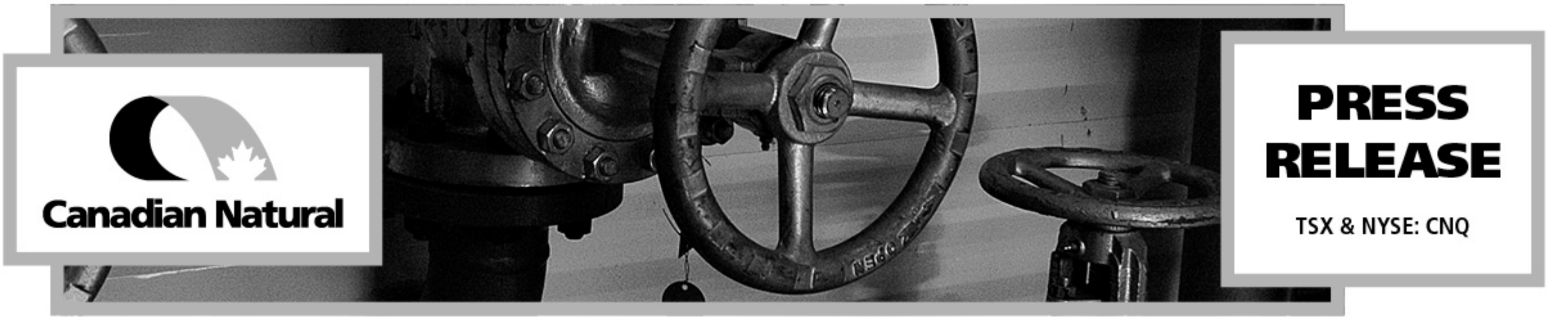

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2014 SECOND QUARTER RESULTS

CALGARY, ALBERTA – AUGUST 7, 2014 – FOR IMMEDIATE RELEASE

Commenting on second quarter results, Steve Laut, President of Canadian Natural stated, “Canadian Natural’s first half of the year was solid. We have effectively executed on our strategy and have grown production both organically and with the successful integration of acquired assets. As a result, Canadian Natural delivered record quarterly total liquids production, which included record production at our Horizon Oil Sands operations of approximately 119,200 barrels per day of synthetic light crude oil, record North America light crude oil and NGLs production, record Pelican Lake heavy crude oil production and record primary heavy crude oil production. These milestones, combined with strong natural gas production, contributed to record total production this quarter of approximately 817,500 barrels of oil equivalent per day.

Canadian Natural’s large, diverse asset base, defined growth plan and effective strategy to transition to long-life, low decline assets, allows us to retain optionality and remain flexible in our capital allocation. This flexibility has allowed us to take advantage of opportunistic acquisitions and allocate capital to the highest return projects. Canadian Natural’s large, diverse asset base, effective and efficient operations and proven strategy delivers increasing free cash flow. By effectively transitioning to longer life, low decline assets, Canadian Natural will generate increasing, more sustainable free cash flow, maximizing value for our shareholders.”

Canadian Natural’s Chief Financial Officer, Corey Bieber, continued, “The execution of our defined growth plan, combined with factors such as higher sales volumes in North America and strong netbacks, has led us to deliver record cash flow this quarter of approximately $2.6 billion. Canadian Natural is committed to maintaining financial discipline in all our operations, which further supports our increasing free cash flow generation. Operating costs declined this quarter over Q1/14 as a result of production growth and continued effective and efficient operations. Our dedication to disciplined capital allocation and cost control enables us to maintain a strong balance sheet. This quarter demonstrates how the Company is poised to continue to grow its balanced portfolio while remaining in an enviable position to return value to shareholders.”

QUARTERLY HIGHLIGHTS

($ Millions, except per common share amounts)	Three Months Ended Jun 30 2014	Mar 31 2014	Jun 30 2013	Six Months Ended Jun 30 2014	Jun 30 2013
Net earnings	**$ 1,070**	$ 622	$ 476	**$ 1,692**	$ 689
Per common share – basic	**$ 0.98**	$ 0.57	$ 0.44	**$ 1.55**	$ 0.63
– diluted	**$ 0.97**	$ 0.57	$ 0.44	**$ 1.54**	$ 0.63
Adjusted net earnings from operations (1)	**$ 1,150**	$ 921	$ 462	**$ 2,071**	$ 863
Per common share – basic	**$ 1.05**	$ 0.85	$ 0.42	**$ 1.90**	$ 0.79
– diluted	**$ 1.04**	$ 0.85	$ 0.42	**$ 1.89**	$ 0.79
Cash flow from operations (2)	**$ 2,633**	$ 2,146	$ 1,670	**$ 4,779**	$ 3,241
Per common share – basic	**$ 2.41**	$ 1.97	$ 1.53	**$ 4.38**	$ 2.97
– diluted	**$ 2.39**	$ 1.97	$ 1.53	**$ 4.36**	$ 2.97
Capital expenditures, net of dispositions	**$ 5,456**	$ 1,893	$ 1,792	**$ 7,349**	$ 3,528
Daily production, before royalties					
Natural gas (MMcf/d)	**1,634**	1,175	1,122	**1,406**	1,136
Crude oil and NGLs (bbl/d)	**545,169**	488,788	436,363	**517,134**	462,615
Equivalent production (BOE/d) (3)	**817,471**	684,647	623,315	**751,426**	651,921

(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 record cash flow from operations of approximately $2.63 billion in Q2/14 compared to approximately $1.67 billion in Q2/13 and $2.15 billion in Q1/14. The Company achieved record cash flow per share of $2.41, a 58% and 22% increase respectively from Q2/13 and Q1/14 levels. The increase in cash flow from Q1/14 reflects higher North America crude oil and NGLs, synthetic crude oil ("SCO") and natural gas sales volumes, higher North America crude oil and NGLs netbacks, higher realized SCO prices and higher crude oil sales in Offshore Africa, offset by lower North America natural gas netbacks and the impact of a stronger Canadian dollar.
- Adjusted net earnings from operations for Q2/14 were a record $1.15 billion, compared to adjusted net earnings of $462 million in Q2/13 and $921 million Q1/14. Changes in adjusted net earnings reflect the changes in cash flow from operations as well as higher depletion, depreciation and amortization expense from Q2/13 and Q1/14 levels.
- Total crude oil and NGLs production for Q2/14 averaged a record of approximately 545,200 barrels per day ("bbl/d"), a 12% increase over Q1/14. The strong Q2/14 production performance was largely driven by:
  - record SCO production at our Horizon Oil Sands ("Horizon") operations,
  - record North America light crude oil and NGLs production,
  - record Pelican Lake heavy crude oil production,
  - record primary heavy crude oil production, and
  - thermal in situ production volumes exceeding the Company's previously issued quarterly production guidance.
- During Q2/14 Horizon continued to achieve strong and reliable operating performance, with record quarterly SCO production of approximately 119,200 bbl/d, a 5% increase from Q1/14 levels. Horizon Q2/14 operating costs, including natural gas costs, declined to $36.61/bbl, 19% less than Q2/13 levels and 11% less than Q1/14 levels.

Horizon production is targeted to be taken offline for approximately 25 days commencing in mid-August to advance the coker tie-in, originally planned for 2015. Horizon production levels are targeted to average approximately 127,000 bbl/d once the coker tie-in is complete.

- North America light crude oil and NGLs achieved record quarterly production of approximately 93,000 bbl/d in Q2/14. Production increased 46% from Q2/13 levels and 23% from Q1/14 levels, largely as a result of the successful integration of light crude oil and NGLs production volumes acquired to date, as well as a successful drilling program. The increase from Q2/13 levels also reflects the increased NGLs production associated with the Septimus project expansion completed in Q3/13.
- In Q2/14, Pelican Lake operations achieved record quarterly heavy crude oil production volumes of approximately 49,600 bbl/d, a 19% increase from Q2/13 volumes and a 3% increase from Q1/14 volumes. This is the sixth consecutive quarter of production increases, which reflects Canadian Natural's continued success in developing, implementing and optimizing polymer flood technology at our Pelican Lake property.
- In Q2/14, primary heavy crude oil operations achieved record quarterly production of approximately 143,200 bbl/d. Primary heavy crude oil production increased 5% from Q2/13 levels and increased 1% from Q1/14 levels, due to strong results from the Company's effective and efficient drilling program.
- Q2/14 thermal in situ production volumes were approximately 114,400 bbl/d, exceeding the Company's previously issued guidance of 98,000 to 108,000 bbl/d, as a result of stronger than expected production volumes in Primrose North.
  - At Kirby South, the reservoir is responding as expected, with Q2/14 production averaging approximately 15,000 bbl/d. Kirby South production is targeted to grow to facility capacity of 40,000 bbl/d by Q1/15.
  - To date, the Kirby North Phase 1 ("Kirby North") project has now 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. Detailed engineering on the Central Processing Facility is essentially complete and first steam-in is targeted for Q4/16, subject to regulatory requirements.
- Q2/14 total natural gas production was 1,634 MMcf/d, an increase of 46% and 39% respectively from Q2/13 levels and Q1/14 levels. The increase in natural gas production was as a result of property acquisitions and a concentrated liquids-rich natural gas drilling program. The increase from Q2/13 levels also reflects the increased natural gas production associated with the Septimus project expansion completed in Q3/13.
- During the first half of 2014, the Company closed approximately $3.6 billion in asset acquisition transactions, acquiring assets in areas adjacent or proximal to Canadian Natural's current Canadian operations. These high quality assets were acquired at an average cost of $30,200 per flowing barrel and are weighted 79% natural gas and 21% liquids. In Q2/14 the assets, which include associated key strategic facilities, a royalty revenue stream and undeveloped land, were integrated into current operations. Canadian Natural is working to maximize efficiencies of the integrated operations while high grading development opportunities in the Company's large and diverse portfolio.
- Canadian Natural continues its ongoing review of its royalty lands and royalty revenue portfolio. As part of this review a thorough process is taking place to integrate the newly acquired freehold mineral title and royalty lands with Canadian Natural's previously existing royalty portfolio, which also consists of freehold mineral title and royalty lands. This review includes a detailed examination of Canadian Natural's freehold and royalty land position, production volumes, product mix, associated cash flow and collection of payments. For example, as part of this review, to date the Company has identified 47 outstanding offset obligations with compensatory royalties owing to Canadian Natural and an associated offset drilling obligation. Canadian Natural is targeting to determine the best option to maximize value for its shareholders as it relates to its freehold and royalty lands by 2014 year end.
- As expected, heavy crude oil differentials narrowed during Q2/14, resulting in favorable price realizations for the Company. The WCS heavy oil differential as a percent of WTI ("WCS differential") averaged 19% in Q2/14 compared to 20% in Q2/13 and 24% in Q1/14.
- In Q2/14, average North America Exploration and Production operating costs declined by approximately 8% for liquids and approximately 4% for natural gas, over Q1/14 levels, as a result of effective and efficient operations.
- Under the Company's Normal Course Issuer Bid, year to date, Canadian Natural has purchased for cancellation 8,165,000 common shares at a weighted average price of $45.59 per common share.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.225 per share payable on October 1, 2014.

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

	Six Months Ended Jun 30			
	2014		2013	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**470**	**425**	471	459
Natural gas	**48**	**38**	29	23
Dry	**6**	**5**	10	10
Subtotal	**524**	**468**	510	492
Stratigraphic test / service wells	**353**	**352**	321	321
Total	**877**	**820**	831	813
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			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Crude oil and NGLs production (bbl/d)	**285,740**	266,110	241,402	**275,979**	239,014
Net wells targeting crude oil	**151**	263	136	**414**	407
Net successful wells drilled	**149**	260	131	**409**	398
Success rate	**99%**	99%	96%	**99%**	98%

- North America crude oil and NGLs averaged record quarterly production of approximately 285,700 bbl/d in Q2/14, an increase of 18% from Q2/13 levels and 7% from Q1/14 levels.
- In Q2/14, primary heavy crude oil operations achieved record quarterly production of approximately 143,200 bbl/d, an increase of 5% from Q2/13 levels and an increase of 1% from Q1/14 levels. Strong performance combined with effective and efficient operations and a vast inventory of over 8,000 locations enables Canadian Natural to remain an industry leading primary heavy crude oil producer. Canadian Natural continued with its large and cost efficient drilling program, drilling 122 net primary heavy crude oil wells in Q2/14.
- Canadian Natural's primary heavy crude oil assets provide strong netbacks and a high return on capital in the Company's portfolio of diverse and balanced assets. In Q2/14 operating costs declined, as the Company achieved expected efficiencies in sand handling.
- In Q2/14, Pelican Lake operations achieved record heavy crude oil quarterly production volumes of approximately 49,600 bbl/d, a 19% increase from Q2/13 volumes and a 3% increase from Q1/14 volumes. This is the sixth consecutive quarter of production increases, which reflects Canadian Natural's continued success in developing, implementing and optimizing polymer flood technology at our Pelican Lake property. Industry leading Pelican Lake operating costs of $8.92/bbl in Q2/14 represent a 20% decrease in operating costs from Q2/13 levels and an 8% decrease from Q1/14 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 record quarterly production of approximately 93,000 bbl/d in Q2/14. Production increased 46% from Q2/13 levels and 23% from Q1/14 levels, largely as a result of the successful integration of light crude oil and NGLs production volumes acquired to date, as well as a successful drilling program. The increase from Q2/13 levels also reflects the increased NGLs production associated with the Septimus project expansion completed in Q3/13.
- The Company drilled 13 net light crude oil wells in Q2/14. Canadian Natural's light crude oil drilling program will continue to utilize and advance horizontal multi-frac well technology to access new reserves in pools across the Company's land base.

Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Bitumen production (bbl/d)	**114,414**	82,077	90,051	**98,335**	99,419
Net wells targeting bitumen	**3**	11	27	**14**	60
Net successful wells drilled	**3**	11	27	**14**	60
Success rate	**100%**	100%	100%	**100%**	100%

- Q2/14 thermal in situ production volumes were approximately 114,400 bbl/d, exceeding the Company's previously issued guidance of 98,000 to 108,000 bbl/d, as a result of stronger than expected production volumes in Primrose North. Canadian Natural remains a leader in effective and efficient thermal operations; with total Primrose thermal operating costs, including energy costs, of $10.20/bbl for Q2/14.
- At Kirby South, the reservoir is responding and the wells are performing as expected, with Q2/14 production averaging approximately 15,000 bbl/d and Q3/14 production is targeted to average approximately 18,000 bbl/d. In Q2/14, 39 well pairs had been converted to full SAGD production, and 10 well pairs are progressing through the steam circulation phase to initiate the SAGD process.
- Subsequent to Q2/14, Kirby South experienced temporary mechanical issues at its associated steam generating facility, which has temporarily restricted steam generation capacity. Canadian Natural is working to resolve these issues and targets to incrementally increase steam circulation again as of August 2014. As a result of the temporary steam capacity restriction, the production ramp up to facility capacity of 40,000 bbl/d is now targeted for Q1/15.
- To date, the Kirby North project has now 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 Kirby North project includes 56 well pairs and expansion infrastructure for future growth. Detailed engineering on the Central Processing Facility is essentially complete and first steam-in is targeted for Q4/16, subject to regulatory requirements.
- During Q2/13, bitumen emulsion was discovered at surface at 4 separate locations in the Company's Primrose development area, 3 at Primrose East and 1 at Primrose South. The cleanup of all 4 sites is complete and the Company has confirmed there is no on-going contamination of the aquifer. Subsequent to Q2/14, Canadian Natural submitted the initial causation review report relating to seepage to surface at Primrose to the Alberta Energy Regulator ("AER") for review. An independent technical expert review panel (the "Panel") reviewed the causation report and submitted its findings to the AER. The Panel concurs with the main contributing factors outlined by Canadian Natural. Further details can be found on the Company's website at www.cnrl.com.
- Concurrent with the causation review, Canadian Natural has developed methods to prevent seepages for all potential failure mechanisms. This includes the remediation of legacy wellbores, modified steaming strategies, enhanced monitoring techniques and proactive response strategies. Canadian Natural believes that reserves recovered from the Primrose area over its life cycle will be substantially unchanged.
- As a result of the thorough and ongoing investigation process undertaken by Canadian Natural in relation to the Primrose seepage to surface, as well as a detailed review process by the Panel, the implementation of a low pressure steamflood at Primrose East has been delayed longer than previously anticipated. This, in conjunction with the temporary mechanical issues at Kirby South, has resulted in the Company revising 2014 annual thermal production guidance to 112,000 to 122,000 bbl/d.

Natural Gas

	Three Months Ended			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Natural gas production (MMcf/d)	**1,606**	1,147	1,092	**1,378**	1,108
Net wells targeting natural gas	**13**	25	8	**38**	24
Net successful wells drilled	**13**	25	8	**38**	23
Success rate	**100%**	100%	100%	**100%**	96%

- North America natural gas production averaged 1,606 MMcf/d for Q2/14, an increase of 47% and 40% respectively from Q2/13 levels and Q1/14 levels. The increase in natural gas production was as a result of property acquisitions and a concentrated liquids-rich natural gas drilling program. The increase from Q2/13 levels also reflects the increased natural gas production associated with the Septimus project expansion completed in Q3/13.
- 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 Company has commenced optimization of these assets with facility consolidations, well reactivations and facility turnarounds. Canadian Natural will advance development opportunities and continue the fabrication of the Ferrier central processing modules. These activities target to enhance production while reducing the operating costs on the acquired assets.
- Subsequent to Q2/14, as a result of forest fires in British Columbia and Alberta, and third party facility turnarounds in British Columbia, natural gas production was impacted by approximately 130 MMcf/d for approximately 31 days. The impacted production volumes are reflected in the Company's guidance.

International Exploration and Production

	Three Months Ended			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Crude oil production (bbl/d)					
North Sea	**12,615**	16,715	18,901	**14,654**	18,838
Offshore Africa	**13,164**	10,791	18,055	**11,984**	17,089
Natural gas production (MMcf/d)					
North Sea	**5**	7	4	**6**	3
Offshore Africa	**23**	21	26	**22**	25
Net wells targeting crude oil	**1.7**	–	1.0	**1.7**	1.0
Net successful wells drilled	**1.7**	–	1.0	**1.7**	1.0
Success rate	**100%**	–	100%	**100%**	100%

- International crude oil production averaged approximately 25,800 bbl/d during Q2/14, a 6% decrease from Q1/14 levels, and below the Company's previously issued guidance of 27,000 to 31,000 bbl/d. This decrease was primarily as a result of unplanned downtime at Tiffany. Turnaround activities, planned for 25 days and originally scheduled for Q3/14, were advanced and completed in Q2/14. The Q2/14 production impact was approximately 4,500 bbl/d; production will not resume until mid Q3/14 as a result of a third party pipeline outage.
- In Q2/14, the Banff/Kyle FPSO in the central North Sea returned to the field and subsequently resumed production in late July 2014. Combined net production of approximately 3,500 bbl/d was suspended in 2011 after the infrastructure suffered significant storm damage. The wells are currently being reinstated in a controlled manner with net production rates targeted to increase to approximately 5,000 bbl/d once fully operational.
- During Q4/13 the Company contracted a drilling rig for a 6 well (3.5 net) 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.
- During Q2/14, Canadian Natural contracted a drilling rig to undertake the 12-month light crude oil infill drilling program at Espoir, Côte d'Ivoire. The development of Espoir is targeted to commence in the second half of

2014 with a 10 well (5.9 net) drilling program. This program is targeted to add 5,900 BOE/d of net production when complete.

- Canadian Natural previously acquired 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 encountered a series of sands approximately 350 metres thick which contain a hydrocarbon column of approximately 40 metres of light crude oil with 34 degree API gravity. The well, which demonstrated the presence of a working petroleum system, was plugged and the data gathered will be evaluated to determine the extent of the accumulation and the future appraisal plan. 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.
- Canadian Natural has a 50% interest in an exploration right located in the Outeniqua Basin, approximately 175 kilometers off the southern coast of South Africa. Subsequent to Q2/14, on July 21, 2014, the operator commenced drilling the first exploratory well. Canadian Natural is carried on the first US$150 million in gross costs. The targeted drilling time is approximately 120 days.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Synthetic crude oil production (bbl/d)	**119,236**	113,095	67,954	**116,182**	88,255

- During Q2/14 Horizon continued to achieve strong and reliable operating performance, achieving record quarterly SCO production averaging approximately 119,200 bbl/d, a 5% increase over Q1/14 levels. July 2014 SCO production remained strong, averaging approximately 112,700 bbl/d. Horizon production is targeted to be taken offline for approximately 25 days commencing in mid-August to advance the coker tie-in, originally planned for 2015. Horizon production levels are targeted to average approximately 127,000 bbl/d once the coker tie-in is complete.
- As a result of the continued effective and efficient operations, Horizon Q2/14 operating costs, including natural gas costs, declined to $36.61/bbl, 19% less than Q2/13 levels and 11% less than Q1/14 levels. Operating costs are targeted to continue to decline with the phased expansion of production capacity.
- 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 sanctioned cost estimates.
- Overall Horizon Phase 2/3 expansion is 42% physically complete as at Q2/14:
    - Reliability – Tranche 2 is 99% 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 27% 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 expansion is 92% physically complete with current progress tracking ahead of schedule. 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 has accelerated the tie-in to commence August 2014. Horizon SCO production levels are targeted to increase by approximately 12,000 bbl/d with the completion of the coker tie-in.
    - Phase 2B is 33% 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 32% physically complete, and includes the addition of supplementary 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.

- On the Phase 2/3 expansion Canadian Natural has committed to approximately 65% of the Engineering, Procurement and Construction contracts. Over 60% of the construction contracts have been awarded to date, with 85% being lump sum, ensuring greater cost certainty.

MARKETING

	Three Months Ended			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) [1]	**$ 102.98**	$ 98.61	$ 94.23	**$ 100.81**	$ 94.28
WCS blend differential from WTI (%) [2]	**19%**	24%	20%	**21%**	27%
SCO price (US$/bbl)	**$ 103.87**	$ 96.45	$ 99.10	**$ 100.18**	$ 97.18
Condensate benchmark pricing (US$/bbl)	**$ 105.15**	$ 102.53	$ 101.50	**$ 103.85**	$ 104.32
Average realized pricing before risk management (C$/bbl) [3]	**$ 87.03**	$ 79.68	$ 75.10	**$ 83.68**	$ 67.94
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 4.44**	$ 4.52	$ 3.41	**$ 4.48**	$ 3.16
Average realized pricing before risk management (C$/Mcf)	**$ 5.06**	$ 5.69	$ 4.05	**$ 5.32**	$ 3.78

(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					
April	$ 102.03	22%	$ (2.56)	$ 5.59	$ 1.91
May	$ 101.79	19%	$ 4.09	$ 7.82	$ 3.36
June	$ 105.15	18%	$ 1.03	$ 6.51	$ 1.20
July	$ 102.39	19%	$ (2.43)	$ 4.24	$ (3.30)
August*	$ 97.57	23%	$ (3.31)	$ 6.13	$ (4.29)
September*	$ 96.76	22%	$ (2.42)	$ 7.94	$ (2.72)

**Based on current indicative pricing as at August 1, 2014.*

- The Company crude oil and NGLs average realized pricing increased in Q2/14 over Q2/13 and Q1/14 levels due to strong benchmark pricing and narrow WCS differentials.
- The WCS differential averaged 19% during Q2/14 compared with 20% in Q2/13 and 24% in Q1/14. The WCS differential averaged 21% for the six months ended June 30, 2014, compared with 27% for the six months ended June 30, 2013. During Q2/14 the WCS differential tightened from Q1/14 reflecting normal seasonal variations and increased demand as a result of third party refinery expansions. The Company expects the WCS differential to continue to reflect seasonal demand fluctuations, changes in transportation logistics, and refinery utilization and shutdowns.
- Subsequent to Q2/14, the WCS differential averaged 19% in July 2014, and the indicative WCS differential for August 2014 is approximately 23% and September 2014 is approximately 22%.
- Canadian Natural contributed 183,000 bbl/d of its heavy crude oil stream to the WCS blend in Q2/14. The Company remains the largest contributor to the WCS blend, accounting for over 56% of the total blend this quarter.
- SCO pricing during Q2/14 increased 5% from Q2/13 due to increased benchmark pricing and 8% from Q1/14 due to planned third party upgrader turnarounds.

- During Q2/14, AECO natural gas prices increased 30% over Q2/13 levels and decreased 2% from Q1/14 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.

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 underway.

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 approximately 817,500 BOE/d for Q2/14 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 1.3x at June 30, 2014.
- Canadian Natural maintains significant financial stability and liquidity represented by bank credit facilities. As at June 30, 2014, the Company had in place bank credit facilities of $5,802 million, of which $2,225 million, net of commercial paper issuances of $534 million, was available.
- During Q2/14, 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.
- The Company's active commodity hedging program protects investment returns, ensures ongoing balance sheet strength and supports 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 8,165,000 common shares for cancellation at an average price of $45.59 per common share, which includes 2,700,000 common shares purchased subsequent to June 30, 2014 at a weighted average price of $48.76 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 October 1, 2014.

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. Q3/14 production guidance before royalties is forecast to average between 505,000 and 532,000 bbl/d of crude oil and NGLs and between 1,645 and 1,675 MMcf/d of natural gas. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

Forward-Looking Statements

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

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

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

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

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

Management’s Discussion and Analysis

This MD&A of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the three and six months ended June 30, 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 June 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 six months ended June 30, 2014 in relation to the comparable periods in 2013 and the first 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 August 6, 2014.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Product sales	**$ 6,113**	$ 4,968	$ 4,230	**$ 11,081**	$ 8,331
Net earnings	**$ 1,070**	$ 622	$ 476	**$ 1,692**	$ 689
Per common share – basic	**$ 0.98**	$ 0.57	$ 0.44	**$ 1.55**	$ 0.63
– diluted	**$ 0.97**	$ 0.57	$ 0.44	**$ 1.54**	$ 0.63
Adjusted net earnings from operations (1)	**$ 1,150**	$ 921	$ 462	**$ 2,071**	$ 863
Per common share – basic	**$ 1.05**	$ 0.85	$ 0.42	**$ 1.90**	$ 0.79
– diluted	**$ 1.04**	$ 0.85	$ 0.42	**$ 1.89**	$ 0.79
Cash flow from operations (2)	**$ 2,633**	$ 2,146	$ 1,670	**$ 4,779**	$ 3,241
Per common share – basic	**$ 2.41**	$ 1.97	$ 1.53	**$ 4.38**	$ 2.97
– diluted	**$ 2.39**	$ 1.97	$ 1.53	**$ 4.36**	$ 2.97
Capital expenditures, net of dispositions	**$ 5,456**	$ 1,893	$ 1,792	**$ 7,349**	$ 3,528

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

(2) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Cash Flow from Operations" presents certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations

	Three Months Ended			*Six Months Ended*	
($ millions)	***Jun 30 2014***	*Mar 31 2014*	*Jun 30 2013*	***Jun 30 2014***	*Jun 30 2013*
Net earnings as reported	***$ 1,070***	*$ 622*	*$ 476*	***$ 1,692***	*$ 689*
Share-based compensation, net of tax (1)	***189***	*143*	*(49)*	***332***	*22*
Unrealized risk management loss (gain), net of tax (2)	***44***	*38*	*(92)*	***82***	*(41)*
Unrealized foreign exchange (gain) loss, net of tax (3)	***(153)***	*118*	*112*	***(35)***	*190*
Realized foreign exchange gain on repayment of US dollar debt securities, net of tax (4)	**–**	*–*	*–*	**–**	*(12)*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (5)	**–**	*–*	*15*	**–**	*15*
Adjusted net earnings from operations	***$ 1,150***	*$ 921*	*$ 462*	***$ 2,071***	*$ 863*

(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) 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* ***Jun 30 2014***	*Mar 31 2014*	*Jun 30 2013*	*Six Months Ended* ***Jun 30 2014***	*Jun 30 2013*
Net earnings	***$ 1,070***	*$ 622*	*$ 476*	***$ 1,692***	*$ 689*
Non-cash items:					
Depletion, depreciation and amortization	***1,237***	*1,011*	*1,172*	***2,248***	*2,314*
Share-based compensation	***189***	*143*	*(49)*	***332***	*22*
Asset retirement obligation accretion	***50***	*45*	*42*	***95***	*84*
Unrealized risk management loss (gain)	***54***	*49*	*(114)*	***103***	*(52)*
Unrealized foreign exchange (gain) loss	***(153)***	*118*	*112*	***(35)***	*190*
Realized foreign exchange gain on repayment of US dollar debt securities	***–***	*–*	*–*	***–***	*(12)*
Equity (gain) loss from investment	***(3)***	*1*	*–*	***(2)***	*2*
Deferred income tax expense	***189***	*157*	*31*	***346***	*4*
Cash flow from operations	***$ 2,633***	*$ 2,146*	*$ 1,670*	***$ 4,779***	*$ 3,241*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the six months ended June 30, 2014 were $1,692 million compared with $689 million for the six months ended June 30, 2013. Net earnings for the six months ended June 30, 2014 included net after-tax expenses of $379 million compared with $174 million for the six months ended June 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, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the six months ended June 30, 2014 were $2,071 million compared with $863 million for the six months ended June 30, 2013.

Net earnings for the second quarter of 2014 were $1,070 million compared with $476 million for the second quarter of 2013 and $622 million for the first quarter of 2014. Net earnings for the second quarter of 2014 included net after-tax expenses of $80 million compared with net after-tax income of $14 million for the second quarter of 2013 and net after-tax expenses of $299 million for the first quarter of 2014 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, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the second quarter of 2014 were $1,150 million compared with $462 million for the second quarter of 2013 and $921 million for the first quarter of 2014.

The increase in adjusted net earnings for the three and six months ended June 30, 2014 from the comparable periods 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 Offshore Africa segment.

The increase in adjusted net earnings for the second quarter of 2014 from the first quarter of 2014 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 sales volumes in the Offshore Africa segment;
- higher crude oil and NGLs netbacks in the North America segment; and
- higher realized SCO prices;

partially offset by:

- lower natural gas netbacks in the North America segment;
- higher depletion, depreciation and amortization expense; and
- the impact of a stronger Canadian dollar relative to the US dollar.

The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates are expected to continue to contribute to 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 six months ended June 30, 2014 was $4,779 million compared with $3,241 million for the six months ended June 30, 2013. Cash flow from operations for the second quarter of 2014 was $2,633 million compared with $1,670 million for the second quarter of 2013 and $2,146 million for the first 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 depletion, depreciation and amortization expense, as well as due to the impact of cash taxes.

Total production before royalties for the six months ended June 30, 2014 increased 15% to 751,426 BOE/d from 651,921 BOE/d for the six months ended June 30, 2013. Total production before royalties for the second quarter of 2014 increased 31% to 817,471 BOE/d from 623,315 BOE/d for the second quarter of 2013 and increased 19% from 684,647 BOE/d for the first 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)		**Jun 30 2014**		Mar 31 2014		Dec 31 2013		Sep 30 2013
Product sales	**$**	**6,113**	$	4,968	$	4,330	$	5,284
Net earnings	**$**	**1,070**	$	622	$	413	$	1,168
Net earnings per common share								
– basic	**$**	**0.98**	$	0.57	$	0.38	$	1.07
– diluted	**$**	**0.97**	$	0.57	$	0.38	$	1.07

($ millions, except per common share amounts)		Jun 30 2013		Mar 31 2013		Dec 31 2012		Sep 30 2012
Product sales	$	4,230	$	4,101	$	4,059	$	3,978
Net earnings	$	476	$	213	$	352	$	360
Net earnings per common share								
– basic	$	0.44	$	0.19	$	0.32	$	0.33
– diluted	$	0.44	$	0.19	$	0.32	$	0.33

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, the impact of seasonal costs that are dependent on weather, production and 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 the 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			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
WTI benchmark price (US$/bbl)	**$ 102.98**	$ 98.61	$ 94.23	**$ 100.81**	$ 94.28
Dated Brent benchmark price (US$/bbl)	**$ 109.63**	$ 108.20	$ 102.44	**$ 108.92**	$ 107.41
WCS blend differential from WTI (US$/bbl)	**$ 20.03**	$ 23.27	$ 19.10	**$ 21.64**	$ 25.41
WCS blend differential from WTI (%)	**19%**	24%	20%	**21%**	27%
SCO price (US$/bbl)	**$ 103.87**	$ 96.45	$ 99.10	**$ 100.18**	$ 97.18
Condensate benchmark price (US$/bbl)	**$ 105.15**	$ 102.53	$ 101.50	**$ 103.85**	$ 104.32
NYMEX benchmark price (US$/MMBtu)	**$ 4.57**	$ 4.89	$ 4.09	**$ 4.73**	$ 3.72
AECO benchmark price (C$/GJ)	**$ 4.44**	$ 4.52	$ 3.41	**$ 4.48**	$ 3.16
US/Canadian dollar average exchange rate (US$)	**$ 0.9171**	$ 0.9064	$ 0.9774	**$ 0.9118**	$ 0.9844

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$100.81 per bbl for the six months ended June 30, 2014, an increase of 7% from US$94.28 per bbl for the six months ended June 30, 2013. WTI averaged US$102.98 per bbl for the second quarter of 2014, an increase of 9% from US$94.23 per bbl for the second quarter of 2013, and an increase of 4% from US$98.61 per bbl for the first quarter of 2014.

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$108.92 per bbl for the six months ended June 30, 2014 and was consistent with the comparative period. Brent averaged US$109.63 per bbl for the second quarter of 2014, an increase of 7% from US$102.44 per bbl for the second quarter of 2013, and was comparable with the first 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 three and six months ended June 30, 2014 from the comparable periods due to a continued debottlenecking of logistical constraints from Cushing to the US Gulf Coast.

The WCS Heavy Differential averaged 21% for the six months ended June 30, 2014, compared with 27% for the six months ended June 30, 2013. The WCS Heavy Differential averaged 19% for the second quarter of 2014, compared with 20% for the second quarter of 2013, and 24% for the first quarter of 2014. The WCS Heavy Differential for the second quarter of 2014 was comparable with the second quarter of 2013 and tightened from the first quarter of 2014 reflecting normal seasonal variations in addition to increased demand as a result of third party refinery expansions. In July 2014, the WCS Heavy Differential averaged US$19.66 per bbl. To partially mitigate its exposure to fluctuating heavy crude oil differentials, the Company has entered into physical crude oil sales contracts with weighted average fixed WCS differentials as follows: 10,000 bbl/d in the third quarter of 2014 at US$20.81 per bbl and 20,000 bbl/d in the fourth quarter of 2014 at 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: 16,000 bbl/d in the fourth quarter of 2014 at US$21.80 per bbl and 21,000 bbl/d in the first quarter of 2015 at US$21.71 per bbl.

The SCO price averaged US$100.18 per bbl for the six months ended June 30, 2014, an increase of 3% from US$97.18 per bbl for the six months ended June 30, 2013. The SCO price averaged US$103.87 per bbl for the second quarter of 2014, an increase of 5% from US$99.10 per bbl for the second quarter of 2013, and increased 8% from US$96.45 per bbl for the first quarter of 2014. The increase in SCO pricing for the three and six months ended June 30, 2014 from the comparable periods in 2013 was primarily due to an increase in WTI benchmark pricing. The increase in SCO pricing for the second quarter of 2014 from the first quarter of 2014 was due to planned third party upgrader turnarounds.

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

NYMEX natural gas prices averaged US$4.73 per MMBtu for the six months ended June 30, 2014, an increase of 27% from US$3.72 per MMBtu for the six months ended June 30, 2013. NYMEX natural gas prices averaged US$4.57 per MMBtu for the second quarter of 2014, an increase of 12% from US$4.09 per MMBtu for the second quarter of 2013, and a decrease of 7% from US$4.89 per MMBtu for the first quarter of 2014.

AECO natural gas prices for the six months ended June 30, 2014 averaged $4.48 per GJ, an increase of 42% from $3.16 per GJ for the six months ended June 30, 2013. AECO natural gas prices for the second quarter of 2014 averaged $4.44 per GJ, an increase of 30% from $3.41 per GJ for the second quarter of 2013, and a decrease of 2% from $4.52 per GJ for the first quarter of 2014.

Natural gas prices increased for the three and six months ended June 30, 2014 from the comparable periods in 2013 due to increased winter weather related natural gas demand. The colder than normal winter resulted in natural gas storage inventories falling to below five-year lows in the US and Canada as at June 30, 2014.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**400,154**	348,187	331,453	**374,314**	338,433
North America – Oil Sands Mining and Upgrading	**119,236**	113,095	67,954	**116,182**	88,255
North Sea	**12,615**	16,715	18,901	**14,654**	18,838
Offshore Africa	**13,164**	10,791	18,055	**11,984**	17,089
	545,169	488,788	436,363	**517,134**	462,615
Natural gas (MMcf/d)					
North America	**1,606**	1,147	1,092	**1,378**	1,108
North Sea	**5**	7	4	**6**	3
Offshore Africa	**23**	21	26	**22**	25
	1,634	1,175	1,122	**1,406**	1,136
Total barrels of oil equivalent (BOE/d)	**817,471**	684,647	623,315	**751,426**	651,921
Product mix					
Light and medium crude oil and NGLs	**15%**	15%	16%	**15%**	15%
Pelican Lake heavy crude oil	**6%**	7%	7%	**7%**	6%
Primary heavy crude oil	**17%**	20%	22%	**19%**	21%
Bitumen (thermal oil)	**14%**	12%	14%	**13%**	15%
Synthetic crude oil	**15%**	17%	11%	**15%**	14%
Natural gas	**33%**	29%	30%	**31%**	29%
Percentage of product sales (1) (excluding Midstream revenue)					
Crude oil and NGLs	**86%**	86%	88%	**86%**	89%
Natural gas	**14%**	14%	12%	**14%**	11%

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**318,672**	280,826	274,850	**299,854**	282,379
North America – Oil Sands Mining and Upgrading	**111,825**	106,891	65,077	**109,372**	84,532
North Sea	**12,581**	16,662	18,839	**14,610**	18,773
Offshore Africa	**12,733**	9,762	14,974	**11,256**	14,292
	455,811	414,141	373,740	**435,092**	399,976
Natural gas (MMcf/d)					
North America	**1,474**	1,017	1,016	**1,247**	1,054
North Sea	**5**	7	4	**6**	3
Offshore Africa	**19**	18	22	**19**	21
	1,498	1,042	1,042	**1,272**	1,078
Total barrels of oil equivalent (BOE/d)	**705,480**	587,737	547,330	**647,101**	579,600

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

Crude oil and NGLs production for the six months ended June 30, 2014 increased 12% to 517,134 bbl/d from 462,615 bbl/d for the six months ended June 30, 2013. Crude oil and NGLs production for the second quarter of 2014 increased 25% to 545,169 bbl/d from 436,363 bbl/d for the second quarter of 2013 and increased 12% from 488,788 bbl/d for the first quarter of 2014. The increase in production for the six months ended June 30, 2014 from the comparable period in 2013 was due to increased production in the North America segment, primarily related to the acquisitions of producing Canadian crude oil properties in the second quarter of 2014, the ramp up of production at Pelican Lake, the impact of a strong heavy crude oil drilling program, and the impact of strong and reliable production in Horizon, partially offset by lower international production. The increase in production for the second quarter of 2014 from the comparable periods was due to increased production in the North America segment, primarily related to the acquisitions of producing Canadian crude oil properties in the second quarter of 2014, the cyclic nature of the Company's thermal operations and the ramp up of production at Pelican Lake, as well as the impact of strong and reliable production in Horizon, partially offset by lower international production. Crude oil and NGLs production in the second quarter of 2014 was within the Company's previously issued guidance of 519,000 to 546,000 bbl/d.

Natural gas production for the six months ended June 30, 2014 increased 24% to 1,406 MMcf/d from 1,136 MMcf/d for the six months ended June 30, 2013. Natural gas production for the second quarter of 2014 increased 46% to 1,634 MMcf/d from 1,122 MMcf/d for the second quarter of 2013 and increased 39% from 1,175 MMcf/d for the first quarter of 2014. The increase in natural gas production for the three and six months ended June 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, the completion of the Septimus drilling program and plant facility expansion in the third quarter of 2013, as well as the completion of minor acquisitions during 2013. The increase in natural gas production for the second quarter of 2014 from the first quarter of 2014 was primarily a result of the acquisitions of producing Canadian natural gas properties in the second quarter of 2014. Natural gas production in the second quarter of 2014 was within the Company's previously issued guidance of 1,620 to 1,660 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. Third quarter 2014 production guidance is targeted to average between 505,000 and 532,000 bbl/d of crude oil and NGLs and between 1,645 and 1,675 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the six months ended June 30, 2014 increased 11% to average 374,314 bbl/d from 338,433 bbl/d for the six months ended June 30, 2013. For the second quarter of 2014, crude oil and NGLs production increased 21% to average 400,154 bbl/d compared with 331,453 bbl/d for the second quarter of 2013 and increased 15% from 348,187 bbl/d for the first quarter of 2014. The increase in production for the six months ended June 30, 2014 from the comparable period in 2013 was due to increased production primarily related to the acquisitions of producing Canadian crude oil properties in the second quarter of 2014, 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 second quarter of 2014 from the comparable periods was primarily related to the acquisitions of producing Canadian crude oil properties in the second quarter of 2014, the ramp up of production at Pelican Lake, and the cyclic nature of the Company's thermal operations and production at Kirby South. Second quarter 2014 production of crude oil and NGLs exceeded the Company's previously issued guidance of 378,000 to 396,000 bbl/d. Third quarter 2014 production guidance is targeted to average between 393,000 and 410,000 bbl/d for crude oil and NGLs.

Natural gas production for the six months ended June 30, 2014 increased 24% to 1,378 MMcf/d compared with 1,108 MMcf/d for the six months ended June 30, 2013. Natural gas production increased 47% to 1,606 MMcf/d for the second quarter of 2014 compared with 1,092 MMcf/d in the second quarter of 2013 and increased 40% from 1,147 MMcf/d for the first quarter of 2014. The increase in natural gas production for the three and six months ended June 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, the completion of the Septimus drilling program and plant facility expansion in the third quarter of 2013, as well as the completion of minor acquisitions during 2013. The increase in natural gas production for the second quarter of 2014 from the first quarter of 2014 was primarily a result of the acquisitions of producing Canadian natural gas properties in the second quarter of 2014.

North America – Oil Sands Mining and Upgrading

Production averaged 116,182 bbl/d for the six months ended June 30, 2014 compared with 88,255 bbl/d for the six months ended June 30, 2013. For the second quarter of 2014, SCO production increased 75% to 119,236 bbl/d from 67,954 bbl/d for the second quarter of 2013 and increased 5% from 113,095 bbl/d for the first quarter of 2014. Production increased for the three and six months ended June 30, 2014 from the comparable periods due to increased plant reliability. Second quarter 2014 production of SCO exceeded the Company's previously issued guidance of 114,000 to 119,000 bbl/d. Third quarter 2014 production guidance is targeted to average between 82,000 and 89,000 bbl/d, reflecting the impact of a planned plant-wide shutdown of approximately 25 days in order to complete the coker expansion tie-ins.

North Sea

North Sea crude oil production for the six months ended June 30, 2014 decreased 22% to 14,654 bbl/d from 18,838 bbl/d for the six months ended June 30, 2013. Second quarter 2014 crude oil production decreased 33% to 12,615 bbl/d from 18,901 bbl/d for the second quarter of 2013, and decreased 25% from 16,715 bbl/d for the first quarter of 2014. The decrease in production for the three and six months ended June 30, 2014 from the comparable periods in 2013 was primarily due to unplanned downtime on the Tiffany platform in the second quarter of 2014, the cessation of production of approximately 1,300 bbl/d due to the planned decommissioning of the Murchison platform, and natural field declines in other North Sea fields, partially mitigated by a modest drilling program at the Ninian field supported by Brownfield Allowances. The decrease in production for the second quarter of 2014 from the first quarter of 2014 was primarily due to unplanned downtime on the Tiffany platform. The production impact of the Tiffany platform outage was approximately 4,500 bbl/d. Turnaround activities, planned for 25 days and originally scheduled for the third quarter of 2014, were advanced and completed during the downtime. As a result of a temporary shutdown of a third party pipeline in late July 2014, production at the Tiffany platform is not expected to be reinstated until mid-August 2014.

In December 2011, the Banff Floating Production, Storage and Offloading Vessel ("FPSO") and subsea infrastructure suffered storm damage. Operations at Banff/Kyle, with combined net production of approximately 3,500 bbl/d, were suspended. The FPSO has returned to the field and production is currently being reinstated in a controlled manner.

Offshore Africa

Offshore Africa crude oil production decreased 30% to 11,984 bbl/d for the six months ended June 30, 2014 from 17,089 bbl/d for the six months ended June 30, 2013. Second quarter 2014 crude oil production averaged 13,164 bbl/d, decreasing 27% from 18,055 bbl/d for the second quarter of 2013 and increasing 22% from 10,791 bbl/d for the first quarter of 2014. The decrease in production volumes for the six months ended June 30, 2014 from the comparable period in 2013 was due to a temporary shut in of the Baobab field beginning in December 2013 due to a FPSO mooring line failure and natural field declines. Turnaround activities were advanced into this timeframe and production in the Baobab field was reinstated in late January 2014. The Company successfully completed the permanent repairs on the mooring lines in March 2014. The increase in production volumes for the second quarter of 2014 from the first quarter of 2014 was due to the reinstatement of production at Baobab. The decrease in production volumes for the three months ended June 30, 2014 from the comparable period in 2013 was due to natural declines.

International Guidance

The Company's North Sea and Offshore Africa second quarter 2014 crude oil production was 25,779 bbl/d and was below the Company's previously issued guidance of 27,000 to 31,000 bbl/d as a result of the unplanned downtime on the Tiffany platform. The production impact of the Tiffany outage was approximately 4,500 bbl/d. Third quarter 2014 production guidance is targeted to average between 30,000 and 33,000 bbl/d of crude oil.

Crude Oil Inventory Volumes

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

(bbl)	**Jun 30 2014**	Mar 31 2014	Dec 31 2013
North America – Exploration and Production	**1,564,600**	1,069,537	830,673
North America – Oil Sands Mining and Upgrading (SCO)	**1,525,103**	1,693,887	1,550,857
North Sea	**–**	311,457	385,073
Offshore Africa	**1,077,144**	1,156,700	185,476
	4,166,847	4,231,581	2,952,079

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 87.03**	$ 79.68	$ 75.10	**$ 83.68**	$ 67.94
Transportation	**2.74**	2.49	2.32	**2.62**	2.34
Realized sales price, net of transportation	**84.29**	77.19	72.78	**81.06**	65.60
Royalties	**15.62**	14.05	11.60	**14.90**	10.17
Production expense	**19.33**	19.18	16.51	**19.26**	17.04
Netback	**$ 49.34**	$ 43.96	$ 44.67	**$ 46.90**	$ 38.39
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 5.06**	$ 5.69	$ 4.05	**$ 5.32**	$ 3.78
Transportation	**0.26**	0.30	0.29	**0.28**	0.29
Realized sales price, net of transportation	**4.80**	5.39	3.76	**5.04**	3.49
Royalties	**0.41**	0.62	0.28	**0.49**	0.20
Production expense	**1.52**	1.61	1.41	**1.56**	1.48
Netback	**$ 2.87**	$ 3.16	$ 2.07	**$ 2.99**	$ 1.81
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 64.69**	$ 63.14	$ 58.49	**$ 64.00**	$ 53.16
Transportation	**2.35**	2.29	2.18	**2.32**	2.20
Realized sales price, net of transportation	**62.34**	60.85	56.31	**61.68**	50.96
Royalties	**10.49**	10.42	8.29	**10.46**	7.16
Production expense	**15.35**	15.82	13.81	**15.56**	14.28
Netback	**$ 36.50**	$ 34.61	$ 34.21	**$ 35.66**	$ 29.52

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 84.10**	$ 77.54	$ 71.81	**$ 81.06**	$ 63.66
North Sea	**$ 122.88**	$ 121.38	$ 104.47	**$ 122.17**	$ 109.05
Offshore Africa	**$ 119.47**	$ –	$ 107.71	**$ 119.47**	$ 110.70
Company average	**$ 87.03**	$ 79.68	$ 75.10	**$ 83.68**	$ 67.94
Natural gas ($/Mcf) (1) (2)					
North America	**$ 4.95**	$ 5.56	$ 3.90	**$ 5.21**	$ 3.63
North Sea	**$ 6.38**	$ 6.05	$ 7.03	**$ 6.19**	$ 6.15
Offshore Africa	**$ 12.25**	$ 12.18	$ 10.02	**$ 12.22**	$ 10.13
Company average	**$ 5.06**	$ 5.69	$ 4.05	**$ 5.32**	$ 3.78
Company average ($/BOE) (1) (2)	**$ 64.69**	$ 63.14	$ 58.49	**$ 64.00**	$ 53.16

(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 27% to average $81.06 per bbl for the six months ended June 30, 2014 from $63.66 per bbl for the six months ended June 30, 2013. North America realized crude oil prices averaged $84.10 per bbl for the second quarter of 2014, an increase of 17% compared with $71.81 per bbl for the second quarter of 2013 and an increase of 8% compared with $77.54 per bbl for the first quarter of 2014. The increase in realized crude oil prices for the three and six months ended June 30, 2014 from the comparable periods in 2013 was due to higher WTI benchmark pricing, tightening WCS Heavy Differentials and the impact of a weaker Canadian dollar relative to the US dollar. The increase in realized crude oil prices for the second quarter of 2014 from the first quarter of 2014 was due to higher WTI benchmark pricing and tightening WCS Heavy Differentials, partially offset by the impact of a stronger Canadian dollar relative to the US dollar. The Company continues to focus on its crude oil blending marketing strategy and in the second quarter of 2014 contributed approximately 183,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 44% to average $5.21 per Mcf for the six months ended June 30, 2014 from $3.63 per Mcf for the six months ended June 30, 2013. North America realized natural gas prices increased 27% to average $4.95 per Mcf for the second quarter of 2014 compared with $3.90 per Mcf in the second quarter of 2013, and decreased 11% compared with $5.56 per Mcf for the first quarter of 2014. The increase in realized natural gas prices for the three and six months ended June 30, 2014 from the comparable periods in 2013 was primarily due to increased winter weather related natural gas demand resulting in natural gas storage inventories falling to below five-year lows in the US and Canada as at June 30, 2014. The decrease in realized natural gas prices for the second quarter of 2014 from the first quarter of 2014 was primarily due to lower AECO benchmark pricing related to seasonality.

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

(Quarterly Average)		**Jun 30 2014**		Mar 31 2014		Jun 30 2013
Wellhead Price (1) (2)						
Light and medium crude oil and NGLs ($/bbl)	**$**	**85.95**	$	83.57	$	78.15
Pelican Lake heavy crude oil ($/bbl)	**$**	**86.92**	$	79.94	$	75.17
Primary heavy crude oil ($/bbl)	**$**	**85.65**	$	77.78	$	71.75
Bitumen (thermal oil) ($/bbl)	**$**	**79.39**	$	69.73	$	65.99
Natural gas ($/Mcf)	**$**	**4.95**	$	5.56	$	3.90

(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 12% to average $122.17 per bbl for the six months ended June 30, 2014 from $109.05 per bbl for the six months ended June 30, 2013. Realized crude oil prices increased 18% to average $122.88 per bbl for the second quarter of 2014 from $104.47 per bbl for the second quarter of 2013 and were comparable with the first quarter of 2014. The fluctuations in realized crude oil prices for the three and six months ended June 30, 2014 from the comparable periods in 2013 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 increased 8% to average $119.47 per bbl for the six months ended June 30, 2014 from $110.70 per bbl for the six months ended June 30, 2013. Realized crude oil prices increased 11% to average $119.47 per bbl for the second quarter of 2014 from $107.71 per bbl for the second quarter of 2013. The increase in realized crude oil prices for the three and six months ended June 30, 2014 from the comparable periods in 2013 reflected movements in Brent benchmark pricing, the timing of liftings, and the weakening of the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 16.79**	$ 14.75	$ 11.81	**$ 15.85**	$ 10.21
North Sea	**$ 0.33**	$ 0.38	$ 0.34	**$ 0.35**	$ 0.37
Offshore Africa	**$ 3.92**	$ –	$ 18.38	**$ 3.92**	$ 18.05
Company average	**$ 15.62**	$ 14.05	$ 11.60	**$ 14.90**	$ 10.17
Natural gas ($/Mcf) [1]					
North America	**$ 0.39**	$ 0.60	$ 0.25	**$ 0.47**	$ 0.17
Offshore Africa	**$ 1.89**	$ 2.06	$ 1.68	**$ 1.97**	$ 1.63
Company average	**$ 0.41**	$ 0.62	$ 0.28	**$ 0.49**	$ 0.20
Company average ($/BOE) [1]	**$ 10.49**	$ 10.42	$ 8.29	**$ 10.46**	$ 7.16

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

Crude oil and NGLs royalties averaged approximately 21% of product sales for the second quarter of 2014 compared with 17% for the second quarter of 2013 and 20% for the first quarter of 2014. The increase in royalties in the second quarter of 2014 from the comparable periods was primarily due to the increase 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 8% of product sales for the second quarter of 2014 compared with 7% for the second quarter of 2013 and 11% for the first quarter of 2014. The decrease in natural gas royalty rates in the second quarter of 2014 from the first 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 5% for the second quarter of 2014 compared with 17% for the second quarter of 2013. The decrease in royalties from the second quarter of 2013 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			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 14.97**	$ 16.31	$ 14.83	**$ 15.59**	$ 14.72
North Sea	**$ 79.21**	$ 75.51	$ 47.85	**$ 77.46**	$ 60.38
Offshore Africa	**$ 58.41**	$ –	$ 17.98	**$ 58.41**	$ 21.84
Company average	**$ 19.33**	$ 19.18	$ 16.51	**$ 19.26**	$ 17.04
Natural gas ($/Mcf) (1)					
North America	**$ 1.48**	$ 1.54	$ 1.38	**$ 1.51**	$ 1.45
North Sea	**$ 6.12**	$ 5.83	$ 3.53	**$ 5.95**	$ 3.59
Offshore Africa	**$ 3.28**	$ 3.64	$ 2.34	**$ 3.45**	$ 2.30
Company average	**$ 1.52**	$ 1.61	$ 1.41	**$ 1.56**	$ 1.48
Company average ($/BOE) (1)	**$ 15.35**	$ 15.82	$ 13.81	**$ 15.56**	$ 14.28

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

North America

North America crude oil and NGLs production expense for the six months ended June 30, 2014 increased 6% to $15.59 per bbl from $14.72 per bbl for the six months ended June 30, 2013. North America crude oil and NGLs production expense for the second quarter of 2014 averaged $14.97 per bbl, comparable with the second quarter of 2013 and decreased 8% from $16.31 per bbl for the first quarter of 2014. The increase in production expense for the three and six months ended June 30, 2014 from the comparable periods in 2013 was primarily the result of higher energy costs across heavy crude oil and thermal areas, together with higher servicing costs related to heavy crude oil production. The decrease in production expense for the second quarter of 2014 from the first quarter of 2014 was primarily the result of higher production volumes partially related to the acquisitions of producing Canadian crude oil properties in the second quarter of 2014, the cyclic timing of thermal oil production and lower energy costs. 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 six months ended June 30, 2014 increased 4% to $1.51 per Mcf from $1.45 per Mcf for the six months ended June 30, 2013. North America natural gas production expense for the second quarter of 2014 increased 7% to $1.48 per Mcf from $1.38 per Mcf for the second quarter of 2013 and decreased 4% from $1.54 per Mcf for the first quarter of 2014. Natural gas production expense increased for the three and six months ended June 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 have higher operating costs per Mcf than the Company's existing properties. These costs are expected to decline once the acquisitions are fully integrated into the Company's operations. Natural gas production expense decreased for the second quarter of 2014 from the first quarter of 2014 due to normal seasonality, partially offset by the impact of the acquisitions of producing Canadian natural gas properties in the second quarter of 2014 that have higher operating costs per Mcf than the Company's existing 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 six months ended June 30, 2014 increased 28% to $77.46 per bbl from $60.38 per bbl for the six months ended June 30, 2013. North Sea crude oil production expense for the second quarter of 2014 increased 66% to $79.21 per bbl from $47.85 per bbl for the second quarter of 2013 and increased 5% from $75.51 per bbl for the first quarter of 2014. Production expense increased on a per barrel basis for the three and six months ended June 30, 2014 from the comparable periods in 2013 due to production declines on relatively fixed costs from the Tiffany platform and other North Sea fields, the impact of the cessation of production from the Murchison platform in the first quarter of 2014, and the impact of a weaker Canadian dollar. Production expense increased on a per barrel basis for the second quarter of 2014 from the first quarter of 2014 primarily due to the impact of lower production, including from the Tiffany platform. 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 is currently being reinstated in a controlled manner.

Offshore Africa

Offshore Africa crude oil production expense for the six months ended June 30, 2014 increased 167% to $58.41 per bbl from $21.84 per bbl for the six months ended June 30, 2013. Offshore Africa crude oil production expense for the second quarter of 2014 averaged $58.41 per bbl, an increase of 225% from $17.98 per bbl for the second quarter of 2013. Production expense increased for the three and six months ended June 30, 2014 from the comparable periods in 2013 as a result of the timing of liftings from various fields, which have different cost structures. 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			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Expense ($ millions)	**$ 1,099**	$ 879	$ 1,009	**$ 1,978**	$ 2,032
$/BOE (1)	**$ 17.28**	$ 17.55	$ 19.97	**$ 17.40**	$ 19.98

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

Depletion, depreciation and amortization expense for the three and six months ended June 30, 2014 fluctuated from the comparable periods in 2013 as the impact of higher sales volumes in North America in 2014 was offset by the impact of higher depletion, depreciation and amortization expense in the North Sea in 2013 due to the planned cessation of production from the Murchison field. Depletion, depreciation and amortization expense increased for the second quarter of 2014 from the first quarter of 2014 due to higher sales volumes in North America.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Expense ($ millions)	**$ 39**	$ 33	$ 33	**$ 72**	$ 67
$/BOE (1)	**$ 0.59**	$ 0.67	$ 0.65	**$ 0.63**	$ 0.65

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

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

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

During the second quarter of 2014 the Company continued to focus on reliable and efficient operations, leading to production of 119,236 bbl/d, above stated guidance. In August 2014, Horizon will enter into a planned plant-wide shutdown of approximately 25 days in order to complete the coker expansion tie-ins. The impact 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

($/bbl) [1]	Three Months Ended Jun 30 2014	Mar 31 2014	Jun 30 2013	Six Months Ended Jun 30 2014	Jun 30 2013
SCO sales price	**$ 112.69**	$ 107.82	$ 99.63	**$ 110.37**	$ 97.58
Bitumen value for royalty purposes [2]	**$ 75.72**	$ 66.27	$ 61.08	**$ 71.24**	$ 60.71
Bitumen royalties [3]	**$ 6.77**	$ 5.06	$ 4.41	**$ 5.95**	$ 4.05
Transportation	**$ 1.53**	$ 1.96	$ 1.72	**$ 1.73**	$ 1.64

(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 $110.37 per bbl for the six months ended June 30, 2014, an increase of 13% compared with $97.58 per bbl for six months ended June 30, 2013. Realized SCO sales prices averaged $112.69 per bbl for the second quarter of 2014, an increase of 13% compared with $99.63 per bbl for the second quarter of 2013 and an increase of 5% compared with $107.82 per bbl for the first 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.

($ millions)	Three Months Ended Jun 30 2014	Mar 31 2014	Jun 30 2013	Six Months Ended Jun 30 2014	Jun 30 2013
Cash production costs	**$ 404**	$ 412	$ 394	**$ 816**	$ 771
Less: costs incurred during turnaround periods	**–**	–	(104)	**–**	(104)
Adjusted cash production costs	**$ 404**	$ 412	$ 290	**$ 816**	$ 667
Adjusted cash production costs, excluding natural gas costs	**$ 372**	$ 375	$ 268	**$ 747**	$ 617
Adjusted natural gas costs	**32**	37	22	**69**	50
Adjusted cash production costs	**$ 404**	$ 412	$ 290	**$ 816**	$ 667

($/bbl) [1]	Three Months Ended Jun 30 2014	Mar 31 2014	Jun 30 2013	Six Months Ended Jun 30 2014	Jun 30 2013
Adjusted cash production costs, excluding natural gas costs	**$ 33.76**	$ 37.39	$ 41.53	**$ 35.50**	$ 38.81
Adjusted natural gas costs	**2.85**	3.72	3.41	**3.26**	3.15
Adjusted cash production costs	**$ 36.61**	$ 41.11	$ 44.94	**$ 38.76**	$ 41.96
Sales (bbl/d) [2]	**121,091**	111,506	70,950	**116,325**	87,881

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

Adjusted cash production costs averaged $38.76 per bbl for the six months ended June 30, 2014, a decrease of 8% compared with $41.96 per bbl for the six months ended June 30, 2013. Adjusted cash production costs for the second quarter of 2014 averaged $36.61 per bbl, a decrease of 19% compared with $44.94 per bbl for the second quarter of 2013 and a decrease of 11% compared with $41.11 per bbl for the first quarter of 2014 primarily reflecting increased plant reliability and the corresponding impact of higher production volumes on a relatively fixed cost structure. 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

($ millions, except per bbl amounts)	Three Months Ended **Jun 30 2014**	Mar 31 2014	Jun 30 2013	Six Months Ended **Jun 30 2014**	Jun 30 2013
Depletion, depreciation and amortization	**$ 135**	$ 130	$ 161	**$ 265**	$ 278
Less: depreciation incurred during turnaround periods	**–**	–	(79)	**–**	(79)
Adjusted depletion, depreciation and amortization	**$ 135**	$ 130	$ 82	**$ 265**	$ 199
$/bbl [1]	**$ 12.27**	$ 12.95	$ 12.70	**$ 12.59**	$ 12.49

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

Depletion, depreciation and amortization expense reflected the impact of fluctuations in sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended **Jun 30 2014**	Mar 31 2014	Jun 30 2013	Six Months Ended **Jun 30 2014**	Jun 30 2013
Expense ($ millions)	**$ 11**	$ 12	$ 9	**$ 23**	$ 17
$/bbl [1]	**$ 1.07**	$ 1.17	$ 1.32	**$ 1.12**	$ 1.07

(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 **Jun 30 2014**	Mar 31 2014	Jun 30 2013	Six Months Ended **Jun 30 2014**	Jun 30 2013
Revenue	**$ 30**	$ 31	$ 29	**$ 61**	$ 56
Production expense	**10**	9	9	**19**	17
Midstream cash flow	**20**	22	20	**42**	39
Depreciation	**3**	2	2	**5**	4
Equity (gain) loss from investment	**(3)**	1	–	**(2)**	2
Segment earnings before taxes	**$ 20**	$ 19	$ 18	**$ 39**	$ 33

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 June 30, 2014, Redwater Partnership had interim borrowings of $1,076 million under the syndicated credit facility.

Subsequent to June 30, 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			Six Months Ended	
	Jun 30 2014	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Expense ($ millions)	**$ 90**	$ 90	$ 81	**$ 180**	$ 160
$/BOE (1)	**$ 1.21**	$ 1.49	$ 1.43	**$ 1.34**	$ 1.36

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

Administration expense for the three and six months ended June 30, 2014 increased from the comparable periods in 2013 primarily due to higher staffing and general corporate costs.

SHARE-BASED COMPENSATION

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2014**	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Expense (recovery)	**$ 189**	$ 143	$ (49)	**$ 332**	$ 22

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 $332 million share-based compensation expense for the six months ended June 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 six months ended June 30, 2014, the Company capitalized $63 million of share-based compensation expense to property, plant and equipment in the Oil Sands Mining and Upgrading segment (June 30, 2013 – $5 million expense).

For the six months ended June 30, 2014, the Company paid $6 million for stock options surrendered for cash settlement (June 30, 2013 – $1 million).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2014**	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Expense, gross	**$ 136**	$ 115	$ 112	**$ 251**	$ 225
Less: capitalized interest	**44**	47	40	**91**	76
Expense, net	**$ 92**	$ 68	$ 72	**$ 160**	$ 149
$/BOE [(1)]	**$ 1.24**	$ 1.13	$ 1.26	**$ 1.19**	$ 1.27
Average effective interest rate	**3.9%**	4.3%	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 six months ended June 30, 2014 increased from the comparable periods primarily due to the impact of higher overall debt levels. Capitalized interest of $91 million for the six months ended June 30, 2014 was primarily related to the Horizon Phase 2/3 expansion.

The Company's average effective interest rate for three and six months ended June 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 as well as the repayment of $400 million of 4.50% medium-term notes and US$400 million of 5.15% notes during the first quarter of 2013. The Company's average effective interest rate for the second quarter of 2014 decreased from the first quarter of 2014 primarily due to an increase in the utilization of the lower cost credit facilities related to the acquisition of certain producing Canadian crude oil and natural gas properties in the second quarter of 2014.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2014**	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Natural gas financial instruments	**$ 12**	$ –	$ –	**$ 12**	$ –
Foreign currency contracts	**45**	(75)	(19)	**(30)**	(102)
Realized loss (gain)	**57**	(75)	(19)	**(18)**	(102)
Crude oil and NGLs financial instruments	**49**	(3)	(54)	**46**	(30)
Natural gas financial instruments	**(24)**	45	–	**21**	–
Foreign currency contracts	**29**	7	(60)	**36**	(22)
Unrealized loss (gain)	**54**	49	(114)	**103**	(52)
Net loss (gain)	**$ 111**	$ (26)	$ (133)	**$ 85**	$ (154)

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

The Company recorded a net unrealized loss of $103 million ($82 million after-tax) on its risk management activities for the six months ended June 30, 2014, including an unrealized loss of $54 million ($44 million after-tax) for the second quarter of 2014 (March 31, 2014 – unrealized loss of $49 million; $38 million after-tax; June 30, 2013 – unrealized gain of $114 million; $92 million after-tax).

FOREIGN EXCHANGE

($ millions)	Three Months Ended Jun 30 2014	Mar 31 2014	Jun 30 2013	Six Months Ended Jun 30 2014	Jun 30 2013
Net realized loss (gain)	**$ 31**	$ (1)	$ 1	**$ 30**	$ (31)
Net unrealized (gain) loss (1)	**(153)**	118	112	**(35)**	190
Net (gain) loss	**$ (122)**	$ 117	$ 113	**$ (5)**	$ 159

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

The net realized foreign exchange loss for the six months ended June 30, 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 gain for the six months ended June 30, 2014 reflects the revaluation of US dollar debt. The net unrealized (gain) loss for each of the periods presented included the impact of cross currency swaps (three months ended June 30, 2014 – unrealized loss of $109 million, March 31, 2014 – unrealized gain of $100 million, June 30, 2013 – unrealized gain of $86 million; six months ended June 30, 2014 – unrealized loss of $9 million; June 30, 2013 – unrealized gain of $135 million). The US/Canadian dollar exchange rate at June 30, 2014 was US$0.9367 (March 31, 2014 – US$0.9047; December 31, 2013 – US$0.9402; June 30, 2013 – US$0.9513).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Jun 30 2014	Mar 31 2014	Jun 30 2013	Six Months Ended Jun 30 2014	Jun 30 2013
North America (1)	**$ 225**	$ 192	$ 111	**$ 417**	$ 233
North Sea	**(44)**	(15)	25	**(59)**	18
Offshore Africa	**10**	4	36	**14**	71
PRT (recovery) expense – North Sea	**(12)**	(61)	(33)	**(73)**	(46)
Other taxes	**6**	6	6	**12**	10
Current income tax expense	**185**	126	145	**311**	286
Deferred income tax expense	**178**	91	44	**269**	40
Deferred PRT expense (recovery) – North Sea	**11**	66	(13)	**77**	(36)
Deferred income tax expense	**189**	157	31	**346**	4
	$ 374	$ 283	$ 176	**$ 657**	$ 290
Income tax rate and other legislative changes (2)	**–**	–	(15)	**–**	(15)
	$ 374	283	$ 161	**$ 657**	$ 275
Effective income tax rate on adjusted net earnings from operations (3)	**24.8%**	23.5%	27.9%	**24.2%**	28.0%

(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.

For 2014, based on forward commodity prices and the current availability of tax pools, the Company expects to incur current income tax expense of $850 million to $950 million in Canada and recoveries of $170 million to $190 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Jun 30 2014	Three Months Ended Mar 31 2014	Three Months Ended Jun 30 2013	Six Months Ended Jun 30 2014	Six Months Ended Jun 30 2013
Exploration and Evaluation					
Net expenditures	**$ 884**	$ 117	$ 10	**$ 1,001**	$ 87
Property, Plant and Equipment					
Net property acquisitions	**2,746**	(4)	–	**2,742**	11
Well drilling, completion and equipping	**441**	641	419	**1,082**	974
Production and related facilities	**429**	415	466	**844**	1,003
Capitalized interest and other [2]	**21**	23	29	**44**	57
Net expenditures	**3,637**	1,075	914	**4,712**	2,045
Total Exploration and Production	**4,521**	1,192	924	**5,713**	2,132
Oil Sands Mining and Upgrading					
Horizon Phase 2/3 construction costs	**649**	444	555	**1,093**	910
Sustaining capital	**87**	60	158	**147**	209
Turnaround costs	**4**	2	80	**6**	97
Capitalized interest and other [2]	**84**	73	22	**157**	60
Total Oil Sands Mining and Upgrading	**824**	579	815	**1,403**	1,276
Midstream	**26**	25	4	**51**	9
Abandonments [3]	**76**	87	37	**163**	92
Head office	**9**	10	12	**19**	19
Total net capital expenditures	**$ 5,456**	$ 1,893	$ 1,792	**$ 7,349**	$ 3,528
By segment					
North America	**$ 4,387**	$ 1,087	$ 826	**$ 5,474**	$ 1,919
North Sea	**107**	88	62	**195**	147
Offshore Africa	**27**	17	36	**44**	66
Oil Sands Mining and Upgrading	**824**	579	815	**1,403**	1,276
Midstream	**26**	25	4	**51**	9
Abandonments [3]	**76**	87	37	**163**	92
Head office	**9**	10	12	**19**	19
Total	**$ 5,456**	$ 1,893	$ 1,792	**$ 7,349**	$ 3,528

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.
(2) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.
(3) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

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

Net capital expenditures for the six months ended June 30, 2014 were $7,349 million compared with $3,528 million for the six months ended June 30, 2013. Net capital expenditures for the second quarter of 2014 were $5,456 million compared with $1,792 million for the second quarter of 2013 and $1,893 million for the first quarter of 2014.

The increase in capital expenditures for the three and six months ended June 30, 2014 from the comparable periods 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 second quarter of 2014 from the first quarter of 2014 was primarily due to the acquisition of certain Canadian crude oil and natural gas properties in the second quarter of 2014 and increased Horizon Phase 2/3 site construction activity, offset by lower well drilling, completion and equipping activities.

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 six months ended June 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 $468 million.

Drilling Activity

	Three Months Ended			Six Months Ended	
(number of wells)	**Jun 30 2014**	Mar 31 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Net successful natural gas wells	**13**	25	8	**38**	23
Net successful crude oil wells [(1)]	**154**	271	159	**425**	459
Dry wells	**2**	3	5	**5**	10
Stratigraphic test / service wells	**22**	330	16	**352**	321
Total	**191**	629	188	**820**	813
Success rate (excluding stratigraphic test / service wells)	**99%**	99%	97%	**99%**	98%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 77% of the total capital expenditures for the six months ended June 30, 2014 compared with approximately 57% for the six months ended June 30, 2013.

During the second quarter of 2014, the Company targeted 13 net natural gas wells, including 9 wells in Northeast British Columbia and 4 wells in Northwest Alberta. The Company also targeted 154 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 122 primary heavy crude oil wells, 16 Pelican Lake heavy crude oil wells, 3 bitumen (thermal oil) wells and 1 light crude oil well were drilled. Another 12 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for the second quarter of 2014 averaged approximately 114,400 bbl/d compared with approximately 90,000 bbl/d for the second quarter of 2013 and approximately 82,000 bbl/d for the first 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 16 horizontal wells were drilled during the second quarter of 2014. Pelican Lake production averaged approximately 49,600 bbl/d for the second quarter of 2014 compared with 41,700 bbl/d for the second quarter of 2013 and 48,000 bbl/d for the first 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 third quarter of 2014, the Company's overall planned drilling activity in North America is expected to be 247 net crude oil wells, 4 net bitumen wells and 14 net natural gas wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

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

North Sea

The Company commenced drilling in the Ninian field late in the fourth quarter of 2013 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. This 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 to commence in the latter half 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, the operator commenced drilling an exploratory well in the third quarter of 2014.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Jun 30 2014**	Mar 31 2014	Dec 31 2013	Jun 30 2013
Working capital deficit [1]	**$ 991**	$ 1,025	$ 1,574	$ 948
Long-term debt [2] [3]	**$ 13,437**	$ 10,354	$ 9,661	$ 10,033
Share capital	**$ 4,321**	$ 4,100	$ 3,854	$ 3,736
Retained earnings	**22,856**	22,193	21,876	20,748
Accumulated other comprehensive income	**46**	44	42	67
Shareholders' equity	**$ 27,223**	$ 26,337	$ 25,772	$ 24,551
Debt to book capitalization [3] [4]	**33%**	28%	27%	29%
Debt to market capitalization [3] [5]	**20%**	18%	20%	24%
After-tax return on average common shareholders' equity [6]	**13%**	11%	9%	6%
After-tax return on average capital employed [3] [7]	**10%**	8%	7%	5%

(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 June 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 June 30, 2014, the Company had in place bank credit facilities of $5,802 million, of which $2,225 million, net of commercial paper issuances of $534 million, was available. Credit facilities at June 30, 2014 included a $1,000 million non-revolving term credit facility 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 June 30, 2014, the Company had maturities of long-term debt aggregating $1,310 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 $13,437 million at June 30, 2014, resulting in a debt to book capitalization ratio of 33% (March 31, 2014 – 28%; December 31, 2013 – 27%; June 30, 2013 – 29%). 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 June 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 August 5, 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 has also entered into physical crude oil sales contracts as follows: 10,000 bbl/d in the third quarter of 2014 and 20,000 bbl/d in the fourth quarter of 2014. In addition, the Company has entered into crude oil WCS differential swaps as follows: 16,000 bbl/d in the fourth quarter of 2014 and 21,000 bbl/d in the first quarter of 2015. An additional 500,000 MMBtu/d of natural gas volumes were hedged for July 2014 to October 2014 using AECO basis swaps and 200,000 GJ/d of natural gas volumes were hedged for July 2014 to December 2014 using price collars. Further details related to the Company's commodity derivative financial instruments outstanding at June 30, 2014 are discussed in note 14 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at June 30, 2014, there were 1,093,554,000 common shares outstanding (December 31, 2013 – 1,087,322,000 common shares) and 65,991,000 stock options outstanding. As at August 5, 2014, the Company had 1,092,103,000 common shares outstanding and 64,169,000 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 six months ended June 30, 2014, the Company purchased for cancellation 5,465,000 common shares at a weighted average price of $44.02 per common share, for a total cost of $241 million. Retained earnings were reduced by $220 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2014, the Company purchased 2,700,000 common shares at a weighted average price of $48.76 per common share for a total cost of $132 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 June 30, 2014:

($ millions)	Remaining 2014	2015	2016	2017	2018	Thereafter
Product transportation and pipeline	$ 220	$ 411	$ 311	$ 277	$ 242	$ 1,625
Offshore equipment operating leases and offshore drilling	$ 124	$ 258	$ 81	$ 61	$ 55	$ 17
Long-term debt (1)	$ 1,441	$ 400	$ 2,625	$ 2,294	$ 427	$ 6,324
Interest and other financing expense (2)	$ 271	$ 505	$ 461	$ 381	$ 322	$ 4,039
Office leases	$ 20	$ 46	$ 46	$ 49	$ 51	$ 346
Other	$ 166	$ 191	$ 107	$ 30	$ 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 June 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 six months ended June 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	Jun 30 2014	Dec 31 2013
ASSETS			
Current assets			
Cash and cash equivalents		**$ 31**	$ 16
Accounts receivable		**1,992**	1,427
Current income taxes		**5**	–
Inventory		**789**	632
Prepaids and other		**277**	141
		3,094	2,216
Exploration and evaluation assets	4	**3,526**	2,609
Property, plant and equipment	5	**50,862**	46,487
Other long-term assets	6	**507**	442
		$ 57,989	$ 51,754
LIABILITIES			
Current liabilities			
Accounts payable		**$ 581**	$ 637
Accrued liabilities		**2,928**	2,519
Current income taxes		**–**	359
Current portion of long-term debt	7	**1,844**	1,444
Current portion of other long-term liabilities	8	**576**	275
		5,929	5,234
Long-term debt	7	**11,593**	8,217
Other long-term liabilities	8	**4,714**	4,348
Deferred income taxes		**8,530**	8,183
		30,766	25,982
SHAREHOLDERS' EQUITY			
Share capital	10	**4,321**	3,854
Retained earnings		**22,856**	21,876
Accumulated other comprehensive income	11	**46**	42
		27,223	25,772
		$ 57,989	$ 51,754

Commitments and contingencies (note 15).

Approved by the Board of Directors on August 6, 2014

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Jun 30 2014**	Three Months Ended Jun 30 2013	Six Months Ended **Jun 30 2014**	Six Months Ended Jun 30 2013
Product sales		**$ 6,113**	$ 4,230	**$ 11,081**	$ 8,331
Less: royalties		**(742)**	(446)	**(1,314)**	(792)
Revenue		**5,371**	3,784	**9,767**	7,539
Expenses					
Production		**1,388**	1,096	**2,599**	2,231
Transportation and blending		**895**	738	**1,726**	1,593
Depletion, depreciation and amortization	5	**1,237**	1,172	**2,248**	2,314
Administration		**90**	81	**180**	160
Share-based compensation	8	**189**	(49)	**332**	22
Asset retirement obligation accretion	8	**50**	42	**95**	84
Interest and other financing expense		**92**	72	**160**	149
Risk management activities	14	**111**	(133)	**85**	(154)
Foreign exchange (gain) loss		**(122)**	113	**(5)**	159
Equity (gain) loss from investment	6	**(3)**	–	**(2)**	2
		3,927	3,132	**7,418**	6,560
Earnings before taxes		**1,444**	652	**2,349**	979
Current income tax expense	9	**185**	145	**311**	286
Deferred income tax expense	9	**189**	31	**346**	4
Net earnings		**$ 1,070**	$ 476	**$ 1,692**	$ 689
Net earnings per common share					
Basic	13	**$ 0.98**	$ 0.44	**$ 1.55**	$ 0.63
Diluted	13	**$ 0.97**	$ 0.44	**$ 1.54**	$ 0.63

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended **Jun 30 2014**	Three Months Ended Jun 30 2013	Six Months Ended **Jun 30 2014**	Six Months Ended Jun 30 2013
Net earnings	**$ 1,070**	$ 476	**$ 1,692**	$ 689
Items that may be reclassified subsequently to net earnings				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income during the period, net of taxes of $nil (2013 – $1 million) – three months ended; $nil (2013 – $3 million) – six months ended	**–**	6	**1**	22
Reclassification to net earnings, net of taxes of $nil (2013 – $nil) – three months ended; $nil (2013 – $nil) – six months ended	**1**	(1)	**4**	(2)
	1	5	**5**	20
Foreign currency translation adjustment				
Translation of net investment	**1**	(6)	**(1)**	(11)
Other comprehensive income (loss), net of taxes	**2**	(1)	**4**	9
Comprehensive income	**$ 1,072**	$ 475	**$ 1,696**	$ 698

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Six Months Ended Jun 30 2014	Jun 30 2013
Share capital	10		
Balance – beginning of period		**$ 3,854**	$ 3,709
Issued upon exercise of stock options		**385**	39
Previously recognized liability on stock options exercised for common shares		**103**	11
Purchase of common shares under Normal Course Issuer Bid		**(21)**	(23)
Balance – end of period		**4,321**	3,736
Retained earnings			
Balance – beginning of period		**21,876**	20,516
Net earnings		**1,692**	689
Purchase of common shares under Normal Course Issuer Bid	10	**(220)**	(184)
Dividends on common shares	10	**(492)**	(273)
Balance – end of period		**22,856**	20,748
Accumulated other comprehensive income	11		
Balance – beginning of period		**42**	58
Other comprehensive income, net of taxes		**4**	9
Balance – end of period		**46**	67
Shareholders' equity		**$ 27,223**	$ 24,551

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Three Months Ended Jun 30 2014	Three Months Ended Jun 30 2013	Six Months Ended Jun 30 2014	Six Months Ended Jun 30 2013
Operating activities				
Net earnings	**$ 1,070**	$ 476	**$ 1,692**	$ 689
Non-cash items				
Depletion, depreciation and amortization	**1,237**	1,172	**2,248**	2,314
Share-based compensation	**189**	(49)	**332**	22
Asset retirement obligation accretion	**50**	42	**95**	84
Unrealized risk management loss (gain)	**54**	(114)	**103**	(52)
Unrealized foreign exchange (gain) loss	**(153)**	112	**(35)**	190
Realized foreign exchange gain on repayment of US dollar debt securities	**–**	–	**–**	(12)
Equity (gain) loss from investment	**(3)**	–	**(2)**	2
Deferred income tax expense	**189**	31	**346**	4
Other	**20**	18	**51**	56
Abandonment expenditures	**(76)**	(37)	**(163)**	(92)
Net change in non-cash working capital	**(120)**	87	**(857)**	(302)
	2,457	1,738	**3,810**	2,903
Financing activities				
Issue (repayment) of bank credit facilities and commercial paper, net	**2,369**	(5)	**1,708**	1,251
Issue of medium-term notes, net	**992**	498	**992**	98
Issue (repayment) of US dollar debt securities, net	**–**	–	**1,100**	(398)
Issue of common shares on exercise of stock options	**190**	9	**385**	39
Purchase of common shares under Normal Course Issuer Bid	**(176)**	(175)	**(241)**	(207)
Dividends on common shares	**(246)**	(136)	**(463)**	(251)
Net change in non-cash working capital	**(6)**	(5)	**(11)**	(11)
	3,123	186	**3,470**	521
Investing activities				
Net expenditures on exploration and evaluation assets	**(884)**	(10)	**(1,001)**	(87)
Net expenditures on property, plant and equipment	**(4,496)**	(1,745)	**(6,185)**	(3,349)
Investment in other long-term assets	**(113)**	–	**(113)**	–
Net change in non-cash working capital	**(75)**	(170)	**34**	(8)
	(5,568)	(1,925)	**(7,265)**	(3,444)
Increase (decrease) in cash and cash equivalents	**12**	(1)	**15**	(20)
Cash and cash equivalents – beginning of period	**19**	18	**16**	37
Cash and cash equivalents – end of period	**$ 31**	$ 17	**$ 31**	$ 17
Interest paid	**$ 110**	$ 97	**$ 245**	$ 239
Income taxes paid	**$ 147**	$ 71	**$ 602**	$ 284

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.

Subsequent to June 30, 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	**968**	**–**	**33**	**–**	**1,001**
Transfers to property, plant and equipment	**(84)**	**–**	**–**	**–**	**(84)**
Foreign exchange adjustments	**–**	**–**	**–**	**–**	**–**
At June 30, 2014	**$ 3,454**	**$ –**	**$ 72**	**$ –**	**$ 3,526**

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	**4,852**	**195**	**11**	**1,403**	**51**	**19**	**6,531**
Transfers from E&E assets	**84**	**–**	**–**	**–**	**–**	**–**	**84**
Disposals/derecognitions	**(143)**	**–**	**–**	**(45)**	**–**	**(1)**	**(189)**
Foreign exchange adjustments and other	**–**	**14**	**12**	**–**	**–**	**–**	**26**
At June 30, 2014	**$ 58,603**	**$ 5,409**	**$ 3,379**	**$ 20,724**	**$ 559**	**$ 326**	**$ 89,000**
Accumulated depletion and depreciation							
At December 31, 2013	$ 28,315	$ 3,467	$ 2,551	$ 1,414	$ 111	$ 203	$ 36,061
Expense	**1,812**	**121**	**33**	**265**	**5**	**12**	**2,248**
Disposals/derecognitions	**(143)**	**–**	**–**	**(45)**	**–**	**(1)**	**(189)**
Foreign exchange adjustments and other	**12**	**(15)**	**23**	**(2)**	**–**	**–**	**18**
At June 30, 2014	**$ 29,996**	**$ 3,573**	**$ 2,607**	**$ 1,632**	**$ 116**	**$ 214**	**$ 38,138**
Net book value							
– at June 30, 2014	**$ 28,607**	**$ 1,836**	**$ 772**	**$ 19,092**	**$ 443**	**$ 112**	**$ 50,862**
– at December 31, 2013	$ 25,495	$ 1,733	$ 805	$ 17,952	$ 397	$ 105	$ 46,487

Project costs not subject to depletion and depreciation	**Jun 30 2014**	Dec 31 2013
Horizon	**$ 5,298**	$ 4,051
Kirby Thermal Oil Sands	**$ 449**	$ 1,532

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 six months ended June 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 total cash consideration of $468 million (year ended December 31, 2013 – $252 million), together with associated asset retirement obligations of $38 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 six months ended June 30, 2014, pre-tax interest of $91 million (June 30, 2013 – $76 million) was capitalized to property, plant and equipment using a capitalization rate of 4.0% (June 30, 2013 – 4.4%).

6. OTHER LONG-TERM ASSETS

		Jun 30 2014		Dec 31 2013
Investment in North West Redwater Partnership	**$**	**308**	$	306
North West Redwater Partnership subordinated debt		**115**		–
Other		**84**		136
	$	**507**	$	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 June 30, 2014, Redwater Partnership had interim borrowings of $1,076 million under the syndicated credit facility.

Subsequent to June 30, 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

	Jun 30 2014	Dec 31 2013
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ 2,944**	$ 1,246
Medium-term notes	**2,400**	1,400
	5,344	2,646
US dollar denominated debt, unsecured		
Commercial paper (June 30, 2014 – US$500 million; December 31, 2013 – US$500 million)	**534**	532
US dollar debt securities (June 30, 2014 – US$7,150 million; December 31, 2013 – US$6,150 million)	**7,633**	6,541
Less: original issue discount on US dollar debt securities (1)	**(20)**	(18)
	8,147	7,055
Fair value impact of interest rate swaps on US dollar debt securities (2)	**4**	9
	8,151	7,064
Long-term debt before transaction costs	**13,495**	9,710
Less: transaction costs (1) (3)	**(58)**	(49)
	13,437	9,661
Less: current portion of commercial paper	**534**	532
current portion of other long-term debt (1) (2) (3)	**1,310**	912
	$ 11,593	$ 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 $4 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 June 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 June 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 June 30, 2014 was 2.1% (June 30, 2013 – 2.1%), and on long-term debt outstanding for the six months ended June 30, 2014 was 4.0% (June 30, 2013 – 4.4%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $421 million, including a $46 million financial guarantee related to Horizon and $261 million of letters of credit related to North Sea operations, were outstanding at June 30, 2014. Subsequent to June 30, 2014, the financial guarantee related to Horizon was reduced to $43 million.

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

	Jun 30 2014	Dec 31 2013
Asset retirement obligations	**$ 4,396**	$ 4,162
Share-based compensation	**546**	260
Risk management (note 14)	**253**	136
Other	**95**	65
	5,290	4,623
Less: current portion	**576**	275
	$ 4,714	$ 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:

	Jun 30 2014	Dec 31 2013
Balance – beginning of period	**$ 4,162**	$ 4,266
Liabilities incurred	**17**	62
Liabilities acquired	**280**	131
Liabilities settled	**(163)**	(207)
Asset retirement obligation accretion	**95**	171
Revision of estimates	**–**	375
Change in discount rate	**–**	(723)
Foreign exchange adjustments	**5**	87
Balance – end of period	**$ 4,396**	$ 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.

	Jun 30 2014	Dec 31 2013
Balance – beginning of period	**$ 260**	$ 154
Share-based compensation expense	**332**	135
Cash payment for stock options surrendered	**(6)**	(4)
Transferred to common shares	**(103)**	(50)
Capitalized to Oil Sands Mining and Upgrading	**63**	25
Balance – end of period	**546**	260
Less: current portion	**398**	216
	$ 148	$ 44

9. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Current corporate income tax – North America	**$ 225**	$ 111	**$ 417**	$ 233
Current corporate income tax – North Sea	**(44)**	25	**(59)**	18
Current corporate income tax – Offshore Africa	**10**	36	**14**	71
Current PRT (1) recovery – North Sea	**(12)**	(33)	**(73)**	(46)
Other taxes	**6**	6	**12**	10
Current income tax expense	**185**	145	**311**	286
Deferred corporate income tax expense	**178**	44	**269**	40
Deferred PRT (1) expense (recovery) – North Sea	**11**	(13)	**77**	(36)
Deferred income tax expense	**189**	31	**346**	4
Income tax expense	**$ 374**	$ 176	**$ 657**	$ 290

(1) Petroleum Revenue Tax.

10. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Six Months Ended Jun 30, 2014		
Issued common shares	**Number of shares** (thousands)		**Amount**
Balance – beginning of period	**1,087,322**	**$**	**3,854**
Issued upon exercise of stock options	**11,697**		**385**
Previously recognized liability on stock options exercised for common shares	**–**		**103**
Purchase of common shares under Normal Course Issuer Bid	**(5,465)**		**(21)**
Balance – end of period	**1,093,554**	**$**	**4,321**

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 six months ended June 30, 2014, the Company purchased for cancellation 5,465,000 common shares at a weighted average price of $44.02 per common share, for a total cost of $241 million. Retained earnings were reduced by $220 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2014, the Company purchased 2,700,000 common shares at a weighted average price of $48.76 per common share for a total cost of $132 million.

Stock Options

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

	Six Months Ended Jun 30, 2014		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**72,741**	**$**	**34.36**
Granted	**8,039**	**$**	**40.62**
Surrendered for cash settlement	**(760)**	**$**	**32.88**
Exercised for common shares	**(11,697)**	**$**	**32.93**
Forfeited	**(2,332)**	**$**	**35.60**
Outstanding – end of period	**65,991**	**$**	**35.35**
Exercisable – end of period	**15,875**	**$**	**37.02**

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:

	Jun 30 2014	Jun 30 2013
Derivative financial instruments designated as cash flow hedges	**$ 86**	$ 106
Foreign currency translation adjustment	**(40)**	(39)
	$ 46	$ 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 June 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.

	Jun 30 2014	Dec 31 2013
Long-term debt (1)	**$ 13,437**	$ 9,661
Total shareholders' equity	**$ 27,223**	$ 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		Six Months Ended	
	Jun 30 2014	Jun 30 2013	**Jun 30 2014**	Jun 30 2013
Weighted average common shares outstanding – basic (thousands of shares)	**1,093,522**	1,089,302	**1,091,719**	1,090,858
Effect of dilutive stock options (thousands of shares)	**9,452**	1,719	**5,447**	1,896
Weighted average common shares outstanding – diluted (thousands of shares)	**1,102,974**	1,091,021	**1,097,166**	1,092,754
Net earnings	**$ 1,070**	$ 476	**$ 1,692**	$ 689
Net earnings per common share – basic	**$ 0.98**	$ 0.44	**$ 1.55**	$ 0.63
– diluted	**$ 0.97**	$ 0.44	**$ 1.54**	$ 0.63

14. FINANCIAL INSTRUMENTS

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

	Jun 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	**$ 1,992**	**$ –**	**$ –**	**$ –**	**$ 1,992**
Accounts payable	**–**	**–**	**–**	**(581)**	**(581)**
Accrued liabilities	**–**	**–**	**–**	**(2,928)**	**(2,928)**
Other long-term liabilities	**–**	**(134)**	**(119)**	**(45)**	**(298)**
Long-term debt (1)	**–**	**–**	**–**	**(13,437)**	**(13,437)**
	$ 1,992	**$ (134)**	**$ (119)**	**$ (16,991)**	**$ (15,252)**

	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 liabilities and fixed rate long-term debt were outlined below:

	Jun 30, 2014		
	Carrying amount	**Fair value**	
Asset (liability) (1) (5)		**Level 1**	**Level 2**
Other long-term liabilities	**$ (253)**	**$ –**	**$ (253)**
Fixed rate long-term debt (2) (3) (4)	**(9,959)**	**(11,163)**	**–**
	$ (10,212)	**$ (11,163)**	**$ (253)**

	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 $4 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)	Jun 30, 2014	Dec 31, 2013
Derivatives held for trading		
Crude oil price collars	**$ (81)**	$ (33)
Crude oil WCS differential swaps	**2**	–
Foreign currency forward contracts	**(31)**	(3)
Natural gas AECO basis swaps	**(17)**	(1)
Natural gas AECO put options, net of put premium financing obligations	**(9)**	(2)
Natural gas price collars	**2**	–
Cash flow hedges		
Foreign currency forward contracts	**(11)**	(1)
Cross currency swaps	**(108)**	(96)
	$ (253)	$ (136)
Included within:		
Current portion of other long-term liabilities	**$ (133)**	$ (38)
Other long-term liabilities	**(120)**	(98)
	$ (253)	$ (136)

For the six months ended June 30, 2014, the Company recognized a loss of $8 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 liability were recognized in the financial statements as follows:

Asset (liability)		**Six Months Ended Jun 30, 2014**		Year Ended Dec 31, 2013
Balance – beginning of period	**$**	**(136)**	$	(257)
Cost of outstanding put options		**9**		9
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**(103)**		(39)
Foreign exchange		**(19)**		165
Other comprehensive income		**5**		(5)
		(244)		(127)
Add: put premium financing obligations [1]		**(9)**		(9)
Balance – end of period		**(253)**		(136)
Less: current portion		**(133)**		(38)
	$	**(120)**	$	(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				Six Months Ended			
		Jun 30 2014		Jun 30 2013		**Jun 30 2014**		Jun 30 2013
Net realized risk management loss (gain)	**$**	**57**	$	(19)	**$**	**(18)**	$	(102)
Net unrealized risk management loss (gain)		**54**		(114)		**103**		(52)
	$	**111**	$	(133)	**$**	**85**	$	(154)

Financial Risk Factors

a) Market risk

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

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At June 30, 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	Jul 2014	–	Sep 2014	50,000 bbl/d	US$80.00	–	US$122.09	Brent
	Jul 2014	–	Dec 2014	50,000 bbl/d	US$75.00	–	US$121.57	Brent
	Jul 2014	–	Dec 2014	50,000 bbl/d	US$80.00	–	US$120.17	Brent
	Jul 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
	Jul 2014	–	Sep 2014	25,000 bbl/d	US$90.00	–	US$110.88	WTI
	Jul 2014	–	Dec 2014	50,000 bbl/d	US$75.00	–	US$105.54	WTI
	Jul 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 (1) differential swaps (2)	Oct 2014	–	Dec 2014	6,000 bbl/d			US$20.32	WCS (1)
	Jan 2015	–	Mar 2015	11,000 bbl/d			US$20.74	WCS (1)

(1) Western Canadian Select.
(2) Subsequent to June 30, 2014, the Company entered into an additional 10,000 bbl/d of US$22.69 WCS differential swaps for the period October 2014 to December 2014 and 10,000 bbl/d of US$22.78 WCS differential swaps for the period January 2015 to March 2015.

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

The cost of outstanding put options and their respective periods of settlement as at June 30, 2014 were as follows:

	Q3 2014	Q4 2014
Cost	$7	$2

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At June 30, 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 June 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	Jul 2014	–	Mar 2016	US$500	1.109	Three-month LIBOR plus 0.375%	Three-month CDOR [1] plus 0.309%
	Jul 2014	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Jul 2014	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Jul 2014	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Jul 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 June 30, 2014, were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at June 30, 2014, the Company had US$2,137 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 June 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 June 30, 2014, the Company had no net risk management assets 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	$	581	$	–	$	–	$	–
Accrued liabilities	$	2,928	$	–	$	–	$	–
Risk management	$	133	$	79	$	35	$	6
Other long-term liabilities	$	45	$	–	$	–	$	–
Long-term debt (1)	$	1,841	$	2,358	$	3,488	$	5,824

(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	$	220	$	411	$	311	$	277	$	242	$	1,625
Offshore equipment operating leases and offshore drilling	$	124	$	258	$	81	$	61	$	55	$	17
Office leases	$	20	$	46	$	46	$	49	$	51	$	346
Other	$	166	$	191	$	107	$	30	$	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

	Exploration and Production															
	North America				North Sea				Offshore Africa				Total Exploration and Production			
(millions of Canadian dollars, unaudited)	Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2014	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Segmented product sales	**4,463**	3,189	**8,120**	5,997	**226**	187	**424**	364	**172**	206	**196**	414	**4,861**	3,582	**8,740**	6,775
Less: royalties	**(659)**	(384)	**(1,175)**	(660)	–	–	**(1)**	(1)	**(9)**	(34)	**(13)**	(67)	**(668)**	(418)	**(1,189)**	(728)
Segmented revenue	**3,804**	2,805	**6,945**	5,337	**226**	187	**423**	363	**163**	172	**183**	347	**4,193**	3,164	**7,551**	6,047
Segmented expenses																
Production	**752**	588	**1,415**	1,193	**143**	75	**266**	177	**81**	36	**88**	83	**976**	699	**1,769**	1,453
Transportation and blending	**897**	735	**1,725**	1,590	**1**	1	**3**	3	–	1	–	1	**898**	737	**1,728**	1,594
Depletion, depreciation and amortization	**1,006**	855	**1,822**	1,726	**65**	114	**123**	226	**28**	40	**33**	80	**1,099**	1,009	**1,978**	2,032
Asset retirement obligation accretion	**26**	23	**48**	46	**10**	8	**19**	17	**3**	2	**5**	4	**39**	33	**72**	67
Realized risk management activities	**57**	(19)	**(18)**	(102)	–	–	–	–	–	–	–	–	**57**	(19)	**(18)**	(102)
Equity (gain) loss from investment	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Total segmented expenses	**2,738**	2,182	**4,992**	4,453	**219**	198	**411**	423	**112**	79	**126**	168	**3,069**	2,459	**5,529**	5,044
Segmented earnings (loss) before the following	**1,066**	623	**1,953**	884	**7**	(11)	**12**	(60)	**51**	93	**57**	179	**1,124**	705	**2,022**	1,003
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Unrealized risk management activities																
Foreign exchange (gain) loss																
Total non-segmented expenses																
Earnings 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 Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2014	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Segmented product sales	**1,241**	643	**2,323**	1,552	**30**	29	**61**	56	**(19)**	(24)	**(43)**	(52)	**6,113**	4,230	**11,081**	8,331
Less: royalties	**(74)**	(28)	**(125)**	(64)	**–**	–	**–**	–	**–**	–	**–**	–	**(742)**	(446)	**(1,314)**	(792)
Segmented revenue	**1,167**	615	**2,198**	1,488	**30**	29	**61**	56	**(19)**	(24)	**(43)**	(52)	**5,371**	3,784	**9,767**	7,539
Segmented expenses																
Production	**404**	394	**816**	771	**10**	9	**19**	17	**(2)**	(6)	**(5)**	(10)	**1,388**	1,096	**2,599**	2,231
Transportation and blending	**17**	18	**37**	33	**–**	–	**–**	–	**(20)**	(17)	**(39)**	(34)	**895**	738	**1,726**	1,593
Depletion, depreciation and amortization	**135**	161	**265**	278	**3**	2	**5**	4	**–**	–	**–**	–	**1,237**	1,172	**2,248**	2,314
Asset retirement obligation accretion	**11**	9	**23**	17	**–**	–	**–**	–	**–**	–	**–**	–	**50**	42	**95**	84
Realized risk management activities	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**57**	(19)	**(18)**	(102)
Equity (gain) loss from investment	**–**	–	**–**	–	**(3)**	–	**(2)**	2	**–**	–	**–**	–	**(3)**	–	**(2)**	2
Total segmented expenses	**567**	582	**1,141**	1,099	**10**	11	**22**	23	**(22)**	(23)	**(44)**	(44)	**3,624**	3,029	**6,648**	6,122
Segmented earnings (loss) before the following	**600**	33	**1,057**	389	**20**	18	**39**	33	**3**	(1)	**1**	(8)	**1,747**	755	**3,119**	1,417
Non-segmented expenses																
Administration													**90**	81	**180**	160
Share-based compensation													**189**	(49)	**332**	22
Interest and other financing expense													**92**	72	**160**	149
Unrealized risk management activities													**54**	(114)	**103**	(52)
Foreign exchange (gain) loss													**(122)**	113	**(5)**	159
Total non-segmented expenses													**303**	103	**770**	438
Earnings before taxes													**1,444**	652	**2,349**	979
Current income tax expense													**185**	145	**311**	286
Deferred income tax expense													**189**	31	**346**	4
Net earnings													**1,070**	476	**1,692**	689

Capital Expenditures [1]

	Six Months Ended					
	Jun 30, 2014			Jun 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	**$ 968**	**$ (84)**	**$ 884**	$ 80	$ (45)	$ 35
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa	**33**	**–**	**33**	7	–	7
	$ 1,001	**$ (84)**	**$ 917**	$ 87	$ (45)	$ 42
Property, plant and equipment						
Exploration and Production						
North America	**$ 4,506**	**$ 287**	**$ 4,793**	$ 1,839	$ (48)	$ 1,791
North Sea	**195**	**–**	**195**	147	–	147
Offshore Africa	**11**	**–**	**11**	59	–	59
	4,712	**287**	**4,999**	2,045	(48)	1,997
Oil Sands Mining and Upgrading [3]	**1,403**	**(45)**	**1,358**	1,276	(317)	959
Midstream	**51**	**–**	**51**	9	–	9
Head office	**19**	**(1)**	**18**	19	–	19
	$ 6,185	**$ 241**	**$ 6,426**	$ 3,349	$ (365)	$ 2,984

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

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

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

Segmented Assets

	Total Assets	
	Jun 30 2014	Dec 31 2013
Exploration and Production		
North America	**$ 33,712**	$ 29,234
North Sea	**2,220**	1,964
Offshore Africa	**893**	981
Other	**35**	25
Oil Sands Mining and Upgrading	**19,878**	18,604
Midstream	**1,139**	841
Head office	**112**	105
	$ 57,989	$ 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 June 30, 2014:	
Interest coverage (times)	
Net earnings [(1)]	9.9x
Cash flow from operations [(2)]	21.1x

(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, August 7, 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, August 14, 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 25456329

WEBCAST

The conference call will also be broadcast live on the internet and may be accessed through the Canadian Natural website at www.cnrl.com.

For further information, please contact:

CANADIAN NATURAL RESOURCES LIMITED
2100, 855 - 2nd Street S.W.
Calgary, Alberta
T2P 4J8

Telephone: (403) 514-7777
Facsimile: (403) 514-7888
Email: ir@cnrl.com
Website: www.cnrl.com

Trading Symbol - CNQ
Toronto Stock Exchange
New York Stock Exchange

STEVE W. LAUT
President

COREY B. BIEBER
Chief Financial Officer &
Senior Vice-President, Finance

DOUGLAS A. PROLL
Executive Vice-President