 bbl/d for the third quarter of 2015 and was comparable with the second quarter of 2016. The increase in production for the three and nine months ended September 30, 2016 from comparable periods was due to successful production optimization, more than offsetting natural field declines.

Offshore Africa

Offshore Africa crude oil production for the nine months ended September 30, 2016 increased 61% to 27,576 bbl/d from 17,140 bbl/d for the nine months ended September 30, 2015. Offshore Africa crude oil production for the third quarter of 2016 increased 24% to 26,171 bbl/d from 21,077 bbl/d for the third quarter of 2015, and decreased 15% from 30,858 bbl/d for the second quarter of 2016. Production volumes increased for the three and nine months ended September 30, 2016 from the comparable periods in 2015 reflecting the impact of additional wells coming on stream at the Espoir and Baobab fields during 2015 and 2016, partially offset by natural field declines and unplanned downtime primarily related to the Espoir FPSO. The decrease from the second quarter of 2016 primarily reflected the downtime at the Espoir FPSO.

International Guidance

The Company's North Sea and Offshore Africa third quarter 2016 crude oil production of 49,621 bbl/d was within the Company's previously issued guidance of 49,000 to 53,000 bbl/d. Fourth quarter 2016 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)	**Sep 30 2016**	Jun 30 2016	Sep 30 2015
North Sea	**940,089**	1,244,684	450,023
Offshore Africa	**1,587,341**	1,248,197	1,353,011
	2,527,430	2,492,881	1,803,034

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2016	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 39.66**	$ 39.98	$ 41.55	**$ 34.14**	$ 43.58
Transportation	**2.51**	2.81	2.56	**2.60**	2.60
Realized sales price, net of transportation	**37.15**	37.17	38.99	**31.54**	40.98
Royalties	**3.48**	3.59	4.09	**2.97**	4.57
Production expense	**13.85**	14.31	15.70	**14.03**	16.25
Netback	**$ 19.82**	$ 19.27	$ 19.20	**$ 14.54**	$ 20.16
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 2.44**	$ 1.50	$ 3.22	**$ 2.06**	$ 3.22
Transportation	**0.40**	0.35	0.39	**0.34**	0.38
Realized sales price, net of transportation	**2.04**	1.15	2.83	**1.72**	2.84
Royalties	**0.09**	0.02	0.11	**0.06**	0.09
Production expense	**1.08**	1.22	1.31	**1.18**	1.38
Netback	**$ 0.87**	$ (0.09)	$ 1.41	**$ 0.48**	$ 1.37
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 29.39**	$ 27.28	$ 33.46	**$ 25.24**	$ 34.22
Transportation	**2.51**	2.61	2.56	**2.44**	2.56
Realized sales price, net of transportation	**26.88**	24.67	30.90	**22.80**	31.66
Royalties	**2.27**	2.13	2.81	**1.89**	3.01
Production expense	**10.83**	11.38	12.68	**11.13**	13.09
Netback	**$ 13.78**	$ 11.16	$ 15.41	**$ 9.78**	$ 15.56

(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			Nine Months Ended	
	Sep 30 2016	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 36.84**	$ 37.59	$ 39.26	**$ 31.45**	$ 41.42
North Sea	**$ 60.00**	$ 54.60	$ 62.28	**$ 53.23**	$ 67.38
Offshore Africa	**$ 58.30**	$ 54.62	$ 65.31	**$ 52.81**	$ 69.23
Company average	**$ 39.66**	$ 39.98	$ 41.55	**$ 34.14**	$ 43.58
Natural gas ($/Mcf) (1) (2)					
North America	**$ 2.30**	$ 1.30	$ 2.99	**$ 1.88**	$ 2.98
North Sea	**$ 5.27**	$ 6.83	$ 9.44	**$ 6.16**	$ 9.71
Offshore Africa	**$ 5.39**	$ 6.01	$ 9.01	**$ 6.23**	$ 10.34
Company average	**$ 2.44**	$ 1.50	$ 3.22	**$ 2.06**	$ 3.22
Company average ($/BOE) (1) (2)	**$ 29.39**	$ 27.28	$ 33.46	**$ 25.24**	$ 34.22

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

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

North America

North America realized crude oil prices decreased 24% to $31.45 per bbl for the nine months ended September 30, 2016 from $41.42 per bbl for the nine months ended September 30, 2015. North America realized crude oil prices averaged $36.84 per bbl for the third quarter of 2016, a decrease of 6% compared with $39.26 per bbl for the third quarter of 2015 and a decrease of 2% compared with $37.59 per bbl for the second quarter of 2016. The decrease in realized crude oil prices for the three and nine months ended September 30, 2016 from the comparable periods was primarily due to lower WTI benchmark pricing. The Company continues to focus on its crude oil blending marketing strategy and, in the third quarter of 2016, contributed approximately 191,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 37% to average $1.88 per Mcf for the nine months ended September 30, 2016 from $2.98 per Mcf for the nine months ended September 30, 2015. North America realized natural gas prices decreased 23% to average $2.30 per Mcf for the third quarter of 2016 compared with $2.99 per Mcf for the third quarter of 2015, and increased 77% compared with $1.30 per Mcf for the second quarter of 2016. The decrease in natural gas prices per Mcf for the three and nine months ended September 30, 2016 from the comparable periods in 2015 was primarily due to warmer than normal winter temperatures in 2016. US natural gas inventories were at near record high levels at the end of the 2015/2016 winter season.

The increase in natural gas prices per Mcf for the third quarter compared with the second quarter was primarily due to reduced natural gas production growth, warm weather in the third quarter of 2016 and strong substitution of gas for coal in U.S. electricity generation. While natural gas prices are anticipated to remain volatile in the near term, ongoing normalization of storage inventories is expected to continue to reduce pressure on natural gas pricing entering the 2016/2017 winter season.

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

(Quarterly Average)	**Sep 30 2016**	Jun 30 2016	Sep 30 2015
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 38.16**	$ 39.56	$ 40.88
Pelican Lake heavy crude oil ($/bbl)	**$ 37.57**	$ 40.60	$ 39.54
Primary heavy crude oil ($/bbl)	**$ 38.52**	$ 38.84	$ 39.97
Bitumen (thermal oil) ($/bbl)	**$ 33.68**	$ 32.91	$ 37.46
Natural gas ($/Mcf)	**$ 2.30**	$ 1.30	$ 2.99

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

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

North Sea

North Sea realized crude oil prices decreased 21% to average $53.23 per bbl for the nine months ended September 30, 2016 from $67.38 per bbl for the nine months ended September 30, 2015. North Sea realized crude oil prices decreased 4% to average $60.00 per bbl for the third quarter of 2016 from $62.28 per bbl for the third quarter of 2015 and increased 10% from $54.60 per bbl for the second 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 third quarter of 2016 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices decreased 24% to average $52.81 per bbl for the nine months ended September 30, 2016 from $69.23 per bbl for the nine months ended September 30, 2015. Offshore Africa realized crude oil prices decreased 11% to average $58.30 per bbl for the third quarter of 2016 from $65.31 per bbl for the third quarter of 2015 and increased 7% from $54.62 per bbl for the second 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 third quarter of 2016 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2016	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 3.81**	$ 3.93	$ 4.34	**$ 3.22**	$ 4.86
North Sea	**$ 0.12**	$ 0.18	$ 0.17	**$ 0.13**	$ 0.14
Offshore Africa	**$ 2.47**	$ 2.12	$ 2.89	**$ 2.17**	$ 3.04
Company average	**$ 3.48**	$ 3.59	$ 4.09	**$ 2.97**	$ 4.57
Natural gas ($/Mcf) (1)					
North America	**$ 0.09**	$ 0.01	$ 0.11	**$ 0.06**	$ 0.09
Offshore Africa	**$ 0.24**	$ 0.27	$ 0.41	**$ 0.28**	$ 0.47
Company average	**$ 0.09**	$ 0.02	$ 0.11	**$ 0.06**	$ 0.09
Company average ($/BOE) (1)	**$ 2.27**	$ 2.13	$ 2.81	**$ 1.89**	$ 3.01

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

North America

North America crude oil and natural gas royalties for the three and nine months ended September 30, 2016 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 11% of product sales for the nine months ended September 30, 2016 compared with 13% of product sales for the nine months ended September 30, 2015. Crude oil and NGLs royalties averaged approximately 11% of product sales for the third quarter of 2016 compared with 12% for the third quarter of 2015 and 11% for the second quarter of 2016. The decrease in royalties for the three and nine months ended September 30, 2016 from comparable periods in 2015 was primarily due to lower realized crude oil prices. North America crude oil and NGLs royalties per bbl are anticipated to average 10% to 12% of product sales for 2016.

Natural gas royalties averaged approximately 3% of product sales for the nine months ended September 30, 2016, comparable with the nine months ended September 30, 2015. Natural gas royalties averaged approximately 4% of product sales for the third quarter of 2016 compared with 4% for the third quarter of 2015 and 1% for the second quarter of 2016. The increase in natural gas royalties in the third quarter of 2016 from the second quarter of 2016 reflected higher realized natural gas prices. North America natural gas royalties are now anticipated to average 4% to 6% of product sales for 2016.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 4% for the nine months ended September 30, 2016, comparable with the nine months ended September 30, 2015. Royalty rates as a percentage of product sales averaged approximately 4% for the third quarter of 2016, consistent with the comparable quarters in 2015 and 2016. Royalties as a percentage of product sales reflected the timing of liftings from various fields and the status of payout in the various fields. Offshore Africa royalty rates are anticipated to average 4% to 6% of product sales for 2016.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2016	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 11.69**	$ 12.30	$ 11.64	**$ 11.80**	$ 12.85
North Sea	**$ 39.41**	$ 40.74	$ 72.69	**$ 42.75**	$ 65.64
Offshore Africa	**$ 16.32**	$ 20.13	$ 40.53	**$ 18.29**	$ 37.85
Company average	**$ 13.85**	$ 14.31	$ 15.70	**$ 14.03**	$ 16.25
Natural gas ($/Mcf) [1]					
North America	**$ 1.04**	$ 1.17	$ 1.25	**$ 1.13**	$ 1.30
North Sea	**$ 2.15**	$ 3.33	$ 3.85	**$ 2.98**	$ 4.80
Offshore Africa	**$ 1.68**	$ 1.76	$ 1.43	**$ 1.58**	$ 1.86
Company average	**$ 1.08**	$ 1.22	$ 1.31	**$ 1.18**	$ 1.38
Company average ($/BOE) [1]	**$ 10.83**	$ 11.38	$ 12.68	**$ 11.13**	$ 13.09

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

North America

North America crude oil and NGLs production expense for the nine months ended September 30, 2016 decreased 8% to $11.80 per bbl from $12.85 per bbl for the nine months ended September 30, 2015. North America crude oil and NGLs production expense for the third quarter of 2016 of $11.69 per bbl was comparable with the third quarter of 2015 and decreased 5% from $12.30 per bbl for the second quarter of 2016. The Company continues to successfully reduce its production costs and achieve efficiencies across the asset base, through focused cost and production optimization, together with lower industry service costs. North America crude oil and NGLs production expense is anticipated to average $11.25 to $12.25 per bbl for 2016.

North America natural gas production expense for the nine months ended September 30, 2016 decreased 13% to $1.13 per Mcf from $1.30 per Mcf for the nine months ended September 30, 2015. North America natural gas production expense for the third quarter of 2016 decreased 17% to $1.04 per Mcf from $1.25 per Mcf for the third quarter of 2015 and decreased 11% from $1.17 per Mcf for the second quarter of 2016. Consistent with crude oil and NGL production costs, the Company continues to successfully reduce its natural gas production costs and achieve efficiencies across the asset base, through focused cost and production optimization, together with lower industry service costs. North America natural gas production expense guidance is anticipated to average $1.05 to $1.25 per Mcf for 2016.

North Sea

North Sea crude oil production expense for the nine months ended September 30, 2016 decreased 35% to $42.75 per bbl from $65.64 per bbl for the nine months ended September 30, 2015. North Sea crude oil production expense for the third quarter of 2016 decreased 46% to $39.41 per bbl from $72.69 per bbl for the third quarter of 2015 and was comparable with the second quarter of 2016. The Company continues to successfully reduce its production costs and achieve efficiencies through focused cost and production optimization, together with lower industry service costs. The decrease in production expense in 2016 also reflected fluctuations in the Canadian dollar and the UK pound sterling. North Sea crude oil production expense guidance is anticipated to average $40.50 to $46.50 per bbl for 2016.

Offshore Africa

Offshore Africa oil production expense for the nine months ended September 30, 2016 decreased 52% to $18.29 per bbl from $37.85 per bbl for the nine months ended September 30, 2015. Offshore Africa crude oil production expense for the third quarter of 2016 decreased 60% to average $16.32 per bbl from $40.53 per bbl for the third quarter of 2015 and decreased 19% from $20.13 per bbl for the second quarter of 2016. The fluctuations in production expense for the three and nine months ended September 30, 2016 from the comparable periods were primarily due to the timing of liftings from various fields, including the Olowi field, which have different cost structures, fluctuating production volumes on a relatively fixed cost base, the impact of inventory valuation adjustments at the Olowi field and fluctuations in the Canadian dollar. Offshore Africa production expense is anticipated to average $14.50 to $18.50 per bbl for 2016.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2016**	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Expense	**$ 1,031**	$ 1,036	$ 1,208	**$ 3,136**	$ 3,579
$/BOE (1)	**$ 16.84**	$ 17.03	$ 18.25	**$ 16.82**	$ 18.02

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

The decrease in depletion, depreciation and amortization expense for the three and nine months ended September 30, 2016 from the comparable periods in 2015 was primarily due to lower sales volumes and depletion rates in North America. Depletion, depreciation and amortization expense for the third quarter of 2016 was comparable with the second quarter of 2016.

Depletion, depreciation and amortization on a per barrel basis for the nine months ended September 30, 2016 decreased 7% to $16.82 per BOE from $18.02 per BOE for the nine months ended September 30, 2015. Depletion, depreciation and amortization expense on a per barrel basis for the third quarter of 2016 decreased 8% to $16.84 per BOE from $18.25 per BOE for the third quarter of 2015 and was comparable with the second quarter of 2016. The decrease in depletion, depreciation and amortization expense per BOE for the three and nine months ended September 30, 2016 from comparable periods in 2015 in was primarily due to a lower depletable base in North America.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)	Three Months Ended **Sep 30 2016**	Three Months Ended Jun 30 2016	Three Months Ended Sep 30 2015	Nine Months Ended **Sep 30 2016**	Nine Months Ended Sep 30 2015
Expense	**$ 28**	$ 28	$ 36	**$ 85**	$ 107
$/BOE (1)	**$ 0.46**	$ 0.46	$ 0.54	**$ 0.45**	$ 0.54

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

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

Asset retirement obligation accretion expense for the nine months ended September 30, 2016 decreased 17% to $0.45 per BOE from $0.54 per BOE for the nine months ended September 30, 2015. Asset retirement obligation accretion expense for the third quarter of 2016 decreased 15% to $0.46 per BOE from $0.54 per BOE for the third quarter of 2015, and was comparable with the second quarter of 2016.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

The Company continues to focus on reliable and efficient operations. During the third quarter of 2016, Horizon completed a major turnaround, including additional turnaround maintenance primarily required in the coker, delaying ramp up of operations. The Company achieved record SCO production in September of 148,049 bbl/d following the reinstatement of plant capacity in August, with total third quarter SCO production averaging 67,586 bbl/d.

The construction, commissioning and operational teams at Horizon have continued to work together to execute a safe and effective start-up of the Phase 2B expansion.

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

($/bbl) (1)	Three Months Ended **Sep 30 2016**	Three Months Ended Jun 30 2016	Three Months Ended Sep 30 2015	Nine Months Ended **Sep 30 2016**	Nine Months Ended Sep 30 2015
SCO sales price	**$ 58.61**	$ 61.78	$ 60.66	**$ 55.13**	$ 62.82
Bitumen value for royalty purposes (2)	**$ 30.16**	$ 30.93	$ 33.20	**$ 22.89**	$ 34.92
Bitumen royalties (3)	**$ 0.62**	$ 0.39	$ 1.32	**$ 0.34**	$ 1.11
Transportation	**$ 3.40**	$ 1.34	$ 1.82	**$ 2.09**	$ 1.87

(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 $55.13 per bbl for the nine months ended September 30, 2016, a decrease of 12% compared with $62.82 per bbl for the nine months ended September 30, 2015. Realized SCO sales prices averaged $58.61 per bbl for the third quarter of 2016, a decrease of 3% compared with $60.66 per bbl for the third quarter of 2015 and a decrease of 5% compared with $61.78 per bbl for the second quarter of 2016. The decrease in SCO pricing for the three and nine months ended September 30, 2016 from the comparable periods was primarily due to changes in WTI benchmark pricing, the impact of industry wide planned upgrader outages, and unplanned production outages at several third party oilsands facilities due to the Fort McMurray forest fires.

The increase in transportation expenses per barrel for the three and nine months ended September 30, 2016 from the comparable periods reflected lower sales volumes as a result of the major turnaround during the third quarter of 2016.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 16 to the Company's unaudited interim consolidated financial statements.

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2016**	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Cash production costs	**$ 326**	$ 293	$ 321	**$ 916**	$ 988
Less: costs incurred during turnaround periods	**(151)**	—	—	**(151)**	(45)
Adjusted cash production costs	**$ 175**	$ 293	$ 321	**$ 765**	$ 943
Adjusted cash production costs, excluding natural gas costs	**$ 161**	$ 278	$ 300	**$ 721**	$ 886
Adjusted natural gas costs	**14**	15	21	**44**	57
Adjusted cash production costs	**$ 175**	$ 293	$ 321	**$ 765**	$ 943

	Three Months Ended			Nine Months Ended	
($/bbl) (1)	**Sep 30 2016**	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Adjusted cash production costs, excluding natural gas costs	**$ 24.92**	$ 25.44	$ 25.28	**$ 25.22**	$ 26.89
Natural gas costs	**2.13**	1.38	1.76	**1.55**	1.74
Adjusted cash production costs	**$ 27.05**	$ 26.82	$ 27.04	**$ 26.77**	$ 28.63
Sales (bbl/d)	**70,005**	119,988	129,033	**104,221**	120,617

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

Adjusted cash production costs for the nine months ended September 30, 2016 decreased 6% to $26.77 per bbl from $28.63 per bbl for the nine months ended September 30, 2015. Adjusted cash production costs for the third quarter of 2016 averaged $27.05 per bbl, comparable with the third quarter of 2015 and the second quarter of 2016. Adjusted cash production costs for the three and nine months ended September 30, 2016 primarily reflected the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, and lower industry service costs. Adjusted cash production costs for the nine months ended September 30, 2016 also reflected the minor cost impact of the Fort McMurray forest fires. Cash production costs are anticipated to average $27.00 to $30.00 per bbl for 2016.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2016**	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Depletion, depreciation and amortization	**$ 182**	$ 135	$ 165	**$ 464**	$ 423
Less: depreciation incurred during turnaround period	**(99)**	—	—	**(99)**	(5)
Adjusted depletion, depreciation and amortization	**$ 83**	$ 135	$ 165	**$ 365**	$ 418
$/bbl	**$ 12.96**	$ 12.32	$ 13.95	**$ 12.77**	$ 12.70

Adjusted depletion, depreciation and amortization expense on a per barrel basis for the nine months ended September 30, 2016 was comparable with the nine months ended September 30, 2015. Adjusted depletion, depreciation and amortization expense on a per barrel basis for the third quarter of 2016 decreased 7% to $12.96 per bbl from $13.95 per bbl for the third quarter of 2015 and increased 5% from $12.32 per bbl for the second quarter of 2016.

Adjusted depletion, depreciation and amortization expense per barrel for the three and nine months ended September 30, 2016 and the comparable periods primarily reflected fluctuations in production volumes on assets depreciated on a straight line basis and the impact and timing of minor asset derecognitions.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2016**	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Expense	**$ 8**	$ 7	$ 8	**$ 22**	$ 23
$/bbl (1)	**$ 1.13**	$ 0.67	$ 0.65	**$ 0.76**	$ 0.70

(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 nine months ended September 30, 2016 increased 9% to $0.76 per bbl from $0.70 per bbl for the nine months ended September 30, 2015. Asset retirement obligation accretion expense for the third quarter of 2016 increased 74% to $1.13 per bbl from $0.65 per bbl for the third quarter of 2015 and increased 69% from $0.67 per bbl for the second quarter of 2016 due to lower sales volumes as a result of the major turnaround.

MIDSTREAM

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2016**	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Revenue	**$ 31**	$ 31	$ 33	**$ 88**	$ 103
Production expense	**7**	7	7	**20**	25
Midstream cash flow	**24**	24	26	**68**	78
Depreciation	**3**	3	3	**9**	9
Equity loss (gain) from Redwater Partnership	**4**	3	20	**(19)**	32
Segment earnings before taxes	**$ 17**	$ 18	$ 3	**$ 78**	$ 37

The Company has a 50% interest in the North West Redwater Partnership (“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, each committed to provide funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2015, the Company and APMC each provided $112 million of subordinated debt (year ended December 31, 2014 – $113 million). During the first quarter of 2016, the Company and APMC each provided an additional $99 million in subordinated debt. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

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

As at September 30, 2016, Redwater Partnership had additional borrowings of $969 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

($ millions, except per BOE amounts)	Three Months Ended Sep 30 2016	Jun 30 2016	Sep 30 2015	Nine Months Ended Sep 30 2016	Sep 30 2015
Expense	**$ 82**	$ 91	$ 93	**$ 259**	$ 297
$/BOE [1]	**$ 1.21**	$ 1.27	$ 1.20	**$ 1.21**	$ 1.28

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

Administration expense on a per BOE basis for the nine months ended September 30, 2016 decreased 5% to $1.21 per BOE from $1.28 per BOE for the nine months ended September 30, 2015. Administration expense for the third quarter of 2016 was comparable with the third quarter of 2015 and decreased 5% from $1.27 per BOE for the second quarter of 2016. Administration expense per BOE decreased for the nine months ended September 30, 2016 from the comparable period in 2015 primarily due to lower staffing related costs and general corporate costs, partially offset by the impacts of lower recoveries related to the capital expenditure program, and lower sales volumes on a relatively fixed cost base. The decrease in the third quarter of 2016 from the second quarter of 2016 was primarily due to lower general corporate costs, partially offset by the impact of lower sales volumes on a relatively fixed cost base.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Sep 30 2016	Jun 30 2016	Sep 30 2015	Nine Months Ended Sep 30 2016	Sep 30 2015
Expense (Recovery)	**$ 74**	$ 122	$ (87)	**$ 313**	$ (102)

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 $313 million share-based compensation expense for the nine months ended September 30, 2016, primarily as a result of remeasurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period and changes in the Company's share price. For the nine months ended September 30, 2016, the Company capitalized $61 million of share-based compensation costs to property, plant and equipment in the Oil Sands Mining and Upgrading segment (September 30, 2015 – $22 million costs recovered).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended Sep 30 2016	Jun 30 2016	Sep 30 2015	Nine Months Ended Sep 30 2016	Sep 30 2015
Expense, gross	**$ 157**	$ 153	$ 142	**$ 463**	$ 433
Less: capitalized interest	**67**	67	64	**195**	184
Expense, net	**$ 90**	$ 86	$ 78	**$ 268**	$ 249
$/BOE [1]	**$ 1.34**	$ 1.19	$ 1.00	**$ 1.25**	$ 1.08
Average effective interest rate	**3.8%**	3.9%	3.8%	**3.9%**	3.9%

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

Gross interest and other financing expense for the three and nine months ended September 30, 2016 increased from the comparable periods in 2015 primarily due to the impact of higher overall debt levels. Capitalized interest of $195 million for the nine months ended September 30, 2016 was primarily related to the Horizon Phase 2/3 expansion.

Net interest and other financing expense for the nine months ended September 30, 2016 increased 16% to $1.25 per BOE from $1.08 per BOE for the nine months ended September 30, 2015. Net interest and other financing expense on a per BOE basis for the third quarter of 2016 increased 34% to $1.34 per BOE from $1.00 per BOE for the third quarter of 2015 and increased 13% from $1.19 per BOE for the second quarter of 2016. The increase for the three and nine months ended September 30, 2016 from the comparable periods in 2015 was primarily due to higher overall debt levels and lower sales volumes. The increase for the third quarter of 2016 from the second quarter of 2016 was primarily due to lower sales volumes.

The Company's average effective interest rates for the three and nine months ended September 30, 2016 were consistent with the comparable periods.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2016**	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Crude oil and NGLs financial instruments	**$ —**	$ —	$ (173)	**$ —**	$ (381)
Foreign currency contracts	**(23)**	49	(90)	**22**	(207)
Realized (gain) loss	**(23)**	49	(263)	**22**	(588)
Crude oil and NGLs financial instruments	**—**	—	(12)	**—**	205
Natural gas financial instruments	**(2)**	—	—	**(2)**	—
Foreign currency contracts	**12**	(52)	(17)	**34**	(5)
Unrealized loss (gain)	**10**	(52)	(29)	**32**	200
Net (gain) loss	**$ (13)**	$ (3)	$ (292)	**$ 54**	$ (388)

During the nine months ended September 30, 2016, net realized risk management losses were related to the settlement of foreign currency contracts. The Company recorded a net unrealized loss of $32 million ($28 million after-tax) on its risk management activities for the nine months ended September 30, 2016, including an unrealized loss of $10 million ($11 million after-tax) for the third quarter of 2016 (June 30, 2016 - unrealized gain of $52 million; $46 million after-tax; September 30, 2015 – unrealized gain of $29 million; $24 million after-tax), primarily related to changes in the fair value of these contracts.

Complete details related to outstanding derivative financial instruments at September 30, 2016 are disclosed in note 14 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2016**	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Net realized loss (gain)	**$ 12**	$ 9	$ (28)	**$ 40**	$ (92)
Net unrealized loss (gain) (1)	**39**	40	351	**(255)**	688
Net loss (gain)	**$ 51**	$ 49	$ 323	**$ (215)**	$ 596

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

The net realized foreign exchange loss for the nine months ended September 30, 2016 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for the nine months ended September 30, 2016 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (three months ended September 30, 2016 – unrealized loss of $23 million, June 30, 2016 – unrealized gain of $9 million, September 30, 2015 – unrealized gain of $267 million; nine months ended September 30, 2016 - unrealized loss of $362 million, September 30, 2015 - unrealized gain of $520 million). The US/Canadian dollar exchange rate at September 30, 2016 was US$0.7624 (June 30, 2016 – US$0.7687, September 30, 2015 – US$0.7466).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended **Sep 30 2016**	Jun 30 2016	Sep 30 2015	Nine Months Ended **Sep 30 2016**	Sep 30 2015
North America (1)	**$ (168)**	$ (68)	$ 65	**$ (355)**	$ 152
North Sea	**(43)**	(8)	(16)	**(74)**	(99)
Offshore Africa	**5**	8	5	**17**	12
PRT recovery – North Sea	**(77)**	(31)	(61)	**(163)**	(187)
Other taxes	**2**	3	2	**6**	9
Current income tax recovery	**(281)**	(96)	(5)	**(569)**	(113)
Deferred corporate income tax (recovery) expense	**(32)**	(52)	8	**(51)**	217
Deferred PRT expense (recovery) – North Sea	**50**	10	10	**(144)**	47
Deferred income tax recovery	**18**	(42)	18	**(195)**	264
	(263)	(138)	13	**(764)**	151
Income tax rate and other legislative changes(2)	**107**	—	—	**221**	(351)
	$ (156)	$ (138)	$ 13	**$ (543)**	$ (200)
Effective income tax rate on adjusted net earnings (loss) from operations (3)	**27%**	37%	28%	**30%**	10%

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

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

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

The current corporation income tax and PRT recoveries in the North Sea in the third quarter of 2016 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the Murchison platform.

The effective income tax rate for the the three and nine months ended 2016 and the comparable periods included the impact of non-taxable items in North America and the North Sea as well as 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 September 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million.

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

In June 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $579 million.

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

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

For 2016, the Company now expects to recognize current income tax recoveries of $110 million to $150 million in Canada and recoveries of $210 million to $240 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES (1)

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2016**	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Exploration and Evaluation					
Net expenditures (proceeds) (2) (3)	**$ —**	$ 20	$ 5	**$ (10)**	$ 80
Property, Plant and Equipment					
Net property acquisitions (2) (3)	**17**	110	(70)	**158**	(8)
Well drilling, completion and equipping	**186**	98	237	**512**	728
Production and related facilities	**104**	94	191	**319**	754
Capitalized interest and other (4)	**20**	21	23	**65**	76
Net expenditures	**327**	323	381	**1,054**	1,550
Total Exploration and Production	**327**	343	386	**1,044**	1,630
Oil Sands Mining and Upgrading					
Horizon Phases 2/3 construction costs	**400**	583	668	**1,405**	1,609
Sustaining capital	**151**	76	64	**303**	246
Turnaround costs	**103**	29	3	**138**	13
Capitalized interest and other (4)	**77**	86	42	**244**	156
Total Oil Sands Mining and Upgrading	**731**	774	777	**2,090**	2,024
Midstream	**2**	1	2	**4**	6
Abandonments (5)	**122**	36	65	**232**	265
Head office	**3**	4	10	**13**	24
Total net capital expenditures	**$ 1,185**	$ 1,158	$ 1,240	**$ 3,383**	$ 3,949
By segment					
North America (2) (3)	**$ 259**	$ 319	$ 199	**$ 827**	$ 1,007
North Sea	**63**	10	41	**89**	196
Offshore Africa	**5**	14	146	**128**	427
Oil Sands Mining and Upgrading	**731**	774	777	**2,090**	2,024
Midstream	**2**	1	2	**4**	6
Abandonments (5)	**122**	36	65	**232**	265
Head office	**3**	4	10	**13**	24
Total	**$ 1,185**	$ 1,158	$ 1,240	**$ 3,383**	$ 3,949

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.

(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) 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 nine months ended September 30, 2016 were $3,383 million compared with $3,949 million for the nine months ended September 30, 2015. Net capital expenditures for the third quarter of 2016 were $1,185 million compared with $1,240 million for the third quarter of 2015 and $1,158 million for the second quarter of 2016.

The Company continues to proactively manage the cost structures within its crude oil and natural gas drilling programs. As a result of realizing significant drilling and completions cost reductions during 2016, the Company has reallocated $50 million of development capital across the basin in the second half of 2016. During the third quarter, the Company targeted 89 crude oil wells in North America, including 1 producing bitumen (thermal oil) well. Capital expenditures for 2016 are now targeted to be approximately $4,370 million.

Drilling Activity

	Three Months Ended			Nine Months Ended	
(number of wells)	**Sep 30 2016**	Jun 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Net successful natural gas wells	**—**	1	4	**5**	15
Net successful crude oil wells (1)	**85**	—	66	**93**	113
Dry wells	**4**	—	4	**4**	6
Stratigraphic test / service wells	**6**	1	1	**206**	93
Total	**95**	2	75	**308**	227
Success rate (excluding stratigraphic test / service wells)	**96%**	100%	95%	**96%**	96%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 26% of the total net capital expenditures for the nine months ended September 30, 2016 compared with approximately 28% for the nine months ended September 30, 2015.

During the third quarter of 2016, the Company targeted 89 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 85 primary heavy crude oil wells and 1 bitumen (thermal oil) well were drilled. Another 3 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for the third quarter of 2016 averaged approximately 103,500 bbl/d compared with approximately 133,200 bbl/d for the third quarter of 2015 and approximately 93,200 bbl/d for the second quarter of 2016. Production volumes in the third quarter of 2016 reflected the cyclic nature of thermal oil production at Primrose, together with the reinstatement of the Primrose East pipeline following the completion of repairs in May 2016.

Operating performance at the Pelican Lake tertiary recovery project continued to be strong, leading to average production of approximately 47,600 bbl/d in the third quarter of 2016 compared with 50,900 bbl/d in the third quarter of 2015 and 47,800 bbl/d in the second quarter of 2016.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the third quarter of 2016 continued to focus on field construction of the hydrogen unit, hydrotreater unit, vacuum distillation unit and distillation recovery unit, sour water concentrator, tank farms, tailings re-handling plant, froth treatment, froth tank, tailings transfer pumphouses and pipelines, extraction plant, ore preparation plants, and superpot along with engineering, procurement and construction related to tailings retrofit, combined hydrotreater and sulphur recovery units. The Company commissioned certain key components of the project in the second quarter.

During the turnaround in the third quarter, the Company successfully completed the tie-in of major components as planned. The construction, commissioning and operational teams at Horizon worked together to execute a safe and effective start-up of the Phase 2B expansion.

North Sea

During the third quarter, the Company successfully completed the removal of the platform top side structures at Murchison on schedule and under sanctioned costs, with further decommissioning efforts planned for 2017. Further, by the end of the fourth quarter of 2016, the Company targets to drill 1 gross well (0.9 net well) at Ninian.

Offshore Africa

In the second quarter of 2016, the Company demobilized the drilling rigs at Baobab and Espoir. No additional drilling activity is currently planned for the remainder of 2016.

LIQUIDITY AND CAPITAL RESOURCES

	Three Months Ended			
($ millions, except ratios)	**Sep 30 2016**	Jun 30 2016	Dec 31 2015	Sep 30 2015
Working capital (1)	**$ 489**	$ 686	$ 1,193	$ 309
Long-term debt (2) (3)	**$ 17,292**	$ 17,236	$ 16,794	$ 16,510
Share capital	**$ 4,367**	$ 4,167	$ 4,541	$ 4,533
Retained earnings	**21,237**	21,816	22,765	22,885
Accumulated other comprehensive income	**40**	36	75	67
Shareholders' equity	**$ 25,644**	$ 26,019	$ 27,381	$ 27,485
Debt to book capitalization (3) (4)	**40%**	40%	38%	38%
Debt to market capitalization (3) (5)	**27%**	28%	34%	37%
After-tax return on average common shareholders' equity (6)	**(2%)**	(2%)	(2%)	2%
After-tax return on average capital employed (3) (7)	**(1%)**	0%	(1%)	2%

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

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

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

(4) Calculated as 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 September 30, 2016, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2015. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated cash 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 cash flow from operations, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. In response to the current commodity price environment, the Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing the Company's borrowing capacity:
  - During the third quarter of 2016, the Company issued $1,000 million of 3.31% medium-term notes due February 2022. After issuing these securities, the Company has $2,000 million remaining on its base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
  - In October 2015, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
  - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US $2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under the US commercial paper program.
  - During the first quarter of 2016, the Company prepaid $250 million of the previously outstanding $1,000 million non-revolving term credit facility and extended the maturity date to February 2019 from January 2017. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at September 30, 2016, the $750 million facility was fully drawn. During the first quarter of 2016, the Company also entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn at September 30, 2016. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages;
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place to minimize the impact in the event of a default.

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

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

At September 30, 2016, the Company had in place bank credit facilities of $7,351 million, of which approximately $2,345 million, net of commercial paper issuances of $656 million, was available for general corporate purposes.

At September 30, 2016, the Company had total US dollar denominated debt with a carrying amount of $10,714 million (US$8,169 million), excluding transaction costs. This included $4,682 million (US$3,569 million) hedged by way of cross currency swaps (US$2,150 million) and foreign currency forwards (US$1,419 million). The fixed repayment amount of these hedging instruments is $4,307 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt of approximately $375 million to $10,339 million as at September 30, 2016.

Long-term debt was $17,292 million at September 30, 2016, resulting in a debt to book capitalization ratio of 40% (December 31, 2015 – 38%; September 30, 2015 – 38%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operations is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at September 30, 2016 are discussed in note 7 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedge policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. At November 2, 2016, 50,000 GJ/d of currently forecasted natural gas volumes were hedged using AECO swaps. Further details related to the Company's commodity derivative financial instruments outstanding at September 30, 2016 are discussed in note 14 of the Company's unaudited interim consolidated financial statements.

Share Capital

As at September 30, 2016, there were 1,104,100,000 common shares outstanding (December 31, 2015 – 1,094,668,000 common shares) and 59,775,000 stock options outstanding. As at November 1, 2016, the Company had 1,105,732,000 common shares outstanding and 57,915,000 stock options outstanding.

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

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

The Company's Normal Course Issuer Bid announced in 2015 expired April 2016 and was not renewed. For the nine months ended September 30, 2016, the Company did not purchase any common shares for cancellation.

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 September 30, 2016:

($ millions)	Remaining 2016	2017	2018	2019	2020	Thereafter
Product transportation and pipeline	$ 107	$ 391	$ 336	$ 284	$ 267	$ 1,484
Offshore equipment operating leases and offshore drilling	$ 63	$ 139	$ 103	$ 57	$ 34	$ 41
Long-term debt (1) (2)	$ 656	$ 1,443	$ 2,809	$ 2,751	$ 2,102	$ 7,599
Interest and other financing expense (3)	$ 127	$ 628	$ 543	$ 479	$ 431	$ 4,420
Office leases	$ 10	$ 42	$ 41	$ 41	$ 41	$ 185
Other	$ 45	$ 37	$ 47	$ —	$ —	$ —

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

(2) At September 30, 2016, 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 September 30, 2016.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases 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, 2015 and the unaudited interim financial statements for the nine months ended September 30, 2016.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2015.

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	**Sep 30 2016**	Dec 31 2015
ASSETS			
Current assets			
Cash and cash equivalents		**$ 19**	$ 69
Accounts receivable		**1,082**	1,277
Current income taxes		**794**	677
Inventory		**616**	525
Prepaids and other		**227**	162
Investment in PrairieSky Royalty Ltd.	5	**605**	974
Current portion of other long-term assets	6	**190**	375
		3,533	4,059
Exploration and evaluation assets	3	**2,422**	2,586
Property, plant and equipment	4	**51,018**	51,475
Other long-term assets	6	**987**	1,155
		$ 57,960	$ 59,275
LIABILITIES			
Current liabilities			
Accounts payable		**$ 626**	$ 571
Accrued liabilities		**2,029**	2,089
Current portion of long-term debt	7	**2,098**	1,729
Current portion of other long-term liabilities	8	**389**	206
		5,142	4,595
Long-term debt	7	**15,194**	15,065
Other long-term liabilities	8	**2,868**	2,890
Deferred income taxes		**9,112**	9,344
		32,316	31,894
SHAREHOLDERS' EQUITY			
Share capital	10	**4,367**	4,541
Retained earnings		**21,237**	22,765
Accumulated other comprehensive income	11	**40**	75
		25,644	27,381
		$ 57,960	$ 59,275

Commitments and contingencies (note 15).

Approved by the Board of Directors on November 2, 2016

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Sep 30 2016	Three Months Ended Sep 30 2015	Nine Months Ended Sep 30 2016	Nine Months Ended Sep 30 2015
Product sales		**$ 2,477**	$ 3,316	**$ 7,426**	$ 10,204
Less: royalties		**(142)**	(202)	**(361)**	(634)
Revenue		**2,335**	3,114	**7,065**	9,570
Expenses					
Production		**994**	1,166	**3,007**	3,607
Transportation and blending		**444**	540	**1,445**	1,804
Depletion, depreciation and amortization	3, 4	**1,216**	1,376	**3,609**	4,011
Administration		**82**	93	**259**	297
Share-based compensation	8	**74**	(87)	**313**	(102)
Asset retirement obligation accretion	8	**36**	44	**107**	130
Interest and other financing expense		**90**	78	**268**	249
Risk management activities	14	**(13)**	(292)	**54**	(388)
Foreign exchange loss (gain)		**51**	323	**(215)**	596
Gain on disposition of properties	3	**—**	(49)	**(32)**	(49)
(Gain) loss from investments	5, 6	**(50)**	20	**(216)**	32
		2,924	3,212	**8,599**	10,187
Earnings (loss) before taxes		**(589)**	(98)	**(1,534)**	(617)
Current income tax recovery	9	**(281)**	(5)	**(569)**	(113)
Deferred income tax expense (recovery)	9	**18**	18	**(195)**	264
Net loss		**$ (326)**	$ (111)	**$ (770)**	$ (768)
Net loss per common share					
Basic	13	**$ (0.29)**	$ (0.10)	**$ (0.70)**	$ (0.70)
Diluted	13	**$ (0.29)**	$ (0.10)	**$ (0.70)**	$ (0.70)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2016	Three Months Ended Sep 30 2015	Nine Months Ended Sep 30 2016	Nine Months Ended Sep 30 2015
Net loss	**$ (326)**	$ (111)	**$ (770)**	$ (768)
Items that may be reclassified subsequently to net earnings (loss)				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized (loss) income during the period, net of taxes of $1 million (2015 – $5 million) – three months ended; $1 million (2015 – $1 million) – nine months ended	**(5)**	35	**(4)**	(8)
Reclassification to net earnings (loss), net of taxes of $1 million (2015 – $nil) – three months ended; $nil (2015 – $1 million) – nine months ended	**(10)**	(5)	**(3)**	(11)
	(15)	30	**(7)**	(19)
Foreign currency translation adjustment				
Translation of net investment	**19**	44	**(28)**	35
Other comprehensive income (loss), net of taxes	**4**	74	**(35)**	16
Comprehensive loss	**$ (322)**	$ (37)	**$ (805)**	$ (752)

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Nine Months Ended **Sep 30 2016**	Sep 30 2015
Share capital	10		
Balance – beginning of period		**$ 4,541**	$ 4,432
Issued upon exercise of stock options		**321**	84
Previously recognized liability on stock options exercised for common shares		**51**	17
Return of capital on PrairieSky Royalty Ltd. share distribution	5	**(546)**	—
Balance – end of period		**4,367**	4,533
Retained earnings			
Balance – beginning of period		**22,765**	24,408
Net loss		**(770)**	(768)
Dividends on common shares	10	**(758)**	(755)
Balance – end of period		**21,237**	22,885
Accumulated other comprehensive income (loss)	11		
Balance – beginning of period		**75**	51
Other comprehensive (loss) income, net of taxes		**(35)**	16
Balance – end of period		**40**	67
Shareholders' equity		**$ 25,644**	$ 27,485

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Sep 30 2016**	Three Months Ended Sep 30 2015	Nine Months Ended **Sep 30 2016**	Nine Months Ended Sep 30 2015
Operating activities					
Net loss		**$ (326)**	$ (111)	**$ (770)**	$ (768)
Non-cash items					
Depletion, depreciation and amortization		**1,216**	1,376	**3,609**	4,011
Share-based compensation		**74**	(87)	**313**	(102)
Asset retirement obligation accretion		**36**	44	**107**	130
Unrealized risk management loss (gain)		**10**	(29)	**32**	200
Unrealized foreign exchange loss (gain)		**39**	351	**(255)**	688
(Gain) loss from investments	5, 6	**(46)**	20	**(193)**	32
Deferred income tax expense (recovery)		**18**	18	**(195)**	264
Gain on disposition of properties		**—**	(49)	**(32)**	(49)
Other		**14**	19	**38**	81
Abandonment expenditures		**(122)**	(65)	**(232)**	(265)
Net change in non-cash working capital		**(14)**	121	**(225)**	(75)
		899	1,608	**2,197**	4,147
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net		**(684)**	(168)	**1,048**	1,043
Issue of medium-term notes, net	7	**998**	—	**998**	107
Repayment of US dollar debt securities	7	**(279)**	—	**(834)**	—
Issue of common shares on exercise of stock options		**170**	1	**321**	84
Dividends on common shares		**(252)**	(252)	**(504)**	(748)
Net change in non-cash working capital		**—**	—	**—**	(40)
		(47)	(419)	**1,029**	446
Investing activities					
Net (expenditures) proceeds on exploration and evaluation assets		**—**	(5)	**10**	(80)
Net expenditures on property, plant and equipment		**(1,063)**	(1,170)	**(3,161)**	(3,604)
Investment in other long-term assets		**—**	—	**(99)**	(112)
Net change in non-cash working capital		**206**	(16)	**(26)**	(792)
		(857)	(1,191)	**(3,276)**	(4,588)
(Decrease) increase in cash and cash equivalents		**(5)**	(2)	**(50)**	5
Cash and cash equivalents – beginning of period		**24**	32	**69**	25
Cash and cash equivalents – end of period		**$ 19**	$ 30	**$ 19**	$ 30
Interest paid, net		**$ 194**	$ 172	**$ 499**	$ 447
Income taxes (received) paid		**$ (327)**	$ (128)	**$ (440)**	$ 136

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, 2015, except as discussed in Note 2. 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, 2015.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2016, the Company adopted the amendment to IFRS 11 “Joint Arrangements” to clarify the accounting treatment when an entity acquires interests in joint ventures and joint operations. The amendment requires these acquisitions to be accounted for as business combinations. The Company adopted this amendment prospectively. Adoption of this amended standard did not result in a significant impact to the Company’s consolidated financial statements.

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2015	$ 2,500	$ —	$ 86	$ —	$ 2,586
Additions	**20**	**—**	**5**	**—**	**25**
Transfers to property, plant and equipment	**(167)**	**—**	**—**	**—**	**(167)**
Disposals/derecognitions	**(3)**	**—**	**(18)**	**—**	**(21)**
Foreign exchange adjustments	**—**	**—**	**(1)**	**—**	**(1)**
At September 30, 2016	**$ 2,350**	**$ —**	**$ 72**	**$ —**	**$ 2,422**

During the nine months ended September 30, 2016, the Company disposed of a number of North America exploration and evaluation assets totalling $3 million for consideration of $35 million, resulting in a pre-tax gain on sale of properties of $32 million.

In connection with the Company's notice of withdrawal from Block CI-12 in Côte d'Ivoire, Offshore Africa in the second quarter of 2016, the Company derecognized $18 million of exploration and evaluation assets.

4. 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, 2015	$ 60,540	$ 7,414	$ 5,173	$ 24,343	$ 577	$ 378	$ 98,425
Additions	**872**	**89**	**123**	**2,090**	**4**	**13**	**3,191**
Transfers from E&E assets	**167**	**—**	**—**	**—**	**—**	**—**	**167**
Disposals/derecognitions	**(331)**	**—**	**—**	**(120)**	**—**	**—**	**(451)**
Foreign exchange adjustments and other	**—**	**(390)**	**(275)**	**—**	**—**	**—**	**(665)**
At September 30, 2016	**$ 61,248**	**$ 7,113**	**$ 5,021**	**$ 26,313**	**$ 581**	**$ 391**	**$100,667**
Accumulated depletion and depreciation							
At December 31, 2015	$ 35,347	$ 5,264	$ 3,659	$ 2,294	$ 132	$ 254	$ 46,950
Expense	**2,588**	**314**	**196**	**464**	**9**	**20**	**3,591**
Disposals/derecognitions	**(331)**	**—**	**—**	**(120)**	**—**	**—**	**(451)**
Foreign exchange adjustments and other	**6**	**(272)**	**(180)**	**5**	**—**	**—**	**(441)**
At September 30, 2016	**$ 37,610**	**$ 5,306**	**$ 3,675**	**$ 2,643**	**$ 141**	**$ 274**	**$ 49,649**
Net book value							
- at September 30, 2016	**$ 23,638**	**$ 1,807**	**$ 1,346**	**$ 23,670**	**$ 440**	**$ 117**	**$ 51,018**
- at December 31, 2015	$ 25,193	$ 2,150	$ 1,514	$ 22,049	$ 445	$ 124	$ 51,475

Project costs not subject to depletion and depreciation	**Sep 30 2016**	Dec 31 2015
Horizon	**$ 5,836**	$ 6,017
Kirby Thermal Oil Sands – North	**$ 836**	$ 816

During the nine months ended September 30, 2016, 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 $158 million. These transactions were accounted for using the acquisition method of accounting. In connection with these acquisitions, the Company assumed associated asset retirement obligations of $29 million. 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 nine months ended September 30, 2016, pre-tax interest of $195 million (September 30, 2015 – $184 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (September 30, 2015 – 3.9%).

5. INVESTMENT IN PRAIRIESKY ROYALTY LTD.

In connection with the disposal of a number of North America royalty income assets in 2015, the Company acquired approximately 44.4 million common shares of PrairieSky Royalty Ltd. ("PrairieSky").

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

As the Company’s remaining investment of approximately 22.6 million common shares constitutes less than 20% of the outstanding common shares of PrairieSky, the investment is accounted for at fair value through profit or loss and is remeasured at each reporting date. As at September 30, 2016, the Company’s investment in PrairieSky of $605 million (December 31, 2015 – $974 million) was classified as a current asset.

The gain from investment related to PrairieSky was comprised as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Fair value gain from PrairieSky	**$ 50**	$ —	**$ 174**	$ —
Dividend income from PrairieSky	**4**	—	**23**	—
	$ 54	$ —	**$ 197**	$ —

6. OTHER LONG-TERM ASSETS

	Sep 30 2016	Dec 31 2015
Investment in North West Redwater Partnership	**$ 273**	$ 254
North West Redwater Partnership subordinated debt [(1)]	**377**	254
Risk Management (note 14)	**421**	854
Other	**106**	168
	1,177	1,530
Less: current portion	**190**	375
	$ 987	$ 1,155

(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, each committed to provide funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2015, the Company and APMC each provided $112 million of subordinated debt (year ended December 31, 2014 – $113 million). During the first quarter of 2016, the Company and APMC each provided an additional $99 million in subordinated debt. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

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

As at September 30, 2016, Redwater Partnership had additional borrowings of $969 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 September 30, 2016, the Company recognized an equity loss from Redwater Partnership of $4 million (three months ended September 30, 2015 – loss of $20 million; nine months ended September 30, 2016 – gain of $19 million; nine months ended September 30, 2015 – loss of $32 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.

7. LONG-TERM DEBT

		Sep 30 2016		Dec 31 2015
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**3,146**	$	2,385
Medium-term notes		**3,500**		2,500
		6,646		4,885
US dollar denominated debt, unsecured				
Bank credit facilities (September 30, 2016 - US$919 million; December 31, 2015 - US$657 million)		**1,204**		909
Commercial paper (US$500 million)		**656**		692
US dollar debt securities (September 30, 2016 - US$6,750 million; December 31, 2015 - US$7,500 million)		**8,854**		10,380
		10,714		11,981
Long-term debt before transaction costs and original issue discounts, net		**17,360**		16,866
Less: original issue discounts, net (1)		**(10)**		(10)
transaction costs (1) (2)		**(58)**		(62)
		17,292		16,794
Less: current portion of commercial paper		**656**		692
current portion of other long-term debt (1) (2)		**1,442**		1,037
	$	**15,194**	$	15,065

(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 September 30, 2016, the Company had in place bank credit facilities of $7,351 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.

During the first quarter of 2016, the Company prepaid $250 million of the previously outstanding $1,000 million non-revolving term credit facility and extended the maturity date to February 2019 from January 2017. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at September 30, 2016, the $750 million facility was fully drawn. During the first quarter of 2016, the Company also entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn at September 30, 2016. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.

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 September 30, 2016, 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 September 30, 2016 was 1.9% (September 30, 2015 – 1.6%), and on total long-term debt outstanding for the nine months ended September 30, 2016 was 3.9% (September 30, 2015 – 3.9%).

At September 30, 2016, letters of credit and guarantees aggregating $279 million, including a $39 million financial guarantee related to Horizon and $143 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

During the third quarter of 2016, the Company issued $1,000 million of 3.31% medium-term notes due February 2022. After issuing these securities, the Company has $2,000 million remaining on its base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

US Dollar Debt Securities

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

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

In October 2015, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

8. OTHER LONG-TERM LIABILITIES

	Sep 30 2016	Dec 31 2015
Asset retirement obligations	**$ 2,792**	$ 2,950
Share-based compensation	**448**	128
Other	**17**	18
	3,257	3,096
Less: current portion	**389**	206
	$ 2,868	$ 2,890

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 5.9% (December 31, 2015 – 5.9%). Reconciliations of the discounted asset retirement obligations were as follows:

	Sep 30 2016	Dec 31 2015
Balance – beginning of period	**$ 2,950**	$ 4,221
Liabilities incurred	**1**	7
Liabilities acquired, net	**29**	129
Liabilities settled	**(232)**	(370)
Asset retirement obligation accretion	**107**	173
Revision of cost, inflation rates and timing estimates	**—**	(313)
Change in discount rate	**—**	(1,150)
Foreign exchange adjustments	**(63)**	253
Balance – end of period	**2,792**	2,950
Less: current portion	**67**	101
	$ 2,725	$ 2,849

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.

	Sep 30 2016	Dec 31 2015
Balance – beginning of period	**$ 128**	$ 203
Share-based compensation expense (recovery)	**313**	(46)
Cash payment for stock options surrendered	**(3)**	(1)
Transferred to common shares	**(51)**	(18)
Capitalized to (recovered from) Oil Sands Mining and Upgrading	**61**	(10)
Balance – end of period	**448**	128
Less: current portion	**322**	105
	$ 126	$ 23

9. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Current corporate income tax (recovery) expense – North America	**$ (168)**	$ 65	**$ (355)**	$ 152
Current corporate income tax recovery – North Sea	**(43)**	(16)	**(74)**	(99)
Current corporate income tax expense – Offshore Africa	**5**	5	**17**	12
Current PRT (1) recovery – North Sea	**(77)**	(61)	**(163)**	(187)
Other taxes	**2**	2	**6**	9
Current income tax recovery	**(281)**	(5)	**(569)**	(113)
Deferred corporate income tax (recovery) expense	**(32)**	8	**(51)**	217
Deferred PRT (1) expense (recovery) – North Sea	**50**	10	**(144)**	47
Deferred income tax expense (recovery)	**18**	18	**(195)**	264
Income tax (recovery) expense	**$ (263)**	$ 13	**$ (764)**	$ 151

(1) Petroleum Revenue Tax.

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

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

10. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued common shares	Nine Months Ended Sep 30, 2016 Number of shares (thousands)		Amount
Balance – beginning of period	**1,094,668**	**$**	**4,541**
Issued upon exercise of stock options	**9,432**		**321**
Previously recognized liability on stock options exercised for common shares	**—**		**51**
Return of capital on PrairieSky Royalty Ltd. share distribution (note 5)	**—**		**(546)**
Balance – end of period	**1,104,100**	**$**	**4,367**

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 November 2, 2016, the Board of Directors approved the regular quarterly dividend at $0.25 per common share, an increase from the previous regular quarterly dividend of $0.23 per common share.

Normal Course Issuer Bid

The Company's Normal Course Issuer Bid, announced in 2015, expired April 2016 and was not renewed.

Stock Options

The following table summarizes information relating to stock options outstanding at September 30, 2016:

	Nine Months Ended Sep 30, 2016 Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of period	**74,615**	**$**	**34.88**
Granted	**5,022**	**$**	**24.32**
Surrendered for cash settlement	**(454)**	**$**	**34.18**
Exercised for common shares	**(9,432)**	**$**	**34.06**
Forfeited	**(9,976)**	**$**	**39.74**
Outstanding – end of period	**59,775**	**$**	**33.31**
Exercisable – end of period	**17,341**	**$**	**35.03**

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.

11. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

		Sep 30 2016		Sep 30 2015
Derivative financial instruments designated as cash flow hedges	**$**	**51**	$	75
Foreign currency translation adjustment		**(11)**		(8)
	$	**40**	$	67

12. 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 September 30, 2016, the ratio was within the target range at 40%.

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.

	Sep 30 2016	Dec 31 2015
Long-term debt [(1)]	**$ 17,292**	$ 16,794
Total shareholders' equity	**$ 25,644**	$ 27,381
Debt to book capitalization	**40%**	38%

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

13. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
	Sep 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Weighted average common shares outstanding – basic (thousands of shares)	**1,102,117**	1,094,398	**1,098,219**	1,093,638
Effect of dilutive stock options (thousands of shares)	**—**	—	**—**	—
Weighted average common shares outstanding – diluted (thousands of shares)	**1,102,117**	1,094,398	**1,098,219**	1,093,638
Net loss	**$ (326)**	$ (111)	**$ (770)**	$ (768)
Net loss per common share – basic	**$ (0.29)**	$ (0.10)	**$ (0.70)**	$ (0.70)
– diluted	**$ (0.29)**	$ (0.10)	**$ (0.70)**	$ (0.70)

14. FINANCIAL INSTRUMENTS

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

	Sep 30, 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	**$ 1,082**	**$ —**	**$ —**	**$ —**	**$ 1,082**
Investment in PrairieSky	**—**	**605**	**—**	**—**	**605**
Other long-term assets	**377**	**1**	**420**	**—**	**798**
Accounts payable	**—**	**—**	**—**	**(626)**	**(626)**
Accrued liabilities	**—**	**—**	**—**	**(2,029)**	**(2,029)**
Long-term debt [1]	**—**	**—**	**—**	**(17,292)**	**(17,292)**
	$ 1,459	**$ 606**	**$ 420**	**$ (19,947)**	**$ (17,462)**

	Dec 31, 2015				
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	$ 1,277	$ —	$ —	$ —	$ 1,277
Investment in PrairieSky	—	974	—	—	974
Other long-term assets	254	36	818	—	1,108
Accounts payable	—	—	—	(571)	(571)
Accrued liabilities	—	—	—	(2,089)	(2,089)
Long-term debt [1]	—	—	—	(16,794)	(16,794)
	$ 1,531	$ 1,010	$ 818	$ (19,454)	$ (16,095)

(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:

	Sep 30, 2016			
	Carrying amount	**Fair value**		
Asset (liability) [1] [2]		**Level 1**	**Level 2**	**Level 3**
Investment in PrairieSky [3]	**$ 605**	**$ 605**	**$ —**	**$ —**
Other long-term assets [4]	**$ 798**	**$ —**	**$ 421**	**$ 377**
Fixed rate long-term debt [5] [6]	**$ (12,286)**	**$ (12,903)**	**$ —**	**$ —**

	Dec 31, 2015			
	Carrying amount	Fair value		
Asset (liability) [1] [2]		Level 1	Level 2	Level 3
Investment in PrairieSky [3]	$ 974	$ 974	$ —	$ —
Other long-term assets [4]	$ 1,108	$ —	$ 854	$ 254
Fixed rate long-term debt [5] [6]	$ (12,808)	$ (12,431)	$ —	$ —

(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 investment in PrairieSky is based on quoted market prices.

(4) The fair value of North West 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)	**Sep 30 2016**	Dec 31 2015
Derivatives held for trading		
Foreign currency forward contracts	**$ (1)**	$ 36
Natural gas AECO swaps	**2**	—
Cash flow hedges		
Foreign currency forward contracts	**(4)**	30
Cross currency swaps	**424**	788
	$ 421	$ 854
Included within:		
Current portion of other long-term assets	**$ 164**	$ 305
Other long-term assets	**257**	549
	$ 421	$ 854

For the nine months ended September 30, 2016, the Company recognized a gain of $3 million (year ended December 31, 2015 – gain of $5 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)	Sep 30 2016	Dec 31 2015
Balance – beginning of period	**$ 854**	$ 599
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	**(32)**	(374)
Foreign exchange	**(393)**	669
Other comprehensive loss	**(8)**	(40)
Balance – end of period	**421**	854
Less: current portion	**164**	305
	$ 257	$ 549

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2016	Sep 30 2015	**Sep 30 2016**	Sep 30 2015
Net realized risk management (gain) loss	**$ (23)**	$ (263)	**$ 22**	$ (588)
Net unrealized risk management loss (gain)	**10**	(29)	**32**	200
	$ (13)	$ (292)	**$ 54**	$ (388)

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 September 30, 2016, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts

	Remaining term			Volume	Weighted average price	Index
Natural Gas						
AECO swaps	Nov 2016	-	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 September 30, 2016, 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 September 30, 2016, 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	Oct 2016	—	May 2017	US$1,100	1.170	5.70%	5.10%
	Oct 2016	—	Nov 2021	US$500	1.022	3.45%	3.96%
	Oct 2016	—	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments were designated as hedges at September 30, 2016 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at September 30, 2016, the Company had US$2,555 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$1,419 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 September 30, 2016, 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 September 30, 2016, the Company had net risk management assets of $425 million with specific counterparties related to derivative financial instruments (December 31, 2015 – $854 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	$ 626	$ —	$ —	$ —
Accrued liabilities	$ 2,029	$ —	$ —	$ —
Long-term debt (1)	$ 2,098	$ 2,809	$ 4,853	$ 7,600

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

15. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	Remaining 2016	2017	2018	2019	2020	Thereafter
Product transportation and pipeline	$ 107	$ 391	$ 336	$ 284	$ 267	$ 1,484
Offshore equipment operating leases and offshore drilling	$ 63	$ 139	$ 103	$ 57	$ 34	$ 41
Office leases	$ 10	$ 42	$ 41	$ 41	$ 41	$ 185
Other	$ 45	$ 37	$ 47	$ —	$ —	$ —

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases 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.

16. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2016	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Segmented product sales	**1,779**	2,273	**4,968**	7,252	**171**	152	**402**	505	**134**	156	**440**	334	**2,084**	2,581	**5,810**	8,091
Less: royalties	**(132)**	(179)	**(332)**	(581)	**—**	—	**(1)**	(1)	**(6)**	(7)	**(18)**	(15)	**(138)**	(186)	**(351)**	(597)
Segmented revenue	**1,647**	2,094	**4,636**	6,671	**171**	152	**401**	504	**128**	149	**422**	319	**1,946**	2,395	**5,459**	7,494
Segmented expenses																
Production	**518**	615	**1,630**	2,011	**107**	139	**299**	434	**38**	86	**147**	156	**663**	840	**2,076**	2,601
Transportation and blending	**422**	521	**1,395**	1,755	**15**	14	**37**	43	**1**	—	**2**	1	**438**	535	**1,434**	1,799
Depletion, depreciation and amortization	**854**	1,059	**2,606**	3,183	**117**	95	**315**	281	**60**	54	**215**	115	**1,031**	1,208	**3,136**	3,579
Asset retirement obligation accretion	**17**	23	**50**	70	**8**	10	**26**	29	**3**	3	**9**	8	**28**	36	**85**	107
Realized risk management activities	**(23)**	(263)	**22**	(588)	**—**	—	**—**	—	**—**	—	**—**	—	**(23)**	(263)	**22**	(588)
Gain on disposition of properties	**—**	(49)	**(32)**	(49)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	(49)	**(32)**	(49)
(Gain) loss from investments	**(54)**	—	**(197)**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(54)**	—	**(197)**	—
Total segmented expenses	**1,734**	1,906	**5,474**	6,382	**247**	258	**677**	787	**102**	143	**373**	280	**2,083**	2,307	**6,524**	7,449
Segmented earnings (loss) before the following	**(87)**	188	**(838)**	289	**(76)**	(106)	**(276)**	(283)	**26**	6	**49**	39	**(137)**	88	**(1,065)**	45
Non–segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Unrealized risk management activities																
Foreign exchange loss (gain)																
Total non–segmented expenses																
Earnings (loss) before taxes																
Current income tax recovery																
Deferred income tax expense (recovery)																
Net loss																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter–segment elimination and other				Total			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2016	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Segmented product sales	**380**	722	**1,578**	2,071	**31**	33	**88**	103	**(18)**	(20)	**(50)**	(61)	**2,477**	3,316	**7,426**	10,204
Less: royalties	**(4)**	(16)	**(10)**	(37)	**—**	—	**—**	—	**—**	—	**—**	—	**(142)**	(202)	**(361)**	(634)
Segmented revenue	**376**	706	**1,568**	2,034	**31**	33	**88**	103	**(18)**	(20)	**(50)**	(61)	**2,335**	3,114	**7,065**	9,570
Segmented expenses																
Production	**326**	321	**916**	988	**7**	7	**20**	25	**(2)**	(2)	**(5)**	(7)	**994**	1,166	**3,007**	3,607
Transportation and blending	**22**	22	**60**	62	**—**	—	**—**	—	**(16)**	(17)	**(49)**	(57)	**444**	540	**1,445**	1,804
Depletion, depreciation and amortization	**182**	165	**464**	423	**3**	3	**9**	9	**—**	—	**—**	—	**1,216**	1,376	**3,609**	4,011
Asset retirement obligation accretion	**8**	8	**22**	23	**—**	—	**—**	—	**—**	—	**—**	—	**36**	44	**107**	130
Realized risk management activities	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(23)**	(263)	**22**	(588)
Gain on disposition of properties	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	(49)	**(32)**	(49)
(Gain) loss from investments	**—**	—	**—**	—	**4**	20	**(19)**	32	**—**	—	**—**	—	**(50)**	20	**(216)**	32
Total segmented expenses	**538**	516	**1,462**	1,496	**14**	30	**10**	66	**(18)**	(19)	**(54)**	(64)	**2,617**	2,834	**7,942**	8,947
Segmented earnings (loss) before the following	**(162)**	190	**106**	538	**17**	3	**78**	37	**—**	(1)	**4**	3	**(282)**	280	**(877)**	623
Non–segmented expenses																
Administration													**82**	93	**259**	297
Share-based compensation													**74**	(87)	**313**	(102)
Interest and other financing expense													**90**	78	**268**	249
Unrealized risk management activities													**10**	(29)	**32**	200
Foreign exchange loss (gain)													**51**	323	**(215)**	596
Total non–segmented expenses													**307**	378	**657**	1,240
Earnings (loss) before taxes													**(589)**	(98)	**(1,534)**	(617)
Current income tax recovery													**(281)**	(5)	**(569)**	(113)
Deferred income tax expense (recovery)													**18**	18	**(195)**	264
Net loss													**(326)**	(111)	**(770)**	(768)

Capital Expenditures [1]

	Nine Months Ended					
	Sep 30, 2016			Sep 30, 2015		
	Net expenditures	**Non-cash and fair value changes[2]**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes[2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [3]	**$ 17**	**$ (167)**	**$ (150)**	$ 63	$ (223)	$ (160)
North Sea	**—**	**—**	**—**	—	—	—
Offshore Africa	**5**	**(18)**	**(13)**	28	—	28
	$ 22	**$ (185)**	**$ (163)**	$ 91	$ (223)	$ (132)
Property, plant and equipment						
Exploration and Production						
North America	**$ 842**	**$ (134)**	**$ 708**	$ 989	$ (111)	$ 878
North Sea	**89**	**—**	**89**	196	(3)	193
Offshore Africa	**123**	**—**	**123**	399	—	399
	1,054	**(134)**	**920**	1,584	(114)	1,470
Oil Sands Mining and Upgrading [4]	**2,090**	**(120)**	**1,970**	2,024	(86)	1,938
Midstream	**4**	**—**	**4**	6	—	6
Head office	**13**	**—**	**13**	24	—	24
	$ 3,161	**$ (254)**	**$ 2,907**	$ 3,638	$ (200)	$ 3,438

(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, and other fair value adjustments.

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

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

Segmented Assets

	Sep 30 2016	Dec 31 2015
Exploration and Production		
North America	**$ 28,612**	$ 30,937
North Sea	**2,237**	2,734
Offshore Africa	**1,557**	1,755
Other	**54**	73
Oil Sands Mining and Upgrading	**24,157**	22,598
Midstream	**1,226**	1,054
Head office	**117**	124
	$ 57,960	$ 59,275

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 September 30, 2016:	
Interest coverage (times)	
Net earnings (loss) (1)	(1.4)x
Cash flow from operations (2)	6.5x

(1) Net earnings (loss) 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) Cash 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.

This Page Left Intentionally Blank

This Page Left Intentionally Blank

This Page Left Intentionally Blank

Corporate Information

Board of Directors

Catherine M. Best, FCA, ICD.D
N. Murray Edwards, O.C.
Honourable Gary A. Filmon, P.C., O.C., O.M.
Christopher L. Fong
Ambassador Gordon D. Giffin
Wilfred A. Gobert
Steve. W. Laut
Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C.
David A. Tuer
Annette Verschuren, O.C.

Officers

N. Murray Edwards
Executive Chairman of the Board

Steve W. Laut
President

Tim S. McKay
Chief Operating Officer

Lyle G. Stevens
Executive Vice-President, Canadian Conventional

Corey B. Bieber
Chief Financial Officer and Senior Vice-President, Finance

Réal M. Cusson
Senior Vice-President, Marketing

Réal J.H. Doucet
Senior Vice-President, Horizon Projects

Darren M. Fichter
Senior Vice-President, Exploitation

Allan E. Frankiw
Senior Vice-President, Production

Ronald K. Laing
Senior, Vice-President, Corporate Development and Land

Bill R. Peterson
Senior Vice-President, Production and Development Operations

Ken W. Stagg
Senior Vice-President, Exploration

Scott G. Stauth
Senior Vice-President, North America Operations

Jeffrey J. Wilson
Executive Exploration Advisor

Paul M. Mendes
Vice-President, Legal, General Counsel and Corporate Secretary

Betty Yee
Vice-President, Land

International Operations
CNR International (U.K.) Limited
Aberdeen, Scotland

David. B. Whitehouse
Vice-President and Managing Director, International
W. David R. Bell
Vice-President, Exploration, International
Barry Duncan
Vice-President, Finance, International
Andrew M. McBoyle
Vice-President, Exploitation, International

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