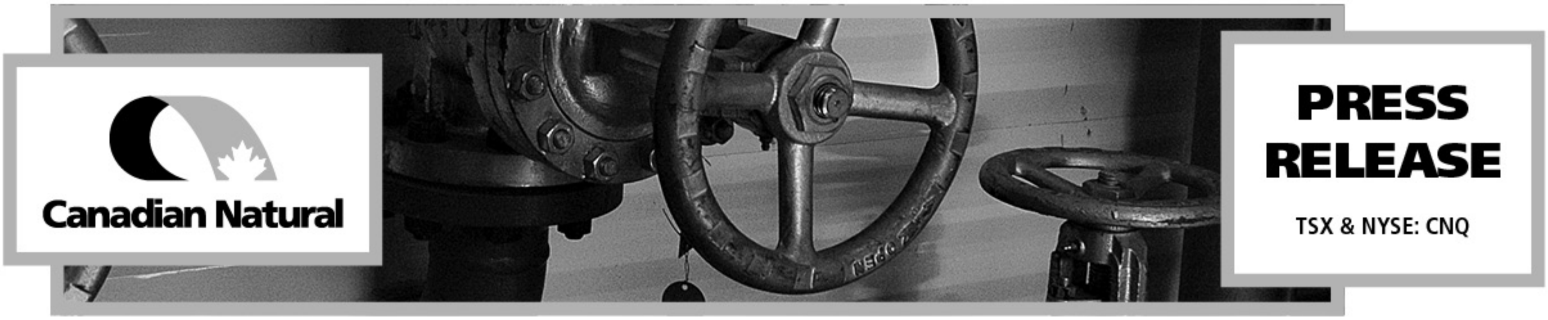

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2014 THIRD QUARTER RESULTS

CALGARY, ALBERTA – NOVEMBER 6, 2014 – FOR IMMEDIATE RELEASE

Commenting on third quarter results, Steve Laut, President of Canadian Natural, stated, “Canadian Natural continued the effective execution of our proven strategy. Our strong, well-balanced asset base generates free cash flow to fund our transition to longer life, low decline assets. Quarterly production increased by approximately 94,000 barrels of oil equivalent per day over third quarter 2013 levels, representing a 13% increase to approximately 797,000 barrels of oil equivalent per day, generating strong quarterly cash flow of $2.44 billion.

Canadian Natural’s transition to longer life, low decline assets remains on track. The Horizon coker expansion tie-in was completed in the third quarter of 2014, ahead of the original 2015 schedule, increasing Horizon production capacity by 12,000 barrels per day. Horizon production averaged approximately 123,100 barrels per day in October 2014, reflecting the effective startup of the expanded facility. Expansion activities remain on track and on budget, with Phase 2B targeted to add 45,000 barrels per day of production capacity in late 2016, and Phase 3 targeted to add another 80,000 barrels per day of production capacity in late 2017.

At Pelican Lake our leading edge polymer flood achieved another quarterly record, with production of approximately 51,900 barrels per day of heavy crude oil, reflecting the continued excellent reservoir performance. At Kirby South, our latest thermal in situ project, reservoir performance has been as expected. With the steam generator issues behind us, production is targeted to ramp up to 40,000 barrels per day in line with original projections of reservoir performance.

Our balanced and diverse asset base combined with the effectiveness of our teams enables us to remain nimble and flexible. The integration of acquisitions continues to progress smoothly, and approximately $70 million in cost efficiencies will be realized in 2014 due to synergies achieved.

As always, we remain focused on effective and efficient operations and optimizing our capital allocation to maximize value for shareholders.”

Canadian Natural’s Chief Financial Officer, Corey Bieber, continued, “We are in an enviable position with our diverse asset base supported by a strong balance sheet. Our liquidity and credit remain robust with current available liquidity of approximately $2.4 billion through our committed banking facilities. Our capital programs are flexible, allowing us to proactively respond to market conditions and enabling us to allocate capital to those projects which generate the highest returns.”

QUARTERLY HIGHLIGHTS

($ Millions, except per common share amounts)	Three Months Ended Sep 30 2014	Three Months Ended Jun 30 2014	Three Months Ended Sep 30 2013	Nine Months Ended Sep 30 2014	Nine Months Ended Sep 30 2013
Net earnings	**$ 1,039**	$ 1,070	$ 1,168	**$ 2,731**	$ 1,857
Per common share – basic	**$ 0.95**	$ 0.98	$ 1.07	**$ 2.50**	$ 1.70
– diluted	**$ 0.94**	$ 0.97	$ 1.07	**$ 2.49**	$ 1.70
Adjusted net earnings from operations (1)	**$ 984**	$ 1,150	$ 1,009	**$ 3,055**	$ 1,872
Per common share – basic	**$ 0.90**	$ 1.05	$ 0.93	**$ 2.80**	$ 1.72
– diluted	**$ 0.89**	$ 1.04	$ 0.93	**$ 2.78**	$ 1.72
Cash flow from operations (2)	**$ 2,440**	$ 2,633	$ 2,454	**$ 7,219**	$ 5,695
Per common share – basic	**$ 2.23**	$ 2.41	$ 2.26	**$ 6.61**	$ 5.23
– diluted	**$ 2.21**	$ 2.39	$ 2.26	**$ 6.57**	$ 5.22
Capital expenditures, net of dispositions	**$ 2,175**	$ 5,456	$ 1,655	**$ 9,524**	$ 5,183
Daily production, before royalties					
Natural gas (MMcf/d)	**1,674**	1,634	1,163	**1,497**	1,145
Crude oil and NGLs (bbl/d)	**518,007**	545,169	509,182	**517,428**	478,308
Equivalent production (BOE/d) (3)	**796,931**	817,471	702,938	**766,871**	669,170

(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 generated cash flow from operations of approximately $2.44 billion in Q3/14 compared to approximately $2.45 billion in Q3/13 and $2.63 billion in Q2/14. The reduction in cash flow from Q2/14 levels reflects lower synthetic crude oil ("SCO") sales volumes at Horizon Oil Sands ("Horizon") operations as a result of the planned turnaround for the coker tie-in, as well as lower benchmark pricing, partially offset by higher sales in the North America Exploration and Production segment.
- Adjusted net earnings from operations for Q3/14 were $984 million, compared to adjusted net earnings of $1,009 million in Q3/13 and $1,150 million Q2/14. Changes in adjusted net earnings reflect the changes in cash flow.
- Total production for Q3/14 increased approximately 94,000 BOE/d, or 13%, to 796,931 BOE/d from Q3/13 levels of 702,938 BOE/d and decreased 3% from Q2/14 levels of 817,471 BOE/d. The increase from Q3/13 levels is as a result of strong production in all areas, as well as acquisitions made in 2014. The decrease in production from Q2/14 levels was largely due to the planned 25 day turnaround required at Horizon for the coker tie-in.
- During Q3/14 Horizon continued to achieve strong and reliable operating performance and successfully completed the coker tie-in, originally scheduled for 2015. Horizon achieved quarterly SCO production of approximately 82,000 bbl/d, reflecting the 25 day planned turnaround. Horizon achieved an effective ramp up of production after the coker tie-in, with strong October 2014 production of approximately 123,100 bbl/d, representing a 94% plant utilization rate. Production levels are targeted to average approximately 127,000 bbl/d for the remainder of the year, at the high end of the expected plant utilization rate of 94 - 96%.
- North America light crude oil and NGLs achieved quarterly production of approximately 93,500 bbl/d in Q3/14. Production increased 33% from Q3/13 levels, and is comparable to Q2/14 levels, largely as a result of the successful integration of light crude oil and NGLs production volumes acquired in 2014, as well as a successful drilling program.

- In Q3/14, primary heavy crude oil operations achieved record quarterly production of approximately 143,400 bbl/d. Primary heavy crude oil production increased 2% from Q3/13 levels and achieved a slight increase from Q2/14 levels. The strong performance from Canadian Natural's primary heavy crude oil assets is largely due to the Company's large undeveloped land base.
- In Q3/14, Pelican Lake operations achieved record quarterly heavy crude oil production volumes of approximately 51,900 bbl/d, a 14% increase from Q3/13 volumes and a 5% increase from Q2/14 volumes. This is the seventh consecutive quarter of production increases, which reflects Canadian Natural's continued success in developing, implementing and optimizing leading edge polymer flood technology at Pelican Lake.
- Q3/14 thermal in situ production volumes were approximately 115,300 bbl/d, within the Company's previously issued guidance of 110,000 bbl/d to 120,000 bbl/d.
  - At Kirby South, Q3/14 production averaged approximately 18,100 bbl/d, reflecting the impact of the previously announced mechanical issues at the steam generating facility. Canadian Natural has remedied these issues and the production ramp up has resumed. October 2014 production averaged approximately 22,000 bbl/d, and current production is averaging approximately 25,000 bbl/d, reflecting the strong performance of the reservoir.
  - To date, the Kirby North Phase 1 ("Kirby North") project has received all regulatory permits. Targeted project capital for Kirby North is $1.45 billion, or approximately $36,000 per flowing barrel at a project capacity of 40,000 bbl/d. The overall project is 33% complete and in Q3/14 site construction commenced on the Central Processing Facility. First steam-in is targeted for Q4/16.
  - Canadian Natural's stepwise plan to return to steaming operations at Primrose with enhanced mitigation strategies in place has progressed:
    - In September 2014, Canadian Natural received approval from the Alberta Energy Regulator ("AER") to implement a low pressure steamflood in Primrose East Area 1. The steamflood commenced and production is ramping up as expected.
    - Primrose South received approval for additional cyclic steam stimulation ("CSS") on four pads in September 2014; production is targeted to ramp up in 2015.
    - Additionally, during Q3/14, an application for low pressure CSS was submitted to the AER for Primrose East Area 2.
- Q3/14 total natural gas production was 1,674 MMcf/d, an increase of 44% and 2% from Q3/13 levels and Q2/14 levels respectively. The increase from Q3/13 levels was as a result of property acquisitions and the increase from Q2/14 levels was due to a continuing concentrated liquids-rich natural gas drilling program and the successful integration of acquired assets.
- In Q3/14, North Sea light crude oil production averaged 18,200 bbl/d, an increase of 17% and 44% from Q3/13 and Q2/14 levels respectively. The increase in production over Q2/14 levels was primarily due to the reinstatement of the Banff/Kyle Floating Production Storage and Offtake vessel ("FPSO") in July 2014. Production had been suspended in 2011 after the infrastructure suffered storm damage.
- Canadian Natural continues to review its royalty lands and royalty revenue portfolio. A thorough review process has been ongoing and Canadian Natural continues to evaluate the options to maximize the value of these assets for its shareholders. Based on the analysis completed to date, Canadian Natural reports the following information for quarterly royalty volumes:

ROYALTY PRODUCTION VOLUMES (1)

	Royalty volumes attributable to		
	Third Party	Canadian Natural (2)	Total
Natural gas (MMcf/d)	17.8	3.2	21.0
Crude oil (bbl/d)	2,977	724	3,701
NGLs (bbl/d)	402	61	463
Total (BOE/d)	**6,339**	**1,326**	**7,665**

REVENUE BY PRODUCT (1)

($ millions)	Royalty revenue attributable to Third Party	Canadian Natural (2)	Total
Natural gas	$ 7.2	$ 1.4	$ 8.6
Crude oil	$ 25.9	$ 5.7	$ 31.6
NGLs	$ 2.0	$ 0.3	$ 2.3
Other revenue (3)	$ 2.2	$ -	$ 2.2
Total	**$ 37.3**	**$ 7.4**	**$ 44.7**

REVENUE BY ROYALTY CLASSIFICATION (1)

($ millions)	Royalty revenue attributable to Third Party	Canadian Natural (2)	Total
Fee title	$ 21.6	$ 5.6	$ 27.2
Gross overriding royalty (4)	$ 13.5	$ 1.8	$ 15.3
Other revenue (3)	$ 2.2	$ -	$ 2.2
Total	**$ 37.3**	**$ 7.4**	**$ 44.7**

ROYALTY REALIZED PRICING (1)

	Total
Natural gas ($/Mcf)	$ 4.50
Crude oil ($/bbl)	$ 93.80
NGLs ($/bbl)	$ 53.98
Total ($/BOE)	**$ 60.88**

ROYALTY ACREAGE

(gross acres, millions)	Leased to Third Party and Unleased	Canadian Natural (2)	Total
Fee title	2.76	0.17	2.93
Gross overriding royalty (4)	1.69	1.50	3.19
Total	**4.45**	**1.67**	**6.12**

(1) Based on the Company's current estimate of revenue and volumes attributable to Q2/14 and subject to final revision.
(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.

- The development of leased acreage is ongoing and lease requests on undeveloped acreage continue to be evaluated. Production on the royalty lands continues to grow; as over 168 new wells have been rig released on royalty lands since June 1, 2014, of which 19 wells were drilled by Canadian Natural.
- The Company continues to focus on lease compliance, well commitments, offset drilling obligations and compensatory royalties payable, with 97 offset obligations currently identified.
- Canadian Natural is reviewing the best option to maximize value for its shareholders as it relates to its fee title and royalty lands and is targeting to finalize its strategy in this regard by late 2014 or early 2015.

- Royalty production volumes highlighted above 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.

- Under the Company's Normal Course Issuer Bid, year to date, Canadian Natural has purchased for cancellation 9,675,000 common shares at a weighted average price of $45.01 per common share.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.225 per share payable on January 1, 2014.

CORPORATE UPDATE

Canadian Natural is pleased to announce the appointment of Annette Verschuren to the Board of Directors of the Company. Ms. Verschuren is Chair and CEO of NRStor Inc., an energy storage project developer accelerating the development and construction of industry leading energy storage technologies. She began her career in the coal mining industry with Cape Breton Development Corporation and held various executive positions with Canada Development Investment Corporation and Imasco Ltd. She is former president of The Home Depot Canada and Asia and prior to that was president and co-owner of the arts and crafts retailer, Michaels of Canada. Ms. Verschuren is an Officer of The Order of Canada and holds honorary doctorate degrees from several notable Canadian universities including St. Francis Xavier University, where she also earned a Bachelor of Business Administration degree. She currently serves on two other publicly traded company boards, sits on a number of not-for-profit boards and serves as Chancellor of Cape Breton University.

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 production facilities by processing its own or third party volumes, 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, natural gas and NGLs. A large diversified project portfolio enables the effective allocation of capital to higher return opportunities.

OPERATIONS REVIEW

Drilling activity

	Nine Months Ended Sep 30			
	2014		2013	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**774**	**698**	824	793
Natural gas	**81**	**59**	44	33
Dry	**13**	**11**	18	17
Subtotal	**868**	**768**	886	843
Stratigraphic test / service wells	**365**	**363**	331	330
Total	**1,233**	**1,131**	1,217	1,173
Success rate (excluding stratigraphic test / service wells)		**99%**		98%

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sept 30 2013
Crude oil and NGLs production (bbl/d)	**288,858**	285,740	256,329	**280,319**	244,849
Net wells targeting crude oil	**275**	151	294	**689**	701
Net successful wells drilled	**270**	149	287	**679**	685
Success rate	**98%**	99%	98%	**99%**	98%

- North America crude oil and NGLs achieved record quarterly production of approximately 288,900 bbl/d in Q3/14, an increase of 13% from Q3/13 levels and 1% from Q2/14 levels.
- In Q3/14, primary heavy crude oil operations achieved record quarterly production of approximately 143,400 bbl/d. Primary heavy crude oil production increased 2% from Q3/13 levels and achieved a slight increase from Q2/14 levels. The Company's large undeveloped land base, effective and efficient drilling program and vast inventory of over 8,000 well locations enables Canadian Natural to remain the industry leading primary heavy crude oil producer. Canadian Natural continued with its large and cost efficient drilling program, drilling 245 net primary heavy crude oil wells in Q3/14.
- Canadian Natural's primary heavy crude oil assets provide strong netbacks and the highest return on capital in the Company's North America portfolio of diverse and balanced assets.
- In Q3/14, Pelican Lake operations achieved record heavy crude oil quarterly production volumes of approximately 51,900 bbl/d, a 14% increase from Q3/13 volumes and a 5% increase from Q2/14 volumes. This is the seventh consecutive quarter of production increases, which reflects Canadian Natural's continued success in developing, implementing and optimizing polymer flood technology at Pelican Lake.
  - Industry leading Pelican Lake operating costs drive high netbacks and significant free cash flow generation. These industry leading Q3/14 operating costs of $7.82/bbl represent a 17% decrease in operating costs from Q3/13 levels and a 12% decrease from Q2/14 levels. The increasing polymer flood production response combined with continued optimization and effective and efficient operations have driven cost improvements.
- North America light crude oil and NGLs achieved quarterly production of approximately 93,500 bbl/d in Q3/14. Production increased 33% from Q3/13 levels, and is comparable to Q2/14 levels, largely as a result of the successful integration of light crude oil and NGLs production volumes acquired in 2014, as well as a successful drilling program. The increase from Q3/13 levels also reflects the increased NGLs production associated with the Septimus project expansion completed in Q3/13.

Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Bitumen production (bbl/d)	**115,256**	114,414	109,200	**104,037**	102,715
Net wells targeting bitumen	**1**	3	47	**15**	107
Net successful wells drilled	**1**	3	47	**15**	107
Success rate	**100%**	100%	100%	**100%**	100%

- Q3/14 thermal in situ production volumes were approximately 115,300 bbl/d, within the Company's previously issued quarterly guidance of 110,000 bbl/d to 120,000 bbl/d.

- At Kirby South, Q3/14 production averaged approximately 18,100 bbl/d, reflecting the impact of the previously announced mechanical issues at the associated steam generating facility. Canadian Natural has remedied these issues and the production ramp up has resumed. October 2014 production averaged approximately 22,000 bbl/d, and current production is averaging approximately 25,000 bbl/d, reflecting the strong performance of the reservoir. The total cost to repair the steam generators was approximately $5 million. Kirby South production is targeted to grow to facility capacity of 40,000 bbl/d.
- To date, the Kirby North project has received all regulatory permits. Targeted project capital for Kirby North is $1.45 billion, or approximately $36,000 per flowing barrel at a project capacity of 40,000 bbl/d. The overall project is 33% complete and in Q3/14 site construction commenced on the Central Processing Facility. First steam-in is targeted for Q4/16.
- Canadian Natural's stepwise plan to return to steaming operations at Primrose with enhanced mitigation strategies in place has progressed:
  - In September 2014, Canadian Natural received approval from the Alberta Energy Regulator ("AER") to implement a low pressure steamflood in Primrose East Area 1. The steamflood commenced and production is ramping up as expected.
  - Primrose South received approval for additional CSS on four pads in September 2014; production is targeted to ramp up in 2015.
  - Additionally, during Q3/14, an application for low pressure CSS was submitted to the AER for Primrose East Area 2.
  - Canadian Natural believes that reserves recovered from the Primrose area over its life cycle will be substantially unchanged.

Natural Gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Natural gas production (MMcf/d)	**1,644**	1,606	1,136	**1,468**	1,118
Net wells targeting natural gas	**22**	13	10	**60**	34
Net successful wells drilled	**21**	13	10	**59**	33
Success rate	**95%**	100%	100%	**98%**	97%

- North America natural gas production averaged 1,644 MMcf/d for Q3/14, an increase of 45% and 2% from Q3/13 levels and Q2/14 levels respectively. The increase from Q3/13 levels was as a result of property acquisitions and the increase from Q2/14 levels was due to a continuing concentrated liquids-rich natural gas drilling program and the successful integration of acquired assets.
- In Q2/14, Canadian Natural completed natural gas and light crude oil property acquisitions in areas adjacent or proximal to the Company's current operations. The integration and optimization of the acquired assets is progressing well. In Q3/14 Canadian Natural's North America natural gas operating costs decreased to $1.36/Mcf, 8% below Q2/14 levels. The Company continues to enhance production while further reducing operating costs as the optimization process continues with facility consolidations, well reactivations and facility turnarounds.

International Exploration and Production

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Crude oil production (bbl/d)					
North Sea	**18,197**	12,615	15,522	**15,848**	17,720
Offshore Africa	**13,684**	13,164	16,172	**12,557**	16,780
Natural gas production (MMcf/d)					
North Sea	**7**	5	4	**7**	3
Offshore Africa	**23**	23	23	**22**	24
Net wells targeting crude oil	**1.8**	1.7	–	**3.5**	1.0
Net successful wells drilled	**1.8**	1.7	–	**3.5**	1.0
Success rate	**100%**	100%	–	**100%**	100%

- International crude oil production averaged approximately 31,900 bbl/d during Q3/14, comparable to Q3/13 levels and a 24% increase from Q2/14 levels. The increase in production over Q2/14 levels was primarily due to the reinstatement of the Banff/Kyle FPSO in July 2014. Production was suspended in 2011 after the infrastructure suffered storm damage.
- During Q2/14, Canadian Natural contracted a drilling rig to undertake the 12-month light crude oil infill development drilling program at Espoir, Côte d'Ivoire. Drilling is targeted to commence in late Q4/14 with a 10 well (5.9 net) drilling program. This program is targeted to add 5,900 BOE/d of net production when complete.
- During Q4/13 the Company contracted a drilling rig for a 6 well (3.5 net) infill development drilling program at the Baobab field in Côte d'Ivoire. This rig is expected to arrive no later than Q1/15 to commence an approximate 16-month light crude oil drilling program, which is targeted to add 11,000 BOE/d of net production when complete.
- Canadian Natural previously acquired a working interest in two exploration blocks in Côte d'Ivoire which are prospective for deepwater channel/fan structures similar to Jubilee crude oil discoveries in Offshore Africa. In Q2/14, an exploratory well was drilled on Block CI-514, in which the Company has a 36% working interest. The well demonstrated the presence of a working petroleum system. A second well is targeted to be drilled in the first half of 2015 to evaluate the up-dip potential of the initial well. These results enhance the prospectivity of Canadian Natural's Block CI-12, located approximately 35 km west of Canadian Natural's current production at Espoir and Baobab, where new 3D seismic has been acquired and is being evaluated for further exploration targets.
- Canadian Natural has a 50% interest in the Block 11B/12B Exploration Right located in the Outeniqua Basin, approximately 175 kilometers off the southern coast of South Africa. During Q3/14, the operator, Total E&P South Africa BV, a wholly owned subsidiary of Total SA, commenced drilling the first exploratory well. Subsequent to Q3/14, the exploration well was suspended due to mechanical issues with marine equipment on the drilling rig. The rig safely left the well location and, as the available drilling window has ended, it has since been demobilized by the operator. The South African authorities have formally confirmed that the well drilled satisfies the work obligation for the initial period of the Block 11B/12B Exploration Right. The operator is reviewing the course of action to re-enter the well as soon as possible, and has indicated drilling operations are unlikely to resume in the area before 2016.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Synthetic crude oil production (bbl/d) [(1)]	**82,012**	119,236	111,959	**104,667**	96,244

(1) The Company has commenced production of diesel for internal use at Horizon. Q3/14 SCO production excludes 875 bbl/d of SCO consumed internally as diesel.

- During Q3/14 Horizon continued to achieve strong and reliable operating performance and successfully completed the coker tie-in, originally scheduled for 2015. Horizon achieved quarterly SCO production of approximately 82,000 bbl/d, reflecting the 25 day planned turnaround. Horizon achieved an effective ramp up of production after the coker tie-in, with strong October 2014 production of approximately 123,100 bbl/d, representing a 94% plant utilization rate. Production levels are targeted to average approximately 127,000 bbl/d for the remainder of the year, at the high end of the expected plant utilization rate of 94 - 96%.
- During Q3/14 the production of diesel for internal use commenced at Horizon. In Q4/14, 1,500 bbl/d of diesel production is targeted to be produced at Horizon. The production and use of internally produced diesel fuel at Horizon will reduce operating costs and provides additional volumes beyond reported production targets.
- Canadian Natural continues to deliver on its strategy to transition to a longer life, low decline asset base while providing significant and growing free cash flow. Canadian Natural's staged expansion to 250,000 bbl/d of SCO production capacity continues to progress on track and within cost estimates.
- Overall Horizon Phase 2/3 expansion is 50% physically complete as at Q3/14:
  - Reliability – Tranche 2 is 100% physically complete. This phase will increase performance, overall production reliability and the Gas Recovery Unit will recover additional SCO barrels in 2014.
  - Directive 74 includes technological investment and research into tailings management. This project remains on track and is physically 41% complete.
  - Phase 2A is a coker expansion which will utilize pre-invested infrastructure and equipment to expand the Coker Plant and alleviate the current bottleneck. The coker tie-in 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 commence August 2014. The Coker Expansion Unit is fully operational and 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.
  - Phase 2B is 42% physically complete. This phase expands the capacity of major components such as gas/oil hydrotreatment, froth treatment and the hydrogen plant. This phase is targeted to add another 45,000 bbl/d of production capacity in late 2016.
  - Phase 3 is on track and on schedule. This phase is 38% 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.
  - The projects currently under construction continue to progress on track and within sanctioned cost estimates.
- For the Phase 2/3 expansion Canadian Natural has committed to approximately 67% of the Engineering, Procurement and Construction contracts. Over 68% of the construction contracts have been awarded to date, with 85% being lump sum, ensuring greater cost certainty.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 97.21**	$ 102.98	$ 105.82	**$ 99.60**	$ 98.17
WCS blend differential from WTI (%) (2)	**21%**	19%	16%	**21%**	23%
SCO price (US$/bbl)	**$ 94.31**	$ 103.87	$ 109.97	**$ 98.20**	$ 101.49
Condensate benchmark pricing (US$/bbl)	**$ 93.49**	$ 105.15	$ 103.83	**$ 100.36**	$ 104.16
Average realized pricing before risk management (C$/bbl) (3)	**$ 79.99**	$ 87.03	$ 89.24	**$ 82.35**	$ 75.32
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 4.00**	$ 4.44	$ 2.68	**$ 4.32**	$ 3.00
Average realized pricing before risk management (C$/Mcf)	**$ 4.54**	$ 5.06	$ 3.15	**$ 5.03**	$ 3.56

(1) West Texas Intermediate ("WTI").

(2) Western Canadian Select ("WCS").

(3) Average crude oil and NGLs pricing excludes SCO. Pricing is net of blending costs and excluding risk management activities.

Benchmark Pricing	**WTI Pricing (US$/bbl)**	**WCS Blend Differential from WTI (%)**	**SCO premium/ (discount) from WTI (US$/bbl)**	**Dated Brent premium/ (discount) from WTI (US$/bbl)**	**Condensate premium/ (discount) from WTI (US$/bbl)**
2014					
July	$ 102.39	19%	$ (2.43)	$ 4.24	$ (3.30)
August	$ 96.08	23%	$ (3.31)	$ 5.53	$ (4.29)
September	$ 93.03	20%	$ (2.98)	$ 4.26	$ (3.57)
October	$ 84.34	16%	$ (0.48)	$ 2.93	$ (0.09)
November*	$ 80.51	16%	$ (0.45)	$ 4.81	$ (2.13)
December*	$ 80.40	19%	$ (4.07)	$ 5.21	$ (4.23)

**Based on current indicative pricing as at October 31, 2014.*

- Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$97.21/bbl for Q3/14, a decrease of 8% from US$105.82/bbl for Q3/13, and a decrease of 6% from US$102.98/bbl for Q2/14. However, Q3/14 realized prices were offset by the impact of the weaker Canadian dollar, which increased the Canadian dollar sales price the Company received for its crude oil sales, based on US dollar denominated benchmarks. The Company realized Canadian dollar WTI benchmark pricing of C$109.96/bbl for July 2014, C$104.98/bbl for August 2014 and C$102.45/bbl for September 2014.
- The WCS differential averaged 21% during Q3/14 compared with 16% in Q3/13 and 19% in Q2/14. The WCS differential averaged 21% for the nine months ended September 30, 2014, compared with 23% for the nine months ended September 30, 2013.
- Subsequent to Q3/14, the WCS differential averaged 16% in October 2014, and the indicative WCS differential for November 2014 is approximately 16% and December 2014 is approximately 19%.
- Canadian Natural contributed approximately 160,000 bbl/d of its heavy crude oil stream to the WCS blend in Q3/14. The Company remains the largest contributor to the WCS blend, accounting for over 56% of the total blend this quarter.
- SCO pricing during Q3/14 decreased 14% and 9% from Q3/13 levels and Q2/14 levels respectively, primarily due to a decrease in benchmark pricing.

- During Q3/14, AECO natural gas prices increased 49% over Q3/13 levels and decreased 10% from Q2/14 levels. Natural gas prices increased from the comparable period in 2013 due to increased winter weather related natural gas demand. The colder than normal winter resulted in natural gas storage inventories falling below five-year lows in the US and Canada. The decrease from Q2/14 levels is due to decreased summer weather related natural gas demand and an increase in natural gas storage levels.

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. Work is progressing and site preparation and deep underground construction is targeted to be completed in Q4/14.

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 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 796,931 BOE/d for Q3/14 with approximately 98% of production located in G8 countries.
- Canadian Natural has a strong balance sheet with debt to book capitalization of 33% and debt to EBITDA of 1.4x at September 30, 2014.
- Canadian Natural maintains significant financial stability and liquidity represented by bank credit facilities. As at September 30, 2014, the Company had in place bank credit facilities of $5,802 million, of which $2,358 million, net of commercial paper issuances of $560 million, was available.
- The Company's commodity hedging program is utilized, as required, to protect investment returns, ensure ongoing balance sheet strength and support the Company's 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.
- Under the Company's Normal Course Issuer Bid, Canadian Natural has purchased year to date 9,675,000 common shares for cancellation at an average price of $45.01 per common share, which includes 790,000 common shares purchased subsequent to September 30, 2014 at a weighted average price of $39.49 per common share.
- Canadian Natural's Board of Directors has declared a quarterly cash dividend on common shares of C$0.225 per share payable on January 1, 2014.
- The Company has a strong balance sheet and cash flow generation which enables it to weather volatility in commodity prices. Additionally, Canadian Natural retains significant capital expenditure program flexibility to proactively adapt to changing market conditions.

OUTLOOK

The Company forecasts 2014 production levels before royalties to average between 531,000 and 557,000 bbl/d of crude oil and NGLs and between 1,550 and 1,570 MMcf/d of natural gas. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

MANAGEMENT’S DISCUSSION AND ANALYSIS

Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the “Company”) in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as “forward-looking statements”) within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words “believe”, “anticipate”, “expect”, “plan”, “estimate”, “target”, “continue”, “could”, “intend”, “may”, “potential”, “predict”, “should”, “will”, “objective”, “project”, “forecast”, “goal”, “guidance”, “outlook”, “effort”, “seeks”, “schedule”, “proposed” or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses and other guidance provided throughout this Management’s Discussion and Analysis (“MD&A”), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansions, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the construction and future operations of the North West Redwater bitumen upgrader and refinery, 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 nine months ended September 30, 2014 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2013.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company’s unaudited interim consolidated financial statements for the period ended September 30, 2014 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 refers primarily to the Company’s financial results for the three and nine months ended September 30, 2014 in relation to the comparable periods in 2013 and the second quarter of 2014. 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, 2013, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated November 4, 2014.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Product sales	**$ 5,370**	$ 6,113	$ 5,284	**$ 16,451**	$ 13,615
Net earnings	**$ 1,039**	$ 1,070	$ 1,168	**$ 2,731**	$ 1,857
Per common share – basic	**$ 0.95**	$ 0.98	$ 1.07	**$ 2.50**	$ 1.70
– diluted	**$ 0.94**	$ 0.97	$ 1.07	**$ 2.49**	$ 1.70
Adjusted net earnings from operations (1)	**$ 984**	$ 1,150	$ 1,009	**$ 3,055**	$ 1,872
Per common share – basic	**$ 0.90**	$ 1.05	$ 0.93	**$ 2.80**	$ 1.72
– diluted	**$ 0.89**	$ 1.04	$ 0.93	**$ 2.78**	$ 1.72
Cash flow from operations (2)	**$ 2,440**	$ 2,633	$ 2,454	**$ 7,219**	$ 5,695
Per common share – basic	**$ 2.23**	$ 2.41	$ 2.26	**$ 6.61**	$ 5.23
– diluted	**$ 2.21**	$ 2.39	$ 2.26	**$ 6.57**	$ 5.22
Capital expenditures, net of dispositions	**$ 2,175**	$ 5,456	$ 1,655	**$ 9,524**	$ 5,183

(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			*Nine Months Ended*	
($ millions)	***Sep 30 2014***	*Jun 30 2014*	*Sep 30 2013*	***Sep 30 2014***	*Sep 30 2013*
Net earnings as reported	***$ 1,039***	*$ 1,070*	*$ 1,168*	***$ 2,731***	*$ 1,857*
Share-based compensation, net of tax (1)	***(122)***	*189*	*48*	***210***	*70*
Unrealized risk management (gain) loss, net of tax (2)	***(118)***	*44*	*99*	***(36)***	*58*
Unrealized foreign exchange loss (gain), net of tax (3)	***185***	*(153)*	*(75)*	***150***	*115*
Realized foreign exchange gain on repayment of US dollar debt securities, net of tax (4)	***–***	*–*	*–*	***–***	*(12)*
Gain on corporate acquisition/disposition of properties, net of tax (5)	***–***	*–*	*(231)*	***–***	*(231)*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (6)	***–***	*–*	*–*	***–***	*15*
Adjusted net earnings from operations	***$ 984***	*$ 1,150*	*$ 1,009*	***$ 3,055***	*$ 1,872*

(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 and natural gas.

(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) During the first quarter of 2013, the Company repaid US$400 million of 5.15% notes.

(5) During the third quarter of 2013, the Company recorded an after-tax gain of $231 million related to the acquisition of Barrick Energy Inc. and the disposition of a 50% working interest in an exploration right in South Africa.

(6) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted. During the second quarter of 2013, the Government of British Columbia substantively enacted legislation to increase its provincial corporate income tax rate effective April 1, 2013, resulting in an increase in the Company's deferred income tax liability of $15 million.

Cash Flow from Operations

($ millions)	Three Months Ended Sep 30 2014	Jun 30 2014	Sep 30 2013	Nine Months Ended Sep 30 2014	Sep 30 2013
Net earnings	**$ 1,039**	$ 1,070	$ 1,168	**$ 2,731**	$ 1,857
Non-cash items:					
Depletion, depreciation and amortization	**1,226**	1,237	1,258	**3,474**	3,572
Share-based compensation	**(122)**	189	48	**210**	70
Asset retirement obligation accretion	**49**	50	41	**144**	125
Unrealized risk management (gain) loss	**(150)**	54	121	**(47)**	69
Unrealized foreign exchange loss (gain)	**185**	(153)	(75)	**150**	115
Realized foreign exchange gain on repayment of US dollar debt securities	**–**	–	–	**–**	(12)
Equity loss (gain) from investment	**5**	(3)	1	**3**	3
Deferred income tax expense	**208**	189	123	**554**	127
Gain on corporate acquisition/disposition of properties	**–**	–	(289)	**–**	(289)
Current income tax on disposition of properties	**–**	–	58	**–**	58
Cash flow from operations	**$ 2,440**	$ 2,633	$ 2,454	**$ 7,219**	$ 5,695

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the nine months ended September 30, 2014 were $2,731 million compared with $1,857 million for the nine months ended September 30, 2013. Net earnings for the nine months ended September 30, 2014 included net after-tax expenses of $324 million compared with $15 million for the nine months ended September 30, 2013 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of a realized foreign exchange gain on repayment of long-term debt, the gain on corporate acquisition/disposition of properties, 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 nine months ended September 30, 2014 were $3,055 million compared with $1,872 million for the nine months ended September 30, 2013.

Net earnings for the third quarter of 2014 were $1,039 million compared with $1,168 million for the third quarter of 2013 and $1,070 million for the second quarter of 2014. Net earnings for the third quarter of 2014 included net after-tax income of $55 million compared with $159 million for the third quarter of 2013 and net after-tax expenses of $80 million for the second quarter of 2014 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, and the gain on corporate acquisition/disposition of properties. Excluding these items, adjusted net earnings from operations for the third quarter of 2014 were $984 million compared with $1,009 million for the third quarter of 2013 and $1,150 million for the second quarter of 2014.

The increase in adjusted net earnings for the nine months ended September 30, 2014 from the comparable period in 2013 was primarily due to:

- higher crude oil and NGLs, natural gas, and SCO sales volumes in the North America and Oil Sands Mining and Upgrading segments;
- higher crude oil and NGLs and natural gas netbacks in the North America segment;
- higher realized SCO prices; and
- the impact of a weaker Canadian dollar relative to the US dollar;

partially offset by:

- lower crude oil sales volumes in the North Sea and Offshore Africa segments.

The decrease in adjusted net earnings for the third quarter of 2014 from the third quarter of 2013 was primarily due to:

- lower crude oil and NGLs netbacks in the North America segment;
- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment due to the completion of the Horizon coker expansion tie-in;
- lower crude oil sales volumes in the North Sea segment; and
- lower realized SCO prices;

partially offset by:

- higher crude oil and NGLs and natural gas sales volumes in the North America segment;
- higher crude oil sales volumes in the Offshore Africa segment;
- higher natural gas netbacks in the North America segment; and
- the impact of a weaker Canadian dollar relative to the US dollar.

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

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower crude oil and NGLs and natural gas netbacks in the North America segment;
- lower realized SCO prices; and
- lower crude oil sales volumes in the North Sea segment;

partially offset by:

- higher crude oil and NGLs sales volumes in the North America segment.

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 and are discussed in detail in the relevant sections of this MD&A.

Cash flow from operations for the nine months ended September 30, 2014 was $7,219 million compared with $5,695 million for the nine months ended September 30, 2013. Cash flow from operations for the third quarter of 2014 was $2,440 million compared with $2,454 million for the third quarter of 2013 and $2,633 million for the second quarter of 2014. 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, excluding the impact of cash taxes.

Total production before royalties for the nine months ended September 30, 2014 increased 15% to 766,871 BOE/d from 669,170 BOE/d for the nine months ended September 30, 2013. Total production before royalties for the third quarter of 2014 increased 13% to 796,931 BOE/d from 702,938 BOE/d for the third quarter of 2013 and decreased 3% from 817,471 BOE/d for the second quarter of 2014.

SUMMARY OF QUARTERLY RESULTS

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

($ millions, except per common share amounts)		**Sep 30 2014**		Jun 30 2014		Mar 31 2014		Dec 31 2013
Product sales	**$**	**5,370**	$	6,113	$	4,968	$	4,330
Net earnings	**$**	**1,039**	$	1,070	$	622	$	413
Net earnings per common share								
– basic	**$**	**0.95**	$	0.98	$	0.57	$	0.38
– diluted	**$**	**0.94**	$	0.97	$	0.57	$	0.38

($ millions, except per common share amounts)		Sep 30 2013		Jun 30 2013		Mar 31 2013		Dec 31 2012
Product sales	$	5,284	$	4,230	$	4,101	$	4,059
Net earnings	$	1,168	$	476	$	213	$	352
Net earnings per common share								
– basic	$	1.07	$	0.44	$	0.19	$	0.32
– diluted	$	1.07	$	0.44	$	0.19	$	0.32

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

- **Crude oil pricing** – The impact of fluctuating demand, inventory storage levels and 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, the results from the Pelican Lake water and polymer flood projects, the strong heavy crude oil drilling program, 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 in North America, 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 due to the cessation of production of 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** – Changes in the Canadian dollar relative to the US dollar that 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 acquisition/disposition of properties** – Fluctuations due to the recognition of gains on corporate acquisitions/dispositions in the third quarter of 2013.

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
WTI benchmark price (US$/bbl)	**$ 97.21**	$ 102.98	$ 105.82	**$ 99.60**	$ 98.17
Dated Brent benchmark price (US$/bbl)	**$ 101.90**	$ 109.63	$ 110.35	**$ 106.55**	$ 108.40
WCS blend differential from WTI (US$/bbl)	**$ 20.19**	$ 20.03	$ 17.42	**$ 21.15**	$ 22.72
WCS blend differential from WTI (%)	**21%**	19%	16%	**21%**	23%
SCO price (US$/bbl)	**$ 94.31**	$ 103.87	$ 109.97	**$ 98.20**	$ 101.49
Condensate benchmark price (US$/bbl)	**$ 93.49**	$ 105.15	$ 103.83	**$ 100.36**	$ 104.16
NYMEX benchmark price (US$/MMBtu)	**$ 4.07**	$ 4.57	$ 3.60	**$ 4.51**	$ 3.68
AECO benchmark price (C$/GJ)	**$ 4.00**	$ 4.44	$ 2.68	**$ 4.32**	$ 3.00
US/Canadian dollar average exchange rate (US$)	**$ 0.9183**	$ 0.9171	$ 0.9629	**$ 0.9139**	$ 0.9770

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$99.60 per bbl for the nine months ended September 30, 2014, an increase of 1% from US$98.17 per bbl for the nine months ended September 30, 2013. WTI averaged US$97.21 per bbl for the third quarter of 2014, a decrease of 8% from US$105.82 per bbl for the third quarter of 2013, and a decrease of 6% from US$102.98 per bbl for the second quarter of 2014. For the three and nine months ended September 30, 2014 realized prices were also impacted by the weaker Canadian dollar that increased the Canadian dollar sales price the Company received for its crude oil sales as realized pricing is based on US dollar denominated benchmarks.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Dated Brent ("Brent") pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$106.55 per bbl for the nine months ended September 30, 2014, a decrease of 2% from US$108.40 per bbl for the nine months ended September 30, 2013. Brent averaged US$101.90 per bbl for the third quarter of 2014, a decrease of 8% from US$110.35 per bbl for the third quarter of 2013, and a decrease of 7% from US$109.63 per bbl for the second quarter of 2014.

WTI and Brent pricing continued to reflect volatility in supply and demand factors and geopolitical events. The Brent differential from WTI tightened for the nine months ended September 30, 2014 from the comparable period due to continued debottlenecking of logistical constraints from Cushing to the US Gulf Coast. Subsequent to September 30, 2014, WTI and Brent benchmark crude oil prices have continued to decline reflecting overall world supply and demand factors.

The WCS Heavy Differential averaged 21% for the nine months ended September 30, 2014 compared with 23% for the nine months ended September 30, 2013. The WCS Heavy Differential averaged 21% for the third quarter of 2014 compared with 16% for the third quarter of 2013 and 19% for the second quarter of 2014. In October 2014, the WCS Heavy Differential averaged US$13.74 per bbl or 16%. To partially mitigate its exposure to fluctuating heavy crude oil differentials, the Company entered into 20,000 bbl/d of physical crude oil sales contracts for the fourth quarter of 2014 at a weighted average fixed WCS differential of US$20.68 per bbl. In addition, the Company has entered into crude oil WCS differential swaps with weighted average fixed WCS differentials as follows: 30,000 bbl/d in the fourth quarter of 2014 at US$21.07 per bbl and 30,000 bbl/d in the first quarter of 2015 at US$21.49 per bbl.

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$98.20 per bbl for the nine months ended September 30, 2014, a decrease of 3% from US$101.49 per bbl for the nine months ended September 30, 2013. The SCO price averaged US$94.31 per bbl for the third quarter of 2014, a decrease of 14% from US$109.97 per bbl for the third quarter of 2013, and decreased 9% from US$103.87 per bbl for the second quarter of 2014. The decrease in SCO pricing for the three and nine months ended September 30, 2014 from the comparable periods was primarily due to a decrease in WTI benchmark pricing.

NYMEX natural gas prices averaged US$4.51 per MMBtu for the nine months ended September 30, 2014, an increase of 23% from US$3.68 per MMBtu for the nine months ended September 30, 2013. NYMEX natural gas prices averaged US$4.07 per MMBtu for the third quarter of 2014, an increase of 13% from US$3.60 per MMBtu for the third quarter of 2013, and a decrease of 11% from US$4.57 per MMBtu for the second quarter of 2014.

AECO natural gas prices for the nine months ended September 30, 2014 averaged $4.32 per GJ, an increase of 44% from $3.00 per GJ for the nine months ended September 30, 2013. AECO natural gas prices for the third quarter of 2014 averaged $4.00 per GJ, an increase of 49% from $2.68 per GJ for the third quarter of 2013, and a decrease of 10% from $4.44 per GJ for the second quarter of 2014.

Natural gas prices increased for the three and nine months ended September 30, 2014 from the comparable periods in 2013 due to lower natural gas storage levels in 2014. The colder than normal winter resulted in natural gas storage inventories falling to below five-year lows in the US and Canada as at September 30, 2014. Natural gas prices decreased for the third quarter of 2014 from the second quarter of 2014 due to decreased summer weather related natural gas demand and a strong rebuild in storage inventory levels.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**404,114**	400,154	365,529	**384,356**	347,564
North America – Oil Sands Mining and Upgrading (1)	**82,012**	119,236	111,959	**104,667**	96,244
North Sea	**18,197**	12,615	15,522	**15,848**	17,720
Offshore Africa	**13,684**	13,164	16,172	**12,557**	16,780
	518,007	545,169	509,182	**517,428**	478,308
Natural gas (MMcf/d)					
North America	**1,644**	1,606	1,136	**1,468**	1,118
North Sea	**7**	5	4	**7**	3
Offshore Africa	**23**	23	23	**22**	24
	1,674	1,634	1,163	**1,497**	1,145
Total barrels of oil equivalent (BOE/d)	**796,931**	817,471	702,938	**766,871**	669,170
Product mix					
Light and medium crude oil and NGLs	**16%**	15%	14%	**15%**	15%
Pelican Lake heavy crude oil	**7%**	6%	6%	**6%**	6%
Primary heavy crude oil	**18%**	17%	20%	**19%**	21%
Bitumen (thermal oil)	**14%**	14%	16%	**14%**	15%
Synthetic crude oil (1)	**10%**	15%	16%	**14%**	14%
Natural gas	**35%**	33%	28%	**32%**	29%
Percentage of product sales (1) (2) (excluding Midstream revenue)					
Crude oil and NGLs	**85%**	86%	93%	**85%**	90%
Natural gas	**15%**	14%	7%	**15%**	10%

(1) The Company has commenced production of diesel for internal use at Horizon. Third quarter 2014 SCO production before royalties excludes 875 bbl/d of SCO consumed internally as diesel.

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**329,533**	318,672	299,194	**309,855**	288,046
North America – Oil Sands Mining and Upgrading (1)	**76,515**	111,825	104,627	**100,152**	91,304
North Sea	**18,062**	12,581	15,481	**15,773**	17,664
Offshore Africa	**12,276**	12,733	11,998	**11,600**	13,519
	436,386	455,811	431,300	**437,380**	410,533
Natural gas (MMcf/d)					
North America	**1,525**	1,474	1,109	**1,341**	1,072
North Sea	**7**	5	4	**7**	3
Offshore Africa	**19**	19	18	**19**	20
	1,551	1,498	1,131	**1,367**	1,095
Total barrels of oil equivalent (BOE/d)	**694,859**	705,480	619,800	**665,214**	592,983

(1) The Company has commenced production of diesel for internal use at Horizon. Third quarter 2014 SCO production before royalties excludes 875 bbl/d of SCO consumed internally as diesel.

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

Crude oil and NGLs production for the nine months ended September 30, 2014 increased 8% to 517,428 bbl/d from 478,308 bbl/d for the nine months ended September 30, 2013. Crude oil and NGLs production for the third quarter of 2014 increased 2% to 518,007 bbl/d from 509,182 bbl/d for the third quarter of 2013 and decreased 5% from 545,169 bbl/d for the second quarter of 2014. The increase in production for the nine months ended September 30, 2014 from the comparable period in 2013 was due to higher production in the North America segment and strong and reliable production in Horizon, partially offset by lower international production. The increase in production for the three months ended September 30, 2014 from the comparable period in 2013 reflected higher production in the North America segment offset by lower production at Horizon related to the successful completion of the coker expansion tie-in. The decrease in production for the third quarter of 2014 from the second quarter of 2014 reflected the impact of Horizon's successful completion of the coker expansion tie-in, partially offset by increased production in the North America and North Sea segments. Crude oil and NGLs production in the third quarter of 2014 was within the Company's previously issued guidance of 505,000 to 532,000 bbl/d.

Natural gas production for the nine months ended September 30, 2014 increased 31% to 1,497 MMcf/d from 1,145 MMcf/d for the nine months ended September 30, 2013. Natural gas production for the third quarter of 2014 increased 44% to 1,674 MMcf/d from 1,163 MMcf/d for the third quarter of 2013 and increased 2% from 1,634 MMcf/d for the second quarter of 2014. The increase in natural gas production for the three and nine months ended September 30, 2014 from the comparable periods in 2013 was primarily a result of the acquisitions of producing Canadian natural gas properties in the second quarter of 2014, and the completion of the Septimus drilling program and plant facility expansion in the third quarter of 2013. The increase in natural gas production for the third quarter of 2014 from the second quarter of 2014 was primarily the result of major turnarounds in the second quarter of 2014 and increases in production at Septimus. Natural gas production in the third quarter of 2014 was within the Company's previously issued guidance of 1,645 to 1,675 MMcf/d.

For 2014, annual production guidance is targeted to average between 531,000 and 557,000 bbl/d of crude oil and NGLs and between 1,550 and 1,570 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the nine months ended September 30, 2014 increased 11% to average 384,356 bbl/d from 347,564 bbl/d for the nine months ended September 30, 2013. For the third quarter of 2014, crude oil and NGLs production increased 11% to average 404,114 bbl/d compared with 365,529 bbl/d for the third quarter of 2013 and increased 1% from 400,154 bbl/d for the second quarter of 2014. The increase in production for the three and nine months ended September 30, 2014 from the comparable periods in 2013 was due to increased production related primarily to the acquisitions of producing Canadian crude oil properties in the second quarter of 2014, production at the Company's thermal areas including Kirby South, the ramp up of production at Pelican Lake, and the impact of a strong heavy crude oil drilling program. The increase in production for the third quarter of 2014 from the second quarter of 2014 was primarily related to production at Kirby South and the ramp up of production at Pelican Lake. Third quarter 2014 production of crude oil and NGLs was within the Company's previously issued guidance of 393,000 to 410,000 bbl/d.

Natural gas production for the nine months ended September 30, 2014 increased 31 % to 1,468 MMcf/d compared with 1,118 MMcf/d for the nine months ended September 30, 2013. Natural gas production increased 45% to 1,644 MMcf/d for the third quarter of 2014 compared with 1,136 MMcf/d in the third quarter of 2013 and increased 2% from 1,606 MMcf/d for the second quarter of 2014. The increase in natural gas production for the three and nine months ended September 30, 2014 from the comparable periods in 2013 was primarily a result of the acquisitions of producing Canadian natural gas properties in the second quarter of 2014, and the completion of the Septimus drilling program and plant facility expansion in the third quarter of 2013. The increase in natural gas production for the third quarter of 2014 from the second quarter of 2014 was primarily the result of major turnarounds in the second quarter of 2014 and increases in production at Septimus.

North America – Oil Sands Mining and Upgrading

Production averaged 104,667 bbl/d for the nine months ended September 30, 2014 compared with 96,244 bbl/d for the nine months ended September 30, 2013. For the third quarter of 2014, SCO production decreased 27% to 82,012 bbl/d from 111,959 bbl/d for the third quarter of 2013 and decreased 31% from 119,236 bbl/d for the second quarter of 2014. Production increased for the nine months ended September 30, 2014 from the comparable period in 2013 due to increased plant reliability. Third quarter 2014 production reflected the successful completion of the Horizon coker expansion tie-in and was within the Company's previously issued guidance of 82,000 to 89,000 bbl/d.

North Sea

North Sea crude oil production for the nine months ended September 30, 2014 decreased 11% to 15,848 bbl/d from 17,720 bbl/d for the nine months ended September 30, 2013. Third quarter 2014 crude oil production increased 17% to 18,197 bbl/d from 15,522 bbl/d for the third quarter of 2013, and increased 44% from 12,615 bbl/d for the second quarter of 2014. Production for the three and nine months ended September 30, 2014 reflected the impact of reinstatement of production from the Banff FPSO in July 2014, which had been offline since December 2011 after suffering storm damage. Production for the three and nine months ended September 30, 2014 also reflected unplanned downtime on the Tiffany platform in the second and third quarters of 2014, the cessation of production due to the planned decommissioning of the Murchison platform, and natural field declines. The increase in production for the third quarter of 2014 from the second quarter of 2014 was primarily due to the reinstatement of production at the Banff FPSO, offset by the unplanned downtime on the Tiffany platform.

Offshore Africa

Offshore Africa crude oil production decreased 25% to 12,557 bbl/d for the nine months ended September 30, 2014 from 16,780 bbl/d for the nine months ended September 30, 2013. Third quarter 2014 crude oil production averaged 13,684 bbl/d, decreasing 15% from 16,172 bbl/d for the third quarter of 2013 and increasing 4% from 13,164 bbl/d for the second quarter of 2014. The decrease in production volumes for the nine months ended September 30, 2014 from the comparable period in 2013 was due to natural field declines as well as a temporary shut in of the Baobab field in December 2013 due to the mooring line failures which was reinstated in late January 2014. The decrease in production volumes for third quarter of 2014 from the third quarter of 2013 was due to natural field declines.

International Guidance

The Company's North Sea and Offshore Africa third quarter 2014 crude oil production was 31,881 bbl/d and was within the Company's previously issued guidance of 30,000 to 33,000 bbl/d.

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)	**Sep 30 2014**	Jun 30 2014	Dec 31 2013
North America – Exploration and Production	**942,861**	1,564,600	830,673
North America – Oil Sands Mining and Upgrading (SCO)	**990,243**	1,525,103	1,550,857
North Sea	**752,276**	–	385,073
Offshore Africa	**706,213**	1,077,144	185,476
	3,391,593	4,166,847	2,952,079

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 79.99**	$ 87.03	$ 89.24	**$ 82.35**	$ 75.32
Transportation	**2.32**	2.74	2.38	**2.51**	2.36
Realized sales price, net of transportation	**77.67**	84.29	86.86	**79.84**	72.96
Royalties	**13.66**	15.62	15.20	**14.46**	11.92
Production expense	**15.99**	19.33	15.90	**18.08**	16.64
Netback	**$ 48.02**	$ 49.34	$ 55.76	**$ 47.30**	$ 44.40
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 4.54**	$ 5.06	$ 3.15	**$ 5.03**	$ 3.56
Transportation	**0.26**	0.26	0.27	**0.27**	0.28
Realized sales price, net of transportation	**4.28**	4.80	2.88	**4.76**	3.28
Royalties	**0.32**	0.41	0.10	**0.43**	0.17
Production expense	**1.45**	1.52	1.38	**1.52**	1.44
Netback	**$ 2.51**	$ 2.87	$ 1.40	**$ 2.81**	$ 1.67
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 59.56**	$ 64.69	$ 67.09	**$ 62.38**	$ 57.97
Transportation	**2.08**	2.35	2.18	**2.24**	2.19
Realized sales price, net of transportation	**57.48**	62.34	64.91	**60.14**	55.78
Royalties	**9.12**	10.49	10.35	**9.97**	8.26
Production expense	**13.15**	15.35	13.36	**14.68**	13.96
Netback	**$ 35.21**	$ 36.50	$ 41.20	**$ 35.49**	$ 33.56

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 78.38**	$ 84.10	$ 87.62	**$ 80.09**	$ 72.18
North Sea	**$ 113.08**	$ 122.88	$ 117.30	**$ 120.76**	$ 111.84
Offshore Africa	**$ 104.82**	$ 119.47	$ 119.48	**$ 111.25**	$ 111.73
Company average	**$ 79.99**	$ 87.03	$ 89.24	**$ 82.35**	$ 75.32
Natural gas ($/Mcf) (1) (2)					
North America	**$ 4.43**	$ 4.95	$ 3.00	**$ 4.91**	$ 3.41
North Sea	**$ 6.93**	$ 6.38	$ 6.12	**$ 6.45**	$ 6.14
Offshore Africa	**$ 11.73**	$ 12.25	$ 10.47	**$ 12.05**	$ 10.24
Company average	**$ 4.54**	$ 5.06	$ 3.15	**$ 5.03**	$ 3.56
Company average ($/BOE) (1) (2)	**$ 59.56**	$ 64.69	$ 67.09	**$ 62.38**	$ 57.97

(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 increased 11% to average $80.09 per bbl for the nine months ended September 30, 2014 from $72.18 per bbl for the nine months ended September 30, 2013. North America realized crude oil prices averaged $78.38 per bbl for the third quarter of 2014, a decrease of 11% compared with $87.62 per bbl for the third quarter of 2013 and a decrease of 7% compared with $84.10 per bbl for the second quarter of 2014. The increase in realized crude oil prices for the nine months ended September 30, 2014 from the comparable period was due to higher WTI benchmark pricing, tightening WCS Heavy Differentials and the impact of a weakening Canadian dollar. The decrease in realized crude oil prices for the third quarter of 2014 from the comparable periods was due to lower WTI benchmark pricing and widening WCS Heavy Differentials, partially offset by the impact of a weakening Canadian dollar. The Company continues to focus on its crude oil blending marketing strategy and in the third quarter of 2014 contributed approximately 160,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 44% to average $4.91 per Mcf for the nine months ended September 30, 2014 from $3.41 per Mcf for the nine months ended September 30, 2013. North America realized natural gas prices increased 48% to average $4.43 per Mcf for the third quarter of 2014 compared with $3.00 per Mcf in the third quarter of 2013, and decreased 11% compared with $4.95 per Mcf for the second quarter of 2014. The increase in realized natural gas prices for the three and nine months ended September 30, 2014 from the comparable periods in 2013 was primarily due to continued low natural gas storage levels in 2014. The decrease in realized natural gas prices for the third quarter of 2014 from the second quarter of 2014 was primarily due to decreased summer weather related natural gas demand and an increase in storage levels from the second quarter of 2014.

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

(Quarterly Average)		**Sep 30 2014**		Jun 30 2014		Sep 30 2013
Wellhead Price (1) (2)						
Light and medium crude oil and NGLs ($/bbl)	**$**	**77.79**	$	85.95	$	83.10
Pelican Lake heavy crude oil ($/bbl)	**$**	**81.52**	$	86.92	$	90.32
Primary heavy crude oil ($/bbl)	**$**	**79.70**	$	85.65	$	89.76
Bitumen (thermal oil) ($/bbl)	**$**	**75.81**	$	79.39	$	86.68
Natural gas ($/Mcf)	**$**	**4.43**	$	4.95	$	3.00

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

North Sea

North Sea realized crude oil prices increased 8% to average $120.76 per bbl for the nine months ended September 30, 2014 from $111.84 per bbl for the nine months ended September 30, 2013. Realized crude oil prices decreased 4% to average $113.08 per bbl for the third quarter of 2014 from $117.30 per bbl for the third quarter of 2013 and decreased 8% from $122.88 per bbl for the second quarter of 2014. The fluctuations in realized crude oil prices for the three and nine months ended September 30, 2014 from the comparable periods reflected movements in Brent benchmark pricing, the timing of liftings, and the weakening of the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices averaged $111.25 per bbl for the nine months ended September 30, 2014 and was comparable with $111.73 per bbl for the nine months ended September 30, 2013. Realized crude oil prices decreased 12% to average $104.82 per bbl for the third quarter of 2014 from $119.48 per bbl for the third quarter of 2013 and decreased 12% from $119.47 per bbl for the second quarter of 2014. The decrease in realized crude oil prices for the three months ended September 30, 2014 from the comparable periods reflected movements in Brent benchmark pricing, the timing of liftings, partially offset by the weakening of the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 13.99**	$ 16.79	$ 15.65	**$ 15.17**	$ 12.15
North Sea	**$ 0.84**	$ 0.33	$ 0.31	**$ 0.43**	$ 0.35
Offshore Africa	**$ 10.79**	$ 3.92	$ 30.83	**$ 7.77**	$ 19.55
Company average	**$ 13.66**	$ 15.62	$ 15.20	**$ 14.46**	$ 11.92
Natural gas ($/Mcf) [1]					
North America	**$ 0.30**	$ 0.39	$ 0.06	**$ 0.41**	$ 0.13
Offshore Africa	**$ 1.88**	$ 1.89	$ 2.06	**$ 1.94**	$ 1.77
Company average	**$ 0.32**	$ 0.41	$ 0.10	**$ 0.43**	$ 0.17
Company average ($/BOE) [1]	**$ 9.12**	$ 10.49	$ 10.35	**$ 9.97**	$ 8.26

(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 nine months ended September 30, 2014 compared with the nine months ended September 30, 2013 reflected movements in benchmark commodity prices and the fluctuations of the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 20% of product sales for the nine months ended September 30, 2014 compared with 17% for the nine months ended September 30, 2013. Crude oil and NGLs royalties averaged approximately 18% of product sales for the third quarter of 2014 compared with 18% for the third quarter of 2013 and 21% for the second quarter of 2014. The increase in royalties for the nine months ended September 30, 2014 from the comparable period in 2013 was due to higher realized crude oil prices. The decrease in royalties in the third quarter of 2014 from the second quarter of 2014 was primarily due to the decrease in realized crude oil prices. Crude oil and NGLs royalties per bbl are anticipated to average 19% to 21% of product sales for 2014.

Natural gas royalties averaged approximately 9% of product sales for the nine months ended September 30, 2014 compared with 4% for the nine months ended September 30, 2013. Natural gas royalties averaged approximately 7% of product sales for the third quarter of 2014 compared with 2% for the third quarter of 2013 and 8% for the second quarter of 2014. The increase in natural gas royalty rates for the three and nine months ended September 30, 2014 from the comparable periods in 2013 was due to higher realized natural gas prices. The decrease in natural gas royalty rates in the third quarter of 2014 from the second quarter of 2014 was primarily due to the decrease in realized natural gas prices. Natural gas royalties are anticipated to average 9% to 10% of product sales for 2014.

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 11% for the third quarter of 2014 compared with 24% for the third quarter of 2013 and 5% for the second quarter of 2014. The decrease in royalties in the third quarter of 2014 compared to the third quarter of 2013 was due to adjustments to royalties on liftings in 2013. The increase in royalties in the third quarter of 2014 compared to the second quarter of 2014 was a result of timing of liftings from various fields.

Offshore Africa royalty rates are anticipated to average 4.5% to 6.5% of product sales for 2014.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 14.52**	$ 14.97	$ 13.04	**$ 15.20**	$ 14.12
North Sea	**$ 76.48**	$ 79.21	$ 78.66	**$ 77.31**	$ 66.55
Offshore Africa	**$ 27.20**	$ 58.41	$ 25.13	**$ 40.91**	$ 22.23
Company average	**$ 15.99**	$ 19.33	$ 15.90	**$ 18.08**	$ 16.64
Natural gas ($/Mcf) [1]					
North America	**$ 1.36**	$ 1.48	$ 1.33	**$ 1.45**	$ 1.41
North Sea	**$ 19.21**	$ 6.12	$ 5.79	**$ 10.58**	$ 4.57
Offshore Africa	**$ 2.68**	$ 3.28	$ 2.82	**$ 3.18**	$ 2.46
Company average	**$ 1.45**	$ 1.52	$ 1.38	**$ 1.52**	$ 1.44
Company average ($/BOE) [1]	**$ 13.15**	$ 15.35	$ 13.36	**$ 14.68**	$ 13.96

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

North America

North America crude oil and NGLs production expense for the nine months ended September 30, 2014 increased 8% to $15.20 per bbl from $14.12 per bbl for the nine months ended September 30, 2013. North America crude oil and NGLs production expense for the third quarter of 2014 increased 11% to $14.52 per bbl from $13.04 per bbl for the third quarter of 2013 and decreased 3% from $14.97 per bbl for the second quarter of 2014. The increase in production expense for the three and nine months ended September 30, 2014 from the comparable periods in 2013 was primarily due to higher trucking and energy costs across the heavy crude oil and thermal areas, together with higher servicing costs related to heavy crude oil production. The decrease in production expense for the third quarter of 2014 from the second quarter of 2014 was primarily the result of the cyclic nature of the Company's thermal operations and lower production expense in the heavy crude oil areas, reflecting the Company's continuous focus on cost control. North America crude oil and NGLs production expense is anticipated to average $13.00 to $15.00 per bbl for 2014.

North America natural gas production expense for the nine months ended September 30, 2014 increased 3% to $1.45 per Mcf from $1.41 per Mcf for the nine months ended September 30, 2013. North America natural gas production expense for the third quarter of 2014 increased 2% to $1.36 per Mcf from $1.33 per Mcf for the third quarter of 2013 and decreased 8% from $1.48 per Mcf for the second quarter of 2014. Natural gas production expense increased for the three and nine months ended September 30, 2014 from the comparable periods in 2013 due to the acquisitions of producing Canadian natural gas properties in the second quarter of 2014 that had higher production expense per Mcf than the Company's existing properties. The production expense on the acquired assets has declined as expected as they have become fully integrated into the Company's operations. Natural gas production expense decreased for the third quarter of 2014 from the second quarter of 2014 due to production expense efficiencies gained through the continued effective integration of acquired properties. North America natural gas production expense is anticipated to average $1.35 to $1.45 per Mcf for 2014.

North Sea

North Sea crude oil production expense for the nine months ended September 30, 2014 increased 16% to $77.31 per bbl from $66.55 per bbl for the nine months ended September 30, 2013. North Sea crude oil production expense for the third quarter of 2014 decreased 3% to $76.48 per bbl from $78.66 per bbl for the third quarter of 2013 and decreased 3% from $79.21 per bbl for the second quarter of 2014. Production expense increased on a per barrel basis for the nine months ended September 30, 2014 from the comparable period in 2013 due to natural field declines on relatively fixed costs in the North Sea, the impact of the unplanned downtime on the Tiffany platform and a weaker Canadian dollar. North Sea crude oil production expense is anticipated to average $64.00 to $68.00 per bbl for 2014 as new drilling activities are targeted to result in additional production from the Ninian fields, and as the Banff FPSO has returned to the field and production has been reinstated.

Offshore Africa

Offshore Africa crude oil production expense for the nine months ended September 30, 2014 increased 84% to $40.91 per bbl from $22.23 per bbl for the nine months ended September 30, 2013. Offshore Africa crude oil production expense for the third quarter of 2014 averaged $27.20 per bbl, an increase of 8% from $25.13 per bbl for the third quarter of 2013 and a decrease of 53% from $58.41 per bbl for the second quarter of 2014. Production expense fluctuated for the three and nine months ended September 30, 2014 from the comparable periods as a result of the timing of liftings from various fields, which have different cost structures, and a weaker Canadian dollar. Offshore Africa crude oil production expense is anticipated to average $38.50 to $42.50 per bbl for 2014.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Expense ($ millions)	**$ 1,087**	$ 1,099	$ 1,089	**$ 3,065**	$ 3,121
$/BOE [(1)]	**$ 16.54**	$ 17.28	$ 20.33	**$ 17.08**	$ 20.10

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

Depletion, depreciation and amortization expense for the nine months ended September 30, 2014 decreased 15% to $17.08 per BOE from $20.10 per BOE for the nine months ended September 30, 2013. Depletion, depreciation and amortization expense for the third quarter of 2014 decreased 19% to $16.54 per BOE from $20.33 per BOE for the third quarter of 2013 and decreased 4% from $17.28 per BOE for the second quarter of 2014. Depletion, depreciation and amortization expense decreased on a per barrel basis for the three and nine months ended September 30, 2014 from the comparable periods in 2013 due to the impact of increased production on component depreciation determined on a straight-line basis as well as the impact of lower depletion, depreciation and amortization expense in the North Sea resulting from the planned cessation of production from the Murchison field in 2013.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Expense ($ millions)	**$ 37**	$ 39	$ 32	**$ 109**	$ 99
$/BOE [(1)]	**$ 0.56**	$ 0.59	$ 0.61	**$ 0.60**	$ 0.64

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

Asset retirement obligation accretion expense for the nine months ended September 30, 2014 decreased 6% to $0.60 per BOE from $0.64 per BOE for the nine months ended September 30, 2013. Asset retirement obligation accretion expense for the third quarter of 2014 decreased 8% to $0.56 per BOE from $0.61 per BOE for the third quarter of 2013 and decreased 5% from $0.59 per BOE for the second quarter of 2014. Asset retirement obligation accretion expense on a per barrel basis decreased for the three and nine months ended September 30, 2014 from the comparable periods primarily due to the impact of increased sales volumes.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

In the third quarter of 2014, Horizon successfully completed the coker expansion tie-in during a planned plant-wide shutdown of 25 days. The third quarter production of 82,012 bbl/d was within stated guidance. The impact of the 25 day plant-wide shutdown has been reflected in the Company's 2014 production, cash production cost and capital expenditure guidance.

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

	Three Months Ended			Nine Months Ended	
($/bbl)	**Sep 30 2014**	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
SCO sales price (1)	**$ 103.91**	$ 112.69	$ 114.19	**$ 108.58**	$ 104.07
Bitumen value for royalty purposes (1) (2)	**$ 74.11**	$ 75.72	$ 82.78	**$ 72.03**	$ 69.38
Bitumen royalties (1) (3)	**$ 7.17**	$ 6.77	$ 6.82	**$ 6.29**	$ 5.13
Transportation	**$ 2.28**	$ 1.53	$ 1.52	**$ 1.88**	$ 1.59

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

Realized SCO sales prices averaged $108.58 per bbl for the nine months ended September 30, 2014, an increase of 4% compared with $104.07 per bbl for nine months ended September 30, 2013. Realized SCO sales prices averaged $103.91 per bbl for the third quarter of 2014, a decrease of 9% compared with $114.19 per bbl for the third quarter of 2013 and a decrease of 8% compared with $112.69 per bbl for the second quarter of 2014, reflecting benchmark pricing and prevailing differentials.

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			Nine Months Ended	
($ millions)	**Sep 30 2014**	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Cash production costs	**$ 398**	$ 404	$ 407	**$ 1,214**	$ 1,178
Less: costs incurred during turnaround periods	**(98)**	–	–	**(98)**	(104)
Adjusted cash production costs	**$ 300**	$ 404	$ 407	**$ 1,116**	$ 1,074
Adjusted cash production costs, excluding natural gas costs	**$ 280**	$ 372	$ 380	**$ 1,027**	$ 997
Adjusted natural gas costs	**20**	32	27	**89**	77
Adjusted cash production costs	**$ 300**	$ 404	$ 407	**$ 1,116**	$ 1,074

	Three Months Ended			Nine Months Ended	
($/bbl) (1)	**Sep 30 2014**	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Adjusted cash production costs, excluding natural gas costs	**$ 34.65**	$ 33.76	$ 37.27	**$ 35.26**	$ 38.21
Adjusted natural gas costs	**2.48**	2.85	2.63	**3.05**	2.95
Adjusted cash production costs	**$ 37.13**	$ 36.61	$ 39.90	**$ 38.31**	$ 41.16
Sales (bbl/d) (2)	**87,826**	121,091	110,750	**106,721**	95,588

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

Adjusted cash production costs averaged $38.31 per bbl for the nine months ended September 30, 2014, a decrease of 7% compared with $41.16 per bbl for the nine months ended September 30, 2013. Adjusted cash production costs for the third quarter of 2014 averaged $37.13 per bbl, a decrease of 7% compared with $39.90 per bbl for the third quarter of 2013 and was comparable with the second quarter of 2014. The decrease in adjusted cash production costs for the three and nine months ended September 30, 2014 from comparable periods in 2013 reflected increased plant reliability and the corresponding impact of higher production volumes on a relatively fixed cost structure, excluding the turnaround period. Cash production costs are anticipated to average $36.00 to $39.00 per bbl for 2014.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2014**	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Depletion, depreciation and amortization	**$ 137**	$ 135	$ 167	**$ 402**	$ 445
Less: depreciation incurred during turnaround periods	**(28)**	–	–	**(28)**	(79)
Adjusted depletion, depreciation and amortization	**$ 109**	$ 135	$ 167	**$ 374**	$ 366
$/bbl (1)	**$ 13.43**	$ 12.27	$ 16.40	**$ 12.83**	$ 14.02

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

Adjusted depletion, depreciation and amortization expense for the nine months ended September 30, 2014 decreased 8% to $12.83 per bbl from $14.02 per bbl for the nine months ended September 30, 2013. Adjusted depletion, depreciation and amortization expense for the third quarter of 2014 decreased 18% to $13.43 per bbl from $16.40 per bbl for the third quarter of 2013 and increased 9% from $12.27 per bbl for the second quarter of 2014. Adjusted depletion, depreciation and amortization expense on a per barrel basis decreased for the three and nine months ended September 30, 2014 from the comparable periods in 2013 primarily due to the impact of higher production on component depreciation determined on a straight-line basis. Adjusted depletion, depreciation and amortization expense on a per barrel basis for the third quarters of 2014 and 2013 also reflected the impact of minor asset derecognitions.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
	Sep 30 2014	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Expense ($ millions)	**$ 12**	$ 11	$ 9	**$ 35**	$ 26
$/bbl (1)	**$ 1.45**	$ 1.07	$ 0.83	**$ 1.21**	$ 0.98

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

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

MIDSTREAM

($ millions)	Three Months Ended Sep 30 2014	Three Months Ended Jun 30 2014	Three Months Ended Sep 30 2013	Nine Months Ended Sep 30 2014	Nine Months Ended Sep 30 2013
Revenue	**$ 30**	$ 30	$ 28	**$ 91**	$ 84
Production expense	**8**	10	9	**27**	26
Midstream cash flow	**22**	20	19	**64**	58
Depreciation	**2**	3	2	**7**	6
Equity loss (gain) from investment	**5**	(3)	1	**3**	3
Segment earnings before taxes	**$ 15**	$ 20	$ 16	**$ 54**	$ 49

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.

In April 2014, Redwater Partnership, the Company and APMC amended certain terms of the processing agreements. In conjunction with these amendments, in order to provide financing for Project completion based on the current revised Project cost estimate of approximately $8,500 million, the Company, along with APMC, each committed to provide additional funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

During the second quarter of 2014, Redwater Partnership executed a $3,500 million syndicated credit facility with a group of financial institutions maturing June 2018 and repaid and cancelled its $1,200 million credit facility previously in place. As at September 30, 2014, Redwater Partnership had interim borrowings of $402 million under the syndicated credit facility.

During the third quarter of 2014, Redwater Partnership issued $500 million of 3.20% series A secured bonds due July 2024 and $500 million of 4.05% series B 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

	Three Months Ended Sep 30 2014	Three Months Ended Jun 30 2014	Three Months Ended Sep 30 2013	Nine Months Ended Sep 30 2014	Nine Months Ended Sep 30 2013
Expense ($ millions)	**$ 87**	$ 90	$ 82	**$ 267**	$ 242
$/BOE (1)	**$ 1.17**	$ 1.21	$ 1.28	**$ 1.28**	$ 1.33

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

Administration expense for the nine months ended September 30, 2014 decreased 4% to $1.28 per BOE from $1.33 per BOE for the nine months ended September 30, 2013. Administration expense for the third quarter of 2014 decreased 9% to $1.17 per BOE from $1.28 per BOE for the third quarter of 2013 and decreased 3% from $1.21 per BOE for the second quarter of 2014. Administration expense decreased for the three and nine months ended September 30, 2014 from the comparable periods in 2013 primarily due to the impact of higher sales volumes, as well as due to the Company's continuous focus on cost efficiencies.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Sep 30 2014	Jun 30 2014	Sep 30 2013	Nine Months Ended Sep 30 2014	Sep 30 2013
Expense (Recovery)	**$ (122)**	$ 189	$ 48	**$ 210**	$ 70

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 $210 million share-based compensation expense for the nine months ended September 30, 2014, primarily as a result of remeasurement of the fair value of outstanding stock options at the end of the period related to an increase in the Company's share price, together with the impact of normal course graded vesting of stock options granted in prior periods and the impact of vested stock options exercised or surrendered during the period. For the nine months ended September 30, 2014, the Company capitalized $42 million of share-based compensation expense to property, plant and equipment in the Oil Sands Mining and Upgrading segment (September 30, 2013 – $13 million expense).

For the nine months ended September 30, 2014, the Company paid $8 million for stock options surrendered for cash settlement (September 30, 2013 – $2 million).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts)	Three Months Ended Sep 30 2014	Jun 30 2014	Sep 30 2013	Nine Months Ended Sep 30 2014	Sep 30 2013
Expense, gross	**$ 135**	$ 136	$ 116	**$ 386**	$ 341
Less: capitalized interest	**56**	44	46	**147**	122
Expense, net	**$ 79**	$ 92	$ 70	**$ 239**	$ 219
$/BOE (1)	**$ 1.06**	$ 1.24	$ 1.10	**$ 1.15**	$ 1.21
Average effective interest rate	**3.9%**	3.9%	4.3%	**4.0%**	4.4%

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

Gross interest and other financing expense for the three and nine months ended September 30, 2014 increased from the comparable periods in 2013 primarily due to the impact of higher overall debt levels. Gross interest and other financing expense for the third quarter of 2014 was comparable with the second quarter of 2014. Capitalized interest of $147 million for the nine months ended September 30, 2014 was primarily related to the Horizon Phase 2/3 expansion.

The Company's average effective interest rate for the three and nine months ended September 30, 2014 decreased from the comparable periods in 2013 primarily due to an increase in the utilization of the lower cost US commercial paper program that was implemented in March 2013. The Company's average effective interest rate for the third quarter of 2014 was comparable with the second quarter of 2014.

Net interest and other financing expense for the nine months ended September 30, 2014 decreased 5% to $1.15 per BOE from $1.21 per BOE for the nine months ended September 30, 2013. Net interest and other financing expense for the third quarter of 2014 decreased 4% to $1.06 per BOE from $1.10 per BOE for the third quarter of 2013 and decreased 15% from $1.24 for the second quarter of 2014. The decrease on a per barrel basis for the nine months ended September 30, 2014 from the comparable period was primarily due to the impact of increased 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			Nine Months Ended	
($ millions)	**Sep 30 2014**	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Crude oil and NGLs financial instruments	**$ –**	$ –	$ 39	**$ –**	$ 39
Natural gas financial instruments	**21**	12	–	**33**	–
Foreign currency contracts	**(17)**	45	(17)	**(47)**	(119)
Realized loss (gain)	**4**	57	22	**(14)**	(80)
Crude oil and NGLs financial instruments	**(70)**	49	57	**(24)**	27
Natural gas financial instruments	**(21)**	(24)	8	**–**	8
Foreign currency contracts	**(59)**	29	56	**(23)**	34
Unrealized (gain) loss	**(150)**	54	121	**(47)**	69
Net (gain) loss	**$ (146)**	$ 111	$ 143	**$ (61)**	$ (11)

Complete details related to outstanding derivative financial instruments at September 30, 2014 are disclosed in note 14 to the Company's unaudited interim consolidated financial statements.

The Company recorded a net unrealized gain of $47 million ($36 million after-tax) on its risk management activities for the nine months ended September 30, 2014, including an unrealized gain of $150 million ($118 million after-tax) for the third quarter of 2014 (June 30, 2014 – unrealized loss of $54 million; $44 million after-tax; September 30, 2013 – unrealized loss of $121 million; $99 million after-tax).

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2014**	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Net realized (gain) loss	**$ (1)**	$ 31	$ 12	**$ 29**	$ (19)
Net unrealized loss (gain) (1)	**185**	(153)	(75)	**150**	115
Net loss (gain)	**$ 184**	$ (122)	$ (63)	**$ 179**	$ 96

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

The net realized foreign exchange loss for the nine months ended September 30, 2014 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 nine months ended September 30, 2014 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 September 30, 2014 – unrealized gain of $153 million, June 30, 2014 – unrealized loss of $109 million, September 30, 2013 – unrealized loss of $55 million; nine months ended September 30, 2014 – unrealized gain of $144 million; September 30, 2013 – unrealized gain of $80 million). The US/Canadian dollar exchange rate at September 30, 2014 was US$0.8922 (June 30, 2014 – US$0.9367; December 31, 2013 – US$0.9402; September 30, 2013 – US$0.9723).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended **Sep 30 2014**	Jun 30 2014	Sep 30 2013	Nine Months Ended **Sep 30 2014**	Sep 30 2013
North America [1]	**$ 162**	$ 225	$ 178	**$ 579**	$ 411
North Sea	**14**	(44)	–	**(45)**	18
Offshore Africa	**21**	10	76	**35**	147
PRT recovery – North Sea	**(114)**	(12)	(15)	**(187)**	(61)
Other taxes	**6**	6	8	**18**	18
Current income tax expense	**89**	185	247	**400**	533
Deferred income tax expense	**158**	178	159	**427**	199
Deferred PRT expense (recovery) – North Sea	**50**	11	(36)	**127**	(72)
Deferred income tax expense	**208**	189	123	**554**	127
	$ 297	$ 374	$ 370	**$ 954**	$ 660
Income tax rate and other legislative changes [2]	**–**	–	–	**–**	(15)
	$ 297	$ 374	$ 370	**$ 954**	$ 645
Effective income tax rate on adjusted net earnings from operations [3]	**24.7%**	24.8%	27.2%	**24.4%**	27.6%

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

(2) During the second quarter of 2013, the Government of British Columbia substantively enacted legislation to increase its provincial corporate income tax rate effective April 1, 2013. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $15 million.

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

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.

The PRT recovery in the North Sea in the third quarter of 2014 included the impact of amendments to tax filings for prior years.

For 2014, based on forward commodity prices and the current availability of tax pools, the Company expects to incur current income tax expense of $700 million to $800 million in Canada and recoveries of $190 million to $210 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Sep 30 2014	Three Months Ended Jun 30 2014	Three Months Ended Sep 30 2013	Nine Months Ended Sep 30 2014	Nine Months Ended Sep 30 2013
Exploration and Evaluation					
Net expenditures (proceeds) [2][3]	**$ 92**	$ 884	$ (238)	**$ 1,093**	$ (151)
Property, Plant and Equipment					
Net property acquisitions [2]	**79**	2,746	174	**2,821**	185
Well drilling, completion and equipping	**498**	441	566	**1,580**	1,540
Production and related facilities	**504**	429	431	**1,348**	1,434
Capitalized interest and other [4]	**34**	21	29	**78**	86
Net expenditures	**1,115**	3,637	1,200	**5,827**	3,245
Total Exploration and Production	**1,207**	4,521	962	**6,920**	3,094
Oil Sands Mining and Upgrading					
Horizon Phase 2/3 construction costs	**670**	649	550	**1,763**	1,460
Sustaining capital	**122**	87	41	**269**	250
Turnaround costs	**15**	4	1	**21**	98
Capitalized interest and other [4]	**38**	84	41	**195**	101
Total Oil Sands Mining and Upgrading	**845**	824	633	**2,248**	1,909
Midstream	**27**	26	3	**78**	12
Abandonments [5]	**82**	76	44	**245**	136
Head office	**14**	9	13	**33**	32
Total net capital expenditures	**$ 2,175**	$ 5,456	$ 1,655	**$ 9,524**	$ 5,183
By segment					
North America [2]	**$ 997**	$ 4,387	$ 1,106	**$ 6,471**	$ 3,025
North Sea	**100**	107	92	**295**	239
Offshore Africa [3]	**110**	27	(236)	**154**	(170)
Oil Sands Mining and Upgrading	**845**	824	633	**2,248**	1,909
Midstream	**27**	26	3	**78**	12
Abandonments [5]	**82**	76	44	**245**	136
Head office	**14**	9	13	**33**	32
Total	**$ 2,175**	$ 5,456	$ 1,655	**$ 9,524**	$ 5,183

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.
(2) Includes Business Combinations.
(3) Includes proceeds from the Company's disposition of 50% interest in its exploration right in South Africa in 2013.
(4) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.
(5) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

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

Net capital expenditures for the nine months ended September 30, 2014 were $9,524 million compared with $5,183 million for the nine months ended September 30, 2013. Net capital expenditures for the third quarter of 2014 were $2,175 million compared with $1,655 million for the third quarter of 2013 and $5,456 million for the second quarter of 2014.

The increase in capital expenditures for the nine months ended September 30, 2014 from the comparable period in 2013 was primarily due to the acquisitions of certain Canadian crude oil and natural gas properties in the second quarter of 2014. The increase in capital expenditures for the third quarter of 2014 from comparable period in 2013 reflected the disposition of a 50% working interest in Block 11B/12B in South Africa in the third quarter of 2013. The decrease in capital expenditures for the third quarter of 2014 from the second quarter of 2014 was primarily due to the acquisition of certain Canadian crude oil and natural gas properties in the second quarter of 2014.

On April 1, 2014, the Company completed the acquisition of certain Canadian crude oil and natural gas properties, including exploration and evaluation assets of $823 million, for cash consideration of $3,110 million, subject to final closing adjustments. During the nine months ended September 30, 2014, the Company also acquired a number of additional producing crude oil and natural gas properties in the North American Exploration and Production segment for total cash consideration of $567 million.

Drilling Activity

	Three Months Ended			Nine Months Ended	
(number of wells)	**Sep 30 2014**	Jun 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Net successful natural gas wells	**21**	13	10	**59**	33
Net successful crude oil wells [(1)]	**273**	154	334	**698**	793
Dry wells	**6**	2	7	**11**	17
Stratigraphic test / service wells	**11**	22	9	**363**	330
Total	**311**	191	360	**1,131**	1,173
Success rate (excluding stratigraphic test / service wells)	**98%**	99%	98%	**99%**	98%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 70% of the total capital expenditures for the nine months ended September 30, 2014 compared with approximately 59% for the nine months ended September 30, 2013.

During the third quarter of 2014, the Company targeted 22 net natural gas wells, including 3 wells in Northeast British Columbia, 13 wells in Northwest Alberta and 6 wells in other areas. The Company also targeted 276 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 245 primary heavy crude oil wells, 8 Pelican Lake heavy crude oil wells, 1 bitumen (thermal oil) well and 3 light crude oil wells were drilled. Another 19 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for the third quarter of 2014 averaged approximately 115,300 bbl/d compared with approximately 109,200 bbl/d for the third quarter of 2013 and approximately 114,400 bbl/d for the second quarter of 2014. Production volumes reflected the cyclic nature of thermal oil production at Primrose and production at Kirby South.

In the second quarter of 2013, the Company discovered bitumen emulsion at surface in areas of the Primrose field. The Company continues to work with the regulator on the causation review of the bitumen emulsion seepage. The Company's near-term steaming plan at Primrose has been modified, with steaming being reduced in certain areas.

Development of the tertiary recovery conversion projects at Pelican Lake continued and 8 horizontal wells were drilled during the third quarter of 2014. Pelican Lake production averaged approximately 51,900 bbl/d for the third quarter of 2014 compared with 45,500 bbl/d for the third quarter of 2013 and 49,600 bbl/d for the second quarter of 2014.

In order to expand its pipeline infrastructure, the Company is participating in the expansion of the Cold Lake pipeline, with construction anticipated to be completed by 2016.

For the fourth quarter of 2014, the Company's overall planned drilling activity in North America is expected to be 328 net crude oil wells and 17 net natural gas wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the third quarter of 2014 was focused on field construction of the gas recovery unit, butane treatment unit, coker expansion, tank farms, cooling water tower, tailings, hydrotransport, froth treatment, tailings transfer pumphouses and pipelines, extraction trains 3 & 4, extraction retrofit 1 & 2, and ore preparation plant civil works along with engineering related to the ore preparation plants, froth treatment plant, hydrotransport, hydrogen unit, hydrotreater unit, vacuum distillation unit and distillation recovery unit.

North Sea

The Company commenced a modest drilling program at the Ninian field late in the fourth quarter of 2013, supported by the Brownfield Allowance program, with the first two wells on stream in the second quarter of 2014. The decommissioning activities at the Murchison platform commenced in the fourth quarter of 2013 and the Company estimates the decommissioning efforts will continue for approximately 5 years.

Offshore Africa

During the fourth quarter of 2013, the Company contracted a drilling rig for a 6 gross well program at the Baobab field in Côte d'Ivoire. The rig is expected to arrive in country no later than the first quarter of 2015. In April 2014, at the Espoir field, the Company contracted a drilling rig for a 10 gross well development program with drilling operations targeted to commence in the latter half of the fourth quarter of 2014.

Exploration activities continue to progress in both Côte d'Ivoire and South Africa. In Côte d'Ivoire, the operator in Block CI-514 commenced drilling an exploratory well in March 2014. Subsequently, the operator completed drilling and encountered the presence of light oil. The well was plugged and the data gathered will now be evaluated to determine the extent of the accumulation and the forward plan for appraisal.

In South Africa, subsequent to the third quarter of 2014, the exploration well drilled on Block 11B/12B was suspended due to mechanical issues with marine equipment on the drilling rig. The rig safely left the well location and, as the available drilling window had ended, it was demobilized by the operator. The South African authorities have formally confirmed that the well drilled satisfies the work obligation for the initial period of the Block 11B/12B Exploration Right. The operator is reviewing the course of action to re-enter the well as soon as possible, and has indicated drilling operations are unlikely to resume in the area before 2016.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Sep 30 2014**	Jun 30 2014	Dec 31 2013	Sep 30 2013
Working capital deficit (1)	**$ 915**	$ 991	$ 1,574	$ 969
Long-term debt (2) (3)	**$ 13,685**	$ 13,437	$ 9,661	$ 9,393
Share capital	**$ 4,388**	$ 4,321	$ 3,854	$ 3,765
Retained earnings	**23,499**	22,856	21,876	21,720
Accumulated other comprehensive income	**47**	46	42	67
Shareholders' equity	**$ 27,934**	$ 27,223	$ 25,772	$ 25,552
Debt to book capitalization (3) (4)	**33%**	33%	27%	27%
Debt to market capitalization (3) (5)	**22%**	20%	20%	21%
After-tax return on average common shareholders' equity (6)	**12%**	13%	9%	9%
After-tax return on average capital employed (3) (7)	**9%**	10%	7%	7%

(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 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 September 30, 2014, 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, 2013. In addition, the Company's ability to renew existing bank credit facilities and raise new debt is also 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.

The Company established a US commercial paper program in 2013. Borrowings of up to a maximum US$1,500 million are authorized. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

As at September 30, 2014, the Company had in place bank credit facilities of $5,802 million, of which $2,358 million, net of commercial paper issuances of $560 million, was available. Credit facilities at September 30, 2014 included a $1,000 million non-revolving term credit facility maturing March 2016, arranged in connection with the acquisition of certain producing Canadian crude oil and natural gas properties completed in the second quarter of 2014.

During the first quarter of 2014, the Company issued US$500 million of three-month LIBOR plus 0.375% notes due March 2016, and concurrently, entered into cross currency swaps to fix the foreign currency exchange rate risk at three-month CDOR plus 0.309% and $555 million. In addition, the Company issued US$500 million of 3.80% notes due April 2024. Proceeds from the securities were used to repay bank indebtedness.

During the second quarter of 2014, the Company issued $500 million of 2.60% medium-term notes due December 2019 and $500 million of 3.55% medium-term notes due June 2024. Proceeds from the securities were used for general corporate purposes and repayment of bank indebtedness.

At September 30, 2014, the Company had maturities of long-term debt aggregating $1,354 million over the next 12 months (US$500 million due November 2014, US$350 million due December 2014, and $400 million medium-term notes due June 2015).

Long-term debt was $13,685 million at September 30, 2014, resulting in a debt to book capitalization ratio of 33% (June 30, 2014 – 33%; December 31, 2013 – 27%; September 30, 2013 – 27%). 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 2014 and 2015 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs. Further details related to the Company's long-term debt at September 30, 2014 are discussed in note 7 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedge policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. As at November 3, 2014, 325,000 bbl/d of currently forecasted 2014 crude oil volumes and 50,000 bbl/d of currently forecasted 2015 crude oil volumes were hedged using price collars. To partially mitigate its exposure to fluctuating heavy crude oil differentials, the Company entered into 20,000 bbl/d of physical crude oil sales contracts for the fourth quarter of 2014. In addition, the Company has entered into crude oil WCS differential swaps as follows: 30,000 bbl/d in the fourth quarter of 2014 and 30,000 bbl/d in the first quarter of 2015. An additional 500,000 MMBtu/d of natural gas volumes were hedged for October 2014 using AECO basis swaps and 200,000 GJ/d of natural gas volumes were hedged for October 2014 to December 2014 using price collars. Further details related to the Company's commodity derivative financial instruments outstanding at September 30, 2014 are discussed in note 14 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at September 30, 2014, there were 1,091,806,000 common shares outstanding (December 31, 2013 – 1,087,322,000 common shares) and 64,086,000 stock options outstanding. As at November 3, 2014, the Company had 1,091,231,000 common shares outstanding and 63,564,000 stock options outstanding.

On March 5, 2014, the Company's Board of Directors approved an increase in the annual dividend to $0.90 per common share (previous annual dividend rate of $0.80 per common share), beginning with the quarterly dividend payable on April 1, 2014 at $0.225 per common share. This represents a 13% increase from the previous quarterly dividend, reflecting the stability of the Company's cash flow and providing a return to shareholders. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

In April 2014, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"), during the twelve month period commencing April 2014 and ending April 2015, up to 54,596,899 common shares. The Company's Normal Course Issuer Bid announced in 2013 expired April 2014.

For the nine months ended September 30, 2014, the Company purchased for cancellation 8,885,000 common shares at a weighted average price of $45.51 per common share, for a total cost of $404 million. Retained earnings were reduced by $370 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2014, the Company purchased 790,000 common shares at a weighted average price of $39.49 per common share for a total cost of $31 million.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at September 30, 2014:

($ millions)		Remaining 2014		2015		2016		2017		2018		Thereafter
Product transportation and pipeline	$	110	$	432	$	320	$	291	$	260	$	1,714
Offshore equipment operating leases and offshore drilling	$	69	$	304	$	90	$	64	$	57	$	18
Long-term debt (1)	$	1,513	$	400	$	2,664	$	2,194	$	448	$	6,539
Interest and other financing expense (2)	$	134	$	520	$	476	$	395	$	335	$	4,233
Office leases	$	10	$	46	$	46	$	49	$	51	$	343
Other	$	89	$	190	$	131	$	32	$	1	$	–

(1) Long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts 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 September 30, 2014.

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 unaudited interim consolidated financial statements for the nine months ended September 30, 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, 2013.

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	**Sep 30 2014**	Dec 31 2013
ASSETS			
Current assets			
Cash and cash equivalents		**$ 16**	$ 16
Accounts receivable		**1,908**	1,427
Current income taxes		**89**	–
Inventory		**799**	632
Prepaids and other		**257**	141
Current portion of other long-term assets	6	**24**	–
		3,093	2,216
Exploration and evaluation assets	4	**3,544**	2,609
Property, plant and equipment	5	**51,851**	46,487
Other long-term assets	6	**528**	442
		$ 59,016	$ 51,754
LIABILITIES			
Current liabilities			
Accounts payable		**$ 641**	$ 637
Accrued liabilities		**3,070**	2,519
Current income taxes		**–**	359
Current portion of long-term debt	7	**1,914**	1,444
Current portion of other long-term liabilities	8	**297**	275
		5,922	5,234
Long-term debt	7	**11,771**	8,217
Other long-term liabilities	8	**4,611**	4,348
Deferred income taxes		**8,778**	8,183
		31,082	25,982
SHAREHOLDERS' EQUITY			
Share capital	10	**4,388**	3,854
Retained earnings		**23,499**	21,876
Accumulated other comprehensive income	11	**47**	42
		27,934	25,772
		$ 59,016	$ 51,754

Commitments and contingencies (note 15).

Approved by the Board of Directors on November 4, 2014

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Sep 30 2014	Three Months Ended Sep 30 2013	Nine Months Ended Sep 30 2014	Nine Months Ended Sep 30 2013
Product sales		**$ 5,370**	$ 5,284	**$ 16,451**	$ 13,615
Less: royalties		**(658)**	(625)	**(1,972)**	(1,417)
Revenue		**4,712**	4,659	**14,479**	12,198
Expenses					
Production		**1,267**	1,130	**3,866**	3,361
Transportation and blending		**747**	700	**2,473**	2,293
Depletion, depreciation and amortization	5	**1,226**	1,258	**3,474**	3,572
Administration		**87**	82	**267**	242
Share-based compensation	8	**(122)**	48	**210**	70
Asset retirement obligation accretion	8	**49**	41	**144**	125
Interest and other financing expense		**79**	70	**239**	219
Risk management activities	14	**(146)**	143	**(61)**	(11)
Foreign exchange loss (gain)		**184**	(63)	**179**	96
Gain on corporate acquisition/disposition of properties		**–**	(289)	**–**	(289)
Equity loss from investment	6	**5**	1	**3**	3
		3,376	3,121	**10,794**	9,681
Earnings before taxes		**1,336**	1,538	**3,685**	2,517
Current income tax expense	9	**89**	247	**400**	533
Deferred income tax expense	9	**208**	123	**554**	127
Net earnings		**$ 1,039**	$ 1,168	**$ 2,731**	$ 1,857
Net earnings per common share					
Basic	13	**$ 0.95**	$ 1.07	**$ 2.50**	$ 1.70
Diluted	13	**$ 0.94**	$ 1.07	**$ 2.49**	$ 1.70

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2014	Three Months Ended Sep 30 2013	Nine Months Ended Sep 30 2014	Nine Months Ended Sep 30 2013
Net earnings	**$ 1,039**	$ 1,168	**$ 2,731**	$ 1,857
Items that may be reclassified subsequently to net earnings				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized (loss) income during the period, net of taxes of $nil (2013 – $nil) – three months ended; $nil (2013 – $3 million) – nine months ended	**(2)**	(1)	**(1)**	21
Reclassification to net earnings, net of taxes of $1 million (2013 – $nil) – three months ended; $1 million (2013 – $nil) – nine months ended	**3**	1	**7**	(1)
	1	–	**6**	20
Foreign currency translation adjustment				
Translation of net investment	**–**	–	**(1)**	(11)
Other comprehensive income, net of taxes	**1**	–	**5**	9
Comprehensive income	**$ 1,040**	$ 1,168	**$ 2,736**	$ 1,866

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Nine Months Ended Sep 30 2014	Sep 30 2013
Share capital	10		
Balance – beginning of period		**$ 3,854**	$ 3,709
Issued upon exercise of stock options		**448**	65
Previously recognized liability on stock options exercised for common shares		**120**	21
Purchase of common shares under Normal Course Issuer Bid		**(34)**	(30)
Balance – end of period		**4,388**	3,765
Retained earnings			
Balance – beginning of period		**21,876**	20,516
Net earnings		**2,731**	1,857
Purchase of common shares under Normal Course Issuer Bid	10	**(370)**	(244)
Dividends on common shares	10	**(738)**	(409)
Balance – end of period		**23,499**	21,720
Accumulated other comprehensive income	11		
Balance – beginning of period		**42**	58
Other comprehensive income, net of taxes		**5**	9
Balance – end of period		**47**	67
Shareholders' equity		**$ 27,934**	$ 25,552

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2014	Three Months Ended Sep 30 2013	Nine Months Ended Sep 30 2014	Nine Months Ended Sep 30 2013
Operating activities				
Net earnings	**$ 1,039**	$ 1,168	**$ 2,731**	$ 1,857
Non-cash items				
Depletion, depreciation and amortization	**1,226**	1,258	**3,474**	3,572
Share-based compensation	**(122)**	48	**210**	70
Asset retirement obligation accretion	**49**	41	**144**	125
Unrealized risk management (gain) loss	**(150)**	121	**(47)**	69
Unrealized foreign exchange loss (gain)	**185**	(75)	**150**	115
Realized foreign exchange gain on repayment of US dollar debt securities	**–**	–	**–**	(12)
Equity loss from investment	**5**	1	**3**	3
Deferred income tax expense	**208**	123	**554**	127
Gain on corporate acquisition/disposition of properties	**–**	(289)	**–**	(289)
Current income tax on disposition of properties	**–**	58	**–**	58
Other	**18**	17	**69**	73
Abandonment expenditures	**(82)**	(44)	**(245)**	(136)
Net change in non-cash working capital	**(45)**	(294)	**(902)**	(596)
	2,331	2,133	**6,141**	5,036
Financing activities				
(Repayment) issue of bank credit facilities and commercial paper, net	**(151)**	(500)	**1,557**	751
Issue of medium-term notes, net	**–**	–	**992**	98
Issue (repayment) of US dollar debt securities, net	**–**	–	**1,100**	(398)
Issue of common shares on exercise of stock options	**63**	26	**448**	65
Purchase of common shares under Normal Course Issuer Bid	**(163)**	(67)	**(404)**	(274)
Dividends on common shares	**(246)**	(136)	**(709)**	(387)
Net change in non-cash working capital	**(5)**	(6)	**(16)**	(17)
	(502)	(683)	**2,968**	(162)
Investing activities				
Net (expenditures) proceeds on exploration and evaluation assets	**(92)**	238	**(1,093)**	151
Net expenditures on property, plant and equipment	**(2,001)**	(1,849)	**(8,186)**	(5,198)
Current income tax on disposition of properties	**–**	(58)	**–**	(58)
Investment in other long-term assets	**–**	–	**(113)**	–
Net change in non-cash working capital	**249**	220	**283**	212
	(1,844)	(1,449)	**(9,109)**	(4,893)
(Decrease) increase in cash and cash equivalents	**(15)**	1	**–**	(19)
Cash and cash equivalents – beginning of period	**31**	17	**16**	37
Cash and cash equivalents – end of period	**$ 16**	$ 18	**$ 16**	$ 18
Interest paid	**$ 142**	$ 126	**$ 387**	$ 365
Income taxes paid	**$ 63**	$ 30	**$ 665**	$ 314

(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 2500, 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, 2013, except as discussed in note 2. These interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2013.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2014, the Company adopted IFRS 9 "Financial Instruments". IFRS 9 replaces the sections of IAS 39 "Financial Instruments: Recognition and Measurement" that relate to the classification and measurement of financial instruments and hedge accounting.

IFRS 9 replaces the multiple classification and measurement models for financial assets with a new model that has only two measurement categories: amortized cost and fair value through profit or loss. This determination is made at initial recognition. For financial liabilities, the new standard retains most of the IAS 39 requirements. The main change arises in cases where the Company chooses to designate a financial liability as fair value through profit or loss. In these situations, the portion of the fair value change related to the Company's own credit risk is recognized in other comprehensive income rather than net earnings. As a result of adopting IFRS 9, all of the Company's financial assets as at December 31, 2013 were reclassified from loans and receivables at amortized cost to financial assets at amortized cost. There were no changes to the classifications of the Company's financial liabilities. In addition, there were no changes in the carrying values of the Company's financial instruments as a result of the adoption of IFRS 9. The classification and measurement guidance was adopted retrospectively in accordance with the transition provisions of IFRS 9.

The Company also adopted the new hedge accounting guidance in IFRS 9. The new hedge accounting guidance replaces strict quantitative tests of effectiveness with less restrictive assessments of how well the hedging instrument accomplishes the Company's risk management objectives for financial and non-financial risk exposures. IFRS 9 also allows the Company to hedge risk components of non-financial items which meet certain measurability or identifiable characteristics.

Upon adoption of IFRS 9, all of the Company's existing hedging relationships that qualified for hedge accounting under IAS 39 were reassessed with respect to the new hedge accounting requirements in IFRS 9. The hedging relationships have been continued under IFRS 9. The hedge accounting requirements in IFRS 9 have been applied prospectively in accordance with the transition provisions of IFRS 9.

After adoption of IFRS 9, the Company's accounting policies are substantially the same as at December 31, 2013, except for the change in financial asset categories as discussed above.

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" to provide guidance on the recognition of revenue and cash flows arising from an entity's contracts with customers, and related disclosures. The new standard replaces several existing standards related to recognition of revenue and states that revenue should be recognized as performance obligations related to the goods or services delivered are settled. IFRS 15 also provides revenue accounting guidance for contract modifications and multiple-element contracts and prescribes additional disclosure requirements. The new standard is required to be adopted retrospectively effective January 1, 2017, with earlier adoption permitted. The Company is currently assessing the impact of IFRS 15 on its consolidated financial statements.

In July 2014, the IASB issued amendments to IFRS 9 to include accounting guidance to assess and recognize impairment losses on financial assets based on an expected loss model. The amendments are effective January 1, 2018. The Company is currently assessing the impact of this amendment on its consolidated financial statements.

4. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2013	$ 2,570	$ –	$ 39	$ –	$ 2,609
Additions	**1,028**	**–**	**65**	**–**	**1,093**
Transfers to property, plant and equipment	**(160)**	**–**	**–**	**–**	**(160)**
Foreign exchange adjustments	**–**	**–**	**2**	**–**	**2**
At September 30, 2014	**$ 3,438**	**$ –**	**$ 106**	**$ –**	**$ 3,544**

5. 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, 2013	$ 53,810	$ 5,200	$ 3,356	$ 19,366	$ 508	$ 308	$ 82,548
Additions	**5,805**	**295**	**89**	**2,248**	**78**	**33**	**8,548**
Transfers from E&E assets	**160**	**–**	**–**	**–**	**–**	**–**	**160**
Disposals/derecognitions	**(220)**	**–**	**–**	**(92)**	**–**	**(1)**	**(313)**
Foreign exchange adjustments and other	**–**	**289**	**182**	**–**	**–**	**–**	**471**
At September 30, 2014	**$ 59,555**	**$ 5,784**	**$ 3,627**	**$ 21,522**	**$ 586**	**$ 340**	**$ 91,414**
Accumulated depletion and depreciation							
At December 31, 2013	$ 28,315	$ 3,467	$ 2,551	$ 1,414	$ 111	$ 203	$ 36,061
Expense	**2,826**	**146**	**74**	**402**	**7**	**19**	**3,474**
Disposals/derecognitions	**(220)**	**–**	**–**	**(92)**	**–**	**(1)**	**(313)**
Foreign exchange adjustments and other	**3**	**192**	**146**	**–**	**–**	**–**	**341**
At September 30, 2014	**$ 30,924**	**$ 3,805**	**$ 2,771**	**$ 1,724**	**$ 118**	**$ 221**	**$ 39,563**
Net book value							
– at September 30, 2014	**$ 28,631**	**$ 1,979**	**$ 856**	**$ 19,798**	**$ 468**	**$ 119**	**$ 51,851**
– at December 31, 2013	$ 25,495	$ 1,733	$ 805	$ 17,952	$ 397	$ 105	$ 46,487

Project costs not subject to depletion and depreciation	**Sep 30 2014**	Dec 31 2013
Horizon	**$ 5,161**	$ 4,051
Kirby Thermal Oil Sands – North	**$ 571**	$ 322
Kirby Thermal Oil Sands – South	**$ –**	$ 1,345

On April 1, 2014, the Company completed the acquisition of certain Canadian crude oil and natural gas properties, including exploration and evaluation assets of $823 million, for cash consideration of $3,110 million, subject to final closing adjustments. The transaction was accounted for using the acquisition method of accounting. In connection with this acquisition, the Company recognized associated asset retirement obligations of $242 million and other long-term liabilities of $49 million. No debt obligations were assumed and no net deferred tax liabilities were recognized. The above amounts are estimates and may be subject to change based on the receipt of new information. In connection with the agreement, the Company arranged a $1,000 million unsecured non-revolving bank credit facility maturing March 2016.

During the nine months ended September 30, 2014, the Company acquired a number of additional producing crude oil and natural gas properties in the North America Exploration and Production segment for net cash consideration of $567 million (year ended December 31, 2013 – $252 million), together with associated asset retirement obligations of $42 million (year ended December 31, 2013 – $131 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 nine months ended September 30, 2014, pre-tax interest of $147 million (September 30, 2013 – $122 million) was capitalized to property, plant and equipment using a capitalization rate of 4.0% (September 30, 2013 – 4.4%).

6. OTHER LONG-TERM ASSETS

		Sep 30 2014		Dec 31 2013
Investment in North West Redwater Partnership	**$**	**303**	$	306
North West Redwater Partnership subordinated debt		**117**		–
Risk Management (note 14)		**69**		–
Other		**63**		136
		552		442
Less: current portion		**24**		–
	$	**528**	$	442

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.

In April 2014, Redwater Partnership, the Company and APMC amended certain terms of the processing agreements. In conjunction with these amendments, in order to provide financing for Project completion based on the current revised Project cost estimate of approximately $8,500 million, the Company, along with APMC, each committed to provide additional funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

During the second quarter of 2014, Redwater Partnership executed a $3,500 million syndicated credit facility with a group of financial institutions maturing June 2018 and repaid and cancelled its $1,200 million credit facility previously in place. As at September 30, 2014, Redwater Partnership had interim borrowings of $402 million under the syndicated credit facility.

During the third quarter of 2014, Redwater Partnership issued $500 million of 3.20% series A secured bonds due July 2024 and $500 million of 4.05% series B 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.

7. LONG-TERM DEBT

	Sep 30 2014	Dec 31 2013
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ 2,784**	$ 1,246
Medium-term notes	**2,400**	1,400
	5,184	2,646
US dollar denominated debt, unsecured		
Commercial paper (September 30, 2014 – US$500 million; December 31, 2013 – US$500 million)	**560**	532
US dollar debt securities (September 30, 2014 – US$7,150 million; December 31, 2013 – US$6,150 million)	**8,014**	6,541
Less: original issue discount on US dollar debt securities (1)	**(20)**	(18)
	8,554	7,055
Fair value impact of interest rate swaps on US dollar debt securities (2)	**2**	9
	8,556	7,064
Long-term debt before transaction costs	**13,740**	9,710
Less: transaction costs (1) (3)	**(55)**	(49)
	13,685	9,661
Less: current portion of commercial paper	**560**	532
current portion of other long-term debt (1) (2) (3)	**1,354**	912
	$ 11,771	$ 8,217

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

(2) The carrying amount of US$350 million of 4.90% notes due December 2014 was adjusted by $2 million (December 31, 2013 – $9 million) to reflect the fair value impact of hedge accounting.

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

Bank Credit Facilities and Commercial Paper

As at September 30, 2014, the Company had in place bank credit facilities of $5,802 million, comprised of:

- a $200 million demand credit facility;
- a $75 million demand credit facility;
- a $1,000 million non-revolving term credit facility maturing March 2016;
- a $1,500 million revolving syndicated credit facility maturing June 2016;
- a $3,000 million revolving syndicated credit facility maturing June 2017; and
- a £15 million demand credit facility related to the Company's North Sea operations.

Each of the $1,500 million and $3,000 million facilities is extendible annually for one-year periods 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.

The Company's borrowings under the US commercial paper program are authorized up to a maximum US$1,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

As described in note 5, in connection with the agreement to acquire certain producing Canadian crude oil and natural gas properties, the Company arranged a $1,000 million unsecured non-revolving bank credit facility maturing March 2016. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at September 30, 2014, the Company had $1,000 million outstanding under this facility.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at September 30, 2014 was 2.1% (September 30, 2013 – 1.9%), and on long-term debt outstanding for the nine months ended September 30, 2014 was 4.0% (September 30, 2013 – 4.4%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $406 million, including a $39 million financial guarantee related to Horizon and $259 million of letters of credit related to North Sea operations, were outstanding at September 30, 2014.

Medium-Term Notes

During the second quarter of 2014, the Company issued $500 million of 2.60% medium-term notes due December 2019 and $500 million of 3.55% medium-term notes due June 2024. Proceeds from the securities were used for general corporate purposes and repayment of bank indebtedness. After issuing these securities, the Company has $2,000 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

During the first quarter of 2014, the Company issued US$500 million of three-month LIBOR plus 0.375% notes due March 2016, and concurrently entered into cross currency swaps to fix the foreign currency exchange rate risk at three-month CDOR plus 0.309% and $555 million (note 14). In addition, the Company issued US$500 million of 3.80% notes due April 2024. Proceeds from the securities were used to repay bank indebtedness. After issuing these securities, the Company has US$2,000 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.

8. OTHER LONG-TERM LIABILITIES

	Sep 30 2014	Dec 31 2013
Asset retirement obligations	**$ 4,443**	$ 4,162
Share-based compensation	**384**	260
Risk management (note 14)	**–**	136
Other	**81**	65
	4,908	4,623
Less: current portion	**297**	275
	$ 4,611	$ 4,348

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 5.0% (December 31, 2013 – 5.0%). A reconciliation of the discounted asset retirement obligations was as follows:

	Sep 30 2014	Dec 31 2013
Balance – beginning of period	**$ 4,162**	$ 4,266
Liabilities incurred	**29**	62
Liabilities acquired	**284**	131
Liabilities settled	**(245)**	(207)
Asset retirement obligation accretion	**144**	171
Revision of estimates	**–**	375
Change in discount rate	**–**	(723)
Foreign exchange adjustments	**69**	87
Balance – end of period	**$ 4,443**	$ 4,162

Share-Based Compensation

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

	Sep 30 2014	Dec 31 2013
Balance – beginning of period	**$ 260**	$ 154
Share-based compensation expense	**210**	135
Cash payment for stock options surrendered	**(8)**	(4)
Transferred to common shares	**(120)**	(50)
Capitalized to Oil Sands Mining and Upgrading	**42**	25
Balance – end of period	**384**	260
Less: current portion	**256**	216
	$ 128	$ 44

9. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Current corporate income tax – North America	**$ 162**	$ 178	**$ 579**	$ 411
Current corporate income tax – North Sea	**14**	–	**(45)**	18
Current corporate income tax – Offshore Africa	**21**	76	**35**	147
Current PRT [(1)] recovery – North Sea	**(114)**	(15)	**(187)**	(61)
Other taxes	**6**	8	**18**	18
Current income tax expense	**89**	247	**400**	533
Deferred corporate income tax expense	**158**	159	**427**	199
Deferred PRT [(1)] expense (recovery) – North Sea	**50**	(36)	**127**	(72)
Deferred income tax expense	**208**	123	**554**	127
Income tax expense	**$ 297**	$ 370	**$ 954**	$ 660

(1) Petroleum Revenue Tax.

10. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued common shares	Nine Months Ended Sep 30, 2014 Number of shares (thousands)		Amount
Balance – beginning of period	**1,087,322**	**$**	**3,854**
Issued upon exercise of stock options	**13,369**		**448**
Previously recognized liability on stock options exercised for common shares	**–**		**120**
Purchase of common shares under Normal Course Issuer Bid	**(8,885)**		**(34)**
Balance – end of period	**1,091,806**	**$**	**4,388**

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 5, 2014, the Board of Directors approved the regular quarterly dividend at $0.225 per common share, an increase from the previous quarterly dividend of $0.20 per common share, which was approved on November 5, 2013.

Normal Course Issuer Bid

In April 2014, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the twelve month period commencing April 2014 and ending April 2015, up to 54,596,899 common shares. The Company's Normal Course Issuer Bid announced in 2013 expired April 2014.

For the nine months ended September 30, 2014, the Company purchased for cancellation 8,885,000 common shares at a weighted average price of $45.51 per common share, for a total cost of $404 million. Retained earnings were reduced by $370 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2014, the Company purchased 790,000 common shares at a weighted average price of $39.49 per common share for a total cost of $31 million.

Stock Options

The following table summarizes information relating to stock options outstanding at September 30, 2014:

	Nine Months Ended Sep 30, 2014 Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of period	**72,741**	**$**	**34.36**
Granted	**8,993**	**$**	**41.10**
Surrendered for cash settlement	**(909)**	**$**	**33.77**
Exercised for common shares	**(13,369)**	**$**	**33.48**
Forfeited	**(3,370)**	**$**	**35.97**
Outstanding – end of period	**64,086**	**$**	**35.42**
Exercisable – end of period	**15,070**	**$**	**36.71**

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

11. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Sep 30 2014	Sep 30 2013
Derivative financial instruments designated as cash flow hedges	**$ 87**	$ 106
Foreign currency translation adjustment	**(40)**	(39)
	$ 47	$ 67

12. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At September 30, 2014, the ratio was within the target range at 33%.

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

	Sep 30 2014	Dec 31 2013
Long-term debt (1)	**$ 13,685**	$ 9,661
Total shareholders' equity	**$ 27,934**	$ 25,772
Debt to book capitalization	**33%**	27%

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

13. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
	Sep 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Weighted average common shares outstanding – basic (thousands of shares)	**1,092,149**	1,086,813	**1,091,864**	1,089,495
Effect of dilutive stock options (thousands of shares)	**10,613**	1,847	**7,052**	1,899
Weighted average common shares outstanding – diluted (thousands of shares)	**1,102,762**	1,088,660	**1,098,916**	1,091,394
Net earnings	**$ 1,039**	$ 1,168	**$ 2,731**	$ 1,857
Net earnings per common share – basic	**$ 0.95**	$ 1.07	**$ 2.50**	$ 1.70
– diluted	**$ 0.94**	$ 1.07	**$ 2.49**	$ 1.70

14. FINANCIAL INSTRUMENTS

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

	Sep 30, 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	**$ 1,908**	**$ –**	**$ –**	**$ –**	**$ 1,908**
Other long-term assets	**–**	**13**	**56**	**–**	**69**
Accounts payable	**–**	**–**	**–**	**(641)**	**(641)**
Accrued liabilities	**–**	**–**	**–**	**(3,070)**	**(3,070)**
Other long-term liabilities	**–**	**–**	**–**	**(41)**	**(41)**
Long-term debt (1)	**–**	**–**	**–**	**(13,685)**	**(13,685)**
	$ 1,908	**$ 13**	**$ 56**	**$ (17,437)**	**$ (15,460)**

	Dec 31, 2013				
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	$ 1,427	$ –	$ –	$ –	$ 1,427
Accounts payable	–	–	–	(637)	(637)
Accrued liabilities	–	–	–	(2,519)	(2,519)
Other long-term liabilities	–	(39)	(97)	(56)	(192)
Long-term debt (1)	–	–	–	(9,661)	(9,661)
	$ 1,427	$ (39)	$ (97)	$ (12,873)	$ (11,582)

(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 (liabilities) and fixed rate long-term debt are outlined below:

	Sep 30, 2014		
	Carrying amount	**Fair value**	
Asset (liability) (1) (5)		**Level 1**	**Level 2**
Other long-term assets	**$ 69**	**$ –**	**$ 69**
Fixed rate long-term debt (2) (3) (4)	**(10,341)**	**(11,467)**	**–**
	$ (10,272)	**$ (11,467)**	**$ 69**

	Dec 31, 2013		
	Carrying amount	Fair value	
Asset (liability) (1) (5)		Level 1	Level 2
Other long-term liabilities	$ (136)	$ –	$ (136)
Fixed rate long-term debt (2) (3) (4)	(7,883)	(8,628)	–
	$ (8,019)	$ (8,628)	$ (136)

(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) The carrying amount of US$350 million of 4.90% notes due December 2014 was adjusted by $2 million (December 31, 2013 – $9 million) to reflect the fair value impact of hedge accounting.

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

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

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

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

Asset (liability)		Sep 30, 2014		Dec 31, 2013
Derivatives held for trading				
Crude oil price collars	**$**	**21**	$	(33)
Crude oil WCS [1] differential swaps		**(30)**		–
Foreign currency forward contracts		**25**		(3)
Natural gas AECO basis swaps		**(3)**		(1)
Natural gas AECO put options, net of put premium financing obligations		**(2)**		(2)
Natural gas price collars		**2**		–
Cash flow hedges				
Foreign currency forward contracts		**7**		(1)
Cross currency swaps		**49**		(96)
	$	**69**	$	(136)
Included within:				
Current portion of other long-term assets (liabilities)	**$**	**24**	$	(38)
Other long-term assets (liabilities)		**45**		(98)
	$	**69**	$	(136)

(1) Western Canadian Select.

For the nine months ended September 30, 2014, the Company recognized a loss of $5 million (December 31, 2013 – gain of $4 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)	Nine Months Ended Sep 30, 2014	Year Ended Dec 31, 2013
Balance – beginning of period	**$ (136)**	$ (257)
Cost of outstanding put options	**2**	9
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	**47**	(39)
Foreign exchange	**151**	165
Other comprehensive income	**7**	(5)
	71	(127)
Add: put premium financing obligations [(1)]	**(2)**	(9)
Balance – end of period	**69**	(136)
Less: current portion	**24**	(38)
	$ 45	$ (98)

(1) The Company has negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective options. These obligations are reflected in the risk management liability.

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2014	Sep 30 2013	**Sep 30 2014**	Sep 30 2013
Net realized risk management loss (gain)	**$ 4**	$ 22	**$ (14)**	$ (80)
Net unrealized risk management (gain) loss	**(150)**	121	**(47)**	69
	$ (146)	$ 143	**$ (61)**	$ (11)

Financial Risk Factors

a) Market risk

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

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At September 30, 2014, 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	Oct 2014	–	Dec 2014	50,000 bbl/d	US$75.00	–	US$121.57	Brent
	Oct 2014	–	Dec 2014	50,000 bbl/d	US$80.00	–	US$120.17	Brent
	Oct 2014	–	Dec 2014	50,000 bbl/d	US$90.00	–	US$120.10	Brent
	Oct 2014	–	Dec 2014	50,000 bbl/d	US$90.00	–	US$127.36	Brent
	Jan 2015	–	Dec 2015	50,000 bbl/d	US$80.00	–	US$120.52	Brent
	Oct 2014	–	Dec 2014	50,000 bbl/d	US$75.00	–	US$105.54	WTI
	Oct 2014	–	Dec 2014	50,000 bbl/d	US$80.00	–	US$107.81	WTI
	Oct 2014	–	Dec 2014	25,000 bbl/d	US$90.00	–	US$110.19	WTI
WCS differential swaps	Oct 2014	–	Dec 2014	30,000 bbl/d			US$21.07	WCS
	Jan 2015	–	Mar 2015	30,000 bbl/d			US$21.49	WCS

	Remaining term			Volume	Weighted average price			Index
Natural gas								
AECO basis swaps	Oct 2014			500,000 MMBtu/d			US$0.50	AECO/NYMEX
Put options	Oct 2014			750,000 GJ/d			$3.10	AECO
Price collars	Oct 2014	–	Dec 2014	200,000 GJ/d	$4.00	–	$5.03	AECO

During the fourth quarter of 2014, $2 million of put option costs will be settled.

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At September 30, 2014, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt, commercial paper and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At September 30, 2014, the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Oct 2014	–	Mar 2016	US$500	1.109	Three-month LIBOR plus 0.375%	Three-month CDOR [(1)] plus 0.309%
	Oct 2014	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Oct 2014	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Oct 2014	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Oct 2014	–	Mar 2038	US$550	1.170	6.25%	5.76%

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

All cross currency swap derivative financial instruments designated as hedges at September 30, 2014, were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at September 30, 2014, the Company had US$1,818 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$500 million designated as cash flow hedges.

b) Credit risk

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

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At September 30, 2014, 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 and other entities. At September 30, 2014, the Company had net risk management assets of $98 million with specific counterparties related to derivative financial instruments (December 31, 2013 – $nil).

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	$ 641	$ –	$ –	$ –
Accrued liabilities	$ 3,070	$ –	$ –	$ –
Risk management	$ –	$ –	$ –	$ –
Other long-term liabilities	$ 41	$ –	$ –	$ –
Long-term debt (1)	$ 1,913	$ 2,665	$ 3,141	$ 6,039

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

15. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	Remaining 2014	2015	2016	2017	2018	Thereafter
Product transportation and pipeline	$ 110	$ 432	$ 320	$ 291	$ 260	$ 1,714
Offshore equipment operating leases and offshore drilling	$ 69	$ 304	$ 90	$ 64	$ 57	$ 18
Office leases	$ 10	$ 46	$ 46	$ 49	$ 51	$ 343
Other	$ 89	$ 190	$ 131	$ 32	$ 1	$ –

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

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

16. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	Exploration and Production															
	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2014	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Segmented product sales	**4,257**	3,829	**12,377**	9,826	**72**	212	**496**	576	**196**	75	**392**	489	**4,525**	4,116	**13,265**	10,891
Less: royalties	**(577)**	(536)	**(1,752)**	(1,196)	**(1)**	(1)	**(2)**	(2)	**(22)**	(18)	**(35)**	(85)	**(600)**	(555)	**(1,789)**	(1,283)
Segmented revenue	**3,680**	3,293	**10,625**	8,630	**71**	211	**494**	574	**174**	57	**357**	404	**3,925**	3,561	**11,476**	9,608
Segmented expenses																
Production	**755**	580	**2,170**	1,773	**59**	120	**325**	297	**50**	17	**138**	100	**864**	717	**2,633**	2,170
Transportation and blending	**746**	702	**2,471**	2,292	**–**	1	**3**	4	**1**	–	**1**	1	**747**	703	**2,475**	2,297
Depletion, depreciation and amortization	**1,020**	937	**2,842**	2,663	**26**	142	**149**	368	**41**	10	**74**	90	**1,087**	1,089	**3,065**	3,121
Asset retirement obligation accretion	**25**	23	**73**	69	**9**	9	**28**	26	**3**	–	**8**	4	**37**	32	**109**	99
Realized risk management activities	**4**	22	**(14)**	(80)	**–**	–	**–**	–	**–**	–	**–**	–	**4**	22	**(14)**	(80)
Gain on corporate acquisition/disposition of properties	**–**	(65)	**–**	(65)	**–**	–	**–**	–	**–**	(224)	**–**	(224)	**–**	(289)	**–**	(289)
Equity loss from investment	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Total segmented expenses	**2,550**	2,199	**7,542**	6,652	**94**	272	**505**	695	**95**	(197)	**221**	(29)	**2,739**	2,274	**8,268**	7,318
Segmented earnings (loss) before the following	**1,130**	1,094	**3,083**	1,978	**(23)**	(61)	**(11)**	(121)	**79**	254	**136**	433	**1,186**	1,287	**3,208**	2,290
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Unrealized risk management activities																
Foreign exchange loss (gain)																
Total non-segmented expenses																
Earnings before taxes																
Current income tax expense																
Deferred income tax expense																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter-segment elimination and other				Total			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2014	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Segmented product sales	**840**	1,164	**3,163**	2,716	**30**	28	**91**	84	**(25)**	(24)	**(68)**	(76)	**5,370**	5,284	**16,451**	13,615
Less: royalties	**(58)**	(70)	**(183)**	(134)	**–**	–	**–**	–	**–**	–	**–**	–	**(658)**	(625)	**(1,972)**	(1,417)
Segmented revenue	**782**	1,094	**2,980**	2,582	**30**	28	**91**	84	**(25)**	(24)	**(68)**	(76)	**4,712**	4,659	**14,479**	12,198
Segmented expenses																
Production	**398**	407	**1,214**	1,178	**8**	9	**27**	26	**(3)**	(3)	**(8)**	(13)	**1,267**	1,130	**3,866**	3,361
Transportation and blending	**18**	15	**55**	48	**–**	–	**–**	–	**(18)**	(18)	**(57)**	(52)	**747**	700	**2,473**	2,293
Depletion, depreciation and amortization	**137**	167	**402**	445	**2**	2	**7**	6	**–**	–	**–**	–	**1,226**	1,258	**3,474**	3,572
Asset retirement obligation accretion	**12**	9	**35**	26	**–**	–	**–**	–	**–**	–	**–**	–	**49**	41	**144**	125
Realized risk management activities	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**4**	22	**(14)**	(80)
Gain on corporate acquisition/disposition of properties	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	(289)	**–**	(289)
Equity loss from investment	**–**	–	**–**	–	**5**	1	**3**	3	**–**	–	**–**	–	**5**	1	**3**	3
Total segmented expenses	**565**	598	**1,706**	1,697	**15**	12	**37**	35	**(21)**	(21)	**(65)**	(65)	**3,298**	2,863	**9,946**	8,985
Segmented earnings (loss) before the following	**217**	496	**1,274**	885	**15**	16	**54**	49	**(4)**	(3)	**(3)**	(11)	**1,414**	1,796	**4,533**	3,213
Non-segmented expenses																
Administration													**87**	82	**267**	242
Share-based compensation													**(122)**	48	**210**	70
Interest and other financing expense													**79**	70	**239**	219
Unrealized risk management activities													**(150)**	121	**(47)**	69
Foreign exchange loss (gain)													**184**	(63)	**179**	96
Total non-segmented expenses													**78**	258	**848**	696
Earnings before taxes													**1,336**	1,538	**3,685**	2,517
Current income tax expense													**89**	247	**400**	533
Deferred income tax expense													**208**	123	**554**	127
Net earnings													**1,039**	1,168	**2,731**	1,857

Capital Expenditures [1]

	Nine Months Ended					
	Sep 30, 2014			Sep 30, 2013		
	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	**$ 1,028**	**$ (160)**	**$ 868**	$ 97	$ (67)	$ 30
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa [3]	**65**	**–**	**65**	(24)	–	(24)
	$ 1,093	**$ (160)**	**$ 933**	$ 73	$ (67)	$ 6
Property, plant and equipment						
Exploration and Production						
North America	**$ 5,443**	**$ 302**	**$ 5,745**	$ 2,928	$ (59)	$ 2,869
North Sea	**295**	**–**	**295**	239	–	239
Offshore Africa	**89**	**–**	**89**	78	–	78
	5,827	**302**	**6,129**	3,245	(59)	3,186
Oil Sands Mining and Upgrading [4]	**2,248**	**(92)**	**2,156**	1,909	(357)	1,552
Midstream	**78**	**–**	**78**	12	–	12
Head office	**33**	**(1)**	**32**	32	–	32
	$ 8,186	**$ 209**	**$ 8,395**	$ 5,198	$ (416)	$ 4,782

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

(2) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, and other fair value adjustments.

(3) The above noted figures in 2013 do not include the impact of a pre-tax gain on sale of exploration and evaluation assets totaling $224 million on the Company's disposition of its 50% interest in its exploration right in South Africa.

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

Segmented Assets

	Total Assets	
	Sep 30 2014	Dec 31 2013
Exploration and Production		
North America	**$ 33,695**	$ 29,234
North Sea	**2,495**	1,964
Offshore Africa	**1,150**	981
Other	**42**	25
Oil Sands Mining and Upgrading	**20,411**	18,604
Midstream	**1,104**	841
Head office	**119**	105
	$ 59,016	$ 51,754

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 September 30, 2014:

Interest coverage (times)	
Net earnings [(1)]	9.2x
Cash flow from operations [(2)]	20.2x

(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.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Thursday, November 6, 2014. The North American conference call number is 1-877-223-4471 and the outside North American conference call number is 001-647-788-4922. Please call in about 10 minutes before the starting time in order to be patched into the call.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time, Thursday, November 13, 2014. To access the rebroadcast in North America, dial 1-800-585-8367. Those outside of North America, dial 001-416-621-4642. The conference ID number to use is 58425862.

WEBCAST

This call is being webcast and can be accessed on Canadian Natural's website at www.cnrl.com. Presentation slides will be available on Canadian Natural's website in PDF format shortly before the live conference call webcast.

For further information, please contact:

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