CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2016 SECOND QUARTER RESULTS

Commenting on second quarter 2016 results, Steve Laut, President of Canadian Natural stated, “Canadian Natural delivered strong cash flow during the quarter while facing a number of challenges, ranging from low commodity prices to the proactive shut down of the Primrose East pipeline and operational issues at third party owned and operated natural gas facilities, which impacted quarterly production volumes. The major turnaround at Horizon is now largely complete with on spec production targeted for August 11, 2016. Start-up of the Horizon 2B expansion is targeted in October, with full production targeted in November, delivering additional sustainable production and cash flow. As a result, Canadian Natural is in an excellent position to become an even stronger and more robust company.”

Canadian Natural’s Chief Financial Officer, Corey Bieber, continued, “In the first half of 2016, we continued to realize significant operating cost savings of approximately $430 million when compared with the previous year through our continued focus on top tier effectiveness and efficiency. Canadian Natural is nearing an inflection point, with the completion of Horizon Phase 2B. Upon completion, decreased project capital expenditures, coupled with greater cash flow generation potential, significantly enhances our ability to strengthen our balance sheet, maximize returns to shareholders, invest in economic resource development and execute on opportunistic acquisitions.”

QUARTERLY HIGHLIGHTS

	Three Months Ended			Six Months Ended	
($ Millions, except per common share amounts)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Net earnings (loss)	**$ (339)**	$ (105)	$ (405)	**$ (444)**	$ (657)
Per common share – basic	**$ (0.31)**	$ (0.10)	$ (0.37)	**$ (0.41)**	$ (0.60)
– diluted	**$ (0.31)**	$ (0.10)	$ (0.37)	**$ (0.41)**	$ (0.60)
Adjusted net earnings (loss) from operations(1)	**$ (210)**	$ (543)	$ 178	**$ (753)**	$ 199
Per common share – basic	**$ (0.19)**	$ (0.50)	$ 0.16	**$ (0.69)**	$ 0.18
– diluted	**$ (0.19)**	$ (0.50)	$ 0.16	**$ (0.69)**	$ 0.18
Cash flow from operations (2)	**$ 938**	$ 657	$ 1,503	**$ 1,595**	$ 2,873
Per common share – basic	**$ 0.85**	$ 0.60	$ 1.38	**$ 1.45**	$ 2.63
– diluted	**$ 0.85**	$ 0.60	$ 1.37	**$ 1.45**	$ 2.62
Net capital expenditures	**$ 1,158**	$ 1,040	$ 1,297	**$ 2,198**	$ 2,709
Daily production, before royalties					
Natural gas (MMcf/d)	**1,689**	1,786	1,779	**1,738**	1,775
Crude oil and NGLs (bbl/d)	**502,410**	546,927	509,047	**524,668**	555,669
Equivalent production (BOE/d) (3)	**783,988**	844,531	805,547	**814,259**	851,545

(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.

- Canadian Natural realized cash flow from operations in Q2/16 of $938 million, an increase from $657 million in Q1/16. The decrease in Q2/16 from $1,503 million in Q2/15 primarily reflects lower crude oil and NGL and natural gas netbacks and lower sales volumes of North America crude oil and NGLs.
- For Q2/16, the Company had a net loss of $339 million compared to a net loss of $405 million in Q2/15 and net loss of $105 million in Q1/16. Adjusted net loss from operations was $210 million in Q2/16 compared to adjusted net earnings of $178 million in Q2/15 and adjusted net loss of $543 million in Q1/16. Changes in adjusted net earnings primarily reflect the changes in cash flow from operations.
- Canadian Natural's corporate production volumes averaged 783,988 BOE/d in Q2/16, representing a 3% and 7% decrease from Q2/15 and Q1/16 levels respectively. Q2/16 production volumes were lower than Q2/15 and Q1/16 levels due to expected natural production declines, minimal conventional development capital expenditures, as well as unexpected weather and pipeline related events.
- Crude oil and NGL production volumes averaged 502,410 bbl/d in Q2/16.
  - During the quarter, Horizon Oil Sands ("Horizon") operations were not significantly affected by the wild fires in Fort McMurray. Q2/16 production averaged 119,511 bbl/d of synthetic crude oil ("SCO") as minor unplanned downtime was required during the quarter to optimize the diluent recovery unit ("DRU"). Horizon achieved strong operating costs of $26.82/bbl (US$20.81/bbl) in Q2/16, representing an 8% decrease over Q2/15 and comparable to Q1/16, as a result of a continued focus on effective and efficient operations.
  - Kirby South achieved record quarterly production volumes of 38,695 bbl/d as operations continue to be optimized. Operating costs of $8.56/bbl (US$6.64/bbl) represented a 37% and 18% reduction over Q2/15 and Q1/16 levels respectively. The steam to oil ratio ("SOR") was 2.55 in the quarter and is expected to be in the 2.50 - 2.60 range for the rest of the year.
  - At Pelican Lake, Canadian Natural's industry leading polymer flood, quarterly production was 47,797 bbl/d, reflecting strong polymer flood performance offset by natural declines in base primary crude oil production. Q2/16 operating costs have decreased by 2% from Q2/15 to $6.81/bbl (US$5.29/bbl).

- International Exploration & Production ("E&P") quarterly crude oil production volumes averaged 54,218 bbl/d, representing a 45% and 11% increase over Q2/15 and Q1/16 levels respectively.
  - Q2/16 represented the first full quarter of production at Espoir and Baobab in Offshore Africa after the completion of the Company's successful infill drilling program. Crude oil production increased by 81% and 20% from Q2/15 and Q1/16 levels respectively, averaging 30,858 bbl/d. Crude oil operating costs increased in the quarter over Q1/16 to $20.13/bbl (US$15.62/bbl) due to timing of liftings from various fields, however year-over-year have significantly decreased by 54%.
  - Q2/16 North Sea crude oil production averaged 23,360 bbl/d. Production enhancements, increased reliability and waterflood optimization resulted in an increase of production by approximately 3,000 bbl/d, or 15%, in Q2/16 over Q2/15 and comparable to Q1/16. Quarterly crude oil operating costs averaged $40.74/bbl (US$31.62/bbl), reductions of 33% and 15% from Q2/15 and Q1/16 levels respectively, as a result of the Company's continued focus on effective and efficient operations.

- Quarterly natural gas volumes averaged 1,689 MMcf/d, representing a 5% decrease from both Q2/15 and Q1/16 levels mainly due to third party pipeline and facility outages. North America natural gas operating costs in Q2/16 averaged $1.17/Mcf, 9% and 1% lower as compared to Q2/15 and Q1/16 levels respectively, reflecting a continued focus on process optimization.
- During the forest fires in the Fort McMurray region, Horizon's teams effectively and efficiently worked together to mobilize resources and organize logistics in support of over 2,700 evacuees all while ensuring the safety and well-being of everyone on site and keeping operations stable. Horizon personnel focused on supporting its employees, their families, Fort McMurray and neighboring community residents with accommodations, meals, medical treatment, and flights from the Horizon site to Edmonton or Calgary. In support of firefighting efforts, a portion of Horizon's firefighters worked alongside crews from the city and contributed firefighting equipment to help protect critical infrastructure and homes while government officials were offered access to Horizon's aerodrome services. The Company would like to recognize and thank its teams for their strong commitment and hard work through this challenging time.
- Subsequent to June 30, 2016, the Company began a scheduled major turnaround at Horizon to complete maintenance activities within the plant facilities and tie-in of major components of the Horizon Phase 2B expansion. The turnaround is now largely complete with SCO production targeted to resume on August 11, 2016.
- 2016 is a milestone year for Canadian Natural as the Company advances the completion of the Horizon expansion with the addition of 45,000 bbl/d of SCO from Phase 2B, targeted to start up in October 2016 with full production targeted in November 2016. With the completion of Phase 2B, Canadian Natural expects Horizon's 2016 exit nameplate capacity to be rated at 182,000 bbl/d of SCO, resulting in a step change in the sustainability of the production and cash flow profiles for the Company.
- Concurrent with the completion of maintenance activities, tie-in of major components of the Horizon Phase 2B expansion has been completed as planned. Staged completion of plant system commissioning activities commenced in March 2016 and remains on schedule.
- Horizon project capital in 2016 is targeted to range from $1.89 billion to $1.99 billion, the majority of which will be spent over the first nine months of 2016. Horizon project costs in Q2/16 totaled $583 million and are $1,005 million year-to-date. In 2017, Horizon project capital costs are targeted to decline to approximately $1 billion for Phase 3 completion, which is targeted to add incremental production volumes of 80,000 bbl/d in Q4/17. The addition of Phase 3 marks the completion of the current Horizon expansion and volumes are targeted to average 250,000 bbl/d of SCO with operating costs trending below C$25.00/bbl (US$19.40/bbl).
- The Company continues to proactively manage the cost structures within its crude oil and natural gas drilling programs. As a result of realizing 20% to 25% of drilling and completions cost reductions year-over-year and increasing commodity prices, the Company has reallocated $50 million of development capital across the basin while remaining within annual corporate capital guidance. In the second half of 2016, Canadian Natural targets to increase its drilling activity by approximately 130 net North America E&P crude oil wells and 4 net producing thermal in situ wells.
- Canadian Natural continues to realize excellent results from its commitment to effective and efficient operations resulting in approximately $430 million of operating cost savings in the first half of 2016 over the same period in 2015.

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

Operating Costs (Canadian $)	Q2/16	Q2/15	Year-over-Year Percent Reduction
North America Light Crude Oil and NGLs ($/bbl)	**$ 13.84**	$ 15.29	**10%**
Pelican Lake Heavy Crude Oil ($/bbl)	**$ 6.81**	$ 6.98	**2%**
Primary Heavy Crude Oil ($/bbl)	**$ 13.70**	$ 14.92	**8%**
Thermal Oil Sands In Situ ($/bbl)	**$ 12.19**	$ 12.18	**–**
Horizon Oil Sands Mining and Upgrading ($/bbl)	**$ 26.82**	$ 29.25	**8%**
Offshore Africa Light Crude Oil ($/bbl)	**$ 20.13**	$ 43.88	**54%**
North Sea Light Crude Oil ($/bbl)	**$ 40.74**	$ 60.61	**33%**
North America Natural Gas ($/Mcf)	**$ 1.17**	$ 1.28	**9%**
Total Overall ($/BOE)	**$ 13.73**	$ 15.97	**14%**

- Canadian Natural maintains significant financial stability and liquidity represented in part by committed bank credit facilities. As at June 30, 2016, the Company had in place bank credit facilities of approximately $7.4 billion, of which approximately $1.7 billion was undrawn and available. Balance sheet strength was maintained with debt to book capitalization of 40% at June 30, 2016.
- On June 6, 2016, the Company distributed approximately 21.8 million PrairieSky common shares to the shareholders of record of the Company at a volume weighted price of $24.89, completing the previously announced Plan of Arrangement. Subsequent to the distribution, the Company's ownership interest in PrairieSky decreased to approximately 22.6 million shares with a market value of approximately $575 million as at July 31, 2016. Current ownership is less than 10% of the issued and outstanding common shares of PrairieSky, satisfying the requirements of the purchase and sale agreement with PrairieSky**.**
- Canadian Natural declared a quarterly cash dividend on its common shares of C$0.23 per share payable on October 1, 2016.

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 acted on quickly, and, in the right economic conditions, can provide excellent payouts and returns. 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 maximizes value.

Drilling Activity

	Six Months Ended June 30			
	2016		2015	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**11**	**8**	54	47
Natural gas	**6**	**5**	16	11
Dry	**–**	**–**	2	2
Subtotal	**17**	**13**	72	60
Stratigraphic test / service wells	**200**	**200**	128	92
Total	**217**	**213**	200	152
Success rate (excluding stratigraphic test / service wells)		**100%**		97%

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2016	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Crude oil and NGLs production (bbl/d)	**235,468**	251,943	270,021	**243,705**	278,133
Net wells targeting crude oil	**–**	7	4	**7**	44
Net successful wells drilled	**–**	7	4	**7**	42
Success rate	**–**	100%	100%	**100%**	95%

- Q2/16 production volumes of North America crude oil and NGLs averaged 235,468 bbl/d, representing an expected decrease of 13% and 7% from Q2/15 and Q1/16 levels. The year-over-year production decline was modest considering an 84% reduction in drilling activity from 44 net wells in the first half of 2015 to 7 net wells in the first half of 2016.

- North America light crude oil and NGL quarterly production averaged 83,821 bbl/d in Q2/16, representing a 6% and 7% decrease from Q2/15 and Q1/16 levels respectively.
- Quarterly production volumes from Pelican Lake operations averaged 47,797 bbl/d, representing a 8% decrease from Q2/15 and comparable to Q1/16 levels.
- Q2/16 primary heavy crude oil production averaged 103,850 bbl/d, a decrease of 19% and 9% from Q2/15 and Q1/16 levels respectively. This production decline reflects the Company’s proactive decision to reduce its primary heavy crude oil drilling program since 2014.
- In the second half of 2016, Canadian Natural targets to increase its drilling activity by approximately 130 net North America E&P crude oil wells.
- 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 Q2/16 from Q2/15 levels.
  - North America light crude oil and NGL quarterly operating costs were reduced by 10%.
  - At Pelican Lake, industry leading operating costs of $6.81/bbl were achieved, representing a 2% decrease.
  - Strong operating cost reductions of 8% were realized within the primary heavy crude oil operations.
- The Company’s North America E&P crude oil and NGL annual production guidance remains unchanged and is targeted to range from 514,000 bbl/d - 563,000 bbl/d in 2016.

Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2016	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Bitumen production (bbl/d)	**93,213**	118,044	105,019	**105,629**	125,438
Net wells targeting bitumen	**–**	–	–	**–**	3
Net successful wells drilled	**–**	–	–	**–**	3
Success rate	**–**	–	–	**–**	100%

- Thermal in situ quarterly production averaged 93,213 bbl/d in Q2/16, representing a decrease of 11% and 21% from Q2/15 and Q1/16 levels respectively. The decrease in production volumes reflect reduced drilling programs at Primrose since 2014, the normal impacts of cyclical steam stimulation (“CSS”) operations for this asset, and the 13,000 bbl/d quarterly impact of the previously announced proactive shut down of the Primrose East pipeline. The Primrose East pipeline returned to service on May 17, 2016.
- Kirby South achieved record quarterly volumes of 38,695 bbl/d, while operations continue to be optimized. Operating costs of $8.56/bbl represented a 37% and 18% reduction over Q2/15 and Q1/16 levels respectively. The SOR was 2.55 in the quarter and is expected to be in the 2.50 - 2.60 range for the rest of 2016.
- The Company is targeting to drill 3 wells at Primrose/Wolf Lake and one SAGD well pair at the Senlac thermal in situ property in the second half of 2016.
- 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			Six Months Ended	
	Jun 30 2016	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Natural gas production (MMcf/d)	**1,620**	1,722	1,716	**1,672**	1,715
Net wells targeting natural gas	**1**	4	2	**5**	11
Net successful wells drilled	**1**	4	2	**5**	11
Success rate	**100%**	100%	100%	**100%**	100%

- North America natural gas quarterly production volumes averaged 1,620 MMcf/d in Q2/16, a decrease of 6% from both Q2/15 and Q1/16 levels respectively. In Q2/16, approximately 55 MMcf/d was negatively impacted due to an unplanned restriction to the third party Pine River Gas Plant.
  - As mentioned above, the third party operated Pine River Gas Plant experienced unforeseen operational issues in the quarter. In addition, in mid-June the main line to the plant was compromised due to flooding and was subsequently shut in. As a result, the Company has approximately 176 MMcf/d of natural gas production shut in due to the outage. Subsequent to quarter end, the third party is targeting to reinstate natural gas processing volumes of approximately 50 MMcf/d on August 8, 2016, an additional 40 MMcf/d by late-September 2016 and the remaining 86 MMcf/d by December 2016.
- Operations at Septimus, Canadian Natural's liquids-rich Montney natural gas play in British Columbia, continue to perform above expectations, with industry leading operating costs of $0.23/Mcfe in Q2/16.
- North America natural gas quarterly operating costs were $1.17/Mcf in Q2/16, a 9% decrease from Q2/15 levels and were in line with Q1/16 reflecting a continued focus on process optimization.
- The Company's natural gas annual production guidance has been reduced to reflect third party outages and is now targeted to range from 1,705 MMcf/d to 1,735 MMcf/d in 2016.

International Exploration and Production

	Three Months Ended			Six Months Ended	
	Jun 30 2016	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Crude oil production (bbl/d)					
North Sea	**23,360**	23,317	20,330	**23,338**	21,676
Offshore Africa	**30,858**	25,714	17,070	**28,286**	15,139
Natural gas production (MMcf/d)					
North Sea	**30**	29	38	**29**	36
Offshore Africa	**39**	35	25	**37**	24
Net wells targeting crude oil	–	1.2	1.4	**1.2**	2.0
Net successful wells drilled	–	1.2	1.4	**1.2**	2.0
Success rate	–	100%	100%	**100%**	100%

- International E&P quarterly crude oil production volumes averaged 54,218 bbl/d, representing a 45% and 11% increase over Q2/15 and Q1/16 levels respectively.
- Q2/16 represented the first full quarter of production at Espoir and Baobab in Offshore Africa after the completion of the Company's successful infill drilling programs. Crude oil production increased by 81% and 20% from Q2/15 and Q1/16 levels respectively, averaging 30,858 bbl/d. Crude oil operating costs increased in the quarter over Q1/16 to $20.13/bbl (US$15.62/bbl) due to timing of liftings, however year-over-year have decreased significantly by 54%.

- Q2/16 North Sea crude oil production averaged 23,360 bbl/d. Production enhancements, increased reliability and waterflood optimization resulted in an increase of production by approximately 3,000 bbl/d, or 15%, in Q2/16 over Q2/15 and comparable to Q1/16. Quarterly crude oil operating costs averaged $40.74/bbl (US$31.62/bbl), reductions of 33% and 15% from Q2/15 and Q1/16 levels respectively, as a result of the Company's continued focus on effective and efficient operations.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Six Months Ended	
	Jun 30 2016	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Synthetic crude oil production (bbl/d) (1)	**119,511**	127,909	96,607	**123,710**	115,283

(1) The Company produces diesel for internal use at Horizon. Second quarter 2016 SCO production before royalties excludes 2,227 bbl/d of SCO consumed internally as diesel (first quarter 2016 – 2,562 bbl/d; second quarter 2015 – 2,410 bbl/d; six months ended June 30, 2016 - 2,394 bbl/d; six months ended June 30, 2015 - 2,045 bbl/d).

- Q2/16 production averaged 119,511 bbl/d of SCO, representing a 24% increase from Q2/15 and a decrease of 7% from Q1/16. The increase in production from Q2/15 reflects high utilization rates and reliability following the turnaround completed in the prior year. The decrease from Q1/16 reflects minor unplanned downtime in the quarter to optimize performance of the DRU.

- The Company achieved strong quarterly operating costs at Horizon of $26.82/bbl, a 8% reduction from Q2/15 levels and comparable to Q1/16 levels, as a result of safe, steady and reliable operations and a focus on continuous improvement during the quarter.

- Subsequent to June 30, 2016, the Company began a scheduled major turnaround at Horizon to complete maintenance activities within the plant facilities and tie-in of major components of the Horizon Phase 2B expansion. The turnaround is now largely complete with SCO production targeted to resume on August 11, 2016.

- Concurrent with the completion of maintenance activities, tie-in of major components of the Horizon Phase 2B expansion has been completed as planned. Staged completion of plant system commissioning activities commenced in March 2016 and remains on schedule. Phase 2B is targeted to start up in October 2016 with full production targeted in November 2016.

- The Phase 3 expansion is currently on budget and on schedule. This Phase is 83% physically complete, and includes the addition of extraction trains and combined hydrotreater. Phase 3 is targeted to increase production capacity by 80,000 bbl/d in Q4/17 and will result in additional reliability, redundancy and significant operating cost savings for the Horizon project.

- Directive 85 (formerly Directive 74) of the Horizon expansion includes research into tailings management and technological investment. This project remains on track and is 61% physically complete as at June 30, 2016.

MARKETING

	Three Months Ended			Six Months Ended	
	Jun 30 2016	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 45.60**	$ 33.51	$ 57.96	**$ 39.56**	$ 53.29
WCS blend differential from WTI (%) (2)	**29%**	42%	20%	**35%**	25%
SCO price (US$/bbl)	**$ 47.39**	$ 33.77	$ 60.61	**$ 40.58**	$ 52.98
Condensate benchmark pricing (US$/bbl)	**$ 44.10**	$ 34.45	$ 57.98	**$ 39.28**	$ 51.82
Average realized pricing before risk management (C$/bbl) (3)	**$ 39.98**	$ 23.31	$ 53.09	**$ 31.40**	$ 44.62
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 1.18**	$ 2.00	$ 2.53	**$ 1.59**	$ 2.67
Average realized pricing before risk management (C$/Mcf)	**$ 1.50**	$ 2.23	$ 3.06	**$ 1.88**	$ 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$45.60/bbl for Q2/16, a decrease of 21% from US$57.96/bbl from Q2/15 and an increase of 36% from US$33.51/bbl for Q1/16. WTI pricing for the six months ended June 30, 2016 continued to reflect volatility in supply and demand factors and geopolitical events.
- In Q2/16, the WCS Heavy Differential averaged US$13.31/bbl (29%) compared with US$11.60/bbl (20%) and US$14.24/bbl (42%) in Q2/15 and Q1/16 respectively. Fluctuations in the WCS Heavy Differential reflect seasonal demand, changes in transportation logistics, and refinery utilization and shutdowns. Pricing as at July 15, 2016, Q3/16 WCS Heavy Differential is approximately US$13.50/bbl (29%).
- Canadian Natural contributed approximately 197,000 bbl/d of its heavy crude oil stream to the WCS blend in Q2/16. The Company remains the largest contributor to the WCS blend, accounting for 51% of the total blend.
- The SCO price averaged US$47.39/bbl for Q2/16, a decrease of 22% from US$60.61/bbl for the Q2/15, and an increase of 40% from US$33.77/bbl for Q1/16. The fluctuations in SCO pricing for Q2/16 from the comparable periods were primarily due to changes in WTI benchmark pricing, the impact of industry wide planned upgrader outages, as well as unplanned production outages at several third party oil sands facilities due to the fires at Fort McMurray.
- AECO natural gas prices averaged $1.18/GJ ($1.64/Mcfe) for the Q2/16, a decrease of 53% from $2.53/GJ for Q2/15, and a decrease of 41% from $2.00/GJ for Q1/16. The decrease in natural gas prices in Q2/16 compared with Q2/15 and Q1/16 was primarily due to warmer than normal winter temperatures in 2016 as US natural gas inventories were at near record high levels at the end of the winter season. Subsequent to June 30, 2016, reduced natural gas production growth and warm weather have resulted in an upward movement in natural gas pricing. Natural gas prices are anticipated to remain volatile in the near term as a result of excess storage inventory and continued strong US natural gas production. AECO natural gas prices as at July 15, 2016 are improving for the remainder of the year to $2.05/GJ in Q3/16 and $2.59/GJ in Q4/16.

NORTH WEST REDWATER UPGRADING AND REFINING

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: www.nwrpartnership.com/brief-updates.

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 783,988 BOE/d for Q2/16, with approximately 95% of total production located in G7 countries.
- Canadian Natural maintains significant financial stability and liquidity represented in part by committed bank credit facilities. As at June 30, 2016, the Company had in place bank credit facilities of approximately $7.4 billion, of which approximately $1.7 billion, net of commercial paper, was undrawn and available.
- Canadian Natural maintained its strong balance sheet with debt to book capitalization of 40% at June 30, 2016, slightly higher than December 31, 2015 levels, despite year-to-date WTI pricing of US$39.50/bbl and AECO pricing of $1.59/GJ.
- On June 6, 2016, the Company distributed approximately 21.8 million PrairieSky common shares to the shareholders of record of the Company at a volume weighted price of $24.89, completing the previously announced Plan of Arrangement. Subsequent to the distribution, the Company's ownership interest in PrairieSky decreased to approximately 22.6 million shares with a market value of approximately $575 million as at July 31, 2016. Current ownership is less than 10% of the issued and outstanding common shares of PrairieSky, satisfying the requirements of the purchase and sale agreement with PrairieSky.
- Canadian Natural has several financial levers in addition to capital flexibility, current availability under its credit facilities, strong cash flow and access to debt capital markets to effectively manage its liquidity, if necessary. These financial levers include the Company's investment in PrairieSky and cross currency swaps maturing after 2020 with a value of approximately $355 million as at July 31, 2016. Additionally, the Company could monetize its royalty land portfolio producing approximately 2,550 BOE/d, of which approximately 1,050 BOE/d are third party royalty volumes.
- 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%. Subject to legislative approval, the UK government is also proposing to reduce the Supplementary Corporation Tax rate from 20% to 10% effective January 1, 2016.
- Canadian Natural declared a quarterly cash dividend on its common shares of C$0.23 per share payable on October 1, 2016.

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. Q3/16 production guidance before royalties is forecast to average between 458,000 and 484,000 bbl/d of crude oil and NGLs and between 1,645 and 1,685 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.

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 six months ended June 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 June 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 six months ended June 30, 2016 in relation to the comparable periods in 2015 and the first 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 August 3, 2016.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Jun 30 2016	Mar 31 2016	Jun 30 2015	Six Months Ended Jun 30 2016	Jun 30 2015
Product sales	**$ 2,686**	$ 2,263	$ 3,662	**$ 4,949**	$ 6,888
Net earnings (loss)	**$ (339)**	$ (105)	$ (405)	**$ (444)**	$ (657)
Per common share – basic	**$ (0.31)**	$ (0.10)	$ (0.37)	**$ (0.41)**	$ (0.60)
– diluted	**$ (0.31)**	$ (0.10)	$ (0.37)	**$ (0.41)**	$ (0.60)
Adjusted net earnings (loss) from operations (1)	**$ (210)**	$ (543)	$ 178	**$ (753)**	$ 199
Per common share – basic	**$ (0.19)**	$ (0.50)	$ 0.16	**$ (0.69)**	$ 0.18
– diluted	**$ (0.19)**	$ (0.50)	$ 0.16	**$ (0.69)**	$ 0.18
Cash flow from operations (2)	**$ 938**	$ 657	$ 1,503	**$ 1,595**	$ 2,873
Per common share – basic	**$ 0.85**	$ 0.60	$ 1.38	**$ 1.45**	$ 2.63
– diluted	**$ 0.85**	$ 0.60	$ 1.37	**$ 1.45**	$ 2.62
Net capital expenditures	**$ 1,158**	$ 1,040	$ 1,297	**$ 2,198**	$ 2,709

(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 Jun 30 2016	Three Months Ended Mar 31 2016	Three Months Ended Jun 30 2015	Six Months Ended Jun 30 2016	Six Months Ended Jun 30 2015
Net earnings (loss) as reported	**$ (339)**	$ (105)	$ (405)	**$ (444)**	$ (657)
Share-based compensation, net of tax (1)	**122**	117	(79)	**239**	(15)
Unrealized risk management (gain) loss, net of tax (2)	**(46)**	63	162	**17**	171
Unrealized foreign exchange loss (gain), net of tax (3)	**40**	(334)	(76)	**(294)**	337
(Gain) loss from investments, net of tax (4)(5)	**—**	(147)	(3)	**(147)**	12
Gain on disposition of properties, net of tax (6)	**—**	(23)	—	**(23)**	—
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)	**—**	(114)	579	**(114)**	351
Adjusted net earnings (loss) from operations	**$ (210)**	$ (543)	$ 178	**$ (753)**	$ 199

(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. 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.

(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 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) 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 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 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 deferred income tax liability of $228 million.

Cash Flow from Operations

($ millions)	Three Months Ended Jun 30 2016	Three Months Ended Mar 31 2016	Three Months Ended Jun 30 2015	Six Months Ended Jun 30 2016	Six Months Ended Jun 30 2015
Net earnings (loss)	**$ (339)**	$ (105)	$ (405)	**$ (444)**	$ (657)
Non-cash items:					
Depletion, depreciation and amortization	**1,174**	1,219	1,280	**2,393**	2,635
Share-based compensation	**122**	117	(79)	**239**	(15)
Asset retirement obligation accretion	**35**	36	43	**71**	86
Unrealized risk management (gain) loss	**(52)**	74	215	**22**	229
Unrealized foreign exchange loss (gain)	**40**	(334)	(76)	**(294)**	337
(Gain) loss from investments	**—**	(147)	(3)	**(147)**	12
Deferred income tax (recovery) expense	**(42)**	(171)	528	**(213)**	246
Gain on disposition of properties	**—**	(32)	—	**(32)**	—
Cash flow from operations	**$ 938**	$ 657	$ 1,503	**$ 1,595**	$ 2,873

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

The net loss for the six months ended June 30, 2016 was $444 million compared with a net loss of $657 million for the six months ended June 30, 2015. The net loss for the six months ended June 30, 2016 included net after-tax income of $309 million compared with expenses of $856 million for the six months ended June 30, 2015 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, (gain) loss from investments, 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 six months ended June 30, 2016 was $753 million compared with adjusted net earnings of $199 million for the six months ended June 30, 2015.

The net loss for the second quarter of 2016 was $339 million compared with a net loss of $405 million for the second quarter of 2015 and a net loss of $105 million for the first quarter of 2016. The net loss for the second quarter of 2016 included net after-tax expenses of $129 million compared with net after-tax expenses of $583 million for the second quarter of 2015 and net after-tax income of $438 million for the first quarter of 2016 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, (gain) loss from investments, gains on disposition of properties, 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 second quarter of 2016 was $210 million compared with adjusted net earnings of $178 million for the second quarter of 2015 and an adjusted net loss of $543 million for the first quarter of 2016.

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

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

partially offset by:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- higher crude oil and NGL sales volumes in the Offshore Africa segment;
- lower depletion, depreciation and amortization expense in the Exploration and Production segments; and
- the impact of a weaker Canadian dollar relative to the US dollar.

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

- higher crude oil and NGLs netbacks in the Exploration and Production segments; and
- higher realized SCO prices;

partially offset by:

- lower natural gas netbacks in the Exploration and Production segments;
- lower crude oil and NGLs and natural gas sales volumes in the North America segment;
- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower realized risk management gains; and
- the impact of a stronger Canadian dollar relative to the US dollar.

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 six months ended June 30, 2016 was $1,595 million compared with $2,873 million for the six months ended June 30, 2015. Cash flow from operations for the second quarter of 2016 was $938 million compared with $1,503 million for the second quarter of 2015 and $657 million for the first 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 second quarter of 2016 decreased 3% to 783,988 BOE/d from 805,547 BOE/d for the second quarter of 2015 and decreased 7% from 844,531 BOE/d for the first 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)	**Jun 30 2016**	Mar 31 2016	Dec 31 2015	Sep 30 2015
Product sales	**$ 2,686**	$ 2,263	$ 2,963	$ 3,316
Net earnings (loss)	**$ (339)**	$ (105)	$ 131	$ (111)
Net earnings (loss) per common share				
– basic	**$ (0.31)**	$ (0.10)	$ 0.12	$ (0.10)
– diluted	**$ (0.31)**	$ (0.10)	$ 0.12	$ (0.10)
($ millions, except per common share amounts)	Jun 30 2015	Mar 31 2015	Dec 31 2014	Sep 30 2014
Product sales	$ 3,662	$ 3,226	$ 4,850	$ 5,370
Net earnings (loss)	$ (405)	$ (252)	$ 1,198	$ 1,039
Net earnings (loss) per common share				
– basic	$ (0.37)	$ (0.23)	$ 1.10	$ 0.95
– diluted	$ (0.37)	$ (0.23)	$ 1.09	$ 0.94

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

- **Crude oil pricing** – The impact of increased 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 increased 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, as well as 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			Six Months Ended	
	Jun 30 2016	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
WTI benchmark price (US$/bbl)	**$ 45.60**	$ 33.51	$ 57.96	**$ 39.56**	$ 53.29
Dated Brent benchmark price (US$/bbl)	**$ 45.80**	$ 33.92	$ 61.95	**$ 39.86**	$ 57.90
WCS blend differential from WTI (US$/bbl)	**$ 13.31**	$ 14.24	$ 11.60	**$ 13.77**	$ 13.16
WCS blend differential from WTI (%)	**29%**	42%	20%	**35%**	25%
SCO price (US$/bbl)	**$ 47.39**	$ 33.77	$ 60.61	**$ 40.58**	$ 52.98
Condensate benchmark price (US$/bbl)	**$ 44.10**	$ 34.45	$ 57.98	**$ 39.28**	$ 51.82
NYMEX benchmark price (US$/MMBtu)	**$ 1.95**	$ 2.04	$ 2.67	**$ 2.00**	$ 2.81
AECO benchmark price (C$/GJ)	**$ 1.18**	$ 2.00	$ 2.53	**$ 1.59**	$ 2.67
US/Canadian dollar average exchange rate (US$)	**$ 0.7761**	$ 0.7282	$ 0.8132	**$ 0.7518**	$ 0.8095

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 second 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$39.56 per bbl for the six months ended June 30, 2016, a decrease of 26% from US$53.29 per bbl for the six months ended June 30, 2015. WTI averaged US$45.60 per bbl for the second quarter of 2016, a decrease of 21% from US $57.96 per bbl for the second quarter of 2015, and an increase of 36% from US$33.51 per bbl for the first 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$39.86 per bbl for the six months ended June 30, 2016, a decrease of 31% from US$57.90 per bbl for the six months ended June 30, 2015. Brent averaged US$45.80 per bbl for the second quarter of 2016, a decrease of 26% from US$61.95 per bbl for the second quarter of 2015, and an increase of 35% from US$33.92 per bbl for the first quarter of 2016.

WTI and Brent pricing for the six months ended June 30, 2016 continued to reflect volatility in supply and demand factors and geopolitical events. Benchmark pricing in the second quarter of 2016 increased from the first quarter of 2016, primarily due to expected declines in production and inventory as a result of reduced industry wide drilling activity, together with a slight increase in demand.

The WCS Heavy Differential averaged 35% for the six months ended June 30, 2016, compared with 25% for the six months ended June 30, 2015. The WCS Heavy Differential averaged 29% for the second quarter of 2016 compared with 20% for the second quarter of 2015 and 42% for the first quarter of 2016. Fluctuations in the WCS Heavy Differential reflect seasonal demand, changes in transportation logistics, and refinery utilization and shutdowns.

The SCO price averaged US$40.58 per bbl for the six months ended June 30, 2016, a decrease of 23% from US$52.98 per bbl for the six months ended June 30, 2015. The SCO price averaged US$47.39 per bbl for the second quarter of 2016, a decrease of 22% from US$60.61 per bbl for the second quarter of 2015, and an increase of 40% from US$33.77 per bbl for the first quarter of 2016. The fluctuations in SCO pricing for the second quarter of 2016 from the comparable periods were primarily due to changes in 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.

NYMEX natural gas prices averaged US$2.00 per MMBtu for the six months ended June 30, 2016, a decrease of 29% from US$2.81 per MMBtu for the six months ended June 30, 2015. NYMEX natural gas prices averaged US$1.95 per MMBtu for the second quarter of 2016, a decrease of 27% from US$2.67 per MMBtu for the second quarter of 2015, and a decrease of 4% from US$2.04 per MMBtu for the first quarter of 2016.

AECO natural gas prices averaged $1.59 per GJ for the six months ended June 30, 2016, a decrease of 40% from $2.67 per GJ for the six months ended June 30, 2015. AECO natural gas prices averaged $1.18 per GJ for the second quarter of 2016, a decrease of 53% from $2.53 per GJ for the second quarter of 2015, and a decrease of 41% from $2.00 per GJ for the first quarter of 2016.

The decrease in natural gas prices in the second quarter of 2016 compared with the second quarter of 2015 and the first quarter of 2016 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 winter season. Subsequent to June 30, 2016, reduced natural gas production growth and warm weather have resulted in an upward movement in natural gas pricing. Natural gas prices are anticipated to remain volatile in the near term as a result of excess storage inventory and continued strong US natural gas production.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2016	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**328,681**	369,987	375,040	**349,334**	403,571
North America – Oil Sands Mining and Upgrading [(1)]	**119,511**	127,909	96,607	**123,710**	115,283
North Sea	**23,360**	23,317	20,330	**23,338**	21,676
Offshore Africa	**30,858**	25,714	17,070	**28,286**	15,139
	502,410	546,927	509,047	**524,668**	555,669
Natural gas (MMcf/d)					
North America	**1,620**	1,722	1,716	**1,672**	1,715
North Sea	**30**	29	38	**29**	36
Offshore Africa	**39**	35	25	**37**	24
	1,689	1,786	1,779	**1,738**	1,775
Total barrels of oil equivalent (BOE/d)	**783,988**	844,531	805,547	**814,259**	851,545
Product mix					
Light and medium crude oil and NGLs	**18%**	16%	16%	**17%**	15%
Pelican Lake heavy crude oil	**6%**	6%	6%	**6%**	6%
Primary heavy crude oil	**13%**	14%	16%	**13%**	15%
Bitumen (thermal oil)	**12%**	14%	13%	**13%**	15%
Synthetic crude oil [(1)]	**15%**	15%	12%	**15%**	14%
Natural gas	**36%**	35%	37%	**36%**	35%
Percentage of gross revenue [(1) (2)] (excluding Midstream revenue)					
Crude oil and NGLs	**90%**	79%	84%	**85%**	82%
Natural gas	**10%**	21%	16%	**15%**	18%

(1) Second quarter 2016 SCO production before royalties excludes 2,227 bbl/d of SCO consumed internally as diesel (first quarter 2016 – 2,562 bbl/d; second quarter 2015 – 2,410 bbl/d; six months ended June 30, 2016 - 2,394 bbl/d; six months ended June 30, 2015 - 2,045 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2016	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**292,666**	331,313	326,445	**311,989**	353,209
North America – Oil Sands Mining and Upgrading	**118,613**	127,571	95,057	**123,541**	113,632
North Sea	**23,279**	23,264	20,300	**23,272**	21,631
Offshore Africa	**29,658**	24,578	16,342	**27,118**	14,475
	464,216	506,726	458,144	**485,920**	502,947
Natural gas (MMcf/d)					
North America	**1,604**	1,654	1,684	**1,630**	1,664
North Sea	**30**	29	38	**29**	36
Offshore Africa	**37**	34	24	**35**	23
	1,671	1,717	1,746	**1,694**	1,723
Total barrels of oil equivalent (BOE/d)	**742,785**	792,939	749,210	**768,310**	790,196

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 six months ended June 30, 2016 decreased 6% to 524,668 bbl/d from 555,669 bbl/d for the six months ended June 30, 2015. Crude oil and NGL production for the second quarter of 2016 of 502,410 bbl/d was comparable with 509,047 bbl/d for the second quarter of 2015, and decreased 8% from 546,927 bbl/d for the first quarter of 2016. The decrease in crude oil and NGL production for the three and six months ended June 30, 2016 from the comparable periods in 2015 was primarily due to lower drilling activity and natural field declines in North America, partially offset by the impact of higher production at Horizon and in Offshore Africa. The decrease in crude oil and NGLs production for the second quarter of 2016 from the first quarter of 2016 primarily reflected lower drilling activity, natural field declines, the cyclic nature of thermal oil production at Primrose, and minor production disruptions in various fields. Crude oil and NGLs production for the second quarter of 2016 was slightly below the Company's previously issued guidance of 504,000 to 529,000 bbl/d.

For 2016, annual production guidance is targeted to average between 514,000 and 563,000 bbl/d of crude oil and NGLs. Third quarter 2016 production guidance is targeted to average between 458,000 and 484,000 bbl/d of crude oil and NGLs.

Natural gas production for the six months ended June 30, 2016 decreased 2% to 1,738 MMcf/d from 1,775 MMcf/d for the six months ended June 30, 2015. Natural gas production for the second quarter of 2016 decreased 5% to 1,689 MMcf/d from 1,779 MMcf/d for the second quarter of 2015, and decreased 5% from 1,786 MMcf/d for the first quarter of 2016. The decrease in natural gas production for the three and six months ended June 30, 2016 from comparable periods primarily reflected lower production in North America due to the shut in of a third party processing facility and third party pipeline transportation restrictions. During the period mid-June to late July 2016, the Company had approximately 176 MMcf/d of production shut in due to the third party processing facility outage. On August 8, 2016 approximately 50 MMcf/d of volumes are targeted to return to service. In late September 2016 approximately 40 MMcf/d of additional production is targeted to return to service, with the remaining 86 MMcf/d of production targeted to return to service by December 2016.

Primarily as a result of the shut in of the third party processing facility, natural gas production for the second quarter of 2016 was slightly below the Company's previously issued guidance of 1,720 to 1,760 MMcf/d. Annual production guidance is now targeted to average between 1,705 and 1,735 MMcf/d. Third quarter 2016 production guidance is targeted to average between 1,645 and 1,685 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the six months ended June 30, 2016 decreased 13% to average 349,334 bbl/d from 403,571 bbl/d for the six months ended June 30, 2015. North America crude oil and NGLs production for the second quarter of 2016 decreased 12% to 328,681 bbl/d from 375,040 bbl/d for the second quarter of 2015, and decreased 11% from 369,987 bbl/d for the first quarter of 2016. The decrease in production for the three and six months ended June 30, 2016 from the comparable periods 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 which was reinstated in late May 2016, as well as minor production disruptions at various fields. Crude oil and NGLs production for the second quarter of 2016 was within the Company's previously issued guidance of 327,000 to 341,000 bbl/d. Third quarter 2016 production guidance is targeted to average between 337,000 and 351,000 bbl/d of crude oil and NGLs.

Natural gas production for the six months ended June 30, 2016 decreased 3% to average 1,672 MMcf/d from 1,715 MMcf/d for the six months ended June 30, 2015. Natural gas production for the second quarter of 2016 decreased 6% to 1,620 MMcf/d from 1,716 MMcf/d for the second quarter of 2015, and decreased 6% from 1,722 MMcf/d for the first quarter of 2016. The decrease in production for the three and six months ended June 30, 2016 from the comparable periods primarily reflected the shut in of a third party processing facility and third party pipeline transportation restrictions. During the period mid-June to late July 2016, the Company had approximately 176 MMcf/d of production shut in due to the third party processing facility outage. On August 8, 2016 approximately 50 MMcf/d of volumes are targeted to return to service. In late September 2016 approximately 40 MMcf/d of additional production is targeted to return to service, with the remaining 86 MMcf/d of production targeted to return to service by December 2016.

North America – Oil Sands Mining and Upgrading

SCO production for the six months ended June 30, 2016 increased 7% to 123,710 bbl/d from 115,283 bbl/d for the six months ended June 30, 2015. SCO production for the second quarter of 2016 increased 24% to average 119,511 bbl/d compared with 96,607 bbl/d for the second quarter of 2015 and decreased 7% from 127,909 bbl/d for the first quarter of 2016. The increase in production for the three and six months ended June 30, 2016 from the comparable periods in 2015 reflected high utilization rates and reliability following the turnaround completed in the prior year. The decrease in production in the second quarter of 2016 compared with the first quarter of 2016 reflected unplanned maintenance and repairs. Second quarter 2016 production of SCO was slightly below the Company's previously issued guidance of 122,000 to 128,000 bbl/d. Third quarter 2016 production guidance is targeted to average between 72,000 and 80,000 bbl/d, reflecting the planned major maintenance turnaround.

North Sea

North Sea crude oil production for the six months ended June 30, 2016 increased 8% to 23,338 bbl/d from 21,676 bbl/d for the six months ended June 30, 2015. North Sea crude oil production for the second quarter of 2016 increased 15% to 23,360 bbl/d from 20,330 bbl/d for the second quarter of 2015 and was consistent with the first quarter of 2016 due to a focus on optimization activities, offsetting natural field declines.

Offshore Africa

Offshore Africa crude oil production for the six months ended June 30, 2016 increased 87% to 28,286 bbl/d from 15,139 bbl/d for the six months ended June 30, 2015. Offshore Africa crude oil production for the second quarter of 2016 increased 81% to 30,858 bbl/d from 17,070 bbl/d for the second quarter of 2015, and increased 20% from 25,714 bbl/d for the first quarter of 2016. Production volumes increased for the three and six months ended June 30, 2016 from the comparable periods reflecting the impact of additional wells coming on stream at the Espoir and Baobab fields during 2015 and 2016, partially offset by unplanned maintenance activities.

International Guidance

The Company's North Sea and Offshore Africa second quarter 2016 crude oil production of 54,218 bbl/d was slightly below the Company's previously issued guidance of 55,000 to 60,000 bbl/d. Third quarter 2016 production guidance is targeted to average between 49,000 and 53,000 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)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015
North Sea	**1,244,684**	667,879	131,959
Offshore Africa	**1,248,197**	1,830,976	1,459,094
	2,492,881	2,498,855	1,591,053

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2016	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 39.98**	$ 23.31	$ 53.09	**$ 31.40**	$ 44.62
Transportation	**2.81**	2.46	2.80	**2.63**	2.62
Realized sales price, net of transportation	**37.17**	20.85	50.29	**28.77**	42.00
Royalties	**3.59**	1.90	5.91	**2.72**	4.82
Production expense	**14.31**	13.94	17.01	**14.12**	16.53
Netback	**$ 19.27**	$ 5.01	$ 27.37	**$ 11.93**	$ 20.65
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 1.50**	$ 2.23	$ 3.06	**$ 1.88**	$ 3.22
Transportation	**0.35**	0.28	0.38	**0.31**	0.37
Realized sales price, net of transportation	**1.15**	1.95	2.68	**1.57**	2.85
Royalties	**0.02**	0.07	0.05	**0.05**	0.08
Production expense	**1.22**	1.23	1.39	**1.23**	1.42
Netback	**$ (0.09)**	$ 0.65	$ 1.24	**$ 0.29**	$ 1.35
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 27.28**	$ 19.37	$ 38.85	**$ 23.21**	$ 34.59
Transportation	**2.61**	2.20	2.67	**2.40**	2.55
Realized sales price, net of transportation	**24.67**	17.17	36.18	**20.81**	32.04
Royalties	**2.13**	1.30	3.58	**1.70**	3.10
Production expense	**11.38**	11.19	13.39	**11.28**	13.29
Netback	**$ 11.16**	$ 4.68	$ 19.21	**$ 7.83**	$ 15.65

(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			Six Months Ended	
	Jun 30 2016	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 37.59**	$ 20.77	$ 50.96	**$ 28.78**	$ 42.52
North Sea	**$ 54.60**	$ 45.04	$ 73.57	**$ 48.90**	$ 69.52
Offshore Africa	**$ 54.62**	$ 42.99	$ 74.84	**$ 50.61**	$ 73.84
Company average	**$ 39.98**	$ 23.31	$ 53.09	**$ 31.40**	$ 44.62
Natural gas ($/Mcf) (1) (2)					
North America	**$ 1.30**	$ 2.05	$ 2.80	**$ 1.68**	$ 2.97
North Sea	**$ 6.83**	$ 7.02	$ 9.54	**$ 6.92**	$ 9.84
Offshore Africa	**$ 6.01**	$ 7.13	$ 10.49	**$ 6.54**	$ 11.07
Company average	**$ 1.50**	$ 2.23	$ 3.06	**$ 1.88**	$ 3.22
Company average ($/BOE) (1) (2)	**$ 27.28**	$ 19.37	$ 38.85	**$ 23.21**	$ 34.59

(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 32% to $28.78 per bbl for the six months ended June 30, 2016 from $42.52 per bbl for the six months ended June 30, 2015. North America realized crude oil prices averaged $37.59 per bbl for the second quarter of 2016, a decrease of 26% compared with $50.96 per bbl for the second quarter of 2015 and an increase of 81% compared with $20.77 per bbl for the first quarter of 2015. The decrease in realized crude oil prices for the three and six months ended June 30, 2016 from the comparable periods in 2015 was primarily due to lower WTI benchmark pricing. The increase in realized crude oil prices for the second quarter of 2016 from the first quarter of 2016 was primarily due to higher benchmark pricing, reflecting expected declines in production and inventory as a result of reduced industry wide drilling activity, together with a slight increase in demand. The Company continues to focus on its crude oil blending marketing strategy and, in the second quarter of 2016, contributed approximately 197,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 43% to average $1.68 per Mcf for the six months ended June 30, 2016 from $2.97 per Mcf for the six months ended June 30, 2015. North America realized natural gas prices decreased 54% to average $1.30 per Mcf for the second quarter of 2016 compared with $2.80 per Mcf for the second quarter of 2015, and decreased 37% compared with $2.05 per Mcf for the first quarter of 2016.

The decrease in natural gas prices per Mcf for the three and six months ended June 30, 2016 from the comparable periods 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 winter season. Subsequent to June 30, 2016, reduced natural gas production growth and warm weather have resulted in an upward movement in natural gas pricing. Natural gas prices are anticipated to remain volatile in the near term as a result of excess storage inventory and continued strong US natural gas production.

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

(Quarterly Average)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 39.56**	$ 28.30	$ 51.80
Pelican Lake heavy crude oil ($/bbl)	**$ 40.60**	$ 21.76	$ 54.87
Primary heavy crude oil ($/bbl)	**$ 38.84**	$ 19.63	$ 53.85
Bitumen (thermal oil) ($/bbl)	**$ 32.91**	$ 15.72	$ 44.63
Natural gas ($/Mcf)	**$ 1.30**	$ 2.05	$ 2.80

(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 30% to average $48.90 per bbl for the six months ended June 30, 2016 from $69.52 per bbl for the six months ended June 30, 2015. North Sea realized crude oil prices decreased 26% to average $54.60 per bbl for the second quarter of 2016 from $73.57 per bbl for the second quarter of 2015 and increased 21% from $45.04 per bbl for the first 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 second 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 31% to average $50.61 per bbl for the six months ended June 30, 2016 from $73.84 per bbl for the six months ended June 30, 2015. Offshore Africa realized crude oil prices decreased 27% to average $54.62 per bbl for the second quarter of 2016 from $74.84 per bbl for the second quarter of 2015 and increased 27% from $42.99 per bbl for the first 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 second 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			Six Months Ended	
	Jun 30 2016	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 3.93**	$ 2.03	$ 6.40	**$ 2.93**	$ 5.12
North Sea	**$ 0.18**	$ 0.10	$ 0.11	**$ 0.13**	$ 0.13
Offshore Africa	**$ 2.12**	$ 1.90	$ 3.19	**$ 2.05**	$ 3.22
Company average	**$ 3.59**	$ 1.90	$ 5.91	**$ 2.72**	$ 4.82
Natural gas ($/Mcf) (1)					
North America	**$ 0.01**	$ 0.07	$ 0.05	**$ 0.04**	$ 0.08
Offshore Africa	**$ 0.27**	$ 0.32	$ 0.48	**$ 0.29**	$ 0.51
Company average	**$ 0.02**	$ 0.07	$ 0.05	**$ 0.05**	$ 0.08
Company average ($/BOE) (1)	**$ 2.13**	$ 1.30	$ 3.58	**$ 1.70**	$ 3.10

(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 six months ended June 30, 2016 and the comparable periods reflected movements in benchmark commodity prices and fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 11% of product sales for the six months ended June 30, 2016 compared with 13% of product sales for the six months ended June 30, 2015. Crude oil and NGLs royalties averaged approximately 11% of product sales for the second quarter of 2016 compared with 13% for the second quarter of 2015 and 11% for the first quarter of 2016. The decrease in royalties for the three and six months ended June 30, 2016 from comparable periods in 2015 was primarily due to lower realized crude oil prices, offset by gas cost allowance adjustments on NGLs. 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 six months ended June 30, 2016, consistent with the six months ended June 30, 2015. Natural gas royalties averaged approximately 1% of product sales for the second quarter of 2016 compared with 2% for the second quarter of 2015 and 4% for the first quarter of 2016. The decrease in natural gas royalties in the second quarter of 2016 from the second quarter of 2015 reflected lower realized natural gas prices. The decrease from the first quarter of 2016 reflected lower realized natural gas prices in the second quarter, together with gas cost allowance adjustments in the first quarter of 2016. North America natural gas royalties are anticipated to average 3% to 4% 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 six months ended June 30, 2016, consistent with the six months ended June 30, 2015. Royalty rates as a percentage of product sales averaged approximately 4% for the second 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			Six Months Ended	
	Jun 30 2016	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 12.30**	$ 11.46	$ 13.14	**$ 11.86**	$ 13.47
North Sea	**$ 40.74**	$ 47.69	$ 60.61	**$ 44.89**	$ 62.69
Offshore Africa	**$ 20.13**	$ 17.07	$ 43.88	**$ 19.08**	$ 34.71
Company average	**$ 14.31**	$ 13.94	$ 17.01	**$ 14.12**	$ 16.53
Natural gas ($/Mcf) (1)					
North America	**$ 1.17**	$ 1.18	$ 1.28	**$ 1.18**	$ 1.33
North Sea	**$ 3.33**	$ 4.09	$ 6.47	**$ 3.69**	$ 5.27
Offshore Africa	**$ 1.76**	$ 1.29	$ 1.42	**$ 1.55**	$ 2.09
Company average	**$ 1.22**	$ 1.23	$ 1.39	**$ 1.23**	$ 1.42
Company average ($/BOE) (1)	**$ 11.38**	$ 11.19	$ 13.39	**$ 11.28**	$ 13.29

(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 six months ended June 30, 2016 decreased 12% to $11.86 per bbl from $13.47 per bbl for the six months ended June 30, 2015. North America crude oil and NGLs production expense for the second quarter of 2016 decreased 6% to $12.30 per bbl from $13.14 per bbl for the second quarter of 2015 and increased 7% from $11.46 per bbl for the first quarter of 2016. Production costs continued to reflect the Company's ongoing focus on cost control and efficiencies across the asset base, together with lower industry service costs, offset by the impact of lower production volumes. 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 six months ended June 30, 2016 decreased 11% to $1.18 per Mcf from $1.33 per Mcf for the six months ended June 30, 2015. North America natural gas production expense for the second quarter of 2016 decreased 9% to $1.17 per Mcf from $1.28 per Mcf for the second quarter of 2015 and was comparable with the first quarter of 2016. Production costs continued to reflect the Company's ongoing focus on cost control and efficiencies across the asset base, together with lower industry service costs, partially offset by the impact of lower production volumes. 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 six months ended June 30, 2016 decreased 28% to $44.89 per bbl from $62.69 per bbl for the six months ended June 30, 2015. North Sea crude oil production expense for the second quarter of 2016 decreased 33% to $40.74 per bbl from $60.61 per bbl for the second quarter of 2015 and decreased 15% from $47.69 per bbl for the first quarter of 2016. The decrease in production expense for the three and six months ended June 30, 2016 from comparable periods primarily reflected the Company's continuous focus on cost control and efficiencies, together with the impact of inventory valuation adjustments, and fluctuations in the Canadian dollar. 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 six months ended June 30, 2016 decreased 45% to $19.08 per bbl from $34.71 per bbl for the six months ended June 30, 2015. Offshore Africa crude oil production expense for the second quarter of 2016 decreased 54% to average $20.13 per bbl from $43.88 per bbl for the second quarter of 2015 and increased 18% from $17.07 per bbl for the first quarter of 2016. The fluctuations in production expense for the three and six months ended June 30, 2016 from the comparable periods was primarily due to the timing of liftings from various fields, including the Olowi field, which have different cost structures, higher production volumes on a relatively fixed cost base, the impact of inventory valuation adjustments 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			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Expense	**$ 1,036**	$ 1,069	$ 1,158	**$ 2,105**	$ 2,371
$/BOE (1)	**$ 17.03**	$ 16.60	$ 18.02	**$ 16.81**	$ 17.90

(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 six months ended June 30, 2016 from the comparable period was primarily due to lower sales volumes and depletion rates in North America.

Depletion, depreciation and amortization on a per barrel basis for the six months ended June 30, 2016 decreased 6% to $16.81 per BOE from $17.90 per BOE for the six months ended June 30, 2015. Depletion, depreciation and amortization expense on a per barrel basis for the second quarter of 2016 decreased 5% to $17.03 per BOE from $18.02 per BOE for the second quarter of 2015 and increased by 3% from $16.60 per BOE for the first quarter of 2016. The decrease in depletion, depreciation and amortization expense per BOE for the three and six months ended June 30, 2016 from comparable periods in 2015 was primarily due to lower depletion rates in North America. The increase per BOE from the first quarter of 2016 reflected a higher proportion of International sales volumes, which have a higher associated depletion, depreciation and amortization rate.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Expense	**$ 28**	$ 29	$ 36	**$ 57**	$ 71
$/BOE (1)	**$ 0.46**	$ 0.45	$ 0.55	**$ 0.45**	$ 0.53

(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 six months ended June 30, 2016 decreased 15% to $0.45 per BOE from $0.53 per BOE for the six months ended June 30, 2015. Asset retirement obligation accretion expense for the second quarter of 2016 decreased 16% to $0.46 per BOE from $0.55 per BOE for the second quarter of 2015, and was comparable with the first quarter of 2016.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

The Company continues to focus on reliable and efficient operations. During the second quarter of 2016, operating performance continued to be strong, leading to average production of 119,511 bbl/d, reflecting high utilization rates and reliability. In the third quarter of 2016, Horizon entered into a planned major maintenance turnaround, resulting in a plant-wide shut down. SCO production at Horizon is targeted to resume on August 11, 2016, and the impact of the turnaround has been reflected in the Company's 2016 production, cash production cost and capital expenditure guidance.

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

	Three Months Ended			Six Months Ended	
($/bbl) (1)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
SCO sales price	**$ 61.78**	$ 46.63	$ 73.05	**$ 54.11**	$ 64.03
Bitumen value for royalty purposes (2)	**$ 30.93**	$ 11.29	$ 44.09	**$ 20.84**	$ 35.92
Bitumen royalties (3)	**$ 0.39**	$ 0.13	$ 0.99	**$ 0.26**	$ 1.00
Transportation	**$ 1.34**	$ 2.07	$ 1.98	**$ 1.71**	$ 1.89

(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 $54.11 per bbl for the six months ended June 30, 2016, a decrease of 15% compared with $64.03 per bbl for the six months ended June 30, 2015. Realized SCO sales prices averaged $61.78 per bbl for the second quarter of 2016, a decrease of 15% compared with $73.05 per bbl for the second quarter of 2015 and an increase of 32% compared with $46.63 per bbl for the first quarter of 2016. The fluctuations in SCO pricing for the three and six months ended June 30, 2016 from the comparable periods were primarily due to changes in 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.

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 consolidated financial statements.

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Cash production costs	**$ 293**	$ 297	$ 321	**$ 590**	$ 667
Less: costs incurred during turnaround periods	**—**	—	(45)	**—**	(45)
Adjusted cash production costs	**$ 293**	$ 297	$ 276	**$ 590**	$ 622
Adjusted cash production costs, excluding natural gas costs	**$ 278**	$ 282	$ 260	**$ 560**	$ 586
Adjusted natural gas costs	**15**	15	16	**30**	36
Adjusted cash production costs	**$ 293**	$ 297	$ 276	**$ 590**	$ 622

	Three Months Ended			Six Months Ended	
($/bbl) (1)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Cash production costs, excluding natural gas costs	**$ 25.44**	$ 25.17	$ 27.52	**$ 25.30**	$ 27.80
Natural gas costs	**1.38**	1.38	1.73	**1.38**	1.72
Cash production costs	**$ 26.82**	$ 26.55	$ 29.25	**$ 26.68**	$ 29.52
Sales (bbl/d)	**119,988**	123,047	103,388	**121,517**	116,339

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

Adjusted cash production costs for the six months ended June 30, 2016 decreased 10% to $26.68 per bbl from $29.52 per bbl for the six months ended June 30, 2015. Cash production costs for the second quarter of 2016 averaged $26.82 per bbl, a decrease of 8% compared with $29.25 per bbl for the second quarter of 2015 and comparable with the first quarter of 2016. The decrease in cash production costs for the three and six months ended June 30, 2016 from comparable periods in 2015 primarily reflected the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, and lower industry service costs, partially offset by a 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			Six Months Ended	
($ millions, except per bbl amounts)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Depletion, depreciation and amortization	**$ 135**	$ 147	$ 119	**$ 282**	$ 258
Less: depreciation incurred during turnaround period	**—**	—	(5)	**—**	(5)
Adjusted depletion, depreciation and amortization	**135**	147	114	**282**	253
$/bbl	**$ 12.32**	$ 13.11	$ 12.04	**$ 12.72**	$ 11.99

Adjusted depletion, depreciation and amortization expense on a per barrel basis for the six months ended June 30, 2016 increased 6% to $12.72 per bbl from $11.99 per bbl for the six months ended June 30, 2015. Adjusted depletion, depreciation and amortization expense on a per barrel basis for the second quarter of 2016 increased 2% to $12.32 per bbl from $12.04 per bbl for the second quarter of 2015 and decreased 6% from $13.11 per bbl for the first quarter of 2016. The increase in adjusted depletion, depreciation and amortization expense on a total and per barrel basis for the three and six months ended June 30, 2016 from the comparable periods in 2015 was primarily due to higher sales volumes and minor asset derecognitions. The decrease in adjusted depletion, depreciation and amortization expense and on a per barrel basis for the second quarter of 2016 from the first quarter of 2016 reflected minor asset derecognitions in the comparable period, partially offset by lower sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Six Months Ended	
($ millions, except per bbl amounts)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Expense	**$ 7**	$ 7	$ 7	**$ 14**	$ 15
$/bbl [1]	**$ 0.67**	$ 0.65	$ 0.82	**$ 0.66**	$ 0.73

(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 six months ended June 30, 2016 decreased 10% to $0.66 per bbl from $0.73 per bbl for the six months ended June 30, 2015. Asset retirement obligation accretion expense for the second quarter of 2016 decreased 18% to $0.67 per bbl from $0.82 per bbl for the second quarter of 2015 and was comparable with the first quarter of 2016.

MIDSTREAM

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Revenue	**$ 31**	$ 26	$ 35	**$ 57**	$ 70
Production expense	**7**	6	9	**13**	18
Midstream cash flow	**24**	20	26	**44**	52
Depreciation	**3**	3	3	**6**	6
Equity (gain) loss from Redwater Partnership	**3**	(26)	(3)	**(23)**	12
Segment earnings before taxes	**$ 18**	$ 43	$ 26	**$ 61**	$ 34

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 June 30, 2016, Redwater Partnership had additional borrowings of $852 million under its secured $3,500 million syndicated credit facility.

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

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

ADMINISTRATION EXPENSE

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Expense	**$ 91**	$ 86	$ 100	**$ 177**	$ 204
$/BOE (1)	**$ 1.27**	$ 1.14	$ 1.35	**$ 1.20**	$ 1.33

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

Administration expense on a per BOE basis for the six months ended June 30, 2016 decreased 10% to $1.20 per BOE from $1.33 per BOE for the six months ended June 30, 2015. Administration expense for the second quarter of 2016 decreased 6% to $1.27 per BOE from $1.35 per BOE for the second quarter of 2015 and increased 11% from $1.14 per BOE for the first quarter of 2016. Administration expense per BOE decreased for the three and six months ended June 30, 2016 from the comparable periods 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 increase in the second quarter of 2016 from the first quarter of 2016 was primarily due to the impacts of lower recoveries and lower sales volumes on a relatively fixed cost base.

SHARE-BASED COMPENSATION

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Expense (Recovery)	**$ 122**	$ 117	$ (79)	**$ 239**	$ (15)

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 $239 million share-based compensation expense for the six months ended June 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 six months ended June 30, 2016, the Company capitalized $48 million of share-based compensation costs to property, plant and equipment in the Oil Sands Mining and Upgrading segment (June 30, 2015 – $2 million costs recovered).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts and interest rates)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Expense, gross	**$ 153**	$ 153	$ 147	**$ 306**	$ 291
Less: capitalized interest	**67**	61	62	**128**	120
Expense, net	**$ 86**	$ 92	$ 85	**$ 178**	$ 171
$/BOE (1)	**$ 1.19**	$ 1.22	$ 1.16	**$ 1.21**	$ 1.12
Average effective interest rate	**3.9%**	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 six months ended June 30, 2016 increased from the comparable periods in 2015 primarily due to the impact of higher overall debt levels. Capitalized interest of $128 million for the six months ended June 30, 2016 was primarily related to the Horizon Phase 2/3 expansion.

Net interest and other financing expense for the six months ended June 30, 2016 increased 8% to $1.21 per BOE from $1.12 per BOE for the six months ended June 30, 2015. Net interest and other financing expense on a per BOE basis for the second quarter of 2016 increased 3% to $1.19 per BOE from $1.16 per BOE for the second quarter of 2015 and decreased 2% from $1.22 per BOE for the first quarter of 2016. The increase for the three and six months ended June 30, 2016 from the comparable periods in 2015 was primarily due to higher overall debt levels. The decrease from the first quarter of 2016 was primarily due to higher capitalized interest in the second quarter of 2016.

The Company's average effective interest rates for the three and six months ended June 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			Six Months Ended	
($ millions)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Crude oil and NGLs financial instruments	**$ —**	$ —	$ (91)	**$ —**	$ (208)
Foreign currency contracts	**49**	(4)	22	**45**	(117)
Realized loss (gain)	**49**	(4)	(69)	**45**	(325)
Crude oil and NGLs financial instruments	**—**	—	205	**—**	217
Foreign currency contracts	**(52)**	74	10	**22**	12
Unrealized (gain) loss	**(52)**	74	215	**22**	229
Net (gain) loss	**$ (3)**	$ 70	$ 146	**$ 67**	$ (96)

During the six months ended June 30, 2016, net realized risk management losses were related to the settlement of foreign currency contracts. The Company recorded a net unrealized loss of $22 million ($17 million after-tax) on its risk management activities for the six months ended June 30, 2016, including an unrealized gain of $52 million ($46 million after-tax) for the second quarter of 2016 (March 31, 2016 - unrealized loss of $74 million; $63 million after-tax; June 30, 2015 – unrealized loss of $215 million; $162 million after-tax), primarily related to changes in the fair value of these contracts.

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

FOREIGN EXCHANGE

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Net realized loss (gain)	**$ 9**	$ 19	$ (11)	**$ 28**	$ (64)
Net unrealized loss (gain) (1)	**40**	(334)	(76)	**(294)**	337
Net loss (gain)	**$ 49**	$ (315)	$ (87)	**$ (266)**	$ 273

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

The net realized foreign exchange loss for the six months ended June 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 six months ended June 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 June 30, 2016 – unrealized gain of $9 million, March 31, 2016 – unrealized loss of $348 million, June 30, 2015 – unrealized loss of $61 million; six months ended June 30, 2016 - unrealized loss of $339 million, June 30, 2015 - unrealized gain of $253 million). The US/Canadian dollar exchange rate at June 30, 2016 was US$0.7687 (March 31, 2016 – US$0.7710, June 30, 2015 – US$0.8017).

INCOME TAXES

	Three Months Ended			Six Months Ended	
($ millions, except income tax rates)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
North America [1]	**$ (68)**	$ (119)	$ 79	**$ (187)**	$ 87
North Sea	**(8)**	(23)	(19)	**(31)**	(83)
Offshore Africa	**8**	4	5	**12**	7
PRT recovery – North Sea	**(31)**	(55)	(72)	**(86)**	(126)
Other taxes	**3**	1	4	**4**	7
Current income tax recovery	**(96)**	(192)	(3)	**(288)**	(108)
Deferred income tax (recovery) expense	**(52)**	33	498	**(19)**	209
Deferred PRT expense (recovery) – North Sea	**10**	(204)	30	**(194)**	37
Deferred income tax recovery	**(42)**	(171)	528	**(213)**	246
	(138)	(363)	525	**(501)**	138
Income tax rate and other legislative changes[2]	**—**	114	(579)	**114**	(351)
	$ (138)	$ (249)	$ (54)	**$ (387)**	$ (213)
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**37%**	29%	17%	**31%**	64%

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

(2) During the first quarter of 2016 the UK government enacted tax rate reductions relating to PRT, resulting in a decrease in the Company's 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 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 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 PRT recovery in the North Sea in the second 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 six 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 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 income tax liability was increased by $114 million.

The UK government is also proposing to reduce the supplementary corporation tax rate from 20% to 10% effective January 1, 2016, subject to legislative approval.

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 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 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, based on forward commodity prices and the current availability of tax pools, the Company now expects to recognize current income tax recoveries of $160 million to $220 million in Canada and recoveries of $125 million to $175 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Jun 30 2016	Three Months Ended Mar 31 2016	Three Months Ended Jun 30 2015	Six Months Ended Jun 30 2016	Six Months Ended Jun 30 2015
Exploration and Evaluation					
Net expenditures (proceeds) [2] [3]	**$ 20**	$ (30)	$ 29	**$ (10)**	$ 75
Property, Plant and Equipment					
Net property acquisitions [2] [3]	**110**	31	51	**141**	62
Well drilling, completion and equipping	**98**	228	199	**326**	491
Production and related facilities	**94**	121	249	**215**	563
Capitalized interest and other [4]	**21**	24	27	**45**	53
Net expenditures	**323**	404	526	**727**	1,169
Total Exploration and Production	**343**	374	555	**717**	1,244
Oil Sands Mining and Upgrading					
Horizon Phases 2/3 construction costs	**583**	422	535	**1,005**	941
Sustaining capital	**76**	76	94	**152**	182
Turnaround costs	**29**	6	6	**35**	10
Capitalized interest and other [4]	**86**	81	43	**167**	114
Total Oil Sands Mining and Upgrading	**774**	585	678	**1,359**	1,247
Midstream	**1**	1	1	**2**	4
Abandonments [5]	**36**	74	56	**110**	200
Head office	**4**	6	7	**10**	14
Total net capital expenditures	**$ 1,158**	$ 1,040	$ 1,297	**$ 2,198**	$ 2,709
By segment					
North America [2] [3]	**$ 319**	$ 249	$ 307	**$ 568**	$ 808
North Sea	**10**	16	93	**26**	155
Offshore Africa	**14**	109	155	**123**	281
Oil Sands Mining and Upgrading	**774**	585	678	**1,359**	1,247
Midstream	**1**	1	1	**2**	4
Abandonments [5]	**36**	74	56	**110**	200
Head office	**4**	6	7	**10**	14
Total	**$ 1,158**	$ 1,040	$ 1,297	**$ 2,198**	$ 2,709

(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 six months ended June 30, 2016 were $2,198 million compared with $2,709 million for the six months ended June 30, 2015. Net capital expenditures for the second quarter of 2016 were $1,158 million compared with $1,297 million for the second quarter of 2015 and $1,040 million for the first quarter of 2016. Capital expenditures for the three and six months ended June 30, 2016 were consistent with the Company's previously announced capital allocation schedule.

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, while remaining within annual corporate capital guidance. As a result, in the second half of 2016, the Company targets to drill an additional 134 crude oil wells in North America, including 4 producing thermal in situ wells.

Drilling Activity

	Three Months Ended			Six Months Ended	
(number of wells)	**Jun 30 2016**	Mar 31 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Net successful natural gas wells	**1**	4	2	**5**	11
Net successful crude oil wells [1]	**—**	8	5	**8**	47
Dry wells	**—**	—	—	**—**	2
Stratigraphic test / service wells	**1**	199	6	**200**	92
Total	**2**	211	13	**213**	152
Success rate (excluding stratigraphic test / service wells)	**100%**	100%	100%	**100%**	97%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 28% of the total net capital expenditures for the six months ended June 30, 2016 compared with approximately 33% for the six months ended June 30, 2015.

During the second quarter of 2016, the Company targeted 1 net natural gas well in Northwest Alberta.

Overall thermal oil production for the second quarter of 2016 averaged approximately 93,200 bbl/d compared with approximately 105,000 bbl/d for the second quarter of 2015 and approximately 118,100 bbl/d for the first quarter of 2016. Production volumes in the second quarter of 2016 reflected the cyclic nature of thermal oil production at Primrose. The Primrose East pipeline was proactively shut in during the first quarter of 2016 due to pipeline anomalies found on the line during inspection. The repair was completed in May 2016 and has been reflected in 2016 production guidance.

Operating performance at the Pelican Lake tertiary recovery project continued to be strong, leading to average production of approximately 47,800 bbl/d in the second quarter of 2016 compared with 52,000 bbl/d in the second quarter of 2015 and 47,600 bbl/d in the first quarter of 2016.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the second 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 completed the tie-in of major components as planned. Staged completion of Phase 2B commissioning activities remains on schedule with Phase 2B production targeted in the fourth quarter of 2016, adding 45,000 bbl/d of production capacity. The Company targets to complete Phase 3 in the fourth quarter of 2017, adding 80,000 bbl/d of production capacity.

North Sea

No drilling activity is currently planned for 2016. The decommissioning activities at the Murchison platform are ongoing and are expected to continue for approximately five years.

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

($ millions, except ratios)	Three Months Ended **Jun 30 2016**	Mar 31 2016	Dec 31 2015	Jun 30 2015
Working capital [1]	**$ 686**	$ 833	$ 1,193	$ 261
Long-term debt [2] [3]	**$ 17,236**	$ 16,564	$ 16,794	$ 15,983
Share capital	**$ 4,167**	$ 4,576	$ 4,541	$ 4,532
Retained earnings	**21,816**	22,408	22,765	23,248
Accumulated other comprehensive income (loss)	**36**	12	75	(7)
Shareholders' equity	**$ 26,019**	$ 26,996	$ 27,381	$ 27,773
Debt to book capitalization [3] [4]	**40%**	38%	38%	37%
Debt to market capitalization [3] [5]	**28%**	30%	34%	30%
After-tax return on average common shareholders' equity [6]	**(2%)**	(2%)	(2%)	6%
After-tax return on average capital employed [3] [7]	**0%**	(1%)	(1%)	4%

(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 June 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 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:
    - In October 2015, the Company filed base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until November 2017. If issued, these securities may be offered separately or together, 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 June 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 June 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 first quarter of 2016, the Company repaid US$500 million of three-month LIBOR plus 0.375% notes.

At June 30, 2016, the Company had in place bank credit facilities of $7,351 million, of which approximately $1,654 million, net of commercial paper issuances of $650 million, was available for general corporate purposes.

At June 30, 2016, the Company had total US dollar denominated debt with a carrying amount of $10,949 million (US$8,419 million). This included $4,968 million (US$3,819 million) hedged by way of cross currency swaps (US$2,400 million) and foreign currency forwards (US$1,419 million). The fixed repayment amount of these hedging instruments is $4,558 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $410 million to $10,539 million as at June 30, 2016.

Long-term debt was $17,236 million at June 30, 2016, resulting in a debt to book capitalization ratio of 40% (December 31, 2015 – 38%; June 30, 2015 – 37%); 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 June 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 August 3, 2016 the Company had no commodity derivative financial instruments outstanding.

Share Capital

As at June 30, 2016, there were 1,099,223,000 common shares outstanding (December 31, 2015 – 1,094,668,000 common shares) and 65,389,000 stock options outstanding. As at August 2, 2016, the Company had 1,101,540,000 common shares outstanding and 62,555,000 stock options outstanding.

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

On March 2, 2016, the Board of Directors declared a regular quarterly dividend of $0.23 per common share. On an annualized basis, the dividend of $0.92 per common share remains unchanged from the previous annual dividend rate. This reflects confidence in the Company's cash flow and provides a return to shareholders. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

The Company's Normal Course Issuer Bid announced in 2015 expired April 2016 and was not renewed. For the six months ended June 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 June 30, 2016:

($ millions)	Remaining 2016	2017	2018	2019	2020	Thereafter
Product transportation and pipeline	$ 222	$ 383	$ 328	$ 277	$ 264	$ 1,476
Offshore equipment operating leases and offshore drilling	$ 125	$ 92	$ 70	$ 24	$ 1	$ —
Long-term debt (1) (2)	$ 976	$ 1,431	$ 2,792	$ 3,549	$ 2,005	$ 6,549
Interest and other financing expense (3)	$ 334	$ 609	$ 524	$ 451	$ 395	$ 4,335
Office leases	$ 21	$ 42	$ 42	$ 42	$ 42	$ 193
Other	$ 76	$ 38	$ 48	$ 1	$ —	$ —

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

(2) At June 30, 2016, the Company had US$250 million of 6.00% debt securities due August 2016, hedged by way of a cross currency swap with a principal repayment amount fixed at $279 million and 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 June 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 six months ended June 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		**Jun 30 2016**		Dec 31 2015
ASSETS					
Current assets					
Cash and cash equivalents		**$**	**24**	$	69
Accounts receivable			**1,161**		1,277
Current income taxes			**798**		677
Inventory			**611**		525
Prepaids and other			**232**		162
Investment in PrairieSky Royalty Ltd.	5		**555**		974
Current portion of other long-term assets	6		**263**		375
			3,644		4,059
Exploration and evaluation assets	3		**2,489**		2,586
Property, plant and equipment	4		**51,074**		51,475
Other long-term assets	6		**988**		1,155
		$	**58,195**	$	59,275
LIABILITIES					
Current liabilities					
Accounts payable		**$**	**596**	$	571
Accrued liabilities			**1,975**		2,089
Current portion of long-term debt	7		**2,405**		1,729
Current portion of other long-term liabilities	8		**387**		206
			5,363		4,595
Long-term debt	7		**14,831**		15,065
Other long-term liabilities	8		**2,891**		2,890
Deferred income taxes			**9,091**		9,344
			32,176		31,894
SHAREHOLDERS' EQUITY					
Share capital	10		**4,167**		4,541
Retained earnings			**21,816**		22,765
Accumulated other comprehensive income	11		**36**		75
			26,019		27,381
		$	**58,195**	$	59,275

Commitments and contingencies (note 15).

Approved by the Board of Directors on August 3, 2016

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Jun 30 2016	Three Months Ended Jun 30 2015	Six Months Ended Jun 30 2016	Six Months Ended Jun 30 2015
Product sales		**$ 2,686**	$ 3,662	**$ 4,949**	$ 6,888
Less: royalties		**(134)**	(240)	**(219)**	(432)
Revenue		**2,552**	3,422	**4,730**	6,456
Expenses					
Production		**991**	1,188	**2,013**	2,441
Transportation and blending		**491**	629	**1,001**	1,264
Depletion, depreciation and amortization	3, 4	**1,174**	1,280	**2,393**	2,635
Administration		**91**	100	**177**	204
Share-based compensation	8	**122**	(79)	**239**	(15)
Asset retirement obligation accretion	8	**35**	43	**71**	86
Interest and other financing expense		**86**	85	**178**	171
Risk management activities	14	**(3)**	146	**67**	(96)
Foreign exchange loss (gain)		**49**	(87)	**(266)**	273
Gain on disposition of properties	3	**—**	—	**(32)**	—
(Gain) loss from investments	5, 6	**(7)**	(3)	**(166)**	12
		3,029	3,302	**5,675**	6,975
Earnings (loss) before taxes		**(477)**	120	**(945)**	(519)
Current income tax recovery	9	**(96)**	(3)	**(288)**	(108)
Deferred income tax (recovery) expense	9	**(42)**	528	**(213)**	246
Net loss		**$ (339)**	$ (405)	**$ (444)**	$ (657)
Net loss per common share					
Basic	13	**$ (0.31)**	$ (0.37)	**$ (0.41)**	$ (0.60)
Diluted	13	**$ (0.31)**	$ (0.37)	**$ (0.41)**	$ (0.60)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended Jun 30 2016	Three Months Ended Jun 30 2015	Six Months Ended Jun 30 2016	Six Months Ended Jun 30 2015
Net loss	**$ (339)**	$ (405)	**$ (444)**	$ (657)
Items that may be reclassified subsequently to net earnings (loss)				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss) during the period, net of taxes of $3 million (2015 – $5 million) – three months ended; $nil (2015 – $6 million) – six months ended	**25**	(34)	**1**	(43)
Reclassification to net earnings (loss), net of taxes of $1 million (2015 – $1 million) – three months ended; $1 million (2015 – $1 million) – six months ended	**(3)**	(4)	**7**	(6)
	22	(38)	**8**	(49)
Foreign currency translation adjustment				
Translation of net investment	**2**	(5)	**(47)**	(9)
Other comprehensive income (loss), net of taxes	**24**	(43)	**(39)**	(58)
Comprehensive loss	**$ (315)**	$ (448)	**$ (483)**	$ (715)

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Six Months Ended **Jun 30 2016**	Jun 30 2015
Share capital	10		
Balance – beginning of period		**$ 4,541**	$ 4,432
Issued upon exercise of stock options		**151**	83
Previously recognized liability on stock options exercised for common shares		**21**	17
Return of capital on PrairieSky Royalty Ltd. share distribution	5	**(546)**	—
Balance – end of period		**4,167**	4,532
Retained earnings			
Balance – beginning of period		**22,765**	24,408
Net loss		**(444)**	(657)
Dividends on common shares	10	**(505)**	(503)
Balance – end of period		**21,816**	23,248
Accumulated other comprehensive income (loss)	11		
Balance – beginning of period		**75**	51
Other comprehensive loss, net of taxes		**(39)**	(58)
Balance – end of period		**36**	(7)
Shareholders' equity		**$ 26,019**	$ 27,773

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Jun 30 2016**	Three Months Ended Jun 30 2015	Six Months Ended **Jun 30 2016**	Six Months Ended Jun 30 2015
Operating activities					
Net loss		**$ (339)**	$ (405)	**$ (444)**	$ (657)
Non-cash items					
Depletion, depreciation and amortization		**1,174**	1,280	**2,393**	2,635
Share-based compensation		**122**	(79)	**239**	(15)
Asset retirement obligation accretion		**35**	43	**71**	86
Unrealized risk management (gain) loss		**(52)**	215	**22**	229
Unrealized foreign exchange loss (gain)		**40**	(76)	**(294)**	337
(Gain) loss from investments	5, 6	**—**	(3)	**(147)**	12
Deferred income tax (recovery) expense		**(42)**	528	**(213)**	246
Gain on disposition of properties		**—**	—	**(32)**	—
Other		**5**	20	**24**	62
Abandonment expenditures		**(36)**	(56)	**(110)**	(200)
Net change in non-cash working capital		**(190)**	(182)	**(211)**	(196)
		717	1,285	**1,298**	2,539
Financing activities					
Issue of bank credit facilities and commercial paper, net		**602**	334	**1,732**	1,211
Issue of medium-term notes, net	7	**—**	107	**—**	107
Repayment of US dollar debt securities		**—**	—	**(555)**	—
Issue of common shares on exercise of stock options		**121**	48	**151**	83
Dividends on common shares		**(252)**	(251)	**(252)**	(496)
Net change in non-cash working capital		**—**	(27)	**—**	(40)
		471	211	**1,076**	865
Investing activities					
Net (expenditures) proceeds on exploration and evaluation assets		**(20)**	(29)	**10**	(75)
Net expenditures on property, plant and equipment		**(1,102)**	(1,212)	**(2,098)**	(2,434)
Investment in other long-term assets		**—**	—	**(99)**	(112)
Net change in non-cash working capital		**(57)**	(257)	**(232)**	(776)
		(1,179)	(1,498)	**(2,419)**	(3,397)
Increase (decrease) in cash and cash equivalents		**9**	(2)	**(45)**	7
Cash and cash equivalents – beginning of period		**15**	34	**69**	25
Cash and cash equivalents – end of period		**$ 24**	$ 32	**$ 24**	$ 32
Interest paid, net		**$ 123**	$ 119	**$ 305**	$ 275
Income taxes paid (received)		**$ 4**	$ 55	**$ (113)**	$ 264

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	**19**	**—**	**6**	**—**	**25**
Transfers to property, plant and equipment	**(100)**	**—**	**—**	**—**	**(100)**
Disposals/derecognitions	**(3)**	**—**	**(18)**	**—**	**(21)**
Foreign exchange adjustments	**—**	**—**	**(1)**	**—**	**(1)**
At June 30, 2016	**$ 2,416**	**$ —**	**$ 73**	**$ —**	**$ 2,489**

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.

During the six months ended June 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.

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	**612**	**26**	**117**	**1,359**	**2**	**10**	**2,126**
Transfers from E&E assets	**100**	**—**	**—**	**—**	**—**	**—**	**100**
Disposals/derecognitions	**(218)**	**—**	**—**	**(18)**	**—**	**—**	**(236)**
Foreign exchange adjustments and other	**—**	**(448)**	**(318)**	**—**	**—**	**—**	**(766)**
At June 30, 2016	**$ 61,034**	**$ 6,992**	**$ 4,972**	**$ 25,684**	**$ 579**	**$ 388**	**$ 99,649**
Accumulated depletion and depreciation							
At December 31, 2015	$ 35,347	$ 5,264	$ 3,659	$ 2,294	$ 132	$ 254	$ 46,950
Expense	**1,738**	**197**	**137**	**282**	**6**	**15**	**2,375**
Disposals/derecognitions	**(218)**	**—**	**—**	**(18)**	**—**	**—**	**(236)**
Foreign exchange adjustments and other	**4**	**(308)**	**(216)**	**6**	**—**	**—**	**(514)**
At June 30, 2016	**$ 36,871**	**$ 5,153**	**$ 3,580**	**$ 2,564**	**$ 138**	**$ 269**	**$ 48,575**
Net book value							
- at June 30, 2016	**$ 24,163**	**$ 1,839**	**$ 1,392**	**$ 23,120**	**$ 441**	**$ 119**	**$ 51,074**
- at December 31, 2015	$ 25,193	$ 2,150	$ 1,514	$ 22,049	$ 445	$ 124	$ 51,475

Project costs not subject to depletion and depreciation	Jun 30 2016	Dec 31 2015
Horizon	**$ 7,034**	$ 6,017
Kirby Thermal Oil Sands – North	**$ 834**	$ 816

During the six months ended June 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 $141 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 $28 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 six months ended June 30, 2016, pre-tax interest of $128 million (June 30, 2015 – $120 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (June 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 June 30, 2016, the Company's investment in PrairieSky of $555 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		Six Months Ended	
	Jun 30 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Fair value gain from PrairieSky	**$ 3**	$ —	**$ 124**	$ —
Dividend income from PrairieSky	**7**	—	**19**	—
	$ 10	$ —	**$ 143**	$ —

6. OTHER LONG-TERM ASSETS

	Jun 30 2016	Dec 31 2015
Investment in North West Redwater Partnership	**$ 277**	$ 254
North West Redwater Partnership subordinated debt (1)	**369**	254
Risk Management (note 14)	**481**	854
Other	**124**	168
	1,251	1,530
Less: current portion	**263**	375
	$ 988	$ 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 June 30, 2016, Redwater Partnership had additional borrowings of $852 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 June 30, 2016, the Company recognized an equity loss from Redwater Partnership of $3 million (three months ended June 30, 2015 – gain of $3 million; six months ended June 30, 2016 – gain of $23 million; six months ended June 30, 2015 – loss of $12 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

	Jun 30 2016	Dec 31 2015
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ 3,853**	$ 2,385
Medium-term notes	**2,500**	2,500
	6,353	4,885
US dollar denominated debt, unsecured		
Bank credit facilities (June 30, 2016 - US$919 million; December 31, 2015 - US$657 million)	**1,193**	909
Commercial paper (US$500 million)	**650**	692
US dollar debt securities (June 30, 2016 - US$7,000 million; December 31, 2015 - US$7,500 million)	**9,106**	10,380
	10,949	11,981
Long-term debt before transaction costs and original issue discounts, net	**17,302**	16,866
Less: original issue discounts, net (1)	**(10)**	(10)
transaction costs (1) (2)	**(56)**	(62)
	17,236	16,794
Less: current portion of commercial paper	**650**	692
current portion of other long-term debt (1) (2)	**1,755**	1,037
	$ 14,831	$ 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 June 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 June 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 June 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 June 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 June 30, 2016 was 2.0% (June 30, 2015 – 1.9%), and on total long-term debt outstanding for the six months ended June 30, 2016 was 3.9% (June 30, 2015 – 3.9%).

At June 30, 2016, letters of credit and guarantees aggregating $280 million, including a $39 million financial guarantee related to Horizon and $144 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

In October 2015, the Company filed a 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 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

	Jun 30 2016	Dec 31 2015
Asset retirement obligations	**$ 2,868**	$ 2,950
Share-based compensation	**393**	128
Other	**17**	18
	3,278	3,096
Less: current portion	**387**	206
	$ 2,891	$ 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:

	Jun 30 2016	Dec 31 2015
Balance – beginning of period	**$ 2,950**	$ 4,221
Liabilities incurred	**—**	7
Liabilities acquired, net	**28**	129
Liabilities settled	**(110)**	(370)
Asset retirement obligation accretion	**71**	173
Revision of cost, inflation rates and timing estimates	**—**	(313)
Change in discount rate	**—**	(1,150)
Foreign exchange adjustments	**(71)**	253
Balance – end of period	**2,868**	2,950
Less: current portion	**75**	101
	$ 2,793	$ 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.

	Jun 30 2016	Dec 31 2015
Balance – beginning of period	**$ 128**	$ 203
Share-based compensation expense (recovery)	**239**	(46)
Cash payment for stock options surrendered	**(1)**	(1)
Transferred to common shares	**(21)**	(18)
Capitalized to (recovered from) Oil Sands Mining and Upgrading	**48**	(10)
Balance – end of period	**393**	128
Less: current portion	**312**	105
	$ 81	$ 23

9. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Current corporate income tax (recovery) expense – North America	**$ (68)**	$ 79	**$ (187)**	$ 87
Current corporate income tax recovery – North Sea	**(8)**	(19)	**(31)**	(83)
Current corporate income tax expense – Offshore Africa	**8**	5	**12**	7
Current PRT [1] recovery – North Sea	**(31)**	(72)	**(86)**	(126)
Other taxes	**3**	4	**4**	7
Current income tax recovery	**(96)**	(3)	**(288)**	(108)
Deferred corporate income tax (recovery) expense	**(52)**	498	**(19)**	209
Deferred PRT [1] expense (recovery) – North Sea	**10**	30	**(194)**	37
Deferred income tax (recovery) expense	**(42)**	528	**(213)**	246
Income tax (recovery) expense	**$ (138)**	$ 525	**$ (501)**	$ 138

(1) Petroleum Revenue Tax.

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 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.

	Six Months Ended Jun 30, 2016	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,094,668**	**$ 4,541**
Issued upon exercise of stock options	**4,555**	**151**
Previously recognized liability on stock options exercised for common shares	**—**	**21**
Return of capital on PrairieSky Royalty Ltd. share distribution (note 5)	**—**	**(546)**
Balance – end of period	**1,099,223**	**$ 4,167**

Dividend Policy

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

On March 2, 2016, the Board of Directors declared a quarterly dividend of $0.23 per common share ($0.23 per common share on March 4, 2015), beginning with the dividend payable on April 1, 2016.

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 June 30, 2016:

	Six Months Ended Jun 30, 2016		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**74,615**	**$**	**34.88**
Granted	**4,842**	**$**	**23.70**
Surrendered for cash settlement	**(225)**	**$**	**33.93**
Exercised for common shares	**(4,555)**	**$**	**33.16**
Forfeited	**(9,288)**	**$**	**40.18**
Outstanding – end of period	**65,389**	**$**	**33.42**
Exercisable – end of period	**21,255**	**$**	**35.06**

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 (LOSS)

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

		Jun 30 2016		Jun 30 2015
Derivative financial instruments designated as cash flow hedges	**$**	**66**	$	45
Foreign currency translation adjustment		**(30)**		(52)
	$	**36**	$	(7)

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 June 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.

	Jun 30 2016	Dec 31 2015
Long-term debt [1]	**$ 17,236**	$ 16,794
Total shareholders' equity	**$ 26,019**	$ 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		Six Months Ended	
	Jun 30 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Weighted average common shares outstanding – basic (thousands of shares)	**1,097,579**	1,094,143	**1,096,247**	1,093,252
Effect of dilutive stock options (thousands of shares)	**—**	—	**—**	—
Weighted average common shares outstanding – diluted (thousands of shares)	**1,097,579**	1,094,143	**1,096,247**	1,093,252
Net loss	**$ (339)**	$ (405)	**$ (444)**	$ (657)
Net loss per common share – basic	**$ (0.31)**	$ (0.37)	**$ (0.41)**	$ (0.60)
– diluted	**$ (0.31)**	$ (0.37)	**$ (0.41)**	$ (0.60)

14. FINANCIAL INSTRUMENTS

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

	Jun 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	**$ 1,161**	**$ —**	**$ —**	**$ —**	**$ 1,161**
Investment in PrairieSky	**—**	**555**	**—**	**—**	**555**
Other long-term assets	**369**	**15**	**466**	**—**	**850**
Accounts payable	**—**	**—**	**—**	**(596)**	**(596)**
Accrued liabilities	**—**	**—**	**—**	**(1,975)**	**(1,975)**
Long-term debt (1)	**—**	**—**	**—**	**(17,236)**	**(17,236)**
	$ 1,530	**$ 570**	**$ 466**	**$ (19,807)**	**$ (17,241)**

	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:

	Jun 30, 2016			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3**
Investment in PrairieSky (3)	**$ 555**	**$ 555**	**$ —**	**$ —**
Other long-term assets (4)	**$ 850**	**$ —**	**$ 481**	**$ 369**
Fixed rate long-term debt (5) (6)	**$ (11,540)**	**$ (11,981)**	**$ —**	**$ —**

	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)		**Jun 30 2016**		Dec 31 2015
Derivatives held for trading				
Foreign currency forward contracts	**$**	**15**	$	36
Cash flow hedges				
Foreign currency forward contracts		**8**		30
Cross currency swaps		**458**		788
	$	**481**	$	854
Included within:				
Current portion of other long-term assets	**$**	**228**	$	305
Other long-term assets		**253**		549
	$	**481**	$	854

For the six months ended June 30, 2016, the Company recognized a loss of $1 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)	**Jun 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	**(22)**	(374)
Foreign exchange	**(360)**	669
Other comprehensive income (loss)	**9**	(40)
Balance – end of period	**481**	854
Less: current portion	**228**	305
	$ 253	$ 549

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

	Three Months Ended		Six Months Ended	
	Jun 30 2016	Jun 30 2015	**Jun 30 2016**	Jun 30 2015
Net realized risk management loss (gain)	**$ 49**	$ (69)	**$ 45**	$ (325)
Net unrealized risk management (gain) loss	**(52)**	215	**22**	229
	$ (3)	$ 146	**$ 67**	$ (96)

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 June 30, 2016, the Company had no commodity derivative financial instruments outstanding.

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 June 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 June 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	Jul 2016	—	Aug 2016	US$250	1.116	6.00%	5.40%
	Jul 2016	—	May 2017	US$1,100	1.170	5.70%	5.10%
	Jul 2016	—	Nov 2021	US$500	1.022	3.45%	3.96%
	Jul 2016	—	Mar 2038	US$550	1.170	6.25%	5.76%

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

In addition to the cross currency swap contracts noted above, at June 30, 2016, the Company had US$2,322 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 June 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 June 30, 2016, the Company had net risk management assets of $481 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	$ 596	$ —	$ —	$ —
Accrued liabilities	$ 1,975	$ —	$ —	$ —
Long-term debt (1)	$ 2,405	$ 2,793	$ 5,555	$ 6,549

(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	$	222	$	383	$	328	$	277	$	264	$	1,476
Offshore equipment operating leases and offshore drilling	$	125	$	92	$	70	$	24	$	1	$	—
Office leases	$	21	$	42	$	42	$	42	$	42	$	193
Other	$	76	$	38	$	48	$	1	$	—	$	—

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 Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2016	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Segmented product sales	**1,677**	2,645	**3,189**	4,979	**110**	201	**231**	353	**206**	111	**306**	178	**1,993**	2,957	**3,726**	5,510
Less: royalties	**(121)**	(225)	**(200)**	(402)	**(1)**	(1)	**(1)**	(1)	**(7)**	(5)	**(12)**	(8)	**(129)**	(231)	**(213)**	(411)
Segmented revenue	**1,556**	2,420	**2,989**	4,577	**109**	200	**230**	352	**199**	106	**294**	170	**1,864**	2,726	**3,513**	5,099
Segmented expenses																
Production	**545**	645	**1,112**	1,396	**72**	161	**192**	295	**75**	55	**109**	70	**692**	861	**1,413**	1,761
Transportation and blending	**480**	614	**973**	1,234	**12**	16	**22**	29	**—**	—	**1**	1	**492**	630	**996**	1,264
Depletion, depreciation and amortization	**855**	1,020	**1,752**	2,124	**87**	99	**198**	186	**94**	39	**155**	61	**1,036**	1,158	**2,105**	2,371
Asset retirement obligation accretion	**16**	24	**33**	47	**9**	10	**18**	19	**3**	2	**6**	5	**28**	36	**57**	71
Realized risk management activities	**49**	(69)	**45**	(325)	**—**	—	**—**	—	**—**	—	**—**	—	**49**	(69)	**45**	(325)
Gain on disposition of properties	**—**	—	**(32)**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(32)**	—
(Gain) loss from investments	**(10)**	—	**(143)**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(10)**	—	**(143)**	—
Total segmented expenses	**1,935**	2,234	**3,740**	4,476	**180**	286	**430**	529	**172**	96	**271**	137	**2,287**	2,616	**4,441**	5,142
Segmented earnings (loss) before the following	**(379)**	186	**(751)**	101	**(71)**	(86)	**(200)**	(177)	**27**	10	**23**	33	**(423)**	110	**(928)**	(43)
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 (recovery) expense																
Net loss																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter–segment elimination and other				Total			
	Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2016	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Segmented product sales	**674**	689	**1,198**	1,349	**31**	35	**57**	70	**(12)**	(19)	**(32)**	(41)	**2,686**	3,662	**4,949**	6,888
Less: royalties	**(5)**	(9)	**(6)**	(21)	**—**	—	**—**	—	**—**	—	**—**	—	**(134)**	(240)	**(219)**	(432)
Segmented revenue	**669**	680	**1,192**	1,328	**31**	35	**57**	70	**(12)**	(19)	**(32)**	(41)	**2,552**	3,422	**4,730**	6,456
Segmented expenses																
Production	**293**	321	**590**	667	**7**	9	**13**	18	**(1)**	(3)	**(3)**	(5)	**991**	1,188	**2,013**	2,441
Transportation and blending	**15**	19	**38**	40	**—**	—	**—**	—	**(16)**	(20)	**(33)**	(40)	**491**	629	**1,001**	1,264
Depletion, depreciation and amortization	**135**	119	**282**	258	**3**	3	**6**	6	**—**	—	**—**	—	**1,174**	1,280	**2,393**	2,635
Asset retirement obligation accretion	**7**	7	**14**	15	**—**	—	**—**	—	**—**	—	**—**	—	**35**	43	**71**	86
Realized risk management activities	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**49**	(69)	**45**	(325)
Gain on disposition of properties	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(32)**	—
(Gain) loss from investments	**—**	—	**—**	—	**3**	(3)	**(23)**	12	**—**	—	**—**	—	**(7)**	(3)	**(166)**	12
Total segmented expenses	**450**	466	**924**	980	**13**	9	**(4)**	36	**(17)**	(23)	**(36)**	(45)	**2,733**	3,068	**5,325**	6,113
Segmented earnings (loss) before the following	**219**	214	**268**	348	**18**	26	**61**	34	**5**	4	**4**	4	**(181)**	354	**(595)**	343
Non–segmented expenses																
Administration													**91**	100	**177**	204
Share-based compensation													**122**	(79)	**239**	(15)
Interest and other financing expense													**86**	85	**178**	171
Unrealized risk management activities													**(52)**	215	**22**	229
Foreign exchange loss (gain)													**49**	(87)	**(266)**	273
Total non–segmented expenses													**296**	234	**350**	862
Earnings (loss) before taxes													**(477)**	120	**(945)**	(519)
Current income tax recovery													**(96)**	(3)	**(288)**	(108)
Deferred income tax (recovery) expense													**(42)**	528	**(213)**	246
Net loss													**(339)**	(405)	**(444)**	(657)

Capital Expenditures [1]

	Six Months Ended					
	Jun 30, 2016			Jun 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]	**$ 16**	**$ (100)**	**$ (84)**	$ 52	$ (160)	$ (108)
North Sea	**—**	**—**	**—**	—	—	—
Offshore Africa	**6**	**(18)**	**(12)**	23	—	23
	$ 22	**$ (118)**	**$ (96)**	$ 75	$ (160)	$ (85)
Property, plant and equipment						
Exploration and Production						
North America	**$ 584**	**$ (90)**	**$ 494**	$ 756	$ 5	$ 761
North Sea	**26**	**—**	**26**	155	(2)	153
Offshore Africa	**117**	**—**	**117**	258	—	258
	727	**(90)**	**637**	1,169	3	1,172
Oil Sands Mining and Upgrading [4]	**1,359**	**(18)**	**1,341**	1,247	(49)	1,198
Midstream	**2**	**—**	**2**	4	—	4
Head office	**10**	**—**	**10**	14	—	14
	$ 2,098	**$ (108)**	**$ 1,990**	$ 2,434	$ (46)	$ 2,388

(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 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

	Jun 30 2016	Dec 31 2015
Exploration and Production		
North America	**$ 29,146**	$ 30,937
North Sea	**2,382**	2,734
Offshore Africa	**1,684**	1,755
Other	**27**	73
Oil Sands Mining and Upgrading	**23,626**	22,598
Midstream	**1,211**	1,054
Head office	**119**	124
	$ 58,195	$ 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 June 30, 2016:	
Interest coverage (times)	
Net earnings (loss) [1]	(0.6)x
Cash flow from operations [2]	7.9x

(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.

Corporate Information

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Timothy W. Faithfull

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Christopher L. Fong

Ambassador Gordon D. Giffin

Wilfred A. Gobert

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Annette Verschuren, O.C.

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Chief Operating Officer

Lyle G. Stevens
Executive Vice-President, Canadian Conventional

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Chief Financial Officer and Senior Vice-President, Finance

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Réal J.H. Doucet
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Senior Vice-President, Exploitation

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Senior Vice-President, Production and Development Operations

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

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Executive Exploration Advisor

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Vice-President, Land

International Operations
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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

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Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
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