Canadian Natural

SECOND QUARTER REPORT

SIX MONTHS ENDED JUNE 30, 2015

TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2015 SECOND QUARTER RESULTS

Commenting on second quarter results, Steve Laut, President of Canadian Natural stated, “Canadian Natural is in a strong position. Our strong, diverse and well balanced asset base, and the effectiveness of our strategies, combined with our ability to execute these strategies, allows us to react quickly in this challenging commodity price environment.

In the second quarter, we delivered operationally, achieving record gas production at 1.779 Bcf/d, which exceeded production guidance and increased 9% over the same quarter in 2014. Oil production was strong, and we expect to deliver annual oil production at the midpoint of guidance despite the forest fire impact on second quarter oil production.

Canadian Natural’s operations continue to be effective and efficient. We have been able to achieve significant cost savings through better effectiveness, efficiency and innovation. Both operating and capital costs were down significantly from the second quarter in 2014 to the second quarter of this year.”

Canadian Natural’s Chief Financial Officer, Corey Bieber, continued, “The Company has proactively reduced its development programs in the context of lower commodity prices and lower cash flow. Liquidity remains strong at $3.3 billion. During the second quarter, absent the impact of the $579 million charge due to the 20% increase in Alberta corporate income tax rates, our earnings would have been $174 million. This charge effectively translates into lower future cash flows and therefore, lowers reinvestment in the business. Based upon third party research, this lower future capital reinvestment likely equates to about 4,100 fewer person years of direct, indirect and induced employment, with follow-on impact of higher income taxes on future income streams.”

QUARTERLY HIGHLIGHTS

($ Millions, except per common share amounts)	Three Months Ended Jun 30 2015	Three Months Ended Mar 31 2015	Three Months Ended Jun 30 2014	Six Months Ended Jun 30 2015	Six Months Ended Jun 30 2014
Net earnings (loss)	**$ (405)**	$ (252)	$ 1,070	**$ (657)**	$ 1,692
Per common share – basic	**$ (0.37)**	$ (0.23)	$ 0.98	**$ (0.60)**	$ 1.55
– diluted	**$ (0.37)**	$ (0.23)	$ 0.97	**$ (0.60)**	$ 1.54
Adjusted net earnings from operations (1)	**$ 178**	$ 21	$ 1,150	**$ 199**	$ 2,071
Per common share – basic	**$ 0.16**	$ 0.02	$ 1.05	**$ 0.18**	$ 1.90
– diluted	**$ 0.16**	$ 0.02	$ 1.04	**$ 0.18**	$ 1.89
Cash flow from operations (2)	**$ 1,503**	$ 1,370	$ 2,633	**$ 2,873**	$ 4,779
Per common share – basic	**$ 1.38**	$ 1.25	$ 2.41	**$ 2.63**	$ 4.38
– diluted	**$ 1.37**	$ 1.25	$ 2.39	**$ 2.62**	$ 4.36
Capital expenditures, net of dispositions	**$ 1,297**	$ 1,412	$ 5,456	**$ 2,709**	$ 7,349
Daily production, before royalties					
Natural gas (MMcf/d)	**1,779**	1,771	1,634	**1,775**	1,406
Crude oil and NGLs (bbl/d)	**509,047**	602,809	545,169	**555,669**	517,134
Equivalent production (BOE/d) (3)	**805,547**	898,053	817,471	**851,545**	751,426

(1) Adjusted net 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's 2015 second quarter crude oil and NGL production volumes averaged 509,047 bbl/d, and natural gas volumes reached record quarterly levels of 1,779 MMcf/d.
- Operations during Q2/15 were solid as the Company's large, balanced and diverse asset base continues to support the transition to a longer life and lower decline asset base. Q2/15 operational highlights include:
  - Pelican Lake production volumes increased in the second quarter to record levels of 52,015 bbl/d, 5% higher than Q2/14 levels and 2% higher than Q1/15 levels. This leading edge polymer flood continues to perform with increasing production volumes and decreasing operating costs despite no drilling activity since Q3/14. Canadian Natural leverages innovation and technology to create value through strong netbacks and robust economic returns.
  - Operations at Septimus, Canadian Natural's liquids-rich Montney natural gas play in British Columbia, continue to perform above expectations, with industry leading quarterly operating costs of approximately $0.18/Mcfe in Q2/15.
  - Total Offshore Africa quarterly crude oil production in Q2/15 averaged 17,070 bbl/d, an increase of 30% over Q2/14 levels and an increase of 29% over Q1/15 levels. The infill drilling programs at the Espoir and Baobab fields in Côte d'Ivoire continue to be successfully executed with results exceeding expectations.

- To date, 3 gross wells have been drilled at Espoir, adding net production of approximately 4,500 bbl/d. Espoir is targeted to add overall net production volumes of 5,900 bbl/d through a 10 gross well program which includes 4 water injection wells (5.9 net well program) and is currently tracking below sanctioned costs.
- To date, Canadian Natural drilled 1 gross well at Baobab, adding net production volumes of approximately 2,000 bbl/d. Production from the second gross well is targeted to come on stream in the third quarter of 2015. Baobab is targeted to add overall net production volumes of 11,000 bbl/d through a 6 gross well program (3.4 net well program), which is currently tracking below sanctioned costs.

- Thermal operations were temporarily interrupted from late May to early June as a result of Northeastern Alberta forest fires. Employees were safely evacuated and only minor facility damage occurred. Total quarterly production volumes were reduced as a result of the related shut-down at Primrose and production curtailment at Kirby South.
- The Company continues to progress the low pressure steamflood operations at Primrose East Area 1 and the low pressure cyclic steam stimulation ("CSS") operations at Primrose East Area 2. Operations at Primrose East are exceeding expectations, and due to the cyclic nature of operations at Primrose East Area 2, current production volumes are ranging from 15,000 bbl/d to 20,000 bbl/d.
- At Horizon Oil Sands ("Horizon"), the full maintenance turnaround originally scheduled in Q3/15 was deferred to 2016 to capture opportunities for production optimization of Phase 2B. During Q2/15, the Company planned a 10 day turnaround focusing on critical activities. The turnaround was extended from 10 days to 15 days to address necessary found work and the start-up of operations was slightly slower than expected. As a result, production volumes were lower than the Q2/15 guidance range. The Company targets strong production volumes going forward with Q3/15 production volumes targeted to range from 124,000 bbl/d to 131,000 bbl/d. 2015 annual production guidance remains unchanged from 121,000 bbl/d to 131,000 bbl/d.
- Due to Canadian Natural's enhanced focus on operating efficiencies, the 2015 annual operating cost guidance range for Horizon has been further reduced from $31.00/bbl to $34.00/bbl to $30.00/bbl to $33.00/bbl.

▪ Canadian Natural continues to execute capital discipline by proactively managing its drilling programs. As a result of the decrease in commodity pricing and other external events, the Company's drilling activity consisted of just 13 net wells in Q2/15 compared to 191 net wells in Q2/14, a 93% reduction year over year.

▪ Canadian Natural remains committed to its effective and efficient operations, with an enhanced focus on cost optimization. During the second quarter, the Company achieved strong operating cost reductions in the following areas:

	Q2/15	Q2/14	**Year-over-Year Percent Reduction**
North America Light Crude Oil and NGLs ($/bbl)	**$ 15.29**	$ 17.56	**13%**
Pelican Lake Heavy Crude Oil ($/bbl)	**$ 6.98**	$ 8.92	**22%**
Primary Heavy Crude Oil ($/bbl)	**$ 14.92**	$ 17.61	**15%**
Horizon Oil Sands Mining and Upgrading ($/bbl) (1)	**$ 29.25**	$ 36.61	**20%**
North Sea Light Crude Oil ($/bbl)	**$ 60.61**	$ 79.21	**23%**
Offshore Africa Light Crude Oil ($/bbl)	**$ 43.88**	$ 58.41	**25%**
North America Natural Gas ($/Mcf)	**$ 1.28**	$ 1.48	**14%**

(1) Horizon Q2/15 operating costs adjusted to reflect impact of the June 2015 maintenance turnaround.

▪ Given the cyclical nature of Primrose operations and the continued ramp up of production volumes at Kirby South, quarterly cost comparison year over year is not indicative of performance. However, on an annual basis, with a continued focus on effective and efficient operations, thermal operating costs are targeted to reduce by 13%.

▪ In addition to the operating cost efficiencies achieved during the quarter, Canadian Natural continues to attain capital cost savings and has lowered its capital spending program by an additional $245 million from $5,745 million to $5,500 million. This reduction is a result of the Company's ability to optimize its execution strategy, enhance productivity, right scope projects, leverage technology, and achieve lower energy and material costs.

▪ Canadian Natural generated cash flow from operations of approximately $1.5 billion in Q2/15 compared to approximately $2.6 billion in Q2/14 and $1.4 billion in Q1/15. The decrease in Q2/15 from Q2/14 primarily reflects lower benchmark pricing partially offset by reduced operating costs.

- The Company incurred a net loss in Q2/15 of $405 million, compared to net earnings of $1,070 million in Q2/14 and a net loss of $252 million in Q1/15. The net loss in Q2/15 was primarily a result of the 20% increase in the Alberta provincial corporate income tax rate from 10% to 12%, increasing Canadian Natural's deferred income tax liability by $579 million. Adjusted net earnings from operations for Q2/15 were $178 million, compared to adjusted net earnings of $1,150 million in Q2/14 and $21 million in Q1/15. Changes in adjusted net earnings largely reflect the changes in cash flow.
- During Q2/15, Canadian Natural's $1,500 million revolving syndicated credit facility was increased to $2,425 million and the maturity date was extended to June 2019 from June 2016. The Company's $3,000 million revolving syndicated credit facility was reduced to $2,425 million and the maturity date was extended to June 2020 from June 2017. As a result, the Company's available liquidity increased by $350 million, ending the quarter at approximately $3.3 billion.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.23 per share payable on October 1, 2015.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate efficient operations, Canadian Natural focuses its activities in core regions where the Company owns a substantial land base and associated infrastructure. Land inventories are maintained to enable continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning and operating associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs. Furthermore, the Company maintains large project inventories and production diversification among each of the commodities it produces; 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. A large diversified project portfolio enables the effective allocation of capital to higher return opportunities.

Drilling Activity

	Six Months Ended Jun 30			
	2015		2014	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**54**	**47**	470	425
Natural gas	**16**	**11**	48	38
Dry	**2**	**2**	6	5
Subtotal	**72**	**60**	524	468
Stratigraphic test / service wells	**128**	**92**	353	352
Total	**200**	**152**	877	820
Success rate (excluding stratigraphic test / service wells)		**97%**		99%

- As a direct result of the decrease in crude oil and natural gas pricing and other external events, the Company has proactively reduced its 2015 drilling programs. Drilling activity in Q2/15 consisted of 13 net wells compared to 191 net wells in Q2/14.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2015	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Crude oil and NGLs production (bbl/d)	**270,021**	286,333	285,740	**278,133**	275,979
Net wells targeting crude oil	**4**	40	151	**44**	414
Net successful wells drilled	**4**	38	149	**42**	409
Success rate	**100%**	95%	99%	**95%**	99%

- Quarterly production volumes of North America crude oil and NGLs were 270,021 bbl/d in Q2/15, a decrease of 6% from both Q2/14 and Q1/15 levels respectively.
- As expected, North America light crude oil and NGL quarterly production averaged 89,226 bbl/d in Q2/15. Production volumes decreased 4% and 9% from Q2/14 levels and Q1/15 levels respectively, largely as a result of expected production declines offset by the modest light crude oil drilling program in place. North America light crude oil drilling activity consisted of 4 wells in the first half of 2015 compared to 52 net wells in the first half of 2014, a 92% reduction.
- Despite the reduction in production volumes, North America light crude oil and NGL quarterly operating costs decreased to $15.29/bbl in Q2/15, 13% lower than Q2/14 levels of $17.56/bbl and 6% lower than Q1/15 levels of $16.23/bbl.
- Pelican Lake operations achieved record quarterly heavy crude oil production volumes of 52,015 bbl/d, a 5% increase from Q2/14 levels and a 2% increase from Q1/15 levels. Canadian Natural continues to achieve success in developing, implementing and optimizing the leading edge polymer flood technology at Pelican Lake.
- Operational efficiencies continue to be a focus at Pelican Lake. Industry leading quarterly operating costs decreased to $6.98/bbl, 22% lower than Q2/14 and 19% lower than Q1/15.
- In Q2/15, primary heavy crude oil production averaged 128,780 bbl/d, a decrease of 10% and 6% from Q2/14 and Q1/15 levels respectively. The decrease in production volumes reflects a significantly reduced drilling program of 4 net wells in Q2/15 compared to 122 net wells in Q2/14, as well as the Company's prudent decision to shut-in approximately 4,000 bbl/d of primary heavy crude oil production as a result of unfavorable economic conditions.
- The strength of Canadian Natural's primary heavy crude oil asset base is its strong operating free cash flow established by achieving low operating costs. As demonstrated, primary heavy crude oil quarterly operating costs decreased in Q2/15 to $14.92/bbl compared to $17.61/bbl in Q2/14 and $17.21/bbl in Q1/15, cost reductions of 15% and 13% respectively.

Thermal In Situ Oil Sands

	Three Months Ended				
	Jun 30 2015	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Bitumen production (bbl/d)	**105,019**	146,086	114,414	**125,438**	98,335
Net wells targeting bitumen	**–**	3	3	**3**	14
Net successful wells drilled	**–**	3	3	**3**	14
Success rate	**–**	100%	100%	**100%**	100%

- In Q2/15, thermal in situ production volumes averaged 105,019 bbl/d, a decrease of 8% and 28% from Q2/14 and Q1/15 production volume levels respectively. The decrease in Q2/15 from Q1/15 production volumes primarily reflects reduced production volumes impacted by the cyclic nature of Primrose operations, and the Northeastern Alberta forest fires from late May to early June that caused thermal operations at Primrose to temporarily shut down and as well as production curtailments at Kirby South.
- At Kirby South, Q2/15 production volumes were curtailed as a result of the shut-down of the Cold Lake sales pipeline due to the forest fires. Despite the impact of the forest fires, production volumes increased to 26,193 bbl/d as operations continue to ramp up to the targeted 40,000 bbl/d of design capacity. The reservoir continues to perform as expected with very good thermal efficiencies. For wells on Steam Assisted Gravity Drainage ("SAGD"), the steam to oil ratio ("SOR") in Q2/15 was 2.6. For July 2015, Kirby South's production volumes averaged approximately 32,000 bbl/d.
- The Company continues to progress the low pressure steamflood operations at Primrose East Area 1 and the low pressure cyclic steam stimulation ("CSS") operations at Primrose East Area 2. Operations at Primrose East are exceeding expectations, and due to the cyclic nature of operations at Primrose East Area 2, current production volumes are ranging from 15,000 bbl/d to 20,000 bbl/d.

Natural Gas

	Three Months Ended			Six Months Ended	
	Jun 30 2015	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Natural gas production (MMcf/d)	**1,716**	1,713	1,606	**1,715**	1,378
Net wells targeting natural gas	**2**	9	13	**11**	38
Net successful wells drilled	**2**	9	13	**11**	38
Success rate	**100%**	100%	100%	**100%**	100%

- North America natural gas production reached record quarterly levels averaging 1,716 MMcf/d for Q2/15, an increase of 7% from Q2/14 levels and comparable to Q1/15 levels. The increase from Q2/14 levels resulted from additional production volumes acquired in 2014, complemented by a focused liquids-rich natural gas drilling program.
- Operations at Septimus, Canadian Natural's liquids-rich Montney natural gas play in British Columbia, continue to perform above expectations, with industry leading quarterly operating costs of approximately $0.18/Mcfe in Q2/15.
- North America natural gas production volumes during Q2/15 were impacted by 46 MMcf/d as a result of transportation restrictions on the NOVA pipeline system. Restricted pipeline take away capacity anticipated in Northwest Alberta during Q3/15 is currently expected to lower the Company's North America natural gas production volumes by approximately 80 MMcf/d. Canadian Natural's Q3/15 total natural gas production guidance reflects these impacts and is targeted to range from 1,670 MMcf/d to 1,690 MMcf/d.
- North America natural gas quarterly operating costs were $1.28/Mcf in Q2/15, a 14% decrease from Q2/14 levels of $1.48/Mcf, and a 7% decrease from Q1/15 levels of $1.38/Mcf, reflecting a continued focus on cost optimization.

International Exploration and Production

	Three Months Ended			Six Months Ended	
	Jun 30 2015	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Crude oil production (bbl/d)					
North Sea	**20,330**	23,036	12,615	**21,676**	14,654
Offshore Africa	**17,070**	13,188	13,164	**15,139**	11,984
Natural gas production (MMcf/d)					
North Sea	**38**	34	5	**36**	6
Offshore Africa	**25**	24	23	**24**	22
Net wells targeting crude oil	**1.4**	0.6	1.7	**2.0**	1.7
Net successful wells drilled	**1.4**	0.6	1.7	**2.0**	1.7
Success rate	**100%**	100%	100%	**100%**	100%

- International crude oil production averaged 37,400 bbl/d during Q2/15, an increase of 45% from Q2/14 levels and a 3% increase from Q1/15 levels. The increase in production over Q2/14 levels primarily reflected the reinstatement of production from both the Banff FPSO and the Tiffany platform during 2014. The increase in production from Q1/15 was primarily due to bringing new wells onstream at the Baobab and Espoir fields during Q2/15, offset by a planned turnaround performed at Ninian that commenced in late June 2015 and was completed in July 2015.
- The infill drilling programs at the Espoir and Baobab fields in Côte d'Ivoire continue to be successfully executed with results exceeding expectations.
  - To date, 3 gross wells have been drilled at Espoir, adding net production of approximately 4,500 bbl/d. Espoir is targeted to add overall net production volumes of 5,900 bbl/d through a 10 gross well program which includes 4 water injection wells (5.9 net well program) and is currently tracking below sanctioned costs.

- To date, Canadian Natural drilled 1 gross well at Baobab, adding net production volumes of approximately 2,000 bbl/d. Production from the second gross well is targeted to come on stream in the third quarter of 2015. Baobab is targeted to add overall net production volumes of 11,000 bbl/d through a 6 gross well program (3.4 net well program), which is currently tracking below sanctioned costs.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Six Months Ended	
	Jun 30 2015	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Synthetic crude oil production (bbl/d) (1)	**96,607**	134,166	119,236	**115,283**	116,182

(1) The Company has commenced production of diesel for internal use at Horizon. Second quarter 2015 SCO production before royalties excludes 2,410 bbl/d of SCO consumed internally as diesel (first quarter 2015 – 1,676 bbl/d; second quarter 2014 – nil; six months ended June 30, 2015 – 2,045 bbl/d; six months ended June 30, 2014 – nil).

- Horizon quarterly production averaged 96,607 bbl/d of SCO, a decrease of 19% and 28% from Q2/14 and Q1/15 levels respectively. Q2/15 production volumes were lower than targeted volumes primarily as a result of an extension of the 2015 planned maintenance turnaround from 10 days to 15 days in June, to address necessary found work, and a slightly slower than expected start-up of operations post-turnaround. July production volumes averaged approximately 124,200 bbl/d, near the low end of the targeted utilization rate range of 92% to 96%. Q3/15 production guidance is targeted to range from 124,000 bbl/d to 131,000 bbl/d, with a targeted utilization rate of 93% at the midpoint. 2015 annual production guidance remains unchanged at 121,000 bbl/d to 131,000 bbl/d.
- Canadian Natural continues to execute on its strategy to transition to a longer life, low decline asset base while delivering significant and sustainable production. Canadian Natural's staged expansion of Horizon to 250,000 bbl/d of SCO production capacity continues to progress ahead of schedule. Canadian Natural has committed to approximately 82% of the Engineering, Procurement and Construction contracts with over 78% of the construction contracts awarded to date, 85% being lump sum, ensuring greater cost certainty and efficiency.
- Overall Horizon Phase 2/3 expansion is 67% physically complete as at Q2/15:
  - Reliability – Tranche 2 is 100% physically complete. Completion occurred in 2014 resulting in increased performance and overall production reliability. This contributed approximately 5% increase in production levels from Phase 1 production levels.
  - Directive 74 includes technological investment and research into tailings management. This project remains on track and is 55% physically complete.
  - Phase 2A is a coker expansion that was originally scheduled to be completed in mid-2015; however, due to strong construction performance and the early completion of the coker installation, the Company accelerated the tie-in to August 2014. The expanded Coker Unit is now fully operational and the project was completed on time and below budget. Horizon SCO production levels increased by approximately 12,000 bbl/d with the completion of the coker tie-in. Through the completion of Phase 2A, additional coker capacity and equipment were added, increasing the plant nameplate capacity to 133,000 bbl/d. New equipment performance combined with an optimized mining strategy have increased the stability of the extraction and upgrading processes, resulting in a further increase to plant nameplate capacity to 137,000 bbl/d.
  - Phase 2B is 62% physically complete. This Phase expands the capacity of major components such as gas/oil hydrotreatment, froth treatment and the hydrogen plant. Due to continued strong construction performance on the Horizon expansion, certain components of this project will be tied-in during the Q2/16 turnaround. Production volumes after the turnaround are targeted to increase by 4,000 bbl/d in Q3/16 and 10,000 bbl/d in Q4/16, above the original planned production ramp up. Full commissioning of the Phase 2B equipment will be completed as planned in late 2016, adding 45,000 bbl/d of production capacity.
  - Phase 3 is currently on budget and on schedule. This Phase is 59% physically complete, and includes the addition of extraction trains. This phase is targeted to increase production capacity by 80,000 bbl/d in late 2017 and will result in additional reliability, redundancy and significant operating cost savings for the Horizon project.

ROYALTY PRODUCTION AND REVENUE

Canadian Natural reports the following information for quarterly royalty volumes, which are based on the Company's current estimate of revenue and volumes attributable to Q1/15:

- The development of leased acreage is ongoing and lease requests on undeveloped acreage continue to be evaluated. Total drilling activity for the first half of 2015 consisted of 151 wells with 146 drilled by third parties and 5 drilled by Canadian Natural. Compared to Q4/14, total Q1/15 production volumes on the royalty lands decreased by 195 BOE/d, however, crude oil and NGL production increased by 60 bbl/d.
- The Company continues to focus on lease compliance, well commitments, offset drilling obligations and compensatory royalties payable.
- Royalty production volumes highlighted below are not reported in Canadian Natural's quarterly production volumes. Third party royalty revenues are included in reported Product Sales in the Company's consolidated statement of earnings.

Royalty Production Volumes Comparison (1)

	Q1/15	Q4/14
Natural gas (MMcf/d)	22.4	24.0
Crude oil (bbl/d)	4,263	4,203
NGLs (bbl/d)	538	534
Total (BOE/d)	**8,537**	**8,732**

Royalty Production Volumes (1)

	Royalty volumes for Q1/15 attributable to		
	Third Party	Canadian Natural (2)	Total
Natural gas (MMcf/d)	19.2	3.2	22.4
Crude oil (bbl/d)	3,618	645	4,263
NGLs (bbl/d)	490	48	538
Total (BOE/d)	**7,305**	**1,232**	**8,537**

Royalty Revenue by Product (1)

	Royalty revenue for Q1/15 attributable to		
($ millions)	Third Party	Canadian Natural (2)	Total
Natural gas	$ 4	1	5
Crude oil	$ 15	2	17
NGLs	$ 1	–	1
Other revenue (3)	$ 1	–	1
Total	**$ 21**	**3**	**24**

Revenue by Royalty Classification [1]

($ millions)	Royalty revenue for Q1/15 attributable to Third Party	Canadian Natural [2]	Total
Fee title	$ 13	2	15
Gross overriding royalty [4]	$ 7	1	8
Other revenue [3]	$ 1	–	1
Total	**$ 21**	**3**	**24**

Royalty Realized Pricing [1]

	Q1/15
Natural gas ($/Mcf)	$ 2.59
Crude oil ($/bbl)	$ 42.89
NGLs ($/bbl)	$ 27.83
Total ($/BOE)	**$ 31.35**

Royalty Acreage

(gross acres, millions)	Leased to Third Party and Unleased	Canadian Natural [2]	Total
Fee title [5]	3.08	0.26	3.34
Gross overriding royalty [4]	1.83	1.68	3.51
Total	**4.91**	**1.94**	**6.85**

(1) Based on the Company's current estimate of revenue and volumes attributable to the noted period.
(2) Indicates Canadian Natural is both the Lessor and Lessee, thereby incurring intercompany royalties; in addition there are certain Canadian Natural fee title lands where the Company has production where no royalty burden has been recognized in this table.
(3) Includes sulphur revenue, bonus payments, lease rentals and compliance revenue.
(4) Includes Net Profit Interests and other royalties.
(5) Includes fee title and freehold lands.

MARKETING

	Three Months Ended			Six Months Ended	
	Jun 30 2015	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 57.96**	$ 48.57	$ 102.98	**$ 53.29**	$ 100.81
WCS blend differential from WTI (%) (2)	**20%**	30%	19%	**25%**	21%
SCO price (US$/bbl)	**$ 60.61**	$ 45.26	$ 103.87	**$ 52.98**	$ 100.18
Condensate benchmark pricing (US$/bbl)	**$ 57.98**	$ 45.59	$ 105.15	**$ 51.82**	$ 103.85
Average realized pricing before risk management (C$/bbl) (3)	**$ 53.09**	$ 37.03	$ 87.03	**$ 44.62**	$ 83.68
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.53**	$ 2.80	$ 4.44	**$ 2.67**	$ 4.48
Average realized pricing before risk management (C$/Mcf)	**$ 3.06**	$ 3.38	$ 5.06	**$ 3.22**	$ 5.32

(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.

Benchmark Pricing	**WTI Pricing (US$/bbl)**	**WCS Blend Differential from WTI (%)**	**WCS Blend Differential from WTI (US$/bbl)**	**SCO Differential from WTI (US$/bbl)**	**Dated Brent Differential from WTI (US$/bbl)**	**Condensate Differential from WTI (US$/bbl)**
2015						
April	$ 54.63	26%	$ 14.37	$ 0.86	$ 5.13	$ 0.68
May	$ 59.37	20%	$ 11.87	$ 3.43	$ 4.95	$ 1.54
June	$ 59.83	14%	$ 8.54	$ 3.63	$ 1.87	$ (2.22)
July	$ 50.93	15%	$ 7.44	$ 2.62	$ 5.61	$ (4.35)
August*	$ 47.26	28%	$ 13.41	$ (0.64)	$ 4.33	$ (1.36)
September*	$ 47.72	33%	$ 15.95	$ (2.75)	$ 4.33	$ 1.25

**Based on current indicative pricing as at July 31, 2015. SCO and Condensate September pricing based on current indicative pricing as at August 5, 2015.*

- Volatility in supply and demand factors and geopolitical events continued to affect WTI and Brent pricing. The Organization of the Petroleum Exporting Countries' ("OPEC") decision to maintain crude oil production quotas resulted in a year over year decline in benchmark pricing. Crude oil pricing increased in Q2/15 from Q1/15 as a result of slower US shale oil production growth, market response to reduced rig counts and lower crude oil inventories at Cushing as a result of higher refinery utilizations.
- The WCS differential to WTI averaged US$11.60/bbl or 20% in Q2/15 compared to US$20.03/bbl or 19% in Q2/14. The WCS heavy differential narrowed during Q2/15 compared to Q1/15 due to increased refinery utilization and seasonal demand. August 2015 and September 2015 indications of the WCS heavy differential are trending higher to US$13.41/bbl or 28% and US$15.95/bbl or 33%, respectively. This widening is mainly due to planned refinery turnarounds, which are typical during this time of year. Seasonal demand fluctuations, changes in transportation logistics and refinery utilization and shutdowns will continue to be reflected in WCS pricing.
- Canadian Natural contributed approximately 162,000 bbl/d of its heavy crude oil stream to the WCS blend in Q2/15. The Company remains the largest contributor to the WCS blend, accounting for 47% of the total blend.
- SCO pricing averaged US$60.61/bbl during Q2/15 compared to US$45.26/bbl in Q1/15, as a result of an increase in WTI benchmark pricing and industry-wide oil sands production interruptions caused by planned and unplanned production outages. Year over year SCO pricing has decreased resulting from an overall decline in WTI benchmark pricing.

- AECO natural gas pricing in Q2/15 averaged $2.53/GJ, a decrease of 43% and 10% from Q2/14 and Q1/15 pricing respectively. In Q2/15, US natural gas production continued to grow while natural gas inventories remained at normal industry levels, leading to downward pressure on natural gas prices. Natural gas prices were lower in Q2/15 compared to Q1/15 primarily due to seasonal demand. Warmer weather and adequate storage levels primarily resulted in lower natural gas pricing in Q2/15 compared to Q2/14, which had lower than average storage levels due to the cold winter temperatures in 2014.

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 and commodity hedging policy 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 approximately 805,500 BOE/d for Q2/15 with approximately 97% of production located in G8 countries.
- During the second quarter, the Company priced C$500 million principal amount of notes through the reopening of its 2.89% medium-term notes, series 2, due August 14, 2020.
- In Q2/15, the Company increased its $1,500 million revolving syndicated credit facility to $2,425 million and the maturity date was extended to June 2019. The $3,000 million revolving syndicated credit facility was reduced to $2,425 million and the maturity date was extended to June 2020. As a result, the Company's available liquidity increased by $350 million.
- Canadian Natural has a strong balance sheet with debt to book capitalization of 37% and debt to EBITDA of 2.0x at June 30, 2015. All of the Company's credit facilities are now subject to a revised financial covenant that the Consolidated Debt to Capitalization Ratio, as defined in the credit agreements, shall not be more than 0.65 to 1.0.
- Canadian Natural maintains significant financial stability and liquidity represented in part by bank credit facilities. As at June 30, 2015, the Company had in place bank credit facilities of $7,479 million, of which $3,272 million was available.
- The Company's commodity hedging program is utilized to protect investment returns, support ongoing balance sheet strength and the cash flow for its capital expenditure programs. Details of the Company's commodity hedging program can be found on the Company's website at www.cnrl.com.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.23 per share payable on October 1, 2015.
- The Company has a strong balance sheet and cash flow generation which enables it to weather volatility in commodity prices. Canadian Natural retains additional capital expenditure program flexibility to proactively adapt to changing market conditions.

OUTLOOK

The Company forecasts 2015 production levels before royalties to average between 562,000 and 602,000 bbl/d of crude oil and NGLs and between 1,730 and 1,770 MMcf/d of natural gas. Q3/15 production guidance before royalties is forecast to average between 559,000 and 590,000 bbl/d of crude oil and NGLs and between 1,670 and 1,690 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.

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 their 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, 2015 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2014.

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, 2015 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 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, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, 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, 2015 in relation to the comparable periods in 2014 and the first quarter of 2015. 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, 2014, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated August 5, 2015.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Six Months Ended	
	Jun 30 2015	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Product sales	**$ 3,662**	$ 3,226	$ 6,113	**$ 6,888**	$ 11,081
Net earnings (loss)	**$ (405)**	$ (252)	$ 1,070	**$ (657)**	$ 1,692
Per common share – basic	**$ (0.37)**	$ (0.23)	$ 0.98	**$ (0.60)**	$ 1.55
– diluted	**$ (0.37)**	$ (0.23)	$ 0.97	**$ (0.60)**	$ 1.54
Adjusted net earnings from operations (1)	**$ 178**	$ 21	$ 1,150	**$ 199**	$ 2,071
Per common share – basic	**$ 0.16**	$ 0.02	$ 1.05	**$ 0.18**	$ 1.90
– diluted	**$ 0.16**	$ 0.02	$ 1.04	**$ 0.18**	$ 1.89
Cash flow from operations (2)	**$ 1,503**	$ 1,370	$ 2,633	**$ 2,873**	$ 4,779
Per common share – basic	**$ 1.38**	$ 1.25	$ 2.41	**$ 2.63**	$ 4.38
– diluted	**$ 1.37**	$ 1.25	$ 2.39	**$ 2.62**	$ 4.36
Capital expenditures, net of dispositions	**$ 1,297**	$ 1,412	$ 5,456	**$ 2,709**	$ 7,349

(1) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings 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 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 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 from Operations

	Three Months Ended			Six Months Ended	
($ millions)	***Jun 30 2015***	*Mar 31 2015*	*Jun 30 2014*	***Jun 30 2015***	*Jun 30 2014*
Net earnings (loss) as reported	***$ (405)***	*$ (252)*	*$ 1,070*	***$ (657)***	*$ 1,692*
Share-based compensation, net of tax (1)	***(79)***	*64*	*189*	***(15)***	*332*
Unrealized risk management loss, net of tax (2)	***162***	*9*	*44*	***171***	*82*
Unrealized foreign exchange (gain) loss, net of tax (3)	***(76)***	*413*	*(153)*	***337***	*(35)*
Equity (gain) loss from investment, net of tax (4)	***(3)***	*15*	*–*	***12***	*–*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (5)	***579***	*(228)*	*–*	***351***	*–*
Adjusted net earnings from operations	***$ 178***	*$ 21*	*$ 1,150*	***$ 199***	*$ 2,071*

(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 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.

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

(5) 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 Petroleum Revenue Tax ("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 2015	Mar 31 2015	Jun 30 2014	Six Months Ended Jun 30 2015	Jun 30 2014
Net earnings (loss)	***$ (405)***	*$ (252)*	*$ 1,070*	***$ (657)***	*$ 1,692*
Non-cash items:					
Depletion, depreciation and amortization	***1,280***	*1,355*	*1,237*	***2,635***	*2,248*
Share-based compensation	***(79)***	*64*	*189*	***(15)***	*332*
Asset retirement obligation accretion	***43***	*43*	*50*	***86***	*95*
Unrealized risk management loss	***215***	*14*	*54*	***229***	*103*
Unrealized foreign exchange (gain) loss	***(76)***	*413*	*(153)*	***337***	*(35)*
Equity (gain) loss from investment	***(3)***	*15*	*(3)*	***12***	*(2)*
Deferred income tax expense (recovery)	***528***	*(282)*	*189*	***246***	*346*
Cash flow from operations	***$ 1,503***	*$ 1,370*	*$ 2,633*	***$ 2,873***	*$ 4,779*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net loss for the six months ended June 30, 2015 was $657 million compared with net earnings of $1,692 million for the six months ended June 30, 2014. Net loss for the six months ended June 30, 2015 included net after-tax expenses of $856 million compared with $379 million for the six months ended June 30, 2014 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, equity (gain) loss from investment, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the six months ended June 30, 2015 were $199 million compared with $2,071 million for the six months ended June 30, 2014.

Net loss for the second quarter of 2015 was $405 million compared with net earnings of $1,070 million for the second quarter of 2014 and net loss of $252 million for the first quarter of 2015. Net loss for the second quarter of 2015 included net after-tax expenses of $583 million compared with $80 million for the second quarter of 2014 and $273 million for the first quarter of 2015 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, equity (gain) loss from investment, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the second quarter of 2015 were $178 million compared with $1,150 million for the second quarter of 2014 and $21 million for the first quarter of 2015.

The decrease in adjusted net earnings for the six months ended June 30, 2015 from the comparable period in 2014 was primarily due to:

- lower crude oil and NGLs netbacks in the North America and North Sea segments;
- lower realized SCO prices;
- lower natural gas netbacks in the North America segment; and
- higher depletion, depreciation and amortization expense;

partially offset by:

- higher crude oil and NGLs and natural gas sales volumes in the North America and North Sea segments;
- higher realized risk management gains; and
- the impact of a weaker Canadian dollar relative to the US dollar.

The decrease in adjusted net earnings for the second quarter of 2015 from the second quarter of 2014 was primarily due to:

- lower crude oil and NGLs netbacks across all Exploration and Production segments;
- lower SCO sales volumes and realized SCO prices;
- lower crude oil and NGLs sales volumes in the North America segment; and
- lower natural gas netbacks in the North America segment;

partially offset by:

- higher natural gas sales volumes in the North America and North Sea segments;
- higher realized risk management gains; and
- the impact of a weaker Canadian dollar relative to the US dollar.

The increase in adjusted net earnings for the second quarter of 2015 from the first quarter of 2015 was primarily due to:

- higher crude oil and NGLs netbacks in the North America segment;
- higher realized SCO prices; and
- higher crude oil and NGLs sales volumes in the North Sea and Offshore Africa segments;

partially offset by:

- lower crude oil and NGLs and SCO sales volumes in the North America and Oil Sands Mining and Upgrading segments;
- lower natural gas netbacks in the North America segment;
- lower crude oil netbacks in the Offshore Africa segment; and
- lower realized risk management gains.

The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates are expected to continue to contribute to quarterly 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, 2015 was $2,873 million compared with $4,779 million for the six months ended June 30, 2014. Cash flow from operations for the second quarter of 2015 was $1,503 million compared with $2,633 million for the second quarter of 2014 and $1,370 million for the first quarter of 2015. 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, as well as due to the impact of cash taxes.

Total production before royalties for the six months ended June 30, 2015 increased 13% to 851,545 BOE/d from 751,426 BOE/d for the six months ended June 30, 2014. Total production before royalties for the second quarter of 2015 decreased 1% to 805,547 BOE/d from 817,471 BOE/d for the second quarter of 2014 and decreased 10% from 898,053 BOE/d for the first quarter of 2015.

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 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
($ millions, except per common share amounts)		Jun 30 2014		Mar 31 2014		Dec 31 2013		Sep 30 2013
Product sales	$	6,113	$	4,968	$	4,330	$	5,284
Net earnings (loss)	$	1,070	$	622	$	413	$	1,168
Net earnings (loss) per common share								
– basic	$	0.98	$	0.57	$	0.38	$	1.07
– diluted	$	0.97	$	0.57	$	0.38	$	1.07

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, 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 Dated 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 strong heavy crude oil drilling program throughout 2013 and 2014, the impact and timing of acquisitions, and the impact of turnarounds at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore Africa.
- **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 natural gas production due to pricing and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand 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, and turnarounds at Horizon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions, 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 depletion, depreciation and amortization expense in the North Sea resulting from the planned early cessation of production at the Murchison platform, and the impact of turnarounds at Horizon.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately 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 corporate acquisitions/disposition of properties** – Fluctuations due to the recognition of gains on corporate acquisitions/dispositions in the fourth quarter of 2014 and the third quarter of 2013.

BUSINESS ENVIRONMENT

	Three Months Ended			Six Months Ended	
	Jun 30 2015	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
WTI benchmark price (US$/bbl)	**$ 57.96**	$ 48.57	$ 102.98	**$ 53.29**	$ 100.81
Dated Brent benchmark price (US$/bbl)	**$ 61.95**	$ 53.80	$ 109.63	**$ 57.90**	$ 108.92
WCS blend differential from WTI (US$/bbl)	**$ 11.60**	$ 14.75	$ 20.03	**$ 13.16**	$ 21.64
WCS blend differential from WTI (%)	**20%**	30%	19%	**25%**	21%
SCO price (US$/bbl)	**$ 60.61**	$ 45.26	$ 103.87	**$ 52.98**	$ 100.18
Condensate benchmark price (US$/bbl)	**$ 57.98**	$ 45.59	$ 105.15	**$ 51.82**	$ 103.85
NYMEX benchmark price (US$/MMBtu)	**$ 2.67**	$ 2.96	$ 4.57	**$ 2.81**	$ 4.73
AECO benchmark price (C$/GJ)	**$ 2.53**	$ 2.80	$ 4.44	**$ 2.67**	$ 4.48
US/Canadian dollar average exchange rate (US$)	**$ 0.8132**	$ 0.8057	$ 0.9171	**$ 0.8095**	$ 0.9118

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. In the second quarter of 2015, realized prices continued to be impacted by the weak Canadian dollar, which increased the Canadian dollar sales price the Company received for its crude oil and natural gas sales, as realized pricing 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$53.29 per bbl for the six months ended June 30, 2015, a decrease of 47% from US$100.81 per bbl for the six months ended June 30, 2014. WTI averaged US$57.96 per bbl for the second quarter of 2015, a decrease of 44% from US$102.98 per bbl for the second quarter of 2014, and an increase of 19% from US$48.57 per bbl for the first quarter of 2015.

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$57.90 per bbl for the six months ended June 30, 2015, a decrease of 47% from US$108.92 per bbl for the six months ended June 30, 2014. Brent averaged US$61.95 per bbl for the second quarter of 2015, a decrease of 43% from US$109.63 per bbl for the second quarter of 2014, and an increase of 15% from US$53.80 per bbl for the first quarter of 2015.

WTI and Brent pricing continued to reflect volatility in supply and demand factors and geopolitical events. An oversupply of crude oil in the world market together with the Organization of the Petroleum Exporting Countries' ("OPEC") decision to continue to maintain crude oil production quotas resulted in a decline in year-over-year benchmark pricing. Crude oil benchmark pricing increased for the second quarter of 2015 from the first quarter of 2015 due to declines in the growth rate of US shale oil production, market response to reduced rig counts, and lower crude oil inventories at Cushing as a result of higher refinery utilizations.

The WCS Heavy Differential averaged 25% for the six months ended June 30, 2015, compared with 21% for the six months ended June 30, 2014. The WCS Heavy Differential averaged 20% for the second quarter of 2015 compared with 19% for the second quarter of 2014 and 30% for the first quarter of 2015. The WCS Heavy Differential narrowed for the second quarter of 2015 from the first quarter of 2015 primarily due to increased refinery utilization and seasonal demand.

The WCS Heavy Differential is expected to continue to reflect seasonal demand fluctuations, changes in transportation logistics, and refinery utilization and shutdowns.

The SCO price averaged US$52.98 per bbl for the six months ended June 30, 2015, a decrease of 47% from US$100.18 per bbl for the six months ended June 30, 2014. The SCO price averaged US$60.61 per bbl for the second quarter of 2015, a decrease of 42% from US$103.87 per bbl for the second quarter of 2014, and increased 34% from US$45.26 per bbl for the first quarter of 2015. The decrease in SCO pricing for the three and six months ended June 30, 2015 from the comparable periods in 2014 was primarily due to a decrease in WTI benchmark pricing. The increase in SCO pricing for the second quarter of 2015 from the first quarter of 2015 was due to both an increase in WTI benchmark pricing as well as industry-wide oil sands production interruptions caused by planned and unplanned production outages.

NYMEX natural gas prices averaged US$2.81 per MMBtu for the six months ended June 30, 2015, a decrease of 41% from US$4.73 per MMBtu for the six months ended June 30, 2014. NYMEX natural gas prices averaged US$2.67 per MMBtu for the second quarter of 2015, a decrease of 42% from US$4.57 per MMBtu for the second quarter of 2014, and a decrease of 10% from US$2.96 per MMBtu for the first quarter of 2015.

AECO natural gas prices for the six months ended June 30, 2015 averaged $2.67 per GJ, a decrease of 40% from $4.48 per GJ for the six months ended June 30, 2014. AECO natural gas prices for the second quarter of 2015 averaged $2.53 per GJ, a decrease of 43% from $4.44 per GJ for the second quarter of 2014, and a decrease of 10% from $2.80 per GJ for the first quarter of 2015.

In the second quarter of 2015, US natural gas production continued to grow while natural gas inventories remained at normal industry levels, leading to downward pressure on natural gas prices. Natural gas prices were lower in the second quarter of 2015 from the comparable periods primarily due to seasonal demand factors, and as natural gas prices in 2014 reflected lower than average storage levels due to the cold winter temperatures.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2015	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**375,040**	432,419	400,154	**403,571**	374,314
North America – Oil Sands Mining and Upgrading (1)	**96,607**	134,166	119,236	**115,283**	116,182
North Sea	**20,330**	23,036	12,615	**21,676**	14,654
Offshore Africa	**17,070**	13,188	13,164	**15,139**	11,984
	509,047	602,809	545,169	**555,669**	517,134
Natural gas (MMcf/d)					
North America	**1,716**	1,713	1,606	**1,715**	1,378
North Sea	**38**	34	5	**36**	6
Offshore Africa	**25**	24	23	**24**	22
	1,779	1,771	1,634	**1,775**	1,406
Total barrels of oil equivalent (BOE/d)	**805,547**	898,053	817,471	**851,545**	751,426
Product mix					
Light and medium crude oil and NGLs	**16%**	15%	15%	**15%**	15%
Pelican Lake heavy crude oil	**6%**	6%	6%	**6%**	7%
Primary heavy crude oil	**16%**	15%	17%	**15%**	19%
Bitumen (thermal oil)	**13%**	16%	14%	**15%**	13%
Synthetic crude oil (1)	**12%**	15%	15%	**14%**	15%
Natural gas	**37%**	33%	33%	**35%**	31%
Percentage of product sales (1) (2) (excluding Midstream revenue)					
Crude oil and NGLs	**84%**	80%	86%	**82%**	86%
Natural gas	**16%**	20%	14%	**18%**	14%

(1) *Second quarter 2015 SCO production before royalties excludes 2,410 bbl/d of SCO consumed internally as diesel (first quarter 2015 – 1,676 bbl/d; second quarter 2014 – nil; six months ended June 30, 2015 – 2,045 bbl/d; six months ended June 30, 2014 – nil).*

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2015	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**326,445**	380,273	318,672	**353,209**	299,854
North America – Oil Sands Mining and Upgrading	**95,057**	132,413	111,825	**113,632**	109,372
North Sea	**20,300**	22,976	12,581	**21,631**	14,610
Offshore Africa	**16,342**	12,586	12,733	**14,475**	11,256
	458,144	548,248	455,811	**502,947**	435,092
Natural gas (MMcf/d)					
North America	**1,684**	1,643	1,474	**1,664**	1,247
North Sea	**38**	34	5	**36**	6
Offshore Africa	**24**	23	19	**23**	19
	1,746	1,700	1,498	**1,723**	1,272
Total barrels of oil equivalent (BOE/d)	**749,210**	831,637	705,480	**790,196**	647,101

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, 2015 increased 7% to 555,669 bbl/d from 517,134 bbl/d for the six months ended June 30, 2014. Crude oil and NGLs production for the second quarter of 2015 decreased 7% to 509,047 bbl/d from 545,169 bbl/d for the second quarter of 2014 and decreased 16% from 602,809 bbl/d for the first quarter of 2015. The increase in production for the six months ended June 30, 2015 from the comparable period was primarily due to increased production in all exploration and production segments as well as from acquisitions of producing Canadian crude oil properties in 2014. The decrease for the three months ended June 30, 2015 from the comparable periods was primarily related to the completion of an extended planned turnaround at Horizon, the temporary curtailment of both Primrose and Kirby operations due to forest fires in Northeastern Alberta in late May and early June 2015, as well as the cyclic nature of the Primrose operations. As a result of the extended turnaround at Horizon, crude oil and NGLs production for the second quarter of 2015 was slightly below the Company's previously issued guidance of 513,000 to 540,000 bbl/d.

Natural gas production for the six months ended June 30, 2015 increased 26% to 1,775 MMcf/d from 1,406 MMcf/d for the six months ended June 30, 2014. Natural gas production for the second quarter of 2015 increased 9% to 1,779 MMcf/d from 1,634 MMcf/d for the second quarter of 2014 and was comparable with the first quarter of 2015. The increase in natural gas production for the three and six months ended June 30, 2015 from comparable periods in 2014 was primarily a result of acquisitions of producing Canadian natural gas properties in 2014 and growth from higher production volumes in the North Sea. Natural gas production for the second quarter of 2015 exceeded the Company's previously issued guidance of 1,750 to 1,770 MMcf/d.

2015 annual production guidance, revised as of March 5, 2015, remains unchanged and is targeted to average between 562,000 and 602,000 bbl/d of crude oil and NGLs and between 1,730 and 1,770 MMcf/d of natural gas. Third quarter 2015 production guidance is targeted to average between 559,000 and 590,000 bbl/d of crude oil and NGLs and between 1,670 and 1,690 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the six months ended June 30, 2015 increased 8% to average 403,571 bbl/d from 374,314 bbl/d for the six months ended June 30, 2014. For the second quarter of 2015, crude oil and NGLs production decreased 6% to average 375,040 bbl/d compared with 400,154 bbl/d for the second quarter of 2014 and decreased 13% from 432,419 bbl/d for the first quarter of 2015. The increase in production for the six months ended June 30, 2015 from the comparable period in 2014 was primarily due to increased production in the Company's thermal areas, including Kirby South, and increased production related to the acquisitions of producing Canadian crude oil properties in 2014. The decrease for the three months ended June 30, 2015 from the comparable periods was primarily related to the temporary curtailment of both Primrose and Kirby operations due to forest fires in Northeastern Alberta, as well as the cyclic nature of the Primrose operations. Second quarter 2015 production of crude oil and NGLs was within the Company's previously issued guidance of 372,000 to 389,000 bbl/d. Third quarter 2015 production guidance is targeted to average between 393,000 and 413,000 bbl/d of crude oil and NGLs.

Natural gas production for the six months ended June 30, 2015 increased 24% to 1,715 MMcf/d compared with 1,378 MMcf/d for the six months ended June 30, 2014. Natural gas production increased 7% to 1,716 MMcf/d for the second quarter of 2015 compared with 1,606 MMcf/d in the second quarter of 2014 and was comparable with the first quarter of 2015. The increase in natural gas production for the three and six months ended June 30, 2015 from the comparable periods in 2014 was primarily a result of acquisitions of producing Canadian natural gas properties in 2014.

North America – Oil Sands Mining and Upgrading

SCO production for the six months ended June 30, 2015 was comparable with the six months ended June 30, 2014. For the second quarter of 2015, SCO production decreased 19% to 96,607 bbl/d from 119,236 bbl/d for the second quarter of 2014 and decreased 28% from 134,166 bbl/d for the first quarter of 2015. Second quarter 2015 production reflected the successful completion of the Horizon turnaround. The planned turnaround was extended to perform additional maintenance work. As a result, second quarter 2015 production of SCO was below the Company's previously issued guidance of 107,000 to 113,000 bbl/d. July production averaged approximately 124,200 bbl/d after the successful completion of the planned turnaround, with third quarter 2015 production guidance targeted to average between 124,000 to 131,000 bbl/d.

North Sea

North Sea crude oil production for the six months ended June 30, 2015 increased 48% to 21,676 bbl/d from 14,654 bbl/d for the six months ended June 30, 2014. Second quarter 2015 crude oil production increased 61% to 20,330 bbl/d from 12,615 bbl/d for the second quarter of 2014, and decreased 12% from 23,036 bbl/d for the first quarter of 2015. The increase in production for the three and six months ended June 30, 2015 from the comparable periods in 2014 primarily reflected the reinstatement of production from both the Banff FPSO and the Tiffany platform in 2014. The decrease in production for the second quarter of 2015 from the first quarter of 2015 was primarily due to the planned turnaround performed at Ninian that commenced in late June 2015 and was completed in July 2015.

Offshore Africa

Offshore Africa crude oil production increased 26% to 15,139 bbl/d for the six months ended June 30, 2015 from 11,984 bbl/d for the six months ended June 30, 2014. Second quarter 2015 crude oil production increased 30% to 17,070 bbl/d from 13,164 bbl/d for the second quarter of 2014 and increased 29% from 13,188 bbl/d for the first quarter of 2015. The increase in production volumes for the three and six months ended June 30, 2015 from the comparable periods was due to new wells on stream at the Espoir and the Baobab fields in the second quarter of 2015, partially offset by natural field declines.

International Guidance

The Company's North Sea and Offshore Africa second quarter 2015 crude oil production was 37,400 bbl/d and was within the Company's previously issued guidance of 34,000 to 38,000 bbl/d. Third quarter 2015 production guidance is targeted to average between 42,000 and 46,000 bbl/d of crude oil.

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 on crude oil volumes that were stored in various storage facilities, pipelines, or FPSOs, as follows:

(bbl)	**Jun 30 2015**	Mar 31 2015	Dec 31 2014
North America – Exploration and Production	**839,720**	598,825	930,116
North America – Oil Sands Mining and Upgrading (SCO)	**1,074,964**	1,692,043	1,266,063
North Sea	**131,959**	562,540	368,808
Offshore Africa	**1,459,094**	1,086,222	461,997
	3,505,737	3,939,630	3,026,984

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2015	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 53.09**	$ 37.03	$ 87.03	**$ 44.62**	$ 83.68
Transportation	**2.80**	2.46	2.74	**2.62**	2.62
Realized sales price, net of transportation	**50.29**	34.57	84.29	**42.00**	81.06
Royalties	**5.91**	3.83	15.62	**4.82**	14.90
Production expense	**17.01**	16.10	19.33	**16.53**	19.26
Netback	**$ 27.37**	$ 14.64	$ 49.34	**$ 20.65**	$ 46.90
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 3.06**	$ 3.38	$ 5.06	**$ 3.22**	$ 5.32
Transportation	**0.38**	0.36	0.26	**0.37**	0.28
Realized sales price, net of transportation	**2.68**	3.02	4.80	**2.85**	5.04
Royalties	**0.05**	0.12	0.41	**0.08**	0.49
Production expense	**1.39**	1.44	1.52	**1.42**	1.56
Netback	**$ 1.24**	$ 1.46	$ 2.87	**$ 1.35**	$ 2.99
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 38.85**	$ 30.57	$ 64.69	**$ 34.59**	$ 64.00
Transportation	**2.67**	2.44	2.35	**2.55**	2.32
Realized sales price, net of transportation	**36.18**	28.13	62.34	**32.04**	61.68
Royalties	**3.58**	2.65	10.49	**3.10**	10.46
Production expense	**13.39**	13.20	15.35	**13.29**	15.56
Netback	**$ 19.21**	$ 12.28	$ 36.50	**$ 15.65**	$ 35.66

(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 2015	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 50.96**	$ 35.22	$ 84.10	**$ 42.52**	$ 81.06
North Sea	**$ 73.57**	$ 64.59	$ 122.88	**$ 69.52**	$ 122.17
Offshore Africa	**$ 74.84**	$ 71.75	$ 119.47	**$ 73.84**	$ 119.47
Company average	**$ 53.09**	$ 37.03	$ 87.03	**$ 44.62**	$ 83.68
Natural gas ($/Mcf) (1) (2)					
North America	**$ 2.80**	$ 3.14	$ 4.95	**$ 2.97**	$ 5.21
North Sea	**$ 9.54**	$ 10.18	$ 6.38	**$ 9.84**	$ 6.19
Offshore Africa	**$ 10.49**	$ 11.70	$ 12.25	**$ 11.07**	$ 12.22
Company average	**$ 3.06**	$ 3.38	$ 5.06	**$ 3.22**	$ 5.32
Company average ($/BOE) (1) (2)	**$ 38.85**	$ 30.57	$ 64.69	**$ 34.59**	$ 64.00

(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 48% to $42.52 per bbl for the six months ended June 30, 2015 from $81.06 per bbl for the six months ended June 30, 2014. North America realized crude oil prices averaged $50.96 per bbl for the second quarter of 2015, a decrease of 39% compared with $84.10 per bbl for the second quarter of 2014 and an increase of 45% compared with $35.22 per bbl for the first quarter of 2015. The decrease in realized crude oil prices for the three and six months ended June 30, 2015 from the comparable periods in 2014 was primarily due to lower WTI benchmark pricing and a widening WCS Heavy Differential as a percentage of WTI, partially offset by the impact of a weakening Canadian dollar. The increase in realized crude oil prices for the second quarter of 2015 from the first quarter of 2015 was primarily due to higher WTI benchmark pricing and a narrowing WCS Heavy Differential as a percentage of WTI. The Company continues to focus on its crude oil blending marketing strategy and in the second quarter of 2015 contributed approximately 162,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 43% to average $2.97 per Mcf for the six months ended June 30, 2015 from $5.21 per Mcf for the six months ended June 30, 2014. North America realized natural gas prices decreased 43% to average $2.80 per Mcf for the second quarter of 2015 compared with $4.95 per Mcf in the second quarter of 2014, and decreased 11% compared with $3.14 per Mcf for the first quarter of 2015. US natural gas production continued to grow in the second quarter of 2015 while natural gas inventories remained at normal industry levels, leading to downward pressure on natural gas prices. Realized natural gas prices were lower in the second quarter of 2015 from the comparable periods primarily due to seasonal demand factors, and as natural gas prices in 2014 reflected lower than average storage levels due to the cold winter temperatures.

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

(Quarterly Average)	**Jun 30 2015**	Mar 31 2015	Jun 30 2014
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 51.80**	$ 38.78	$ 85.95
Pelican Lake heavy crude oil ($/bbl)	**$ 54.87**	$ 36.21	$ 86.92
Primary heavy crude oil ($/bbl)	**$ 53.85**	$ 37.64	$ 85.65
Bitumen (thermal oil) ($/bbl)	**$ 44.63**	$ 30.25	$ 79.39
Natural gas ($/Mcf)	**$ 2.80**	$ 3.14	$ 4.95

(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 43% to average $69.52 per bbl for the six months ended June 30, 2015 from $122.17 per bbl for the six months ended June 30, 2014. North Sea realized crude oil prices decreased 40% to average $73.57 per bbl for the second quarter of 2015 from $122.88 per bbl for the second quarter of 2014 and increased 14% from $64.59 per bbl for the first quarter of 2015. The fluctuations in realized crude oil prices for the three and six months ended June 30, 2015 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices decreased 38% to average $73.84 per bbl for the six months ended June 30, 2015 from $119.47 per bbl for the six months ended June 30, 2014. Offshore Africa realized crude oil prices decreased 37% to average $74.84 per bbl for the second quarter of 2015 from $119.47 for the second quarter of 2014 and increased 4% from $71.75 per bbl for the first quarter of 2015. The fluctuations in realized crude oil prices for the three and six months ended June 30, 2015 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2015	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 6.40**	$ 4.02	$ 16.79	**$ 5.12**	$ 15.85
North Sea	**$ 0.11**	$ 0.16	$ 0.33	**$ 0.13**	$ 0.35
Offshore Africa	**$ 3.19**	$ 3.27	$ 3.92	**$ 3.22**	$ 3.92
Company average	**$ 5.91**	$ 3.83	$ 15.62	**$ 4.82**	$ 14.90
Natural gas ($/Mcf) [1]					
North America	**$ 0.05**	$ 0.12	$ 0.39	**$ 0.08**	$ 0.47
Offshore Africa	**$ 0.48**	$ 0.54	$ 1.89	**$ 0.51**	$ 1.97
Company average	**$ 0.05**	$ 0.12	$ 0.41	**$ 0.08**	$ 0.49
Company average ($/BOE) [1]	**$ 3.58**	$ 2.65	$ 10.49	**$ 3.10**	$ 10.46

(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, 2015 and the comparable periods reflected movements in benchmark commodity prices and fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 13% of product sales for the six months ended June 30, 2015 compared with 20% of product sales for the six months ended June 30, 2014. Crude oil and NGLs royalties averaged approximately 13% of product sales for the second quarter of 2015 compared with 21% for the second quarter of 2014 and 12% for the first quarter of 2015. The decrease in royalties for the three and six months ended June 30, 2015 from the comparable periods in 2014 was primarily due to lower realized crude oil prices. The increase in royalties for the second quarter of 2015 from the first quarter of 2015 was primarily due to higher realized crude oil prices. Crude oil and NGLs royalties per bbl are anticipated to average 11.5% to 13.5% of product sales for 2015.

Natural gas royalties averaged approximately 3% of product sales for the six months ended June 30, 2015 compared with 10% of product sales for the six months ended June 30, 2014. Natural gas royalties averaged approximately 2% of product sales for the second quarter of 2015 compared with 8% for the second quarter of 2014 and 4% for the first quarter of 2015. The decrease in natural gas royalty rates for the three and six months ended June 30, 2015 from the comparable periods was due to lower realized natural gas prices. Natural gas royalties are anticipated to average 3% to 4% of product sales for 2015.

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, 2015 from 7% for the six months ended June 30, 2014. Royalty rates as a percentage of product sales averaged approximately 4% for the second quarter of 2015 compared with 5% for the second quarter of 2014 and 5% for the first quarter of 2015. The decrease in royalties for the three and six months ended June 30, 2015 from the comparable periods in 2014 was primarily a result of the timing of liftings from various fields and the status of payout in the various fields. Offshore Africa royalty rates are anticipated to average 3.5% to 5.5% of product sales for 2015.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2015	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 13.14**	$ 13.75	$ 14.97	**$ 13.47**	$ 15.59
North Sea	**$ 60.61**	$ 65.23	$ 79.21	**$ 62.69**	$ 77.46
Offshore Africa	**$ 43.88**	$ 15.46	$ 58.41	**$ 34.71**	$ 58.41
Company average	**$ 17.01**	$ 16.10	$ 19.33	**$ 16.53**	$ 19.26
Natural gas ($/Mcf) [1]					
North America	**$ 1.28**	$ 1.38	$ 1.48	**$ 1.33**	$ 1.51
North Sea	**$ 6.47**	$ 3.89	$ 6.12	**$ 5.27**	$ 5.95
Offshore Africa	**$ 1.42**	$ 2.80	$ 3.28	**$ 2.09**	$ 3.45
Company average	**$ 1.39**	$ 1.44	$ 1.52	**$ 1.42**	$ 1.56
Company average ($/BOE) [1]	**$ 13.39**	$ 13.20	$ 15.35	**$ 13.29**	$ 15.56

(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, 2015 decreased 14% to $13.47 per bbl from $15.59 per bbl for the six months ended June 30, 2014. North America crude oil and NGLs production expense for the second quarter of 2015 decreased 12% to $13.14 per bbl from $14.97 per bbl for the second quarter of 2014 and decreased 4% from $13.75 per bbl for the first quarter of 2015. The decrease in production expense for the three and six months ended June 30, 2015 from the comparable periods reflected the Company's continuous focus on efficiencies, cost control across the asset base, and overall lower industry service costs. North America crude oil and NGLs production expense is anticipated to average $12.25 to $14.25 per bbl for 2015.

North America natural gas production expense for the six months ended June 30, 2015 decreased 12% to $1.33 per Mcf from $1.51 per Mcf for the six months ended June 30, 2014. North America natural gas production expense for the second quarter of 2015 decreased 14% to $1.28 per Mcf from $1.48 per Mcf for the second quarter of 2014 and decreased 7% from $1.38 per Mcf for the first quarter of 2015. Natural gas production expense for the three and six months ended June 30, 2015 decreased from the comparable periods due to focused cost control across the asset base, normal seasonality, and overall lower industry service costs. North America natural gas production expense is anticipated to average $1.25 to $1.35 per Mcf for 2015.

North Sea

North Sea crude oil production expense for the six months ended June 30, 2015 decreased 19% to $62.69 per bbl from $77.46 per bbl for the six months ended June 30, 2014. North Sea crude oil production expense for the second quarter of 2015 decreased 23% to $60.61 per bbl from $79.21 per bbl for the second quarter of 2014 and decreased 7% from $65.23 per bbl for the first quarter of 2015. The decrease in production expense for the three and six months ended June 30, 2015 from the comparable periods was primarily due to higher sales volumes on a relatively fixed cost structure, offset by the impact of the weak Canadian dollar compared to 2014. North Sea crude oil production expense has been revised to average $58.00 to $64.00 per bbl for 2015, reflecting the weakening of the Canadian dollar.

Offshore Africa

Offshore Africa crude oil production expense for the six months ended June 30, 2015 decreased 41% to $34.71 per bbl from $58.41 per bbl for the six months ended June 30, 2014. Offshore Africa crude oil production expense for the second quarter of 2015 averaged $43.88 per bbl, a decrease of 25% from $58.41 per bbl for the second quarter of 2014 and an increase of 184% from $15.46 per bbl for the first quarter of 2015. The decrease in production expense for the three and six months ended June 30, 2015 from the comparable periods in 2014 was primarily due to the impact of higher production volumes, and the timing of liftings from various fields, which have different cost structures, offset by the impact of the weak Canadian dollar. The increase in production expense for the second quarter of 2015 from the first quarter of 2015 was primarily due to the timing of liftings from the various fields, which have different cost structures. Offshore Africa crude oil production expense is anticipated to average $24.00 to $28.00 per bbl for 2015.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2015**	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Expense ($ millions)	**$ 1,158**	$ 1,213	$ 1,099	**$ 2,371**	$ 1,978
$/BOE (1)	**$ 18.02**	$ 17.78	$ 17.28	**$ 17.90**	$ 17.40

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

Depletion, depreciation and amortization expense for the six months ended June 30, 2015 increased 3% to $17.90 per BOE from $17.40 per BOE for the six months ended June 30, 2014. Depletion, depreciation and amortization expense for the second quarter of 2015 increased 4% to $18.02 per BOE from $17.28 per BOE for the second quarter of 2014 and was comparable with the first quarter of 2015, primarily related to increased product sales in the International segments which have higher associated depletion rates. The increase in depletion, depreciation and amortization expense for the three and six months ended June 30, 2015 from the comparable periods in 2014 primarily reflected the increase in sales volumes in 2015. The decrease in depletion, depreciation and amortization expense for the second quarter of 2015 from the first quarter of 2015 primarily reflected the decrease in sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2015**	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Expense ($ millions)	**$ 36**	$ 35	$ 39	**$ 71**	$ 72
$/BOE (1)	**$ 0.55**	$ 0.52	$ 0.59	**$ 0.53**	$ 0.63

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

Asset retirement obligation accretion expense for the six months ended June 30, 2015 decreased 16% to $0.53 per BOE from $0.63 per BOE for the six months ended June 30, 2014. Asset retirement obligation accretion expense for the second quarter of 2015 decreased 7% to $0.55 per BOE from $0.59 per BOE for the second quarter of 2014 and increased 6% from $0.52 per BOE for the first quarter of 2015. Asset retirement obligation accretion expense for the three and six months ended June 30, 2015 was consistent with the comparable periods.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

The Company continues to focus on reliable and efficient operations. During the second quarter of 2015, the Company completed the planned turnaround at Horizon, successfully enhancing throughput and reliability.

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

	Three Months Ended			Six Months Ended	
($/bbl)	**Jun 30 2015**	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
SCO sales price (1)	**$ 73.05**	$ 56.75	$ 112.69	**$ 64.03**	$ 110.37
Bitumen value for royalty purposes (1) (2)	**$ 44.09**	$ 29.70	$ 75.72	**$ 35.92**	$ 71.24
Bitumen royalties (1) (3)	**$ 0.99**	$ 1.01	$ 6.77	**$ 1.00**	$ 5.95
Transportation	**$ 1.98**	$ 1.83	$ 1.53	**$ 1.89**	$ 1.73

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Calculated as the quarterly average of the bitumen valuation methodology price.
(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Realized SCO sales prices averaged $64.03 per bbl for the six months ended June 30, 2015, a decrease of 42% compared with $110.37 per bbl for the six months ended June 30, 2014. Realized SCO sales prices averaged $73.05 per bbl for the second quarter of 2015, a decrease of 35% compared with $112.69 per bbl for the second quarter of 2014 and an increase of 29% compared with $56.75 per bbl for the first quarter of 2015, reflecting fluctuations in benchmark pricing and the Canadian dollar.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2015**	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Cash production costs	**$ 321**	$ 346	$ 404	**$ 667**	$ 816
Less: costs incurred during turnaround periods	**(45)**	–	–	**(45)**	–
Adjusted cash production costs	**$ 276**	$ 346	$ 404	**$ 622**	$ 816
Adjusted cash production costs, excluding natural gas costs	**$ 260**	$ 326	$ 372	**$ 586**	$ 747
Adjusted natural gas costs	**16**	20	32	**36**	69
Adjusted cash production costs	**$ 276**	$ 346	$ 404	**$ 622**	$ 816

	Three Months Ended			Six Months Ended	
($/bbl) (1)	**Jun 30 2015**	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Adjusted cash production costs, excluding natural gas costs	**$ 27.52**	$ 28.03	$ 33.76	**$ 27.80**	$ 35.50
Adjusted natural gas costs	**1.73**	1.70	2.85	**1.72**	3.26
Adjusted cash production costs	**$ 29.25**	$ 29.73	$ 36.61	**$ 29.52**	$ 38.76
Sales (bbl/d)	**103,388**	129,433	121,091	**116,339**	116,325

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

Adjusted cash production costs for the six months ended June 30, 2015 decreased 24% to $29.52 per bbl from $38.76 per bbl for the six months ended June 30, 2014. Adjusted cash production costs for the second quarter of 2015 averaged $29.25 per bbl, a decrease of 20% compared with $36.61 per bbl for the second quarter of 2014 and was comparable with the first quarter of 2015. The decrease in adjusted cash production costs for the three and six months ended June 30, 2015 from the comparable periods in 2014 reflected the Company's continuous focus on cost control efficiencies and reliability, together with lower overall industry service costs. Cash production costs are anticipated to average $30.00 to $33.00 per bbl for 2015.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Six Months Ended	
($ millions, except per bbl amounts)	**Jun 30 2015**	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Depletion, depreciation and amortization	**$ 119**	$ 139	$ 135	**$ 258**	$ 265
Less: depreciation incurred during turnaround period	**(5)**	–	–	**(5)**	–
Adjusted depletion, depreciation and amortization	**$ 114**	$ 139	$ 135	**$ 253**	$ 265
$/bbl (1)	**$ 12.04**	$ 11.96	$ 12.27	**$ 11.99**	$ 12.59

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

Adjusted depletion, depreciation and amortization expense on a per barrel basis for the six months ended June 30, 2015 decreased 5% to $11.99 per bbl from $12.59 per bbl for the six months ended June 30, 2014. Adjusted depletion, depreciation and amortization expense on a per barrel basis for the second quarter of 2015 decreased 2% to $12.04 per bbl from $12.27 per bbl for the second quarter of 2014 and was comparable with the first quarter of 2015. Adjusted depletion, depreciation and amortization expense on a per barrel basis decreased for the three and six months ended June 30, 2015 from the comparable periods in 2014 primarily due to a lower depletion rate associated with the increase in productive capacity of the upgrader and related infrastructure.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Six Months Ended	
($ millions, except per bbl amounts)	**Jun 30 2015**	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Expense	**$ 7**	$ 8	$ 11	**$ 15**	$ 23
$/bbl (1)	**$ 0.82**	$ 0.66	$ 1.07	**$ 0.73**	$ 1.12

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

Asset retirement obligation accretion expense for the six months ended June 30, 2015 decreased 35% to $0.73 per bbl from $1.12 per bbl for the six months ended June 30, 2014. Asset retirement obligation accretion expense for the second quarter of 2015 decreased 23% to $0.82 per bbl from $1.07 per bbl for the second quarter of 2014 and increased 24% from $0.66 per bbl for the first quarter of 2015. Asset retirement obligation expense for the three and six months ended June 30, 2015 was consistent with the comparable periods.

MIDSTREAM

($ millions)	Three Months Ended Jun 30 2015	Mar 31 2015	Jun 30 2014	Six Months Ended Jun 30 2015	Jun 30 2014
Revenue	**$ 35**	$ 35	$ 30	**$ 70**	$ 61
Production expense	**9**	9	10	**18**	19
Midstream cash flow	**26**	26	20	**52**	42
Depreciation	**3**	3	3	**6**	5
Equity (gain) loss from investment	**(3)**	15	(3)	**12**	(2)
Segment earnings before taxes	**$ 26**	$ 8	$ 20	**$ 34**	$ 39

Midstream operating results were consistent with the comparable periods.

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.

The Company, along with APMC, have 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 the first quarter of 2015, the Company and APMC each provided an additional $112 million of subordinated debt (year ended December 31, 2014 - $113 million). 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 first quarter of 2015, Redwater Partnership issued $500 million of 2.10% series C senior secured bonds due February 2022 and $500 million of 3.70% series D senior secured bonds due February 2043. As at June 30, 2015, Redwater Partnership had borrowings of $876 million under its secured $3,500 million syndicated credit facility. Subsequent to June 30, 2015, Redwater Partnership issued $500 million of 3.20% series E senior secured bonds due April 2026 and $300 million of senior secured bonds through the reopening of its previously issued 4.05% series B senior secured bonds due July 2044.

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

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

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended Jun 30 2015	Mar 31 2015	Jun 30 2014	Six Months Ended Jun 30 2015	Jun 30 2014
Expense	**$ 100**	$ 104	$ 90	**$ 204**	$ 180
$/BOE (1)	**$ 1.35**	$ 1.31	$ 1.21	**$ 1.33**	$ 1.34

(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, 2015 was comparable with the six months ended June 30, 2014. Administration expense for the second quarter of 2015 increased 12% to $1.35 per BOE from $1.21 per BOE for the second quarter of 2014 and was comparable with the first quarter of 2015. Administration expense per BOE increased for the second quarter of 2015 from the second quarter of 2014 primarily due to lower overhead recoveries associated with the reduction in the capital expenditure program.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Jun 30 2015	Mar 31 2015	Jun 30 2014	Six Months Ended Jun 30 2015	Jun 30 2014
(Recovery) Expense	**$ (79)**	$ 64	$ 189	**$ (15)**	$ 332

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 $15 million share-based compensation recovery for the six months ended June 30, 2015, 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, 2015, the Company recovered $2 million of share-based compensation costs to property, plant and equipment in the Oil Sands Mining and Upgrading segment (June 30, 2014 – $63 million costs capitalized).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended Jun 30 2015	Mar 31 2015	Jun 30 2014	Six Months Ended Jun 30 2015	Jun 30 2014
Expense, gross	**$ 147**	$ 144	$ 136	**$ 291**	$ 251
Less: capitalized interest	**62**	58	44	**120**	91
Expense, net	**$ 85**	$ 86	$ 92	**$ 171**	$ 160
$/BOE (1)	**$ 1.16**	$ 1.07	$ 1.24	**$ 1.12**	$ 1.19
Average effective interest rate	**3.8%**	4.0%	3.9%	**3.9%**	4.0%

(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, 2015 increased from the comparable periods primarily due to the impact of higher overall debt levels. Capitalized interest of $120 million for the six months ended June 30, 2015 was primarily related to the Horizon Phase 2/3 expansion.

The Company's average effective interest rate for the three and six months ended June 30, 2015 was consistent with the comparable periods in 2014. The Company's average effective interest rate for the second quarter of 2015 decreased from the first quarter of 2015 primarily due to the utilization of debt securities bearing a lower rate of interest during the second quarter of 2015.

Net interest and other financing expense for the six months ended June 30, 2015 decreased 6% to $1.12 per BOE from $1.19 per BOE for the six months ended June 30, 2014. Net interest and other financing expense for the second quarter of 2015 decreased 6% to $1.16 per BOE from $1.24 per BOE for the second quarter of 2014 and increased 8% from $1.07 per BOE for the first quarter of 2015. Net interest and other financing expense per BOE decreased for the three and six months ended June 30, 2015 from the comparable periods in 2014 primarily due to the impact of higher capitalized interest, partially offset by the impact of higher overall debt levels. Net interest and other financing expense per BOE for the second quarter of 2015 increased from the first quarter of 2015 primarily due to the impact of decreased sales volumes.

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 2015**	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Crude oil and NGLs financial instruments	**$ (91)**	$ (117)	$ –	**$ (208)**	$ –
Natural gas financial instruments	**–**	–	12	**–**	12
Foreign currency contracts	**22**	(139)	45	**(117)**	(30)
Realized (gain) loss	**(69)**	(256)	57	**(325)**	(18)
Crude oil and NGLs financial instruments	**205**	12	49	**217**	46
Natural gas financial instruments	**–**	–	(24)	**–**	21
Foreign currency contracts	**10**	2	29	**12**	36
Unrealized loss	**215**	14	54	**229**	103
Net loss (gain)	**$ 146**	$ (242)	$ 111	**$ (96)**	$ 85

During the six months ended June 30, 2015, net realized risk management gains were related to the settlement of crude oil and foreign currency contracts. The Company also recorded a net unrealized loss of $229 million ($171 million after-tax) on its risk management activities for the six months ended June 30, 2015, including an unrealized loss of $215 million ($162 million after-tax) for the second quarter of 2015 (March 31, 2015 – unrealized loss of $14 million; $9 million after-tax; June 30, 2014 – unrealized loss of $54 million; $44 million after-tax).

Complete details related to outstanding derivative financial instruments at June 30, 2015 are disclosed in note 12 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2015**	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Net realized (gain) loss	**$ (11)**	$ (53)	$ 31	**$ (64)**	$ 30
Net unrealized (gain) loss (1)	**(76)**	413	(153)	**337**	(35)
Net (gain) loss	**$ (87)**	$ 360	$ (122)	**$ 273**	$ (5)

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

The net realized foreign exchange gain for the six months ended June 30, 2015 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 loss for the six months ended June 30, 2015 was primarily related to the impact of the weakening Canadian dollar with respect to outstanding US dollar debt. The net unrealized (gain) loss for each of the periods presented included the impact of cross currency swaps (three months ended June 30, 2015 – unrealized loss of $61 million, March 31, 2015 – unrealized gain of $314 million, June 30, 2014 – unrealized loss of $109 million; six months ended June 30, 2015 – unrealized gain of $253 million, June 30, 2014 – unrealized loss of $9 million). The US/Canadian dollar exchange rate at June 30, 2015 was US$0.8017 (March 31, 2015 – US$0.7885, December 31, 2014 – US$0.8620; June 30, 2014 – US$0.9367).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended **Jun 30 2015**	 Mar 31 2015	 Jun 30 2014	Six Months Ended **Jun 30 2015**	 Jun 30 2014
North America [1]	**$ 79**	$ 8	$ 225	**$ 87**	$ 417
North Sea	**(19)**	(64)	(44)	**(83)**	(59)
Offshore Africa	**5**	2	10	**7**	14
PRT recovery – North Sea	**(72)**	(54)	(12)	**(126)**	(73)
Other taxes	**4**	3	6	**7**	12
Current income tax (recovery) expense	**(3)**	(105)	185	**(108)**	311
Deferred income tax expense (recovery)	**498**	(289)	178	**209**	269
Deferred PRT expense – North Sea	**30**	7	11	**37**	77
Deferred income tax expense (recovery)	**528**	(282)	189	**246**	346
	$ 525	$ (387)	$ 374	**$ 138**	$ 657
Income tax rate and other legislative changes [2] [3]	**(579)**	228	–	**(351)**	–
	$ (54)	$ (159)	$ 374	**$ (213)**	$ 657
Effective income tax rate on adjusted net earnings from operations [4]	**17.0%**	105.8%	24.8%	**64.0%**	24.2%

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

(2) 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.

(3) During the first quarter of 2015, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and the Petroleum Revenue Tax ("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.

(4) 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 2015 and the comparative quarters reflects the impact of abandonment expenditures on the Murchison platform.

The effective income tax rate for the three and six months ended June 30, 2015 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.

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 are 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 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 2015, based on forward commodity prices and the current availability of tax pools, the Company expects to incur current income tax expense of $200 million to $235 million in Canada and recoveries of $285 million to $335 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Jun 30 2015	Mar 31 2015	Jun 30 2014	Six Months Ended Jun 30 2015	Jun 30 2014
Exploration and Evaluation					
Net expenditures [2]	**$ 29**	$ 46	$ 884	**$ 75**	$ 1,001
Property, Plant and Equipment					
Net property acquisitions [2]	**51**	11	2,746	**62**	2,742
Well drilling, completion and equipping	**199**	292	441	**491**	1,082
Production and related facilities	**249**	314	429	**563**	844
Capitalized interest and other [3]	**27**	26	21	**53**	44
Net expenditures	**526**	643	3,637	**1,169**	4,712
Total Exploration and Production	**555**	689	4,521	**1,244**	5,713
Oil Sands Mining and Upgrading					
Horizon Phase 2/3 construction costs	**535**	406	649	**941**	1,093
Sustaining capital	**94**	88	87	**182**	147
Turnaround costs	**6**	4	4	**10**	6
Capitalized interest and other [3]	**43**	71	84	**114**	157
Total Oil Sands Mining and Upgrading	**678**	569	824	**1,247**	1,403
Midstream	**1**	3	26	**4**	51
Abandonments [4]	**56**	144	76	**200**	163
Head office	**7**	7	9	**14**	19
Total net capital expenditures	**$ 1,297**	$ 1,412	$ 5,456	**$ 2,709**	$ 7,349
By segment					
North America [2]	**$ 307**	$ 501	$ 4,387	**$ 808**	$ 5,474
North Sea	**93**	62	107	**155**	195
Offshore Africa	**155**	126	27	**281**	44
Oil Sands Mining and Upgrading	**678**	569	824	**1,247**	1,403
Midstream	**1**	3	26	**4**	51
Abandonments [4]	**56**	144	76	**200**	163
Head office	**7**	7	9	**14**	19
Total	**$ 1,297**	$ 1,412	$ 5,456	**$ 2,709**	$ 7,349

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

Previously in 2015, the Company reduced its annual capital expenditure guidance by approximately $2,850 million. In August 2015, the Company further exercised its capital flexibility and announced that it would reduce annual capital spending guidance by an additional $245 million. The Company has additional capital flexibility in 2015 to further curtail capital spending if required or to increase capital spending if commodity prices strengthen.

Net capital expenditures for the six months ended June 30, 2015 were $2,709 million compared with $7,349 million for the six months ended June 30, 2014. Net capital expenditures for the second quarter of 2015 were $1,297 million compared with $5,456 million for the second quarter of 2014 and $1,412 million for the first quarter of 2015. The capital expenditures for the three and six months ended June 30, 2015 reflected the Company's previously announced capital allocation strategy, including the planned increase in drilling activities in Offshore Africa.

Drilling Activity

	Three Months Ended			Six Months Ended	
(number of wells)	**Jun 30 2015**	Mar 31 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Net successful natural gas wells	**2**	9	13	**11**	38
Net successful crude oil wells (1)	**5**	42	154	**47**	425
Dry wells	**–**	2	2	**2**	5
Stratigraphic test / service wells	**6**	86	22	**92**	352
Total	**13**	139	191	**152**	820
Success rate (excluding stratigraphic test / service wells)	**100%**	96%	99%	**97%**	99%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 33% of the total capital expenditures for the six months ended June 30, 2015 compared with approximately 77% for the six months ended June 30, 2014.

During the second quarter of 2015, the Company targeted 2 net natural gas wells in Northwest Alberta. The Company also targeted 4 net primary heavy crude oil wells in the Company's Northern Plains region.

Overall thermal oil production for the second quarter of 2015 averaged approximately 105,000 bbl/d compared with approximately 114,400 bbl/d for the second quarter of 2014 and approximately 146,100 bbl/d for the first quarter of 2015. Production volumes reflected the cyclic nature of thermal oil production at Primrose, together with the temporary impact of the forest fires in Northeastern Alberta. Full year thermal production guidance remains unchanged.

Development of the tertiary recovery conversion projects at Pelican Lake continued. Pelican Lake production averaged approximately 52,000 bbl/d for the second quarter of 2015 compared with 49,600 bbl/d for the second quarter of 2014 and 51,100 bbl/d for the first quarter of 2015.

In order to expand its pipeline infrastructure, the Company is participating in the expansion of the Cold Lake pipeline system. Initial pipeline commissioning activities commenced in the first quarter of 2015 with the final phases of the project expected to continue for approximately three years.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the second quarter of 2015 was focused on field construction of the hydrogen unit, hydrotreater unit, vacuum distillation unit and distillation recovery unit, tank farms, tailings, froth treatment, froth tank, tailings transfer pumphouses and pipelines, extraction plant, ore preparation plants, and superpot along with engineering and procurement related to tailings retrofit, and the sour water concentrator, combined hydrotreater and sulphur recovery units.

Targeted annual capital spending in 2015 was further revised from $2,200 million to $2,150 million during the second quarter of 2015 through targeted cost efficiencies, while maintaining planned expansion activities.

North Sea

During 2015, the Company completed one injection well and no further development activities are planned. The decommissioning activities at the Murchison platform are ongoing and are expected to continue for approximately five years.

Offshore Africa

During 2015, at the Espoir field, Côte d'Ivoire, the Company drilled 3 gross wells, adding net production volumes of approximately 4,500 bbl/d to date. The infill drilling program is currently tracking to below its original sanction costs for the 10 gross well program (5.9 net well program).

During 2015, at the Baobab field, Côte d'Ivoire, the Company drilled 1 gross well, adding net production volumes of approximately 2,000 bbl/d to date. Production from the second gross well is targeted to come on stream in the third quarter of 2015. The drilling program is currently tracking to below its original sanction costs for the 6 gross well drilling program (3.4 net well program).

In Block CI-514, the Company has a 36% non-operated interest. In the second quarter of 2014, the operator completed drilling the first exploratory well and encountered the presence of light oil. As a follow-up, in April 2015, a second exploratory well was drilled to evaluate the potential of the initial well. The second exploratory well has been plugged and abandoned, and the results will be evaluated and integrated into the Company's understanding of the block.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Jun 30 2015**	Mar 31 2015	Dec 31 2014	Jun 30 2014
Working capital (deficit) [(1)]	**$ 261**	$ (13)	$ (673)	$ (991)
Long-term debt [(2) (3)]	**$ 15,983**	$ 15,689	$ 14,002	$ 13,437
Share capital	**$ 4,532**	$ 4,474	$ 4,432	$ 4,321
Retained earnings	**23,248**	23,905	24,408	22,856
Accumulated other comprehensive income (loss)	**(7)**	36	51	46
Shareholders' equity	**$ 27,773**	$ 28,415	$ 28,891	$ 27,223
Debt to book capitalization [(3) (4)]	**37%**	36%	33%	33%
Debt to market capitalization [(3) (5)]	**30%**	27%	26%	20%
After-tax return on average common shareholders' equity [(6)]	**6%**	11%	14%	13%
After-tax return on average capital employed [(3) (7)]	**4%**	8%	10%	10%

(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 for the twelve month trailing period; as a percentage of average common shareholders' equity for the period.
(7) Calculated as net earnings 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, 2015, 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, 2014. In addition, the Company's ability to renew existing bank credit facilities and raise new debt is dependent upon maintaining an investment grade debt rating and the condition of capital and credit markets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs supported by its 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 declining commodity prices in late 2014 and the first half of 2015, the Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing the Company's borrowing capacity:
  - During the second quarter of 2015, the Company issued $500 million of series 2 medium-term notes, due August 2020, through the reopening of its previously issued 2.89% notes. In addition, the $1,500 million revolving syndicated credit facility was increased to $2,425 million and the maturity date was extended to June 2019 from June 2016. The $3,000 million revolving syndicated credit facility was reduced to $2,425 million and the maturity date was extended to June 2020 from June 2017. As a result, the Company's available liquidity increased by $350 million;
  - 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 2015, the Company extended its existing $1,000 million non-revolving term credit facility to January 2017. In addition, the Company entered into a new $1,500 million non-revolving term credit facility maturing April 2018. Both facilities were fully drawn at June 30, 2015;

- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages. All of the Company's credit facilities are now subject to a revised financial covenant that the Consolidated Debt to Capitalization Ratio, as defined in the credit agreements, shall not be more than 0.65 to 1.0; and
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place to minimize the impact in the event of a default.

During the second quarter of 2015, the Company repaid $400 million of 4.95% medium term notes.

As at June 30, 2015, the Company had in place bank credit facilities of $7,479 million, of which $3,272 million, net of commercial paper issuances of $623 million, was available for general corporate purposes.

At June 30, 2015, the Company had $623 million of long-term debt maturing over the next 12 months (US$500 million of three-month LIBOR plus 0.375% due March 2016).

Long-term debt was $15,983 million at June 30, 2015, resulting in a debt to book capitalization ratio of 37% (December 31, 2014 – 33%; June 30, 2014 – 33%); 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. The Company has hedged a portion of its production for 2015 at prices that protect investment returns to support ongoing balance sheet strength and the completion of its capital expenditure programs. Further details related to the Company's long-term debt at June 30, 2015 are discussed in note 5 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. As at August 5, 2015, 50,000 bbl/d of currently forecasted crude oil volumes were hedged using price collars for the remainder of 2015. Further details related to the Company's commodity derivative financial instruments outstanding at June 30, 2015 are discussed in note 12 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at June 30, 2015, there were 1,094,378,000 common shares outstanding (December 31, 2014 – 1,091,837,000 common shares) and 67,715,000 stock options outstanding. As at August 4, 2015, the Company had 1,094,391,000 common shares outstanding and 67,395,000 stock options outstanding.

On March 4, 2015, the Board of Directors approved an increase in the annual dividend to $0.92 per common share, (previous annual dividend rate of $0.90 per common share), beginning with the quarterly dividend payable on April 1, 2015, at $0.23 per common share. 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.

In April 2015, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), during the twelve month period commencing April 2015 and ending April 2016, up to 54,640,607 common shares. The Company's Normal Course Issuer Bid announced in 2014 expired April 2015.

For the six months ended June 30, 2015, 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, 2015:

($ millions)	Remaining 2015	2016	2017	2018	2019	Thereafter
Product transportation and pipeline	$ 225	$ 371	$ 325	$ 283	$ 246	$ 1,519
Offshore equipment operating leases and offshore drilling	$ 214	$ 136	$ 84	$ 64	$ 20	$ –
Long-term debt (1)	$ 623	$ 936	$ 2,371	$ 2,749	$ 1,000	$ 8,384
Interest and other financing expense (2)	$ 306	$ 604	$ 524	$ 442	$ 406	$ 4,535
Office leases	$ 21	$ 42	$ 45	$ 46	$ 48	$ 293
Other	$ 85	$ 111	$ 24	$ 34	$ 1	$ –

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

(2) 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, 2015.

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, 2014.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgments 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 critical accounting estimates is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2014.

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	Jun 30 2015	Dec 31 2014
ASSETS			
Current assets			
Cash and cash equivalents		**$ 32**	$ 25
Accounts receivable		**1,488**	1,889
Current income taxes		**653**	228
Inventory		**733**	665
Prepaids and other		**290**	172
Current portion of other long-term assets	4	**364**	510
		3,560	3,489
Exploration and evaluation assets	2	**3,477**	3,557
Property, plant and equipment	3	**52,677**	52,480
Other long-term assets	4	**829**	674
		$ 60,543	$ 60,200
LIABILITIES			
Current liabilities			
Accounts payable		**$ 543**	$ 564
Accrued liabilities		**2,532**	3,279
Current portion of long-term debt	5	**1,246**	980
Current portion of other long-term liabilities	6	**224**	319
		4,545	5,142
Long-term debt	5	**14,737**	13,022
Other long-term liabilities	6	**4,211**	4,175
Deferred income taxes		**9,277**	8,970
		32,770	31,309
SHAREHOLDERS' EQUITY			
Share capital	8	**4,532**	4,432
Retained earnings		**23,248**	24,408
Accumulated other comprehensive income (loss)	9	**(7)**	51
		27,773	28,891
		$ 60,543	$ 60,200

Commitments and contingencies (note 13).

Approved by the Board of Directors on August 5, 2015

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Jun 30 2015	Three Months Ended Jun 30 2014	Six Months Ended Jun 30 2015	Six Months Ended Jun 30 2014
Product sales		**$ 3,662**	$ 6,113	**$ 6,888**	$ 11,081
Less: royalties		**(240)**	(742)	**(432)**	(1,314)
Revenue		**3,422**	5,371	**6,456**	9,767
Expenses					
Production		**1,188**	1,388	**2,441**	2,599
Transportation and blending		**629**	895	**1,264**	1,726
Depletion, depreciation and amortization	3	**1,280**	1,237	**2,635**	2,248
Administration		**100**	90	**204**	180
Share-based compensation	6	**(79)**	189	**(15)**	332
Asset retirement obligation accretion	6	**43**	50	**86**	95
Interest and other financing expense		**85**	92	**171**	160
Risk management activities	12	**146**	111	**(96)**	85
Foreign exchange (gain) loss		**(87)**	(122)	**273**	(5)
Equity (gain) loss from investment	4	**(3)**	(3)	**12**	(2)
		3,302	3,927	**6,975**	7,418
Earnings (loss) before taxes		**120**	1,444	**(519)**	2,349
Current income tax (recovery) expense	7	**(3)**	185	**(108)**	311
Deferred income tax expense	7	**528**	189	**246**	346
Net earnings (loss)		**$ (405)**	$ 1,070	**$ (657)**	$ 1,692
Net earnings (loss) per common share					
Basic	11	**$ (0.37)**	$ 0.98	**$ (0.60)**	$ 1.55
Diluted	11	**$ (0.37)**	$ 0.97	**$ (0.60)**	$ 1.54

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended Jun 30 2015	Three Months Ended Jun 30 2014	Six Months Ended Jun 30 2015	Six Months Ended Jun 30 2014
Net earnings (loss)	**$ (405)**	$ 1,070	**$ (657)**	$ 1,692
Items that may be reclassified subsequently to net earnings				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss) during the period, net of taxes of $5 million (2014 – $nil) – three months ended; $6 million (2014 – $nil) – six months ended	**(34)**	–	**(43)**	1
Reclassification to net earnings (loss), net of taxes of $1 million (2014 – $nil) – three months ended; $1 million (2014 – $nil) – six months ended	**(4)**	1	**(6)**	4
	(38)	1	**(49)**	5
Foreign currency translation adjustment				
Translation of net investment	**(5)**	1	**(9)**	(1)
Other comprehensive income (loss), net of taxes	**(43)**	2	**(58)**	4
Comprehensive income (loss)	**$ (448)**	$ 1,072	**$ (715)**	$ 1,696

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Six Months Ended **Jun 30 2015**	Jun 30 2014
Share capital	8		
Balance – beginning of period		**$ 4,432**	$ 3,854
Issued upon exercise of stock options		**83**	385
Previously recognized liability on stock options exercised for common shares		**17**	103
Purchase of common shares under Normal Course Issuer Bid		**–**	(21)
Balance – end of period		**4,532**	4,321
Retained earnings			
Balance – beginning of period		**24,408**	21,876
Net earnings (loss)		**(657)**	1,692
Purchase of common shares under Normal Course Issuer Bid	8	**–**	(220)
Dividends on common shares	8	**(503)**	(492)
Balance – end of period		**23,248**	22,856
Accumulated other comprehensive income (loss)	9		
Balance – beginning of period		**51**	42
Other comprehensive income (loss), net of taxes		**(58)**	4
Balance – end of period		**(7)**	46
Shareholders' equity		**$ 27,773**	$ 27,223

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Three Months Ended Jun 30 2015	Three Months Ended Jun 30 2014	Six Months Ended Jun 30 2015	Six Months Ended Jun 30 2014
Operating activities				
Net earnings (loss)	**$ (405)**	$ 1,070	**$ (657)**	$ 1,692
Non-cash items				
Depletion, depreciation and amortization	**1,280**	1,237	**2,635**	2,248
Share-based compensation	**(79)**	189	**(15)**	332
Asset retirement obligation accretion	**43**	50	**86**	95
Unrealized risk management loss	**215**	54	**229**	103
Unrealized foreign exchange (gain) loss	**(76)**	(153)	**337**	(35)
Equity (gain) loss from investment	**(3)**	(3)	**12**	(2)
Deferred income tax expense	**528**	189	**246**	346
Other	**20**	20	**62**	51
Abandonment expenditures	**(56)**	(76)	**(200)**	(163)
Net change in non-cash working capital	**(182)**	(120)	**(196)**	(857)
	1,285	2,457	**2,539**	3,810
Financing activities				
Issue of bank credit facilities and commercial paper, net	**334**	2,369	**1,211**	1,708
Issue of medium-term notes, net	**107**	992	**107**	992
Issue of US dollar debt securities, net	**–**	–	**–**	1,100
Issue of common shares on exercise of stock options	**48**	190	**83**	385
Purchase of common shares under Normal Course Issuer Bid	**–**	(176)	**–**	(241)
Dividends on common shares	**(251)**	(246)	**(496)**	(463)
Net change in non-cash working capital	**(27)**	(6)	**(40)**	(11)
	211	3,123	**865**	3,470
Investing activities				
Net expenditures on exploration and evaluation assets	**(29)**	(884)	**(75)**	(1,001)
Net expenditures on property, plant and equipment	**(1,212)**	(4,496)	**(2,434)**	(6,185)
Investment in other long-term assets	**–**	(113)	**(112)**	(113)
Net change in non-cash working capital	**(257)**	(75)	**(776)**	34
	(1,498)	(5,568)	**(3,397)**	(7,265)
(Decrease) increase in cash and cash equivalents	**(2)**	12	**7**	15
Cash and cash equivalents – beginning of period	**34**	19	**25**	16
Cash and cash equivalents – end of period	**$ 32**	$ 31	**$ 32**	$ 31
Interest paid	**$ 119**	$ 110	**$ 275**	$ 245
Income taxes paid	**$ 55**	$ 147	**$ 264**	$ 602

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, 2014. 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, 2014.

2. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	**North Sea**	**Offshore Africa**		
Cost					
At December 31, 2014	$ 3,426	$ –	$ 131	$ –	$ 3,557
Additions	**52**	**–**	**23**	**–**	**75**
Transfers to property, plant and equipment	**(160)**	**–**	**–**	**–**	**(160)**
Foreign exchange adjustments	**–**	**–**	**5**	**–**	**5**
At June 30, 2015	**$ 3,318**	**$ –**	**$ 159**	**$ –**	**$ 3,477**

3. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2014	$ 60,606	$ 6,182	$ 3,858	$ 21,948	$ 570	$ 352	$ 93,516
Additions	**790**	**153**	**258**	**1,247**	**4**	**14**	**2,466**
Transfers from E&E assets	**160**	**–**	**–**	**–**	**–**	**–**	**160**
Disposals/derecognitions	**(189)**	**–**	**–**	**(49)**	**–**	**–**	**(238)**
Foreign exchange adjustments and other	**–**	**468**	**293**	**–**	**–**	**–**	**761**
At June 30, 2015	**$ 61,367**	**$ 6,803**	**$ 4,409**	**$ 23,146**	**$ 574**	**$ 366**	**$ 96,665**
Accumulated depletion and depreciation							
At December 31, 2014	$ 31,886	$ 4,049	$ 2,890	$ 1,864	$ 120	$ 227	$ 41,036
Expense	**2,112**	**184**	**61**	**258**	**6**	**14**	**2,635**
Disposals/derecognitions	**(189)**	**–**	**–**	**(49)**	**–**	**–**	**(238)**
Foreign exchange adjustments and other	**3**	**309**	**237**	**6**	**–**	**–**	**555**
At June 30, 2015	**$ 33,812**	**$ 4,542**	**$ 3,188**	**$ 2,079**	**$ 126**	**$ 241**	**$ 43,988**
Net book value							
– at June 30, 2015	**$ 27,555**	**$ 2,261**	**$ 1,221**	**$ 21,067**	**$ 448**	**$ 125**	**$ 52,677**
– at December 31, 2014	$ 28,720	$ 2,133	$ 968	$ 20,084	$ 450	$ 125	$ 52,480

Project costs not subject to depletion and depreciation	**Jun 30 2015**	Dec 31 2014
Horizon	**$ 6,389**	$ 5,492
Kirby Thermal Oil Sands – North	**$ 760**	$ 681

During the six months ended June 30, 2015, the Company acquired a number of producing crude oil and natural gas properties in the North American Exploration and Production segment for net cash consideration of $62 million together with associated asset retirement obligations of $29 million. No debt obligations were assumed and no net deferred tax liabilities were recognized.

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, 2015, pre-tax interest of $120 million (June 30, 2014 – $91 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (June 30, 2014 – 4.0%).

4. OTHER LONG-TERM ASSETS

		Jun 30 2015		Dec 31 2014
Investment in North West Redwater Partnership	**$**	**286**	$	298
North West Redwater Partnership subordinated debt (1)		**243**		120
Risk Management (note 12)		**569**		599
Other		**95**		167
		1,193		1,184
Less: current portion		**364**		510
	$	**829**	$	674

(1) Includes accrued interest.

Other long-term assets include an investment in the 50% owned Redwater Partnership. Based on Redwater Partnership's voting and decision-making structure and legal form, the investment is accounted for using the equity method. 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.

The Company, along with APMC, have 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 the first quarter of 2015, the Company and APMC each provided an additional $112 million of subordinated debt (year ended December 31, 2014 - $113 million). 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 first quarter of 2015, Redwater Partnership issued $500 million of 2.10% series C senior secured bonds due February 2022 and $500 million of 3.70% series D senior secured bonds due February 2043. Subsequent to June 30, 2015, Redwater Partnership issued $500 million of 3.20% series E senior secured bonds due April 2026 and $300 million of senior secured bonds through the reopening of its previously issued 4.05% series B senior secured bonds due July 2044.

As at June 30, 2015, Redwater Partnership had borrowings of $876 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.

5. LONG-TERM DEBT

		Jun 30 2015		Dec 31 2014
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**3,129**	$	2,404
Medium-term notes		**2,500**		2,400
		5,629		4,804
US dollar denominated debt, unsecured				
Bank credit facilities (June 30, 2015 – US$365 million; December 31, 2014 – $nil)	**$**	**455**	$	–
Commercial paper (US$500 million)		**623**		580
US dollar debt securities (US$7,500 million)		**9,356**		8,701
		10,434		9,281
Long-term debt before transaction costs and original issue discounts, net		**16,063**		14,085
Less: original issue discounts, net (1)		**(10)**		(21)
Less: transaction costs (1) (2)		**(70)**		(62)
		15,983		14,002
Less: current portion of commercial paper		**623**		580
current portion of long-term debt (1) (2)		**623**		400
	$	**14,737**	$	13,022

(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, 2015, the Company had in place bank credit facilities of $7,479 million available for general corporate purposes, comprised of:

- a $100 million demand credit facility;
- a $1,000 million non-revolving term credit facility maturing January 2017;
- a $1,500 million non-revolving term credit facility maturing April 2018;
- 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.

During the second quarter of 2015, the $1,500 million revolving syndicated credit facility was increased to $2,425 million and the maturity date was extended to June 2019 from June 2016. The $3,000 million revolving syndicated credit facility was reduced to $2,425 million and the maturity date was extended to June 2020 from June 2017. Each of the $2,425 million revolving facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.

Borrowings under the $1,000 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at June 30, 2015, the $1,000 million facility was fully drawn. Borrowings under the $1,500 million non-revolving term 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, 2015, the $1,500 million facility was fully drawn.

All of the Company's credit facilities are now subject to a revised financial covenant that the Consolidated Debt to Capitalization Ratio, as defined in the credit agreements, shall not be more than 0.65 to 1.0.

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, 2015 was 1.9% (June 30, 2014 – 2.1%), and on long-term debt outstanding for the six months ended June 30, 2015 was 3.9% (June 30, 2014 – 4.0%).

At June 30, 2015 letters of credit and guarantees aggregating $386 million, including a $39 million financial guarantee related to Horizon and $232 million of letters of credit related to North Sea operations, were outstanding. The letters of credit are supported by dedicated credit facilities.

Medium-Term Notes

During the second quarter of 2015 the Company issued $500 million of series 2 medium-term notes, due August 2020, through the reopening of its previously issued 2.89% notes and repaid $400 million of 4.95% medium-term notes. The Company has $1,500 million remaining on its outstanding $3,000 million base shelf prospectus that allows for the issue of medium-term notes in Canada, which expires in December 2015. If issued, these securities will bear interest as determined at the date of issuance.

US Dollar Debt Securities

The Company has US$800 million remaining on its outstanding US$3,000 million base shelf prospectus that allows for the issue of US dollar debt securities in the United States, which expires in December 2015. If issued, these securities will bear interest as determined at the date of issuance.

6. OTHER LONG-TERM LIABILITIES

	Jun 30 2015	Dec 31 2014
Asset retirement obligations	**$ 4,243**	$ 4,221
Share-based compensation	**168**	203
Other	**24**	70
	4,435	4,494
Less: current portion	**224**	319
	$ 4,211	$ 4,175

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 4.6% (December 31, 2014 – 4.6%). A reconciliation of the discounted asset retirement obligations was as follows:

	Jun 30 2015	Dec 31 2014
Balance – beginning of period	$ 4,221	$ 4,162
Liabilities incurred	3	41
Liabilities acquired	29	404
Liabilities settled	(200)	(346)
Asset retirement obligation accretion	86	193
Revision of cost, inflation rates and timing estimates	–	(907)
Change in discount rate	–	558
Foreign exchange adjustments	104	116
Balance – end of period	4,243	4,221
Less: current portion	103	121
	$ 4,140	$ 4,100

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 2015	Dec 31 2014
Balance – beginning of period	$ 203	$ 260
Share-based compensation (recovery) expense	(15)	66
Cash payment for stock options surrendered	(1)	(8)
Transferred to common shares	(17)	(129)
(Recovered from) capitalized to Oil Sands Mining and Upgrading	(2)	14
Balance – end of period	168	203
Less: current portion	121	158
	$ 47	$ 45

7. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Current corporate income tax expense – North America	**$ 79**	$ 225	**$ 87**	$ 417
Current corporate income tax recovery – North Sea	**(19)**	(44)	**(83)**	(59)
Current corporate income tax expense – Offshore Africa	**5**	10	**7**	14
Current PRT [1] recovery – North Sea	**(72)**	(12)	**(126)**	(73)
Other taxes	**4**	6	**7**	12
Current income tax (recovery) expense	**(3)**	185	**(108)**	311
Deferred corporate income tax expense	**498**	178	**209**	269
Deferred PRT [1] expense – North Sea	**30**	11	**37**	77
Deferred income tax expense	**528**	189	**246**	346
Income tax expense	**$ 525**	$ 374	**$ 138**	$ 657

(1) Petroleum Revenue Tax.

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 are 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 these 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.

8. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Six Months Ended Jun 30, 2015	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,091,837**	**$ 4,432**
Issued upon exercise of stock options	**2,541**	**83**
Previously recognized liability on stock options exercised for common shares	**–**	**17**
Balance – end of period	**1,094,378**	**$ 4,532**

Dividend Policy

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

On March 4, 2015, the Board of Directors approved the regular quarterly dividend at $0.23 per common share, an increase from the previous quarterly dividend of $0.225 per common share, which was approved on March 5, 2014.

Normal Course Issuer Bid

In April 2015, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, during the twelve month period commencing April 2015 and ending April 2016, up to 54,640,607 common shares. The Company's Normal Course Issuer Bid announced in 2014 expired April 2015.

For the six months ended June 30, 2015, the Company did not purchase any common shares for cancellation.

Stock Options

The following table summarizes information relating to stock options outstanding at June 30, 2015:

	Six Months Ended Jun 30, 2015		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**71,708**	**$**	**35.60**
Granted	**4,773**	**$**	**33.25**
Surrendered for cash settlement	**(165)**	**$**	**33.43**
Exercised for common shares	**(2,541)**	**$**	**32.73**
Forfeited	**(6,060)**	**$**	**35.00**
Outstanding – end of period	**67,715**	**$**	**35.60**
Exercisable – end of period	**19,527**	**$**	**36.82**

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.

9. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

		Jun 30 2015		Jun 30 2014
Derivative financial instruments designated as cash flow hedges	**$**	**45**	$	86
Foreign currency translation adjustment		**(52)**		(40)
	$	**(7)**	$	46

10. 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, 2015, the ratio was within the target range at 37%.

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 2015	Dec 31 2014
Long-term debt [1]	**$ 15,983**	$ 14,002
Total shareholders' equity	**$ 27,773**	$ 28,891
Debt to book capitalization	**37%**	33%

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

11. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Six Months Ended	
	Jun 30 2015	Jun 30 2014	**Jun 30 2015**	Jun 30 2014
Weighted average common shares outstanding – basic (thousands of shares)	**1,094,143**	1,093,522	**1,093,252**	1,091,719
Effect of dilutive stock options (thousands of shares) [1]	**–**	9,452	**–**	5,447
Weighted average common shares outstanding – diluted (thousands of shares)	**1,094,143**	1,102,974	**1,093,252**	1,097,166
Net earnings (loss)	**$ (405)**	$ 1,070	**$ (657)**	$ 1,692
Net earnings (loss) per common share – basic	**$ (0.37)**	$ 0.98	**$ (0.60)**	$ 1.55
– diluted	**$ (0.37)**	$ 0.97	**$ (0.60)**	$ 1.54

(1) For the three months ended June 30, 2015 , the dilutive effect of 2,906,000 options has not been included in the determination of the weighted average number of common shares outstanding as the inclusion would be anti-dilutive to the net loss per common share (six months ended June 30, 2015 – 2,356,000).

12. FINANCIAL INSTRUMENTS

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

	Jun 30, 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	**$ 1,488**	**$ –**	**$ –**	**$ –**	**$ 1,488**
Other long-term assets	**243**	**183**	**386**	**–**	**812**
Accounts payable	**–**	**–**	**–**	**(543)**	**(543)**
Accrued liabilities	**–**	**–**	**–**	**(2,532)**	**(2,532)**
Long-term debt (1)	**–**	**–**	**–**	**(15,983)**	**(15,983)**
	$ 1,731	**$ 183**	**$ 386**	**$ (19,058)**	**$ (16,758)**

	Dec 31, 2014				
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	$ 1,889	$ –	$ –	$ –	$ 1,889
Other long-term assets	120	415	184	–	719
Accounts payable	–	–	–	(564)	(564)
Accrued liabilities	–	–	–	(3,279)	(3,279)
Other long-term liabilities	–	–	–	(40)	(40)
Long-term debt (1)	–	–	–	(14,002)	(14,002)
	$ 2,009	$ 415	$ 184	$ (17,885)	$ (15,277)

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

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

	Jun 30, 2015			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3**
Other long-term assets (3)	**$ 812**	**$ –**	**$ 569**	**$ 243**
Fixed rate long-term debt (4) (5)	**$ (11,776)**	**$ (12,483)**	**$ –**	**$ –**

	Dec 31, 2014			
	Carrying amount	Fair value		
Asset (liability) (1) (2)		Level 1	Level 2	Level 3
Other long-term assets (3)	$ 719	$ –	$ 599	$ 120
Fixed rate long-term debt (4) (5)	$ (11,018)	$ (11,855)	$ –	$ –

(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 North West Redwater Partnership subordinated debt is based on the present value of future cash receipts.

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

(5) 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, 2015**	Dec 31, 2014
Derivatives held for trading		
Crude oil price collars	**$ 177**	$ 410
Crude oil WCS [(1)] differential swaps	**–**	(16)
Foreign currency forward contracts	**6**	21
Cash flow hedges		
Foreign currency forward contracts	**9**	11
Cross currency swaps	**377**	173
	$ 569	$ 599
Included within:		
Current portion of other long-term assets	**$ 308**	$ 436
Other long-term assets	**261**	163
	$ 569	$ 599

(1) Western Canadian Select.

For the six months ended June 30, 2015, the Company recognized a gain of $3 million (year ended December 31, 2014 – loss of $3 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair value of derivative financial instruments in Level 1 and 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 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 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 (liability) were recognized in the financial statements as follows:

Asset (liability)	**Six Months Ended Jun 30, 2015**	Year Ended Dec 31, 2014
Balance – beginning of period	**$ 599**	$ (136)
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	**(229)**	451
Foreign exchange	**255**	270
Other comprehensive income (loss)	**(56)**	14
Balance – end of period	**569**	599
Less: current portion	**308**	436
	$ 261	$ 163

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

	Three Months Ended				Six Months Ended			
		Jun 30 2015		Jun 30 2014		**Jun 30 2015**		Jun 30 2014
Net realized risk management (gain) loss	**$**	**(69)**	$	57	**$**	**(325)**	$	(18)
Net unrealized risk management loss		**215**		54		**229**		103
	$	**146**	$	111	**$**	**(96)**	$	85

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, 2015, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Price collars	Jul 2015	–	Dec 2015	50,000 bbl/d	US$80.00	–	US$120.52	Brent

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At June 30, 2015 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, 2015, 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 2015	–	Mar 2016	US$500	1.109	Three-month LIBOR plus 0.375%	Three-month CDOR [(1)] plus 0.309%
	Jul 2015	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Jul 2015	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Jul 2015	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Jul 2015	–	Mar 2038	US$550	1.170	6.25%	5.76%

(1) Canadian Dealer Offered Rate ("CDOR").

All cross currency swap derivative financial instruments were designated as hedges at June 30, 2015 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at June 30, 2015, the Company had US$2,010 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$865 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, 2015, 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, 2015, the Company had net risk management assets of $576 million with specific counterparties related to derivative financial instruments (December 31, 2014 – $622 million).

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	$ 543	$ –	$ –	$ –
Accrued liabilities	$ 2,532	$ –	$ –	$ –
Long-term debt (1)	$ 1,247	$ 2,683	$ 4,832	$ 7,301

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

13. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	Remaining 2015	2016	2017	2018	2019	Thereafter
Product transportation and pipeline	$ 225	$ 371	$ 325	$ 283	$ 246	$ 1,519
Offshore equipment operating leases and offshore drilling	$ 214	$ 136	$ 84	$ 64	$ 20	$ –
Office leases	$ 21	$ 42	$ 45	$ 46	$ 48	$ 293
Other	$ 85	$ 111	$ 24	$ 34	$ 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.

14. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	Exploration and Production															
	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	
	2015	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014
Segmented product sales	**2,645**	4,463	**4,979**	8,120	**201**	226	**353**	424	**111**	172	**178**	196	**2,957**	4,861	**5,510**	8,740
Less: royalties	**(225)**	(659)	**(402)**	(1,175)	**(1)**	–	**(1)**	(1)	**(5)**	(9)	**(8)**	(13)	**(231)**	(668)	**(411)**	(1,189)
Segmented revenue	**2,420**	3,804	**4,577**	6,945	**200**	226	**352**	423	**106**	163	**170**	183	**2,726**	4,193	**5,099**	7,551
Segmented expenses																
Production	**645**	752	**1,396**	1,415	**161**	143	**295**	266	**55**	81	**70**	88	**861**	976	**1,761**	1,769
Transportation and blending	**614**	897	**1,234**	1,725	**16**	1	**29**	3	**–**	–	**1**	–	**630**	898	**1,264**	1,728
Depletion, depreciation and amortization	**1,020**	1,006	**2,124**	1,822	**99**	65	**186**	123	**39**	28	**61**	33	**1,158**	1,099	**2,371**	1,978
Asset retirement obligation accretion	**24**	26	**47**	48	**10**	10	**19**	19	**2**	3	**5**	5	**36**	39	**71**	72
Realized risk management activities	**(69)**	57	**(325)**	(18)	**–**	–	**–**	–	**–**	–	**–**	–	**(69)**	57	**(325)**	(18)
Equity (gain) loss from investment	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Total segmented expenses	**2,234**	2,738	**4,476**	4,992	**286**	219	**529**	411	**96**	112	**137**	126	**2,616**	3,069	**5,142**	5,529
Segmented earnings (loss) before the following	**186**	1,066	**101**	1,953	**(86)**	7	**(177)**	12	**10**	51	**33**	57	**110**	1,124	**(43)**	2,022
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Unrealized risk management activities																
Foreign exchange (gain) loss																
Total non-segmented expenses																
Earnings (loss) before taxes																
Current income tax (recovery) expense																
Deferred income tax expense																
Net earnings (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	
	2015	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014
Segmented product sales	**689**	1,241	**1,349**	2,323	**35**	30	**70**	61	**(19)**	(19)	**(41)**	(43)	**3,662**	6,113	**6,888**	11,081
Less: royalties	**(9)**	(74)	**(21)**	(125)	**–**	–	**–**	–	**–**	–	**–**	–	**(240)**	(742)	**(432)**	(1,314)
Segmented revenue	**680**	1,167	**1,328**	2,198	**35**	30	**70**	61	**(19)**	(19)	**(41)**	(43)	**3,422**	5,371	**6,456**	9,767
Segmented expenses																
Production	**321**	404	**667**	816	**9**	10	**18**	19	**(3)**	(2)	**(5)**	(5)	**1,188**	1,388	**2,441**	2,599
Transportation and blending	**19**	17	**40**	37	**–**	–	**–**	–	**(20)**	(20)	**(40)**	(39)	**629**	895	**1,264**	1,726
Depletion, depreciation and amortization	**119**	135	**258**	265	**3**	3	**6**	5	**–**	–	**–**	–	**1,280**	1,237	**2,635**	2,248
Asset retirement obligation accretion	**7**	11	**15**	23	**–**	–	**–**	–	**–**	–	**–**	–	**43**	50	**86**	95
Realized risk management activities	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(69)**	57	**(325)**	(18)
Equity (gain) loss from investment	**–**	–	**–**	–	**(3)**	(3)	**12**	(2)	**–**	–	**–**	–	**(3)**	(3)	**12**	(2)
Total segmented expenses	**466**	567	**980**	1,141	**9**	10	**36**	22	**(23)**	(22)	**(45)**	(44)	**3,068**	3,624	**6,113**	6,648
Segmented earnings (loss) before the following	**214**	600	**348**	1,057	**26**	20	**34**	39	**4**	3	**4**	1	**354**	1,747	**343**	3,119
Non-segmented expenses																
Administration													**100**	90	**204**	180
Share-based compensation													**(79)**	189	**(15)**	332
Interest and other financing expense													**85**	92	**171**	160
Unrealized risk management activities													**215**	54	**229**	103
Foreign exchange (gain) loss													**(87)**	(122)	**273**	(5)
Total non-segmented expenses													**234**	303	**862**	770
Earnings (loss) before taxes													**120**	1,444	**(519)**	2,349
Current income tax (recovery) expense													**(3)**	185	**(108)**	311
Deferred income tax expense													**528**	189	**246**	346
Net earnings (loss)													**(405)**	1,070	**(657)**	1,692

Capital Expenditures (1)

	Six Months Ended					
	Jun 30, 2015			Jun 30, 2014		
	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	**$ 52**	**$ (160)**	**$ (108)**	$ 968	$ (84)	$ 884
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa	**23**	**–**	**23**	33	–	33
	$ 75	**$ (160)**	**$ (85)**	$ 1,001	$ (84)	$ 917
Property, plant and equipment						
Exploration and Production						
North America	**$ 756**	**$ 5**	**$ 761**	$ 4,506	$ 287	$ 4,793
North Sea	**155**	**(2)**	**153**	195	–	195
Offshore Africa	**258**	**–**	**258**	11	–	11
	1,169	**3**	**1,172**	4,712	287	4,999
Oil Sands Mining and Upgrading (3)	**1,247**	**(49)**	**1,198**	1,403	(45)	1,358
Midstream	**4**	**–**	**4**	51	–	51
Head office	**14**	**–**	**14**	19	(1)	18
	$ 2,434	**$ (46)**	**$ 2,388**	$ 6,185	$ 241	$ 6,426

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

Segmented Assets

	Total Assets	
	Jun 30 2015	Dec 31 2014
Exploration and Production		
North America	**$ 33,177**	$ 34,382
North Sea	**2,845**	2,711
Offshore Africa	**1,606**	1,214
Other	**34**	18
Oil Sands Mining and Upgrading	**21,611**	20,702
Midstream	**1,144**	1,048
Head office	**126**	125
	$ 60,543	$ 60,200

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 November 2013. 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, 2015:

Interest coverage (times)	
Net earnings (1)	5.0x
Cash flow from operations (2)	14.7x

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

(2) 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

Board of Directors

Catherine M. Best, FCA, ICD.D

N. Murray Edwards, O.C.

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Honourable Gary A. Filmon, P.C., O.C., O.M.

Christopher L. Fong

Ambassador Gordon D. Giffin

Wilfred A. Gobert

Steve W. Laut

Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C.

David A. Tuer

Annette Verschuren, O.C.

Officers

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Chairman of the Board

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Tim S. McKay
Chief Operating Officer

Douglas A. Proll
Executive Vice-President

Lyle G. Stevens
Executive Vice-President, Canadian Conventional

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

Réal M. Cusson
Senior Vice-President, Marketing

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

Darren M. Fichter
Senior Vice-President, Exploitation

Terry J. Jocksch
Senior Vice-President, Thermal

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

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Vice-President, Legal and General Counsel

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

Ken W. Stagg
Senior Vice-President, Exploration

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

Betty Yee
Vice-President, Land

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Corporate Secretary

International Operations
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Aberdeen, Scotland

W. David R. Bell
Vice-President, Exploration, International

Barry Duncan
Vice-President, Finance, International

Andrew M. McBoyle
Vice-President, Exploitation, International

David B. Whitehouse
Vice-President, Development Operations, International

Stock Listing

Toronto Stock Exchange
Trading Symbol – CNQ

New York Stock Exchange
Trading Symbol – CNQ

Registrar and Transfer Agent

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