SECOND QUARTER REPORT

SIX MONTHS ENDED JUNE 30, 2013

TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2013 SECOND QUARTER RESULTS

“Canadian Natural achieved in the second quarter of 2013 strong quarterly production from our balanced and diverse asset base,” commented Steve Laut, President of Canadian Natural. “On a per barrel of oil equivalent basis, our overall Exploration and Production operating costs decreased from last quarter resulting in excellent overall netbacks. This, along with strong WTI benchmark pricing, tighter WCS to WTI differentials and better natural gas pricing helped the Company generate solid cash flow in the quarter.

At Kirby South, we are in the final stages of commissioning. Steam injection is expected to commence in late August or early September 2013, approximately three months ahead of the original schedule. Project costs remain within our targeted budget. By the fourth quarter of 2014, thermal in situ production at Kirby South is targeted to grow to 40,000 bbl/d.

Horizon reliability continues to improve after the completion of our first major maintenance turnaround of the plant in May 2013. We continue to achieve safe, steady and reliable operations. In June and July 2013, synthetic crude oil production was 101,000 bbl/d and 110,000 bbl/d, respectively.

During the second quarter, our North America Exploration and Production crude oil and NGL assets, excluding thermal in situ oil sands, achieved record quarterly production of approximately 241,000 bbl/d. These volumes were driven by record quarterly production at our primary heavy crude oil and Pelican Lake operations. This quarter marks the tenth consecutive quarter that our heavy crude oil assets have achieved record production and demonstrates the strong performance ability of the Pelican Lake pool.

As we move into the third quarter of 2013, we expect production volumes to grow in the quarter. Higher production volumes from thermal in situ operations, increased reliability at Horizon Oil Sands Mining operations and continued strong production performance from all other operating areas of the Company are anticipated. We will continue to operate efficiently and effectively to ensure industry competitive operating costs.”

Corey Bieber, Canadian Natural’s Chief Financial Officer, stated, “We are in an excellent position to realize strong cash flow metrics over the last half of 2013. Midpoint guidance for crude oil production in Q3/13 reflects an increase of approximately 19% over Q2/13 volumes. Furthermore, heavy oil differentials have narrowed as expected. At the same time, benchmark North American crude oil pricing has increased and condensate premium costs have reduced. We target very robust netbacks in the last half of 2013, which ultimately results in debt levels reflective of 2012, making our balance sheet even stronger, despite substantial capital investments of approximately $2.075 billion in the calendar year of 2013 on the Horizon Project Phase 2/3 expansion.”

QUARTERLY HIGHLIGHTS

($ Millions, except per common share amounts)	Three Months Ended **Jun 30 2013**	Three Months Ended Mar 31 2013	Three Months Ended Jun 30 2012	Six Months Ended **Jun 30 2013**	Six Months Ended Jun 30 2012
Net earnings	**$ 476**	$ 213	$ 753	**$ 689**	$ 1,180
Per common share – basic	**$ 0.44**	$ 0.19	$ 0.68	**$ 0.63**	$ 1.07
– diluted	**$ 0.44**	$ 0.19	$ 0.68	**$ 0.63**	$ 1.07
Adjusted net earnings from operations (1)	**$ 462**	$ 401	$ 606	**$ 863**	$ 906
Per common share – basic	**$ 0.42**	$ 0.37	$ 0.55	**$ 0.79**	$ 0.82
– diluted	**$ 0.42**	$ 0.37	$ 0.55	**$ 0.79**	$ 0.82
Cash flow from operations (2)	**$ 1,670**	$ 1,571	$ 1,754	**$ 3,241**	$ 3,034
Per common share – basic	**$ 1.53**	$ 1.44	$ 1.60	**$ 2.97**	$ 2.76
– diluted	**$ 1.53**	$ 1.44	$ 1.59	**$ 2.97**	$ 2.75
Capital expenditures, net of dispositions	**$ 1,792**	$ 1,736	$ 1,324	**$ 3,528**	$ 2,920
Daily production, before royalties					
Natural gas (MMcf/d)	**1,122**	1,150	1,255	**1,136**	1,277
Crude oil and NGLs (bbl/d)	**436,363**	489,157	470,523	**462,615**	432,993
Equivalent production (BOE/d) (3)	**623,315**	680,844	679,607	**651,921**	645,943

(1) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").

(2) Cash flow from operations is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and debt repayment. The derivation of this measure is discussed in the MD&A.

(3) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

- Canadian Natural generated cash flow from operations of approximately $1.67 billion in Q2/13 compared to approximately $1.57 billion in Q1/13 and approximately $1.75 billion in Q2/12. The increase from Q1/13 reflects higher crude oil and NGLs and natural gas netbacks and higher realized synthetic crude oil ("SCO") pricing partially offset by lower crude oil and SCO sales volumes in the North America and Oil Sands Mining and Upgrading segments. The cash flow variance from Q2/12 reflects higher crude oil and NGLs sales volumes, higher natural gas netbacks, higher realized SCO pricing and the impact of a weaker Canadian dollar offset by expected lower SCO sales volumes in the Oil Sands Mining and Upgrading segment and expected lower natural gas sales volumes.
- Adjusted net earnings from operations in Q2/13 were $462 million compared to $401 million in Q1/13 and $606 million in Q2/12. Changes in adjusted net earnings primarily reflect the changes in cash flow from operations.
- Total production for Q2/13 averaged 623,315 BOE/d, within the Company's previously announced corporate guidance, which ranged from 617,000 BOE/d to 646,000 BOE/d. As expected, production volumes varied from Q2/12 and Q1/13 levels primarily as a result of expected lower volumes in the Oil Sands Mining and Upgrading segment due to the Company's first major maintenance turnaround at Horizon Oil Sands ("Horizon") and in the Thermal In Situ Oil Sands segment due to production cycle timing.
- In Q2/13, primary heavy crude oil operations achieved record quarterly production of approximately 136,000 bbl/d, representing the Company's tenth consecutive quarter of record primary heavy crude oil production. Primary heavy crude oil production increased 2% and 11% from Q1/13 and Q2/12, respectively. The Company expects continued strong performance from its primary heavy crude oil assets during the second half of 2013, which are targeted to deliver a 13% production increase over 2012 levels.

- In mid-May 2013, facility constraints at Pelican Lake were alleviated with the completion of a new battery. Both Pelican Lake and Woodenhouse production volumes ramped up soon afterward. In Q2/13, Pelican Lake operations achieved record quarterly production volumes of approximately 42,000 bbl/d, 10% higher than Q1/13 volumes. In June and July 2013, monthly average production increased to between 45,000 bbl/d and 46,000 bbl/d, demonstrating the reservoir's continued strong performance. Further production volume increases are expected through the second half of 2013, with targeted exit volumes for 2013 of approximately 50,000 bbl/d.
- Kirby South, the next step in the Company's well defined thermal growth plan, is now in the final stages of commissioning, with first steam-in expected in late August or early September 2013, three months ahead of schedule. Production is targeted to ramp up to 40,000 bbl/d of bitumen by Q4/14.
- During May 2013, the first major maintenance turnaround at Horizon was completed with no major changes to the scope. The sequential start-up of the operation was executed as planned. Q3/13 Horizon SCO production is targeted to increase to between 110,000 bbl/d and 115,000 bbl/d as greater reliability and consistent production is realized after the turnaround. Safe, steady, and reliable operations continue to be a priority at Horizon. Annual SCO production is unchanged and is targeted to range from 100,000 bbl/d to 108,000 bbl/d in 2013.
- At Septimus, the Company's liquids rich natural gas Montney play, the plant expansion was completed and expanded production volumes were achieved in July 2013. At the end of July, total production at Septimus reached approximately 90 MMcf/d of natural gas and approximately 8,600 bbl/d of liquids. During Q2/13, Canadian Natural drilled 6 net wells at Septimus and targets to drill 7 additional net wells in Q3/13. By early September 2013, production is targeted to grow to plant expansion capacity of 125 MMcf/d of natural gas sales, yielding approximately 12,200 bbl/d of liquids, through the plant and deep cut facilities.
- Subsequent to Q2/13, Canadian Natural announced the acquisition of Barrick Energy Inc. The production and undeveloped land base is complementary to Canadian Natural's existing assets and is concentrated in light oil weighted assets with strong netbacks and a long reserve life. This acquisition adds approximately 4,200 bbl/d of light crude oil and NGLs and 4.4 MMcf/d of natural gas production.
- Subsequent to Q2/13, TransCanada Corporation announced a successful open season on its Energy East Pipeline project which is anticipated to add 1.1 MMbbl/d of incremental pipeline capacity to the east coast of Canada. Canadian Natural is a strong supporter of this project and has made commitments of 80,000 bbl/d of crude oil. This commitment is in addition to previously announced commitments of crude oil to Keystone XL and Trans Mountain Expansion of 120,000 bbl/d and 75,000 bbl/d respectively.

Benchmark Pricing	**WTI Pricing (US$/bbl)**	**WCS Blend Differential from WTI (%)**	**SCO Differential from WTI (US$/bbl)**	**Dated Brent Differential from WTI (US$/bbl)**	**Condensate Differential from WTI (US$/bbl)**
2013					
April	$ 92.07	25%	$ 6.14	$ 9.85	$ 10.00
May	$ 94.80	15%	$ 8.33	$ 7.69	$ 6.92
June	$ 95.80	21%	$ 0.02	$ 7.11	$ 4.91
July	$ 104.70	14%	$ 5.98	$ 3.25	$ 1.60
August*	$ 104.74	15%	$ 3.20	$ 3.13	$ (2.78)
September*	$ 103.84	20%	$ 2.27	$ 3.21	$ (4.45)

**Based on current indicative pricing as at July 31, 2013.*

- As expected, heavy crude oil differentials narrowed during the second quarter, resulting in more favorable price realizations for the Company. The WCS heavy crude oil differential ("WCS differential") as a percent of WTI averaged 20% in Q2/13 compared to 34% in Q1/13 and 24% in Q2/12. In July, August and September 2013, the WCS differential, based on current indicative pricing, narrowed to 14%, 15% and 20%, respectively.
- The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During Q2/13, condensate price premiums to WTI narrowed to US$7.27/bbl in Q2/13 compared to US$12.84/bbl in Q1/13. Lower condensate price premiums are expected to continue in the second half of 2013 resulting in higher netbacks for the Company's heavy crude oil sales volumes.

- As expected, the Dated Brent to WTI differential narrowed to US$8.21/bbl in Q2/13 compared to US$18.09/bbl in Q1/13 and US$14.71/bbl in Q2/12. Overall pricing relative to Dated Brent pricing for Canadian Natural's North American crude oil production continues to improve as a result of this narrowing.
- SCO pricing improved in Q2/13 to US$99.10/bbl compared to US$95.24/bbl in Q1/13 and US$89.54/bbl in Q2/12 resulting in more favorable price realizations for the Company.
- Q3/13 production volumes are expected to be strong and will be driven by increased production volumes from Primrose, strong SCO production due to improved Horizon reliability, and continued solid performance from the Company's remaining operating areas. Combining this strong production performance with favorable WTI pricing, narrow heavy oil differentials, and strong SCO premiums should result in a strong third quarter performance for the Company.
- Year to date, Canadian Natural has purchased for cancellation 6,937,500 common shares at a weighted average price of $30.86 per common share.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.125 per share payable on October 1, 2013.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate efficient operations, Canadian Natural focuses its activities in core regions where it can own a substantial land base and associated infrastructure. Land inventories are maintained to enable continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning and operating associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs. Further, the Company maintains large project inventories and production diversification among each of the commodities it produces; light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen and SCO (herein collectively referred to as "crude oil"), natural gas and NGLs. A large diversified project portfolio enables the effective allocation of capital to higher return opportunities.

OPERATIONS REVIEW

Drilling activity (number of wells)

	Six Months Ended Jun 30			
	2013		2012	
	Gross	**Net**	Gross	Net
Crude oil	**471**	**459**	574	544
Natural gas	**29**	**23**	25	23
Dry	**10**	**10**	8	8
Subtotal	**510**	**492**	607	575
Stratigraphic test / service wells	**321**	**321**	589	589
Total	**831**	**813**	1,196	1,164
Success rate (excluding stratigraphic test / service wells)		**98%**		99%

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Crude oil and NGLs production (bbl/d)	**241,402**	236,600	222,127	**239,014**	223,707
Net wells targeting crude oil	**136**	271	231	**407**	472
Net successful wells drilled	**131**	267	229	**398**	464
Success rate	**96%**	99%	99%	**98%**	98%

- North America crude oil and NGLs operations achieved record quarterly production of 241,402 bbl/d in Q2/13, an increase of 9% and 2% from Q2/12 and Q1/13 levels respectively.
- Canadian Natural drilled 121 net primary heavy crude oil wells in Q2/13. Canadian Natural's primary heavy crude oil continues to provide strong netbacks and a high return on capital in the Company's portfolio of diverse and balanced assets. In Q2/13 primary heavy crude oil operations achieved record production volumes of approximately 136,000 bbl/d, resulting in the tenth consecutive quarter of record primary heavy crude oil production volumes, contributing to the targeted 13% primary heavy crude oil production growth in 2013. The Company is targeting to drill another 255 net primary heavy crude oil wells in Q3/13.
- Production volumes at Woodenhouse during Q2/13 averaged approximately 13,500 bbl/d, representing an increase of 13% from Q1/13 levels of approximately 12,000 bbl/d. Current production from Woodenhouse is approximately 15,000 bbl/d.
- During Q2/13, reservoir performance from Canadian Natural's industry leading Pelican Lake polymer flood remained strong. Ten net horizontal production wells were drilled during the quarter and 13 net horizontal production wells are targeted in Q3/13. Construction of the new battery at Pelican Lake was successfully completed in mid-May 2013. Facility constraints that began in Q4/12 have been alleviated by the expansion and as a result, production volumes at Pelican Lake and Woodenhouse have increased. Pelican Lake operations achieved record quarterly crude oil production of approximately 42,000 bbl/d in Q2/13, representing a 10% increase from Q1/13 and a 12% increase from Q2/12.
- North America light crude oil and NGLs Q2/13 production decreased 2% from Q1/13 due to downtime as a result of expansion activities at Septimus and Wembley, spring break-up activities and planned turnarounds. The Company drilled 5 net light crude oil wells in Q2/13 and targets to drill 29 additional net wells in Q3/13. 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.
- Total planned drilling activity for Q3/13 includes 297 net crude oil wells, excluding stratigraphic ("strat") and service wells.

Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Bitumen production (bbl/d)	**90,051**	108,889	94,356	**99,419**	87,341
Net wells targeting crude oil	**27**	33	37	**60**	80
Net successful wells drilled	**27**	33	37	**60**	80
Success rate	**100%**	100%	100%	**100%**	100%

- Q2/13 thermal in situ oil sands ("thermal in situ") production volumes averaged approximately 90,000 bbl/d due to the timing of steaming and production cycles.
- During the second quarter of 2013, bitumen emulsion was discovered at surface at four separate locations in the Company's Primrose development area. The bitumen emulsion seepage has been controlled to specific containment areas totaling 13.5 hectares where it is effectively recovered as it reaches the surface. The rate of bitumen emulsion seepage in all four locations has declined as expected and currently totals less than 20 bbl/d. Canadian Natural believes the cause of the bitumen emulsion seepage is mechanical failures of wellbores in the vicinity of the impacted locations. A complete review is ongoing and Canadian Natural has a specialized team focused on investigating wells in the impacted areas for potential required remediation work.

- The Company's near term steaming plan at Primrose has been modified, with restrictions on steaming in some areas until the investigation with the Alberta Energy Regulator is complete. Canadian Natural's July 2013 production was approximately 120,000 bbl/d with an additional 20,000 bbl/d of production capacity that was restricted due to available plant capacity. The Company targets 2013 thermal in situ production to range from 100,000 bbl/d to 107,000 bbl/d. For 2014, even with these modified steaming strategies, the Company anticipates thermal in situ production, excluding Kirby South, to range from 100,000 bbl/d to 110,000 bbl/d, approximately 10,000 bbl/d less than originally targeted. The Company is of the view that reserves recovered from the Primrose area over its life cycle will be substantially unchanged.
- Kirby South remains ahead of plan and on budget. Drilling was successfully completed on the seventh and final pad in Q2/13. Commissioning is nearing completion with first steam-in expected in late August or early September 2013, ahead of the originally scheduled steam-in date of November 2013. Production is targeted to grow to 40,000 bbl/d by Q4/14.
- Detailed engineering is progressing for Kirby North Phase 1. As of June 30, 2013, the engineering portion was 64% complete. Construction of the main access road has been completed and site preparation will continue into Q3/13.
- Kirby South and Kirby North Phase 1 will contribute to a targeted staged expansion of production volumes from the greater Kirby area over time to 140,000 bbl/d, with the overall thermal in situ development plan targeted to increase to 510,000 bbl/d of production capacity.
- Planned drilling activity for Q3/13 includes 47 net thermal in situ wells, excluding strat and service wells.

Natural Gas

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Natural gas production (MMcf/d)	**1,092**	1,125	1,230	**1,108**	1,255
Net wells targeting natural gas	**8**	16	4	**24**	23
Net successful wells drilled	**8**	15	4	**23**	23
Success rate	**100%**	94%	100%	**96%**	100%

- During Q2/13, North America natural gas production averaged 1,092 MMcf/d, representing a 11% decrease from Q2/12 levels and a 3% decrease from Q1/13 levels. The decrease in production levels year over year was due to expected production declines, reflecting Canadian Natural's strategic decision to allocate capital to higher return crude oil projects. Q3/13 production volumes are targeted to increase to 1,135 MMcf/d to 1,155 MMcf/d.
- At Septimus, the Company's liquids rich natural gas Montney play, the plant expansion was completed and first production was achieved in July 2013. At the end of July, total production at Septimus reached approximately 90 MMcf/d of natural gas and approximately 8,600 bbl/d of liquids. During Q2/13, Canadian Natural drilled 6 net wells at Septimus and targets to drill 7 additional net wells in Q3/13. By early September 2013, production is targeted to grow to plant expansion capacity of 125 MMcf/d of natural gas sales, yielding 12,200 bbl/d of liquids, through the plant and deep cut facilities.
- Canadian Natural has a dominant Montney land position with over one million high quality net acres, the largest in the industry. In Q1/13, the Company commenced the process to monetize approximately 243,000 net acres (approximately 380 net sections) of its Montney land base in the liquids rich fairway in the Graham Kobes area of Northeast British Columbia. In Q2/13, the Information Memorandum was completed. The Company targets to open the associated data room in mid to late August 2013 and conduct presentations in September 2013.

International Exploration and Production

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Crude oil production (bbl/d)					
North Sea	**18,901**	18,774	17,619	**18,838**	20,333
Offshore Africa	**18,055**	16,112	20,598	**17,089**	20,655
Natural gas production (MMcf/d)					
North Sea	**4**	1	2	**3**	2
Offshore Africa	**26**	24	23	**25**	20
Net wells targeting crude oil	**1.0**	–	–	**1.0**	–
Net successful wells drilled	**1.0**	–	–	**1.0**	–
Success rate	**100%**	–	–	**100%**	–

- International crude oil production averaged 36,956 bbl/d during the quarter. The 6% increase in production from Q1/13 was primarily due to the stabilization of the midwater arch which resulted in a reinstatement of production at the Olowi Field in Gabon in late Q1/13. Crude oil production volumes declined 3% from Q2/12 as a result of natural field declines and the cessation of North Sea drilling activity following an increase in the Supplementary Charge Tax Rate in 2011.
- In Q2/13, the Company received a second Brownfield Allowance ("BFA") approval for its Ninian Field development plan which includes four new production wells, four injectors and two well upgrades. The Company received its first BFA approval in Q1/13 for its Tiffany field development plan of a two well infill drilling program which achieved first oil in May 2013. In September 2012, the UK government announced the implementation of the BFA, which allows for a property development allowance on qualifying preapproved field developments. This allowance partially mitigates the impact of previous tax increases.
- The light crude oil infill drilling program at Espoir, Côte d'Ivoire, originally targeted to commence in late Q2/13, has been delayed as the Company is demobilizing the current drilling rig due to ongoing operational and safety issues with the drilling contractor. Canadian Natural is currently re-assessing its drilling options at Espoir, where the Company expects to undertake an 8-well drilling program.
- During Q2/13, Canadian Natural acquired operatorship and a 60% working interest of Block 12 in Côte d'Ivoire, located approximately 35 km west of the Company's current production at Espoir and Baobab. The Company plans to commence new 3D seismic acquisition in Q4/13. Potential exploration drilling is targeted for 2015 to evaluate deepwater channel/fan structures similar to the Jubilee crude oil discoveries in Ghana and plays elsewhere in offshore Africa.
- Exploration work on Block 514 in Côte d'Ivoire, in which Canadian Natural has a 36% working interest, is underway and a seismic program has been completed. Drilling is targeted to commence in the first half of 2014. The Company believes this block is also prospective for deepwater channel/fan structures similar to Jubilee.
- A partner has been selected to jointly conduct exploratory drilling on Canadian Natural's prospective offshore South Africa property. The Company will provide further details on the partnership terms upon receipt of regulatory approval. Targeted drilling windows are from Q4/13 to Q1/14 and from Q4/14 to Q1/15 and the necessary long-lead equipment has been ordered.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Synthetic crude oil production (bbl/d)	**67,954**	108,782	115,823	**88,255**	80,957

- During Q2/13, SCO production averaged 67,954 bbl/d at Horizon Oil Sands. Production volumes were lower than Q1/13 and Q2/12 levels due to the completion of the Company's first major maintenance turnaround in May 2013. Horizon SCO production averaged approximately 101,000 bbl/d in June 2013, approximately 110,000 bbl/d in July 2013 and Q3/13 production guidance is targeted to range from 110,000 bbl/d to 115,000 bbl/d. 2013 annual guidance remains unchanged at 100,000 bbl/d to 108,000 bbl/d of SCO production.
- Canadian Natural's staged expansion to 250,000 bbl/d of SCO production capacity continues to progress on track. Capital expenditures to date on Phase 2/3 expansion are at or below cost estimates as the Company executes its cost focused strategy. Expansion work at Horizon will ultimately add an additional 140,000 bbl/d of SCO production in a staged, disciplined manner. Horizon provides high quality, long life SCO production without decline for decades.
- An update to the staged Phase 2/3 expansion on an Engineering, Procurement and Construction basis at the end of Q2/13 is as follows:
  - Overall Horizon Phase 2/3 expansion is 24% complete.
  - Reliability – Tranche 2 is 90% complete. An additional 5,000 bbl/d of production capacity is targeted to be added in 2014.
  - Directive 74 includes technological investment and research into tailings management. This project remains on track and is currently 18% complete.
  - Phase 2A is a coker expansion. The expansion is 62% complete, and is targeted to add 10,000 bbl/d of production capacity in 2015.
  - Phase 2B is 15% complete. This phase includes lump sum contracts for major components such as gas/oil hydrotreatment, froth treatment and a hydrogen plant. This phase is targeted to add another 45,000 bbl/d of production capacity in 2016.
  - Phase 3 is on track and engineering is underway. This phase is 15% complete, and includes the addition of supplementary extraction trains. This phase is targeted to increase production capacity by 80,000 bbl/d in 2017.
  - The projects which are currently under construction continue to trend at or below cost estimates.
- Total capital budgeted for the Horizon Phase 2/3 expansion in 2013 is $2.075 billion. Canadian Natural continues to be disciplined and cost driven in the Horizon Phase 2/3 expansion to ensure the expansion continues effectively and efficiently.

MARKETING

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 94.23**	$ 94.34	$ 93.50	**$ 94.28**	$ 98.22
WCS blend differential from WTI (%) (2)	**20%**	34%	24%	**27%**	23%
SCO price (US$/bbl)	**$ 99.10**	$ 95.24	$ 89.54	**$ 97.18**	$ 93.82
Condensate benchmark pricing (US$/bbl)	**$ 101.50**	$ 107.18	$ 99.49	**$ 104.32**	$ 104.77
Average realized pricing before risk management (C$/bbl) (3)	**$ 75.10**	$ 60.87	$ 72.12	**$ 67.94**	$ 77.14
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 3.41**	$ 2.92	$ 1.74	**$ 3.16**	$ 2.06
Average realized pricing before risk management (C$/Mcf)	**$ 4.05**	$ 3.51	$ 2.15	**$ 3.78**	$ 2.44

(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$/bbl)**	**WCS Blend Differential from WTI (%)**	**SCO Differential from WTI (US$/bbl)**	**Dated Brent Differential from WTI (US$/bbl)**	**Condensate Differential from WTI (US$/bbl)**
2013					
April	$ 92.07	25%	$ 6.14	$ 9.85	$ 10.00
May	$ 94.80	15%	$ 8.33	$ 7.69	$ 6.92
June	$ 95.80	21%	$ 0.02	$ 7.11	$ 4.91
July	$ 104.70	14%	$ 5.98	$ 3.25	$ 1.60
August*	$ 104.74	15%	$ 3.20	$ 3.13	$ (2.78)
September*	$ 103.84	20%	$ 2.27	$ 3.21	$ (4.45)

**Based on current indicative pricing as at July 31, 2013.*

- As expected, heavy crude oil differentials narrowed during the second quarter, resulting in more favorable price realizations for the Company. The WCS differential averaged 20% in Q2/13 compared to 34% in Q1/13 and 24% in Q2/12. The differential narrowed during Q2/13 compared to Q1/13 due to increased seasonal demand for heavy crude oil, increased pipeline capacity resulting from improved pipeline reliability, and lower unplanned maintenance activity at refineries accessible to Canadian heavy crude oil. In July, August and September 2013, the WCS differential, based on current indicative pricing, narrowed to 14%, 15% and 20%, respectively.
- Canadian Natural contributed over 172,000 bbl/d of its heavy crude oil blends to the WCS blend in Q2/13. The Company remains the largest contributor to the WCS blend, accounting for over 62% of the total blend this quarter.
- The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. Condensate price premiums to WTI narrowed to US$7.27/bbl in Q2/13 compared to US$12.84/bbl in Q1/13, reflecting normal seasonality. Lower condensate price premiums are expected to continue in the second half of 2013 resulting in higher netbacks for the Company's heavy crude oil sales volumes.
- As expected, the Dated Brent to WTI differential narrowed to US$8.21/bbl in Q2/13 compared to US$18.09/bbl in Q1/13 and US$14.71/bbl in Q2/12, reflecting continued debottlenecking of the logistical constraints between Cushing and the Gulf Coast as incremental pipeline capacity continued to grow. Overall pricing relative to Dated Brent pricing for Canadian Natural's North American crude oil production continues to improve as a result of this narrowing.
- SCO pricing averaged US$99.10/bbl during Q2/13, representing a 4% and 11% increase from Q1/13 and Q2/12 pricing, respectively. Pricing increases from Q1/13 and Q2/12 reflect planned and unplanned supply disruptions in Northern Alberta and overall higher diesel demand and result in more favorable price realizations for the Company.

NORTH WEST REDWATER UPGRADING AND REFINING

In Q2/13 work continued on the North West Redwater refinery and completion is targeted for mid-2016. The North West Redwater refinery asset strengthens 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 volatility in pricing all Western Canadian heavy crude oil.

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, diverse asset base and related capital expenditure programs and commodity hedging policy all support a flexible financial position and provide the right 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 623,315 BOE/d for Q2/13 with approximately 96% of production located in G8 countries.
- Subsequent to Q2/13, the Company increased its forecasted 2013 capital spending as a result of the Cold Lake pipeline expansion, the Barrick Energy Inc. acquisition and a minor increase in capital allocated to Exploration and Production.
- Canadian Natural has a strong balance sheet with debt to book capitalization of 29% and debt to EBITDA of 1.4x at June 30, 2013.
- During Q2/13, Canadian Natural's $3,000 million revolving syndicated credit facility was extended to June 2017. Additionally, the Company issued $500 million of 2.89% medium-term notes due August 2020. Proceeds from the securities issued were used to repay bank indebtedness and for general corporate purposes.
- In Q2/13, the Company completed a full quarter of its US commercial paper program. Borrowings of up to a maximum of US$1,500 million are authorized. The program further diversifies the Company's borrowing base and has been well received.
- Canadian Natural maintains significant financial stability and liquidity represented by approximately $2.4 billion of available credit under its bank credit facilities, net of commercial paper issued.
- The Company's commodity hedging program protects investment returns, ensures ongoing balance sheet strength and supports the Company's cash flow for its capital expenditure programs. Approximately 58% of forecasted 2013 crude oil volumes are currently hedged using price collars and physical crude oil sales contracts with fixed WCS differentials. Through the use of collars, the Company has hedged approximately 300,000 bbl/d of crude oil volumes in the second half of 2013, and approximately 150,000 bbl/d of crude oil volumes in 2014. To partially mitigate its exposure to widening heavy crude oil differentials, the Company has entered into physical crude oil sales contracts with weighted average fixed WCS differentials as follows:

Term			Volume	Weighted average price
Jul 2013	–	Sep 2013	20,000 bbl/d	US$21.27/bbl
Oct 2013	–	Dec 2013	17,000 bbl/d	US$21.49/bbl
Jan 2014	–	Mar 2014	8,000 bbl/d	US$21.89/bbl
Apr 2014	–	Jun 2014	9,000 bbl/d	US$21.93/bbl
Jul 2014	–	Sep 2014	10,000 bbl/d	US$20.81/bbl
Oct 2014	–	Dec 2014	10,000 bbl/d	US$20.81/bbl

Details of the Company's commodity hedging program can be found on the Company's website at www.cnrl.com.

- Year to date, Canadian Natural has purchased for cancellation 6,937,500 common shares at a weighted average price of $30.86 per common share.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.125 per share payable on October 1, 2013.

OUTLOOK

The Company forecasts 2013 production levels before royalties to average between 482,000 and 513,000 bbl/d of crude oil and NGLs and between 1,085 and 1,145 MMcf/d of natural gas. Q3/13 production guidance before royalties is forecast to average between 506,000 and 529,000 bbl/d of crude oil and NGLs and between 1,135 and 1,155 MMcf/d of natural gas. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansions, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, construction of the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast, construction of the proposed Energy East pipeline to transport crude oil from Alberta to Quebec and New Brunswick, the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia, and the construction and future operations of the North West Redwater bitumen upgrader and refinery 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, 2013 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2012.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company’s consolidated financial statements for the period ended June 30, 2013 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 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 cash production costs is 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 synthetic crude oil.

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, 2013 in relation to the comparable periods in 2012 and the first quarter of 2013. 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, 2012, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated August 7, 2013.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Product sales	**$ 4,230**	$ 4,101	$ 4,187	**$ 8,331**	$ 8,158
Net earnings	**$ 476**	$ 213	$ 753	**$ 689**	$ 1,180
Per common share – basic	**$ 0.44**	$ 0.19	$ 0.68	**$ 0.63**	$ 1.07
– diluted	**$ 0.44**	$ 0.19	$ 0.68	**$ 0.63**	$ 1.07
Adjusted net earnings from operations (1)	**$ 462**	$ 401	$ 606	**$ 863**	$ 906
Per common share – basic	**$ 0.42**	$ 0.37	$ 0.55	**$ 0.79**	$ 0.82
– diluted	**$ 0.42**	$ 0.37	$ 0.55	**$ 0.79**	$ 0.82
Cash flow from operations (2)	**$ 1,670**	$ 1,571	$ 1,754	**$ 3,241**	$ 3,034
Per common share – basic	**$ 1.53**	$ 1.44	$ 1.60	**$ 2.97**	$ 2.76
– diluted	**$ 1.53**	$ 1.44	$ 1.59	**$ 2.97**	$ 2.75
Capital expenditures, net of dispositions	**$ 1,792**	$ 1,736	$ 1,324	**$ 3,528**	$ 2,920

(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

($ millions)	*Three Months Ended*			*Six Months Ended*	
	Jun 30 2013	*Mar 31 2013*	*Jun 30 2012*	***Jun 30 2013***	*Jun 30 2012*
Net earnings as reported	***$ 476***	*$ 213*	*$ 753*	***$ 689***	*$ 1,180*
Share-based compensation, net of tax (1)	***(49)***	*71*	*(115)*	***22***	*(222)*
Unrealized risk management (gain) loss, net of tax (2)	***(92)***	*51*	*(103)*	***(41)***	*(63)*
Unrealized foreign exchange loss, net of tax (3)	***112***	*78*	*71*	***190***	*11*
Realized foreign exchange gain on repayment of US dollar debt securities (4)	***–***	*(12)*	*–*	***(12)***	*–*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (5)	***15***	*–*	*–*	***15***	*–*
Adjusted net earnings from operations	***$ 462***	*$ 401*	*$ 606*	***$ 863***	*$ 906*

(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 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% unsecured 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

	Three Months Ended			Six Months Ended	
($ millions)	***Jun 30 2013***	*Mar 31 2013*	*Jun 30 2012*	***Jun 30 2013***	*Jun 30 2012*
Net earnings	***$ 476***	*$ 213*	*$ 753*	***$ 689***	*$ 1,180*
Non-cash items:					
Depletion, depreciation and amortization	***1,172***	*1,142*	*1,084*	***2,314***	*2,059*
Share-based compensation	***(49)***	*71*	*(115)*	***22***	*(222)*
Asset retirement obligation accretion	***42***	*42*	*38*	***84***	*75*
Unrealized risk management (gain) loss	***(114)***	*62*	*(144)*	***(52)***	*(84)*
Unrealized foreign exchange loss	***112***	*78*	*71*	***190***	*11*
Realized foreign exchange gain on repayment of US dollar debt securities	***–***	*(12)*	*–*	***(12)***	*–*
Equity loss from jointly controlled entity	***–***	*2*	*5*	***2***	*5*
Deferred income tax expense (recovery)	***31***	*(27)*	*62*	***4***	*10*
Cash flow from operations	***$ 1,670***	*$ 1,571*	*$ 1,754*	***$ 3,241***	*$ 3,034*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the six months ended June 30, 2013 were $689 million compared with $1,180 million for the six months ended June 30, 2012. Net earnings for the six months ended June 30, 2013 included net after-tax expenses of $174 million compared with net after-tax income of $274 million for the six months ended June 30, 2012 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, 2013 were $863 million compared with $906 million for the six months ended June 30, 2012.

Net earnings for the second quarter of 2013 were $476 million compared with $753 million for the second quarter of 2012 and $213 million for the first quarter of 2013. Net earnings for the second quarter of 2013 included net after-tax income of $14 million compared with $147 million for the second quarter of 2012 and net after-tax expenses of $188 million for the first quarter of 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 second quarter of 2013 were $462 million compared with $606 million for the second quarter of 2012 and $401 million for the first quarter of 2013.

The decrease in adjusted net earnings for the six months ended June 30, 2013 from the comparable period in 2012 was primarily due to:

- lower crude oil and NGLs netbacks;
- lower natural gas sales volumes; and
- higher depletion, depreciation and amortization expense;

partially offset by:

- higher crude oil and synthetic crude oil ("SCO") sales volumes in the North America and Oil Sands Mining and Upgrading segments;
- higher realized natural gas netbacks;
- higher realized SCO prices;
- higher realized risk management gains; and
- the impact of a weaker Canadian dollar.

The decrease in adjusted net earnings for the second quarter of 2013 from the comparable period in 2012 was primarily due to:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment due to the May 2013 turnaround;
- lower natural gas sales volumes;
- lower realized risk management gains; and
- higher depletion, depreciation and amortization expense;

partially offset by:

- higher crude oil and NGLs sales volumes;
- higher natural gas netbacks;
- higher realized SCO prices; and
- the impact of a weaker Canadian dollar.

The increase in adjusted net earnings for the second quarter of 2013 from the first quarter of 2013 was primarily due to:

- higher crude oil and NGLs and natural gas netbacks;
- higher realized SCO prices; and
- the impact of a weaker Canadian dollar;

partially offset by:

- lower crude oil and SCO sales volumes in the North America and Oil Sands Mining and Upgrading segments; and
- lower realized risk management gains.

The impacts of share-based compensation, risk management activities and changes 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, 2013 was $3,241 million compared with $3,034 million for the six months ended June 30, 2012. Cash flow from operations for the second quarter of 2013 was $1,670 million compared with $1,754 million for the second quarter of 2012 and $1,571 million for the first quarter of 2013. 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, 2013 increased 1% to 651,921 BOE/d from 645,943 BOE/d for the six months ended June 30, 2012. Total production before royalties for the second quarter of 2013 decreased 8% to 623,315 BOE/d from 679,607 BOE/d for the second quarter of 2012 and 680,844 BOE/d for the first quarter of 2013.

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 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

($ millions, except per common share amounts)		Jun 30 2012		Mar 31 2012		Dec 31 2011		Sep 30 2011
Product sales	$	4,187	$	3,971	$	4,788	$	3,690
Net earnings	$	753	$	427	$	832	$	836
Net earnings per common share								
– basic	$	0.68	$	0.39	$	0.76	$	0.76
– diluted	$	0.68	$	0.39	$	0.76	$	0.76

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 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 record heavy crude oil drilling program, and the impact of the turnaround/suspension and subsequent recommencement of production 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 strategic decision to reduce natural gas drilling activity in North America and the 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, acquisitions of natural gas producing properties in 2011 that had higher operating costs per Mcf than the Company's existing properties, and the turnaround/suspension and subsequent recommencement of production at Horizon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes, 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, and the impact of the turnaround/suspension and subsequent recommencement of production 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.

BUSINESS ENVIRONMENT

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
WTI benchmark price (US$/bbl)	**$ 94.23**	$ 94.34	$ 93.50	**$ 94.28**	$ 98.22
Dated Brent benchmark price (US$/bbl)	**$ 102.44**	$ 112.43	$ 108.21	**$ 107.41**	$ 113.34
WCS blend differential from WTI (US$/bbl)	**$ 19.10**	$ 31.79	$ 22.83	**$ 25.41**	$ 22.15
WCS blend differential from WTI (%)	**20%**	34%	24%	**27%**	23%
SCO price (US$/bbl)	**$ 99.10**	$ 95.24	$ 89.54	**$ 97.18**	$ 93.82
Condensate benchmark price (US$/bbl)	**$ 101.50**	$ 107.18	$ 99.49	**$ 104.32**	$ 104.77
NYMEX benchmark price (US$/MMBtu)	**$ 4.09**	$ 3.35	$ 2.26	**$ 3.72**	$ 2.52
AECO benchmark price (C$/GJ)	**$ 3.41**	$ 2.92	$ 1.74	**$ 3.16**	$ 2.06
US/Canadian dollar average exchange rate (US$)	**$ 0.9774**	$ 0.9917	$ 0.9897	**$ 0.9844**	$ 0.9943

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$94.28 per bbl for the six months ended June 30, 2013, a decrease of 4% from US$98.22 per bbl for the six months ended June 30, 2012. WTI averaged US$94.23 per bbl for the second quarter of 2013 and was consistent with the comparative periods.

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$107.41 per bbl for the six months ended June 30, 2013, a decrease of 5% from US$113.34 per bbl for the six months ended June 30, 2012. Brent averaged US$102.44 per bbl for the second quarter of 2013, a decrease of 5% from US$108.21 per bbl for the second quarter of 2012, and a decrease of 9% from US$112.43 per bbl for the first quarter of 2013.

The Brent differential from WTI tightened for the three and six months ended June 30, 2013 from the comparable periods due to incremental pipeline capacity reflecting a continued debottlenecking of logistical constraints from Cushing to the US Gulf Coast.

The WCS Heavy Differential averaged 27% for the six months ended June 30, 2013 compared with 23% for the six months ended June 30, 2012. The WCS Heavy Differential averaged 20% for the second quarter of 2013 compared with 24% for the second quarter of 2012, and 34% for the first quarter of 2013. The WCS Heavy Differential tightened in the second quarter of 2013 from the comparable periods as a result of increased seasonal heavy oil demand and increased pipeline capacity as pipeline reliability in the second quarter of 2013 improved. The WCS Heavy Differential per barrel tightened in July 2013 to average US$14.20 per bbl and in August 2013 to average US$15.57 per bbl. To partially mitigate its exposure to widening heavy crude oil differentials, as at June 30, 2013, the Company has entered into physical crude oil sales contracts with weighted average fixed WCS differentials as follows: 20,000 bbl/d in the third quarter of 2013 at US$21.27 per bbl; 15,000 bbl/d in the fourth quarter of 2013 at US$21.52 per bbl; 8,000 bbl/d in the first quarter of 2014 at US$21.89 per bbl; 9,000 bbl/d in the second quarter of 2014 at US$21.93 per bbl; and 10,000 bbl/d in the third and fourth quarters of 2014 at US$20.81.

The SCO price averaged US$97.18 per bbl for the six months ended June 30, 2013, an increase of 4% from US$93.82 per bbl for the six months ended June 30, 2012. The SCO price averaged US$99.10 per bbl for the second quarter of 2013, an increase of 11% from US$89.54 per bbl for the second quarter of 2012, and an increase of 4% from US$95.24 per bbl for the first quarter of 2013. The increase in SCO pricing for the three and six months ended June 30, 2013 from the comparable periods was due to planned and unplanned shutdowns of various upgrading facilities in Northern Alberta.

The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During the second quarter of 2013, condensate price premiums to WTI narrowed, reflecting normal seasonality.

The Company anticipates continued volatility in crude oil pricing benchmarks due to supply and demand factors, geopolitical events, and the timing and extent of the economic recovery. 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$3.72 per MMBtu for the six months ended June 30, 2013, an increase of 48% from US$2.52 per MMBtu for the six months ended June 30, 2012. NYMEX natural gas prices averaged US$4.09 per MMBtu for the second quarter of 2013, an increase of 81% from US$2.26 per MMBtu for the second quarter of 2012, and an increase of 22% from US$3.35 per MMBtu for the first quarter of 2013.

AECO natural gas prices for the six months ended June 30, 2013 averaged $3.16 per GJ, an increase of 53% from $2.06 per GJ for the six months ended June 30, 2012. AECO natural gas prices for the second quarter of 2013 averaged $3.41 per GJ, an increase of 96% from $1.74 per GJ for the second quarter of 2012, and an increase of 17% from $2.92 per GJ for the first quarter of 2013.

During the second quarter of 2013, natural gas prices continued to recover from the low pricing levels in 2012. A steady North America production supply forecast and a return to normal winter weather in North America in 2013 has allowed natural gas inventories to return to seasonal levels.

The Company continues to focus on its crude oil marketing strategy including a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that provide crude oil transportation to new markets, and supporting incremental heavy crude oil conversion capacity. Subsequent to June 30, 2013, the Company entered into a 20 year transportation agreement to ship 80,000 bbl/d of crude oil on the proposed Energy East pipeline, subject to regulatory approval.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**331,453**	345,489	316,483	**338,433**	311,048
North America – Oil Sands Mining and Upgrading	**67,954**	108,782	115,823	**88,255**	80,957
North Sea	**18,901**	18,774	17,619	**18,838**	20,333
Offshore Africa	**18,055**	16,112	20,598	**17,089**	20,655
	436,363	489,157	470,523	**462,615**	432,993
Natural gas (MMcf/d)					
North America	**1,092**	1,125	1,230	**1,108**	1,255
North Sea	**4**	1	2	**3**	2
Offshore Africa	**26**	24	23	**25**	20
	1,122	1,150	1,255	**1,136**	1,277
Total barrels of oil equivalent (BOE/d)	**623,315**	680,844	679,607	**651,921**	645,943
Product mix					
Light and medium crude oil and NGLs	**16%**	15%	15%	**15%**	15%
Pelican Lake heavy crude oil	**7%**	5%	5%	**6%**	6%
Primary heavy crude oil	**22%**	20%	18%	**21%**	19%
Bitumen (thermal oil)	**14%**	16%	14%	**15%**	14%
Synthetic crude oil	**11%**	16%	17%	**14%**	13%
Natural gas	**30%**	28%	31%	**29%**	33%
Percentage of product sales (1) (2) (excluding midstream revenue)					
Crude oil and NGLs	**88%**	89%	93%	**89%**	92%
Natural gas	**12%**	11%	7%	**11%**	8%

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

(2) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**274,850**	289,992	272,089	**282,379**	263,020
North America – Oil Sands Mining and Upgrading	**65,077**	104,203	109,569	**84,532**	76,584
North Sea	**18,839**	18,706	17,578	**18,773**	20,282
Offshore Africa	**14,974**	13,603	15,051	**14,292**	16,274
	373,740	426,504	414,287	**399,976**	376,160
Natural gas (MMcf/d)					
North America	**1,016**	1,092	1,218	**1,054**	1,247
North Sea	**4**	1	2	**3**	2
Offshore Africa	**22**	20	19	**21**	17
	1,042	1,113	1,239	**1,078**	1,266
Total barrels of oil equivalent (BOE/d)	**547,330**	612,062	620,700	**579,600**	587,226

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

Crude oil and NGLs production for the six months ended June 30, 2013 increased 7% to 462,615 bbl/d from 432,993 bbl/d for the six months ended June 30, 2012. Crude oil and NGLs production for the second quarter of 2013 decreased 7% to 436,363 bbl/d from 470,523 bbl/d for the second quarter of 2012 and decreased 11% from 489,157 bbl/d for the first quarter of 2013. The increase in production for the six months ended June 30, 2013 from the comparable period in 2012 was primarily due to the impact of a strong heavy crude oil drilling program, and the increased production from the Company's cyclic thermal operations and Horizon. The decrease in production for the second quarter of 2013 from the comparable periods was primarily due to the decrease in production volumes resulting from Horizon's planned maintenance turnaround in May 2013 and from fluctuations in the Company's cyclic thermal operations, partially offset by the impact of a strong heavy crude oil drilling program. Crude oil and NGLs production in the second quarter of 2013 was within the Company's previously issued guidance of 435,000 to 461,000 bbl/d.

Natural gas production for the six months ended June 30, 2013 decreased 11% to 1,136 MMcf/d from 1,277 MMcf/d for the six months ended June 30, 2012. Natural gas production for the second quarter of 2013 decreased 11% to 1,122 MMcf/d from 1,255 MMcf/d for the second quarter of 2012 and decreased 2% from 1,150 MMcf/d for the first quarter of 2013. The decrease in natural gas production for the three and six months ended June 30, 2013 from the comparable periods was primarily a result of a strategic reduction of natural gas drilling as the Company allocated capital to higher return crude oil projects, as well as expected production declines. Natural gas production in the second quarter of 2013 exceeded the Company's previously issued guidance of 1,090 to 1,110 MMcf/d.

For 2013, annual production guidance is targeted to average between 482,000 and 513,000 bbl/d of crude oil and NGLs and between 1,085 and 1,145 MMcf/d of natural gas. Third quarter 2013 production guidance is targeted to average between 506,000 and 529,000 bbl/d of crude oil and NGLs and between 1,135 and 1,155 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the six months ended June 30, 2013 increased 9% to average 338,433 bbl/d from 311,048 bbl/d for the six months ended June 30, 2012. For the second quarter of 2013, crude oil and NGLs production increased 5% to average 331,453 bbl/d compared with 316,483 bbl/d for the second quarter of 2012 and decreased 4% from 345,489 bbl/d for the first quarter of 2013. The increase in crude oil and NGLs production for the three and six months ended June 30, 2013 from the comparable periods in 2012 was primarily due to the impact of a strong heavy crude oil drilling program. The decrease for the second quarter of 2013 from the first quarter of 2013 was primarily due to the decrease in production from the Company's cyclic thermal operations. Second quarter 2013 production of crude oil and NGLs was within the Company's previously issued guidance of 326,000 to 342,000 bbl/d. Third quarter 2013 production guidance is targeted to average between 365,000 and 380,000 bbl/d for crude oil and NGLs.

Natural gas production for the six months ended June 30, 2013 decreased 12% to 1,108 MMcf/d compared with 1,255 MMcf/d for the six months ended June 30, 2012. Natural gas production decreased 11% to 1,092 MMcf/d for the second quarter of 2013 compared with 1,230 MMcf/d in the second quarter of 2012 and decreased 3% from 1,125 MMcf/d for the first quarter of 2013. The decrease in natural gas production for the three and six months ended June 30, 2013 from the comparable periods was primarily a result of a strategic reduction of natural gas drilling as the Company allocated capital to higher return crude oil projects, as well as expected production declines.

North America – Oil Sands Mining and Upgrading

Production averaged 88,255 bbl/d for the six months ended June 30, 2013 compared with 80,957 bbl/d for the six months ended June 30, 2012. For the second quarter of 2013, SCO production averaged 67,954 bbl/d compared with 115,823 bbl/d for the second quarter of 2012 and 108,782 bbl/d for the first quarter of 2013. Production increased for the six months ended June 30, 2013 from the comparable period due to the unplanned maintenance completed during the first quarter of 2012. Second quarter 2013 production reflected the impact of the planned maintenance turnaround. Due to a 6 day extension of the planned turnaround to 30 days from the 24 days originally forecasted, SCO production was below the Company's previously issued guidance of 77,000 to 83,000 bbl/d for the second quarter of 2013. Third quarter 2013 production guidance is targeted to average between 110,000 and 115,000 bbl/d. Annual 2013 production guidance remains unchanged and is targeted to average between 100,000 and 108,000 bbl/d.

North Sea

North Sea crude oil production for the six months ended June 30, 2013 decreased 7% to 18,838 bbl/d from 20,333 bbl/d for the six months ended June 30, 2012. Second quarter 2013 North Sea crude oil production increased 7% to 18,901 bbl/d compared with 17,619 bbl/d for the second quarter of 2012, and was comparable with the first quarter of 2013. The decrease in production for the six months ended June 30, 2013 from the comparable period was primarily due to natural field declines and a reduction in drilling activities as a result of an increase in the UK corporate income tax rate in 2011. The increase in production for the second quarter of 2013 from the second quarter of 2012 was primarily due to higher production from both the Tiffany and Ninian fields in 2013, as well as the temporary shut in of the third-party operated pipeline to Sullom Voe for unplanned maintenance for a portion of 2012, which caused all Ninian and associated fields to be shut in.

The Company received approval for the Brownfield Allowance for the Tiffany field in January 2013 and as a result, during the second quarter the Company drilled one injector well and one additional production well, which came on at Tiffany with production of approximately 1,500 bbl/d, exceeding original forecasted volumes. During the second quarter of 2013, the Company also completed its consolidation of a working interest in a satellite field at the Ninian hub.

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 and associated floating storage unit were subsequently removed from the field and the FPSO is currently undergoing repairs and is targeted to be back in the field in the first half of 2014. The associated repair costs, net of insurance recoveries, are not expected to be significant.

Offshore Africa

Offshore Africa crude oil production decreased 17% to 17,089 bbl/d for the six months ended June 30, 2013 from 20,655 bbl/d for the six months ended June 30, 2012. Second quarter 2013 crude oil production averaged 18,055 bbl/d, decreasing 12% from 20,598 bbl/d for the second quarter of 2012 and increasing 12% from 16,112 bbl/d for the first quarter of 2013. The decrease in production volumes for the three and six months ended June 30, 2013 from the comparable periods in 2012 was due to natural field declines and lower production from Gabon. The increase in production volumes for the second quarter of 2013 from the first quarter of 2013 was due to the stabilization of the midwater arch and the reinstatement of production at the Olowi field in Gabon late in the first quarter of 2013. The final repairs and assessment have been made and issues relating to the long-term operability of the midwater arch have been resolved.

International Guidance

The Company's North Sea and Offshore Africa second quarter 2013 crude oil and NGLs production exceeded the Company's previously issued guidance of 32,000 to 36,000 bbl/d. Third quarter 2013 production guidance is targeted to average between 31,000 and 34,000 bbl/d of crude oil and NGLs.

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 tanks, pipelines, or FPSOs, as follows:

(bbl)	**Jun 30 2013**	Mar 31 2013	Dec 31 2012
North America – Exploration and Production	**691,583**	811,181	643,758
North America – Oil Sands Mining and Upgrading (SCO)	**1,061,417**	1,334,054	993,627
North Sea	**583,227**	409,333	77,018
Offshore Africa	**811,742**	829,793	1,036,509
	3,147,969	3,384,361	2,750,912

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Crude oil and NGLs ($/bbl) (1)					
Sales price (2) (3)	**$ 75.10**	$ 60.87	$ 72.12	**$ 67.94**	$ 77.14
Transportation	**2.32**	2.37	2.13	**2.34**	2.19
Realized sales price, net of transportation	**72.78**	58.50	69.99	**65.60**	74.95
Royalties	**11.60**	8.76	9.18	**10.17**	11.10
Production expense	**16.51**	17.56	16.66	**17.04**	16.72
Netback	**$ 44.67**	$ 32.18	$ 44.15	**$ 38.39**	$ 47.13
Natural gas ($/Mcf) (1)					
Sales price (2) (3)	**$ 4.05**	$ 3.51	$ 2.15	**$ 3.78**	$ 2.44
Transportation	**0.29**	0.29	0.25	**0.29**	0.25
Realized sales price, net of transportation	**3.76**	3.22	1.90	**3.49**	2.19
Royalties	**0.28**	0.12	0.05	**0.20**	0.05
Production expense	**1.41**	1.53	1.15	**1.48**	1.25
Netback	**$ 2.07**	$ 1.57	$ 0.70	**$ 1.81**	$ 0.89
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2) (3)	**$ 58.49**	$ 47.90	$ 51.14	**$ 53.16**	$ 54.19
Transportation	**2.18**	2.21	1.97	**2.20**	2.01
Realized sales price, net of transportation	**56.31**	45.69	49.17	**50.96**	52.18
Royalties	**8.29**	6.05	5.93	**7.16**	7.08
Production expense	**13.81**	14.74	13.06	**14.28**	13.24
Netback	**$ 34.21**	$ 24.90	$ 30.18	**$ 29.52**	$ 31.86

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Crude oil and NGLs ($/bbl) (1) (2) (3)					
North America	**$ 71.81**	$ 55.68	$ 67.44	**$ 63.66**	$ 71.99
North Sea	**$ 104.47**	$ 114.28	$ 109.60	**$ 109.05**	$ 114.53
Offshore Africa	**$ 107.71**	$ 113.70	$ 106.30	**$ 110.70**	$ 116.09
Company average	**$ 75.10**	$ 60.87	$ 72.12	**$ 67.94**	$ 77.14
Natural gas ($/Mcf) (1) (2) (3)					
North America	**$ 3.90**	$ 3.37	$ 1.99	**$ 3.63**	$ 2.32
North Sea	**$ 7.03**	$ 3.65	$ 5.41	**$ 6.15**	$ 5.19
Offshore Africa	**$ 10.02**	$ 10.24	$ 10.68	**$ 10.13**	$ 10.39
Company average	**$ 4.05**	$ 3.51	$ 2.15	**$ 3.78**	$ 2.44
Company average ($/BOE) (1) (2) (3)	**$ 58.49**	$ 47.90	$ 51.14	**$ 53.16**	$ 54.19

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

North America

North America realized crude oil prices decreased 12% to average $63.66 per bbl for the six months ended June 30, 2013 from $71.99 per bbl for the six months ended June 30, 2012. North America realized crude oil prices averaged $71.81 per bbl for the second quarter of 2013, an increase of 6% compared with $67.44 per bbl for the second quarter of 2012 and an increase of 29% compared with $55.68 per bbl for the first quarter of 2013. The decrease in realized crude oil prices for the six months ended June 30, 2013 from the comparable period was due to the widening of the WCS Heavy Differential, lower WTI benchmark pricing, and higher diluent blending costs, partially offset by the impact of a weaker Canadian dollar relative to the US dollar. The increase in realized crude oil prices for the second quarter of 2013 from the comparable periods was due to the impact of the tightening of the WCS Heavy Differential and the weaker 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 2013 contributed approximately 172,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 56% to average $3.63 per Mcf for the six months ended June 30, 2013 from $2.32 per Mcf for the six months ended June 30, 2012. North America realized natural gas prices increased 96% to average $3.90 per Mcf for the second quarter of 2013 compared with $1.99 per Mcf in the second quarter of 2012, and increased 16% compared with $3.37 per Mcf for the first quarter of 2013. The increase in realized natural gas prices for the three and six months ended June 30, 2013 from the comparable periods was primarily due to higher AECO benchmark pricing related to the impact of a steady North America production supply forecast and a return to normal winter weather in North America in 2013, that has allowed natural gas inventories to return to seasonal levels.

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

(Quarterly Average)	**Jun 30 2013**	Mar 31 2013	Jun 30 2012
Wellhead Price (1) (2) (3)			
Light and medium crude oil and NGLs ($/bbl)	**$ 78.15**	$ 73.77	$ 71.56
Pelican Lake heavy crude oil ($/bbl)	**$ 75.17**	$ 54.41	$ 66.13
Primary heavy crude oil ($/bbl)	**$ 71.75**	$ 51.45	$ 66.15
Bitumen (thermal oil) ($/bbl)	**$ 65.99**	$ 50.42	$ 66.88
Natural gas ($/Mcf)	**$ 3.90**	$ 3.37	$ 1.99

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

North Sea

North Sea realized crude oil prices decreased 5% to average $109.05 per bbl for the six months ended June 30, 2013 from $114.53 per bbl for the six months ended June 30, 2012. Realized crude oil prices decreased 5% to average $104.47 per bbl for the second quarter of 2013 from $109.60 per bbl for the second quarter of 2012, and decreased 9% from $114.28 per bbl for the first quarter of 2013. The fluctuations in realized crude oil prices for the three and six months ended June 30, 2013 from the comparable periods reflected movements in Brent benchmark pricing, the timing of liftings, and the weakening of the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices decreased 5% to average $110.70 per bbl for the six months ended June 30, 2013 from $116.09 per bbl for the six months ended June 30, 2012. Realized crude oil prices increased 1% to average $107.71 per bbl for the second quarter of 2013 from $106.30 per bbl for the second quarter of 2012, and decreased 5% from $113.70 per bbl for the first quarter of 2013. The fluctuations in realized crude oil prices for the three and six months ended June 30, 2013 from the comparable periods 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 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 11.81**	$ 8.65	$ 8.33	**$ 10.21**	$ 10.99
North Sea	**$ 0.34**	$ 0.41	$ 0.26	**$ 0.37**	$ 0.28
Offshore Africa	**$ 18.38**	$ 17.71	$ 28.63	**$ 18.05**	$ 24.90
Company average	**$ 11.60**	$ 8.76	$ 9.18	**$ 10.17**	$ 11.10
Natural gas ($/Mcf) [1]					
North America	**$ 0.25**	$ 0.09	$ 0.02	**$ 0.17**	$ 0.02
Offshore Africa	**$ 1.68**	$ 1.57	$ 1.86	**$ 1.63**	$ 1.72
Company average	**$ 0.28**	$ 0.12	$ 0.05	**$ 0.20**	$ 0.05
Company average ($/BOE) [1]	**$ 8.29**	$ 6.05	$ 5.93	**$ 7.16**	$ 7.08

(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, 2013 compared with the six months ended June 30, 2012 reflected movements in benchmark commodity prices and the fluctuations of the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 17% of product sales for the second quarter of 2013 compared with 13% for the second quarter of 2012 and 16% for the first quarter of 2013. The increase in royalties from the second quarter of 2012 was primarily due to the increase in realized crude oil and NGLs prices. Crude oil and NGLs royalties per bbl are anticipated to average 16% to 18% of product sales for 2013.

Natural gas royalties averaged approximately 7% of product sales for the second quarter of 2013 compared with 1% for the second quarter of 2012 and 3% for the first quarter of 2013. The increase in natural gas royalty rates from the second quarter of 2012 was primarily the result of the increase in realized natural gas prices. The increase from the first quarter of 2013 was primarily the result of the increase in realized natural gas prices, as well as gas cost allowance adjustments in the first quarter of 2013. Natural gas royalties are anticipated to average 4% to 6% of product sales for 2013.

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 17% for the second quarter of 2013 compared with 26% for the second quarter of 2012 and 16% for the first quarter of 2013. The decrease in royalties from the second quarter of 2012 was due to adjustments to royalties on liftings during 2012.

Offshore Africa royalty rates are anticipated to average 12% to 14% of product sales for 2013.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 14.83**	$ 14.61	$ 13.10	**$ 14.72**	$ 14.23
North Sea	**$ 47.85**	$ 74.65	$ 68.32	**$ 60.38**	$ 50.21
Offshore Africa	**$ 17.98**	$ 25.72	$ 22.94	**$ 21.84**	$ 18.29
Company average	**$ 16.51**	$ 17.56	$ 16.66	**$ 17.04**	$ 16.72
Natural gas ($/Mcf) (1)					
North America	**$ 1.38**	$ 1.52	$ 1.13	**$ 1.45**	$ 1.24
North Sea	**$ 3.53**	$ 3.77	$ 3.89	**$ 3.59**	$ 3.94
Offshore Africa	**$ 2.34**	$ 2.24	$ 1.78	**$ 2.30**	$ 1.77
Company average	**$ 1.41**	$ 1.53	$ 1.15	**$ 1.48**	$ 1.25
Company average ($/BOE) (1)	**$ 13.81**	$ 14.74	$ 13.06	**$ 14.28**	$ 13.24

(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, 2013 increased 3% to $14.72 per bbl from $14.23 per bbl for the six months ended June 30, 2012. North America crude oil and NGLs production expense for the second quarter of 2013 increased 13% to $14.83 per bbl from $13.10 per bbl for the second quarter of 2012 and increased 2% from $14.61 per bbl for the first quarter of 2013. The increase in production expense for the three and six months ended June 30, 2013 from the comparable periods in 2012 was primarily the result of higher electricity costs, as well as higher trucking costs related to extended seasonal conditions in heavy oil production. The increase in production expense for the second quarter of 2013 from the first quarter of 2013 was primarily a result of higher electricity costs and extended spring season conditions. North America crude oil and NGLs production expense guidance remains unchanged from the previously issued guidance of $12.00 to $14.00 per bbl for 2013.

North America natural gas production expense for the six months ended June 30, 2013 increased 17% to $1.45 per Mcf from $1.24 per Mcf for the six months ended June 30, 2012. North America natural gas production expense for the second quarter of 2013 increased 22% to $1.38 per Mcf from $1.13 per Mcf for the second quarter of 2012 and decreased 9% from $1.52 per Mcf for the first quarter of 2013. Natural gas production expense increased for the three and six months ended June 30, 2013 from the comparable periods in 2012 primarily due to higher electricity costs along with lower production volumes related to the reduction in natural gas activity. Natural gas production expense decreased for the second quarter of 2013 from the first quarter of 2013 due to normal seasonality. North America natural gas production expense is anticipated to average $1.35 to $1.40 per Mcf for 2013.

North Sea

North Sea crude oil production expense for the six months ended June 30, 2013 increased 20% to $60.38 per bbl from $50.21 per bbl for the six months ended June 30, 2012. North Sea crude oil production expense for the second quarter of 2013 decreased 30% to $47.85 per bbl from $68.32 per bbl for the second quarter of 2012 and decreased 36% from $74.65 per bbl for the first quarter of 2013. Production expense increased on a per barrel basis for the six months ended June 30, 2013 from the comparable period due to the impact of production declines on relatively fixed costs as well as higher maintenance activity and increased fuel costs. Production expense decreased for the second quarter of 2013 from the comparable periods due to increased production volumes on relatively fixed costs and the timing of liftings from various fields, which have different cost structures. North Sea crude oil production expense is anticipated to average $62.00 to $66.00 per bbl for 2013 due to natural declines on a relatively fixed cost structure.

Offshore Africa

Offshore Africa crude oil production expense for the six months ended June 30, 2013 increased 19% to $21.84 per bbl from $18.29 per bbl for the six months ended June 30, 2012. Offshore Africa crude oil production expense for the second quarter of 2013 averaged $17.98 per bbl, a decrease of 22% from $22.94 per bbl for the second quarter of 2012, and a decrease of 30% from $25.72 per bbl for the first quarter of 2013. Production expense fluctuated for the three and six months ended June 30, 2013 from the comparable periods 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 $30.00 to $34.00 per bbl for 2013 due to timing of liftings from various fields, which have different cost structures.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Expense ($ millions)	**$ 1,009**	$ 1,023	$ 936	**$ 2,032**	$ 1,846
$/BOE (1)	**$ 19.97**	$ 19.99	$ 18.13	**$ 19.98**	$ 17.93

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

Depletion, depreciation and amortization expense increased for the three and six months ended June 30, 2013 compared with 2012 due to higher sales volumes in North America associated with heavy oil drilling and higher overall future development costs. The decrease in depletion, depreciation and amortization expense for the second quarter of 2013 from the first quarter of 2013 was primarily due to lower sales volumes in North America.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Expense ($ millions)	**$ 33**	$ 34	$ 30	**$ 67**	$ 59
$/BOE (1)	**$ 0.65**	$ 0.66	$ 0.59	**$ 0.65**	$ 0.58

(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

The Company continues to focus on efficient and effective operations at Horizon and place emphasis on safe, steady, reliable operations. In May 2013, the Company successfully completed a planned maintenance turnaround. During the outage, all major scopes of work were completed including the change out of the catalysts in the hydro-treating units. Repairs to certain equipment extended slightly beyond the original forecasted timeframe. The impact of the turnaround has been reflected in the Company's 2013 production, cash production cost and capital expenditure guidance.

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

($/bbl) [1]	Three Months Ended **Jun 30 2013**	Mar 31 2013	Jun 30 2012	Six Months Ended **Jun 30 2013**	Jun 30 2012
SCO sales price [2]	**$ 99.63**	$ 96.19	$ 89.76	**$ 97.58**	$ 93.62
Bitumen value for royalty purposes [3]	**$ 61.08**	$ 60.47	$ 59.83	**$ 60.71**	$ 62.10
Bitumen royalties [4]	**$ 4.41**	$ 3.81	$ 5.20	**$ 4.05**	$ 5.19
Transportation	**$ 1.72**	$ 1.58	$ 1.65	**$ 1.64**	$ 1.78

(1) Amounts expressed on a per unit basis are based on sales volumes excluding the period of turnaround/suspension of production.
(2) Comparative figures have been adjusted to reflect realized product prices before transportation costs.
(3) Calculated as the quarterly average of the bitumen valuation methodology price.
(4) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Realized SCO sales prices averaged $97.58 per bbl for the six months ended June 30, 2013, an increase of 4% compared with $93.62 per bbl for six months ended June 30, 2012. Realized SCO sales prices averaged $99.63 per bbl for the second quarter of 2013, an increase of 11% compared with $89.76 per bbl for the second quarter of 2012 and an increase of 4% compared with $96.19 per bbl for the first quarter of 2013, 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 2013**	Mar 31 2013	Jun 30 2012	Six Months Ended **Jun 30 2013**	Jun 30 2012
Cash production costs	**$ 394**	$ 377	$ 388	**$ 771**	$ 734
Less: costs incurred during the period of turnaround/suspension of production	**(104)**	–	–	**(104)**	(154)
Adjusted cash production costs	**$ 290**	$ 377	$ 388	**$ 667**	$ 580
Adjusted cash production costs, excluding natural gas costs	**$ 268**	$ 349	$ 362	**$ 617**	$ 539
Adjusted natural gas costs	**22**	28	26	**50**	41
Adjusted cash production costs	**$ 290**	$ 377	$ 388	**$ 667**	$ 580

($/bbl) [1]	Three Months Ended **Jun 30 2013**	Mar 31 2013	Jun 30 2012	Six Months Ended **Jun 30 2013**	Jun 30 2012
Adjusted cash production costs, excluding natural gas costs	**$ 41.53**	$ 36.95	$ 34.45	**$ 38.81**	$ 36.79
Adjusted natural gas costs	**3.41**	2.98	2.53	**3.15**	2.82
Adjusted cash production costs	**$ 44.94**	$ 39.93	$ 36.98	**$ 41.96**	$ 39.61
Sales (bbl/d) [2]	**70,950**	105,000	115,552	**87,881**	80,646

(1) Adjusted cash production costs on a per unit basis were based on sales volumes excluding the period of turnaround/suspension of production.
(2) Sales volumes include the period of turnaround/suspension of production.

Adjusted cash production costs averaged $41.96 per bbl for the six months ended June 30, 2013, an increase of 6% compared with $39.61 per bbl for the six months ended June 30, 2012. Adjusted cash production costs for the second quarter of 2013 averaged $44.94 per bbl, an increase of 22% compared with $36.98 per bbl for the second quarter of 2012 and an increase of 13% compared with $39.93 per bbl for the first quarter of 2013 primarily due to lower production volumes excluding the period of turnaround. Cash production costs are anticipated to average $38.00 to $41.00 per bbl for 2013.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions)	Three Months Ended Jun 30 2013	Mar 31 2013	Jun 30 2012	Six Months Ended Jun 30 2013	Jun 30 2012
Depletion, depreciation and amortization	**$ 161**	$ 117	$ 146	**$ 278**	$ 209
Less: depreciation incurred during the period of turnaround/suspension of production	**(79)**	–	–	**(79)**	(6)
Adjusted depletion, depreciation and amortization	**$ 82**	$ 117	$ 146	**$ 199**	$ 203
$/bbl (1)	**$ 12.70**	$ 12.35	$ 13.84	**$ 12.49**	$ 13.83

(1) Amounts expressed on a per unit basis are based on sales volumes excluding the period of turnaround/suspension of production.

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

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions)	Three Months Ended Jun 30 2013	Mar 31 2013	Jun 30 2012	Six Months Ended Jun 30 2013	Jun 30 2012
Expense	**$ 9**	$ 8	$ 8	**$ 17**	$ 16
$/bbl (1)	**$ 1.32**	$ 0.90	$ 0.76	**$ 1.07**	$ 1.08

(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 2013	Mar 31 2013	Jun 30 2012	Six Months Ended Jun 30 2013	Jun 30 2012
Revenue	**$ 29**	$ 27	$ 22	**$ 56**	$ 43
Production expense	**9**	8	7	**17**	14
Midstream cash flow	**20**	19	15	**39**	29
Depreciation	**2**	2	2	**4**	4
Equity loss from jointly controlled entity	**–**	2	5	**2**	5
Segment earnings before taxes	**$ 18**	$ 15	$ 8	**$ 33**	$ 20

Midstream operating results were consistent with the comparable periods.

The Company has a 50% interest in the North West Redwater Partnership (“Redwater”). Redwater 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, an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement. During 2012, the Project received board sanction from Redwater and its partners.

ADMINISTRATION EXPENSE

($ millions)	Three Months Ended **Jun 30 2013**	Mar 31 2013	Jun 30 2012	Six Months Ended **Jun 30 2013**	Jun 30 2012
Expense	**$ 81**	$ 79	$ 77	**$ 160**	$ 142
$/BOE (1)	**$ 1.43**	$ 1.30	$ 1.24	**$ 1.36**	$ 1.20

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

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

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended **Jun 30 2013**	Mar 31 2013	Jun 30 2012	Six Months Ended **Jun 30 2013**	Jun 30 2012
(Recovery) expense	**$ (49)**	$ 71	$ (115)	**$ 22**	$ (222)

The Company's stock option plan provides current employees with the right to receive common shares or a direct cash payment in exchange for stock options surrendered.

The Company recorded a $22 million share-based compensation expense for the six months ended June 30, 2013, 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, 2013, the Company capitalized $5 million in respect of share-based compensation expense to Oil Sands Mining and Upgrading (June 30, 2012 – $15 million recovery).

For the six months ended June 30, 2013, the Company paid $1 million for stock options surrendered for cash settlement (June 30, 2012 – $7 million).

INTEREST AND OTHER FINANCING COSTS

($ millions, except per BOE amounts)	Three Months Ended **Jun 30 2013**	Mar 31 2013	Jun 30 2012	Six Months Ended **Jun 30 2013**	Jun 30 2012
Expense, gross	**$ 112**	$ 113	$ 114	**$ 225**	$ 228
Less: capitalized interest	**40**	36	21	**76**	39
Expense, net	**$ 72**	$ 77	$ 93	**$ 149**	$ 189
$/BOE (1)	**$ 1.26**	$ 1.27	$ 1.50	**$ 1.27**	$ 1.61
Average effective interest rate	**4.3%**	4.5%	4.8%	**4.4%**	4.8%

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

Gross interest and other financing costs for the three and six months ended June 30, 2013 were consistent with the comparable periods. Capitalized interest of $76 million for the six months ended June 30, 2013 was related to the Horizon Phase 2/3 expansion and the Kirby Thermal Oil Sands Project, which includes the Kirby South Project.

The Company's average effective interest rate for the three and six months ended June 30, 2013 decreased from the comparable periods in 2012 primarily due to the repayment of $400 million of 4.50% medium-term notes and US$400 million of 5.15% unsecured notes during the first quarter of 2013 and US$350 million of 5.45% unsecured notes in the fourth quarter of 2012. This indebtedness was retired utilizing cash flow from operations generated in excess of capital expenditures and available bank credit facilities, while maintaining the ongoing dividend program. The Company's average effective interest rate for the second quarter of 2013 decreased from the first quarter of 2013 primarily due to an increase in the utilization of the US commercial paper program during the second quarter of 2013.

RISK MANAGEMENT ACTIVITIES

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

($ millions)	Three Months Ended **Jun 30 2013**	Mar 31 2013	Jun 30 2012	Six Months Ended **Jun 30 2013**	Jun 30 2012
Crude oil and NGLs financial instruments	**$ –**	$ –	$ 19	**$ –**	$ 28
Foreign currency contracts	**(19)**	(83)	(80)	**(102)**	5
Realized (gain) loss	**(19)**	(83)	(61)	**(102)**	33
Crude oil and NGLs financial instruments	**(54)**	24	(180)	**(30)**	(84)
Foreign currency contracts	**(60)**	38	36	**(22)**	–
Unrealized (gain) loss	**(114)**	62	(144)	**(52)**	(84)
Net gain	**$ (133)**	$ (21)	$ (205)	**$ (154)**	$ (51)

Complete details related to outstanding derivative financial instruments at June 30, 2013 are disclosed in note 13 to the Company's unaudited interim consolidated financial statements.

The Company recorded a net unrealized gain of $52 million ($41 million after-tax) on its risk management activities for the six months ended June 30, 2013, including an unrealized gain of $114 million ($92 million after-tax) for the second quarter of 2013 (March 31, 2013 – unrealized loss of $62 million; $51 million after-tax; June 30, 2012 – unrealized gain of $144 million; $103 million after-tax).

FOREIGN EXCHANGE

($ millions)	Three Months Ended **Jun 30 2013**	Mar 31 2013	Jun 30 2012	Six Months Ended **Jun 30 2013**	Jun 30 2012
Net realized loss (gain)	**$ 1**	$ (32)	$ (9)	**$ (31)**	$ (3)
Net unrealized loss (1)	**112**	78	71	**190**	11
Net loss	**$ 113**	$ 46	$ 62	**$ 159**	$ 8

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

The net realized foreign exchange gain for the six months ended June 30, 2013 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US$400 million of 5.15% unsecured notes in the first quarter of 2013. The net unrealized foreign exchange loss for the six months ended June 30, 2013 was primarily related to the impact of the weakening of the Canadian dollar with respect to remaining US dollar debt and the reversal of the life-to-date unrealized foreign exchange gain on the repayment of US$400 million of 5.15% unsecured notes in the first quarter of 2013. The net unrealized (gain) loss for each of the periods presented included the impact of cross currency swaps (three months ended June 30, 2013 – unrealized gain of $86 million, March 31, 2013 – unrealized gain of $49 million, June 30, 2012 – unrealized gain of $47 million; six months ended June 30, 2013 – unrealized gain of $135 million; June 30, 2012 – unrealized gain of $5 million). The US/Canadian dollar exchange rate ended the second quarter of 2013 at US$0.9513 (March 31, 2013 – US$0.9846; December 31, 2012 – US$1.0051; June 30, 2012 – US$0.9813).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Jun 30 2013	Three Months Ended Mar 31 2013	Three Months Ended Jun 30 2012	Six Months Ended Jun 30 2013	Six Months Ended Jun 30 2012
North America [1]	**$ 111**	$ 122	$ 124	**$ 233**	$ 237
North Sea	**25**	(7)	19	**18**	64
Offshore Africa	**36**	35	64	**71**	100
PRT (recovery) expense – North Sea	**(33)**	(13)	1	**(46)**	32
Other taxes	**6**	4	5	**10**	11
Current income tax expense	**145**	141	213	**286**	444
Deferred income tax expense (recovery)	**44**	(4)	59	**40**	11
Deferred PRT (recovery) expense – North Sea	**(13)**	(23)	3	**(36)**	(1)
Deferred income tax expense (recovery)	**31**	(27)	62	**4**	10
	176	114	275	**290**	454
Income tax rate and other legislative changes	**(15)**	–	–	**(15)**	–
	$ 161	$ 114	$ 275	**$ 275**	$ 454
Effective income tax rate on adjusted net earnings from operations [2]	**27.9%**	28.1%	27.1%	**28.0%**	30.1%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.
(2) 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.

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.

For 2013, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $600 million to $700 million in Canada and $40 million to $100 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Jun 30 2013	Three Months Ended Mar 31 2013	Three Months Ended Jun 30 2012	Six Months Ended Jun 30 2013	Six Months Ended Jun 30 2012
Exploration and Evaluation					
Net expenditures	**$ 10**	$ 77	$ 32	**$ 87**	$ 240
Property, Plant and Equipment					
Net property acquisitions	**–**	11	7	**11**	45
Well drilling, completion and equipping	**419**	555	352	**974**	851
Production and related facilities	**466**	537	445	**1,003**	950
Capitalized interest and other [2]	**29**	28	30	**57**	60
Net expenditures	**914**	1,131	834	**2,045**	1,906
Total Exploration and Production	**924**	1,208	866	**2,132**	2,146
Oil Sands Mining and Upgrading					
Horizon Phases 2/3 construction costs	**555**	355	346	**910**	538
Sustaining capital	**158**	51	51	**209**	88
Turnaround costs	**80**	17	3	**97**	5
Capitalized interest and other [2]	**22**	38	5	**60**	8
Total Oil Sands Mining and Upgrading	**815**	461	405	**1,276**	639
Midstream	**4**	5	4	**9**	5
Abandonments [3]	**37**	55	39	**92**	115
Head office	**12**	7	10	**19**	15
Total net capital expenditures	**$ 1,792**	$ 1,736	$ 1,324	**$ 3,528**	$ 2,920
By segment					
North America	**$ 826**	$ 1,093	$ 788	**$ 1,919**	$ 2,011
North Sea	**62**	85	66	**147**	120
Offshore Africa	**36**	30	12	**66**	15
Oil Sands Mining and Upgrading	**815**	461	405	**1,276**	639
Midstream	**4**	5	4	**9**	5
Abandonments [3]	**37**	55	39	**92**	115
Head office	**12**	7	10	**19**	15
Total	**$ 1,792**	$ 1,736	$ 1,324	**$ 3,528**	$ 2,920

(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, 2013 were $3,528 million compared with $2,920 million for the six months ended June 30, 2012. Net capital expenditures for the second quarter of 2013 were $1,792 million compared with $1,324 million for the second quarter of 2012 and $1,736 million for the first quarter of 2013.

The increase in capital expenditures for the three and six months ended June 30, 2013 from the comparable periods was primarily due to the ramp up of Horizon site construction activity and the increase in Horizon turnaround and sustaining capital costs resulting from the planned maintenance turnaround in May 2013.

Subsequent to June 30, 2013, the Company acquired all of the issued and outstanding common shares of Barrick Energy Inc. ("BEI") for total cash consideration of approximately $173 million. BEI's assets include working interests in producing crude oil and natural gas properties and undeveloped land.

Drilling Activity (number of wells)

	Three Months Ended			Six Months Ended	
	Jun 30 2013	Mar 31 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Net successful natural gas wells	**8**	15	4	**23**	23
Net successful crude oil wells [1]	**159**	300	266	**459**	544
Dry wells	**5**	5	2	**10**	8
Stratigraphic test / service wells	**16**	305	5	**321**	589
Total	**188**	625	277	**813**	1,164
Success rate (excluding stratigraphic test / service wells)	**97%**	98%	99%	**98%**	99%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 57% of the total capital expenditures for the six months ended June 30, 2013 compared with approximately 73% for the six months ended June 30, 2012.

During the second quarter of 2013, the Company targeted 8 net natural gas wells, including 6 wells in Northeast British Columbia and 2 wells in Northwest Alberta. The Company also targeted 163 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 121 primary heavy crude oil wells, 10 Pelican Lake heavy crude oil wells, and 27 bitumen (thermal oil) wells were drilled. Another 5 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall Primrose thermal production for the second quarter of 2013 averaged approximately 90,000 bbl/d compared with approximately 94,000 bbl/d for the second quarter of 2012 and approximately 109,000 bbl/d for the first quarter of 2013. Production volumes were in line with expectations due to the cyclic nature of thermal production at Primrose. As part of the phased expansion of its in situ Oil Sands assets, the Company is continuing to develop its Primrose thermal projects. Additional pad drilling was completed and drilled on budget, with these wells coming on production in late 2013.

In the second quarter of 2013, the Company discovered bitumen emulsion at surface in areas of the Primrose field. The Company's view is that the cause of the occurrence is mechanical in nature and is working collaboratively with the regulators in the investigation and remediation plans. To minimize the risk of any future occurrences while the investigation is being conducted, adjustments were immediately made to the current steaming strategy and monitoring programs. The Company does not currently expect a change in thermal in situ 2013 annual production guidance.

The next planned phase of the Company's in situ Oil Sands assets expansion is the Kirby South Project. As at June 30, 2013, the overall project was 98% complete, drilling was complete on all seven pads, and first steam is targeted for the third quarter of 2013.

Development of the tertiary recovery conversion projects at Pelican Lake continued and 10 horizontal wells were drilled during the second quarter of 2013. Pelican Lake production averaged approximately 42,000 bbl/d for the second quarter of 2013 compared with 37,000 bbl/d for the second quarter of 2012 and 38,000 bbl/d for the first quarter of 2013. The new 20,000 bbl/d battery was completed in mid-May, alleviating the previous facility constraints at Pelican Lake and Woodenhouse. Field production is currently being optimized at both Woodenhouse and Pelican Lake.

For the third quarter of 2013, the Company's overall planned drilling activity in North America is expected to be 297 net crude oil wells, 47 net bitumen wells and 9 net natural gas wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the second quarter of 2013 was focused on field construction of the gas recovery unit, sulphur recovery unit, butane treatment unit, coker expansion, tank farms, tailings, hydrotransport and extraction trains 3 and 4, along with engineering related to the froth treatment plants, hydrogen unit, hydrotreater unit, vacuum distillation unit and distillation recovery unit.

North Sea

In December 2011, the Banff 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 and associated floating storage unit were subsequently removed from the field and the FPSO is currently undergoing repairs and is targeted to be back in the field in the first half of 2014. The associated repair costs, net of insurance recoveries, are not expected to be significant.

In September 2012, the UK government announced the implementation of the Brownfield Allowance, which allows for an agreed allowance related to property development for certain pre-approved qualifying field developments. This allowance partially mitigates the impact of previous tax increases. The Company received approval for the Brownfield Allowance for the Tiffany field in January 2013 and as a result, has commenced drilling additional production wells. During the second quarter of 2013, the Company drilled one injector well and one additional production well which came on at Tiffany, with production of approximately 1,500 bbl/d, exceeding original forecasted volumes. In May 2013, the Company received approval for the Ninian field Brownfield Allowance and will commence drilling the second platform in the third quarter of 2013.

During the second quarter of 2013, the Company also completed its consolidation of a working interest in a satellite field at the Ninian hub.

The Company currently plans to decommission the Murchison platform in the North Sea commencing in 2014 and estimates the decommissioning efforts will continue for approximately 5 years.

Offshore Africa

During the fourth quarter of 2011, the Company sanctioned an 8 well drilling program at the Espoir field in Côte d'Ivoire. Due to ongoing operational and safety issues with the drilling contractor, the drilling rig currently on site is being de-mobilized and the Company is assessing its drilling options at Espoir.

The midwater arch at the Olowi field in Gabon was stabilized and production was reinstated in late March 2013. The final repairs and assessment have been made and issues relating to the long-term operability of the midwater arch have been resolved.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Jun 30 2013**		Mar 31 2013		Dec 31 2012		Jun 30 2012
Working capital deficit (1)	**$**	**948**	$	1,178	$	1,264	$	(732)
Long-term debt (2) (3)	**$**	**10,033**	$	9,322	$	8,736	$	8,522
Share capital	**$**	**3,736**	$	3,742	$	3,709	$	3,670
Retained earnings		**20,748**		20,564		20,516		20,193
Accumulated other comprehensive income		**67**		68		58		59
Shareholders' equity	**$**	**24,551**	$	24,374	$	24,283	$	23,922
Debt to book capitalization (3) (4)		**29%**		28%		26%		26%
Debt to market capitalization (3) (5)		**24%**		21%		22%		22%
After-tax return on average common shareholders' equity (6)		**6%**		7%		8%		12%
After-tax return on average capital employed (3) (7)		**5%**		6%		7%		10%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.
(2) Includes the current portion of long-term debt.
(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and 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 costs for the twelve month trailing period; as a percentage of average capital employed for the period.

At June 30, 2013, 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 December 31, 2012 annual MD&A. 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 the first quarter of 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.

At June 30, 2013, the Company had $2,384 million of available credit under its bank credit facilities, net of commercial paper issuances of $263 million.

During the first quarter of 2013, the Company repaid $400 million of 4.50% medium-term notes and US$400 million of 5.15% unsecured notes. The Company retired this indebtedness utilizing cash flow from operations generated in excess of capital expenditures and available bank credit facilities, while maintaining the ongoing dividend program.

During the second quarter of 2013, the $3,000 million revolving syndicated credit facility was extended to June 2017. Additionally, the Company issued $500 million of 2.89% medium-term notes due August 2020. Proceeds from the securities issued were used to repay bank indebtedness and for general corporate purposes. 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 November 2013. If issued, these securities will bear interest as determined at the date of issuance.

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 November 2013. If issued, these securities will bear interest as determined at the date of issuance.

Long-term debt was $10,033 million at June 30, 2013, resulting in a debt to book capitalization ratio of 29% (March 31, 2013 – 28%; December 31, 2012 – 26%; June 30, 2012 – 26%). 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 operating activities 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 crude oil production for 2013 and 2014 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, 2013 are discussed in note 6 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 7, 2013, approximately 58% of currently forecasted 2013 crude oil volumes were hedged using price collars and physical crude oil sales contracts with fixed WCS differentials. Further details related to the Company's commodity related derivative financial instruments outstanding at June 30, 2013 are discussed in note 13 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at June 30, 2013, there were 1,086,969,000 common shares outstanding (June 30, 2012 – 1,096,497,000 common shares) and 67,463,000 stock options outstanding. As at August 6, 2013, the Company had 1,087,477,000 common shares outstanding and 66,328,000 stock options outstanding.

On March 6, 2013, the Company's Board of Directors approved an increase in the annual dividend to be paid by the Company to $0.50 per common share for 2013. The increase represents an approximately 19% increase from 2012, recognizing 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 2013, 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 2013 and ending April 2014, up to 54,635,116 common shares. The Company's Normal Course Issuer Bid announced in 2012 expired April 2013.

For the six months ended June 30, 2013, the Company purchased 6,707,500 common shares at a weighted average price of $30.86 per common share, for a total cost of $207 million. Retained earnings were reduced by $184 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2013, the Company purchased 230,000 common shares at a weighted average price of $30.98 per common share for a total cost of $7 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, 2013:

($ millions)	Remaining 2013	2014	2015	2016	2017	Thereafter
Product transportation and pipeline	$ 117	$ 225	$ 209	$ 138	$ 118	$ 795
Offshore equipment operating leases	$ 65	$ 128	$ 110	$ 80	$ 60	$ 71
Long-term debt (1)	$ 263	$ 894	$ 400	$ 830	$ 2,551	$ 5,153
Interest and other financing costs (2)	$ 226	$ 452	$ 417	$ 400	$ 328	$ 4,026
Office leases	$ 16	$ 34	$ 32	$ 33	$ 35	$ 262
Other	$ 97	$ 99	$ 86	$ 15	$ 2	$ 6

(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 cost 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, 2013.

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 a 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, 2013.

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, 2012.

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	**Jun 30 2013**	Dec 31 2012
ASSETS			
Current assets			
Cash and cash equivalents		**$ 17**	$ 37
Accounts receivable		**1,614**	1,197
Inventory		**656**	554
Prepaids and other		**213**	126
Current portion of other long-term assets	5	**35**	–
		2,535	1,914
Exploration and evaluation assets	3	**2,655**	2,611
Property, plant and equipment	4	**45,251**	44,028
Other long-term assets	5	**369**	427
		$ 50,810	$ 48,980
LIABILITIES			
Current liabilities			
Accounts payable		**$ 667**	$ 465
Accrued liabilities		**2,451**	2,273
Current income tax liabilities		**212**	285
Current portion of long-term debt	6	**263**	798
Current portion of other long-term liabilities	7	**153**	155
		3,746	3,976
Long-term debt	6	**9,770**	7,938
Other long-term liabilities	7	**4,513**	4,609
Deferred income tax liabilities		**8,230**	8,174
		26,259	24,697
SHAREHOLDERS' EQUITY			
Share capital	9	**3,736**	3,709
Retained earnings		**20,748**	20,516
Accumulated other comprehensive income	10	**67**	58
		24,551	24,283
		$ 50,810	$ 48,980

Commitments and contingencies (note 14).

Approved by the Board of Directors on August 7, 2013

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Jun 30 2013	Three Months Ended Jun 30 2012	Six Months Ended Jun 30 2013	Six Months Ended Jun 30 2012
Product sales		**$ 4,230**	$ 4,187	**$ 8,331**	$ 8,158
Less: royalties		**(446)**	(361)	**(792)**	(805)
Revenue		**3,784**	3,826	**7,539**	7,353
Expenses					
Production		**1,096**	1,068	**2,231**	2,106
Transportation and blending		**738**	691	**1,593**	1,408
Depletion, depreciation and amortization	4	**1,172**	1,084	**2,314**	2,059
Administration		**81**	77	**160**	142
Share-based compensation	7	**(49)**	(115)	**22**	(222)
Asset retirement obligation accretion	7	**42**	38	**84**	75
Interest and other financing costs		**72**	93	**149**	189
Risk management activities	13	**(133)**	(205)	**(154)**	(51)
Foreign exchange loss		**113**	62	**159**	8
Equity loss from jointly controlled entity	5	**–**	5	**2**	5
		3,132	2,798	**6,560**	5,719
Earnings before taxes		**652**	1,028	**979**	1,634
Current income tax expense	8	**145**	213	**286**	444
Deferred income tax expense	8	**31**	62	**4**	10
Net earnings		**$ 476**	$ 753	**$ 689**	$ 1,180
Net earnings per common share					
Basic	12	**$ 0.44**	$ 0.68	**$ 0.63**	$ 1.07
Diluted	12	**$ 0.44**	$ 0.68	**$ 0.63**	$ 1.07

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended Jun 30 2013	Three Months Ended Jun 30 2012	Six Months Ended Jun 30 2013	Six Months Ended Jun 30 2012
Net earnings	**$ 476**	$ 753	**$ 689**	$ 1,180
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 $1 million (2012 – $1 million) – three months ended; $3 million (2012 – $5 million) – six months ended	**6**	10	**22**	34
Reclassification to net earnings, net of taxes of $nil (2012 – $nil) – three months ended; $nil (2012 – $nil) – six months ended	**(1)**	(2)	**(2)**	(1)
	5	8	**20**	33
Foreign currency translation adjustment				
Translation of net investment	**(6)**	(8)	**(11)**	–
Other comprehensive (loss) income, net of taxes	**(1)**	–	**9**	33
Comprehensive income	**$ 475**	$ 753	**$ 698**	$ 1,213

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Six Months Ended Jun 30 2013	Jun 30 2012
Share capital	9		
Balance – beginning of period		**$ 3,709**	$ 3,507
Issued upon exercise of stock options		**39**	140
Previously recognized liability on stock options exercised for common shares		**11**	39
Purchase of common shares under Normal Course Issuer Bid		**(23)**	(16)
Balance – end of period		**3,736**	3,670
Retained earnings			
Balance – beginning of period		**20,516**	19,365
Net earnings		**689**	1,180
Purchase of common shares under Normal Course Issuer Bid	9	**(184)**	(121)
Dividends on common shares	9	**(273)**	(231)
Balance – end of period		**20,748**	20,193
Accumulated other comprehensive income	10		
Balance – beginning of period		**58**	26
Other comprehensive income, net of taxes		**9**	33
Balance – end of period		**67**	59
Shareholders' equity		**$ 24,551**	$ 23,922

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Jun 30 2013**	Three Months Ended Jun 30 2012	Six Months Ended **Jun 30 2013**	Six Months Ended Jun 30 2012
Operating activities					
Net earnings		**$ 476**	$ 753	**$ 689**	$ 1,180
Non-cash items					
Depletion, depreciation and amortization		**1,172**	1,084	**2,314**	2,059
Share-based compensation		**(49)**	(115)	**22**	(222)
Asset retirement obligation accretion		**42**	38	**84**	75
Unrealized risk management gain		**(114)**	(144)	**(52)**	(84)
Unrealized foreign exchange loss		**112**	71	**190**	11
Realized foreign exchange gain on repayment of US dollar debt securities		**–**	–	**(12)**	–
Equity loss from jointly controlled entity		**–**	5	**2**	5
Deferred income tax expense		**31**	62	**4**	10
Other		**18**	17	**56**	40
Abandonment expenditures		**(37)**	(39)	**(92)**	(115)
Net change in non-cash working capital		**87**	(117)	**(302)**	113
		1,738	1,615	**2,903**	3,072
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net		**(5)**	(352)	**1,251**	(559)
Issue of medium-term notes, net	6	**498**	498	**98**	498
Repayment of US dollar debt securities		**–**	–	**(398)**	–
Issue of common shares on exercise of stock options		**9**	9	**39**	140
Purchase of common shares under Normal Course Issuer Bid		**(175)**	(114)	**(207)**	(137)
Dividends on common shares		**(136)**	(115)	**(251)**	(214)
Net change in non-cash working capital		**(5)**	(13)	**(11)**	(16)
		186	(87)	**521**	(288)
Investing activities					
Expenditures on exploration and evaluation assets and property, plant and equipment		**(1,755)**	(1,285)	**(3,436)**	(2,805)
Investment in other long-term assets		**–**	2	**–**	2
Net change in non-cash working capital		**(170)**	(248)	**(8)**	(5)
		(1,925)	(1,531)	**(3,444)**	(2,808)
Decrease in cash and cash equivalents		**(1)**	(3)	**(20)**	(24)
Cash and cash equivalents – beginning of period		**18**	13	**37**	34
Cash and cash equivalents – end of period		**$ 17**	$ 10	**$ 17**	$ 10
Interest paid		**$ 97**	$ 93	**$ 239**	$ 226
Income taxes paid		**$ 71**	$ 170	**$ 284**	$ 435

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts in millions of Canadian dollars, unless otherwise stated, unaudited)

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire, Gabon, and South Africa in Offshore Africa.

The Horizon Oil Sands Mining and Upgrading segment ("Horizon") produces synthetic crude oil through bitumen mining and upgrading operations.

Within Western Canada, the Company maintains certain midstream activities that include pipeline operations, an electricity co-generation system and an investment in the North West Redwater Partnership ("Redwater").

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, 2012, 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, 2012.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2013, the Company adopted the following new accounting standards issued by the IASB:

a)
- IFRS 10 "Consolidated Financial Statements" replaced IAS 27 "Consolidated and Separate Financial Statements" (IAS 27 still contains guidance for Separate Financial Statements) and Standing Interpretations Committee ("SIC") 12 "Consolidation – Special Purpose Entities". IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on applying the control principle to determine whether an investor controls an investee.

- IFRS 11 "Joint Arrangements" replaced IAS 31 "Interests in Joint Ventures" and SIC 13 "Jointly Controlled Entities – Non-Monetary Contributions by Venturers". The new standard defines two types of joint arrangements, joint operations and joint ventures. In a joint operation, the parties with joint control have rights to the assets and obligations for the liabilities of the joint arrangement and are required to recognize their proportionate interest in the assets, liabilities, revenues and expenses of the joint arrangement. In a joint venture, the parties have an interest in the net assets of the arrangement and are required to apply the equity method of accounting.

- IFRS 12 "Disclosure of Interests in Other Entities". The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities.

- The Company adopted these standards retrospectively.

b) IFRS 13 "Fair Value Measurement" provides guidance on applying fair value where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value. IFRS 13 was adopted prospectively. As a result of adoption of this standard, the Company has included its own credit risk in measuring the carrying amount of a risk management liability.

c) Amendments to IAS 1 "Presentation of Financial Statements" require items of other comprehensive income that may be reclassified to net earnings to be grouped together. The amendments also require that items in other comprehensive income and net earnings be presented as either a single statement or two consecutive statements. Adoption of this amended standard impacted presentation only.

d) IFRS Interpretation Committee ("IFRIC") 20 "Stripping Costs in the Production Phase of a Surface Mine" requires overburden removal costs during the production phase to be capitalized and depreciated if the Company can demonstrate that probable future economic benefits will be realized, the costs can be reliably measured, and the Company can identify the component of the ore body for which access has been improved.

Adoption of these standards did not have a material impact on the Company's consolidated financial statements.

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2012	$ 2,564	$ –	$ 47	$ –	$ 2,611
Additions	**80**	**–**	**7**	**–**	**87**
Transfers to property, plant and equipment	**(45)**	**–**	**–**	**–**	**(45)**
Foreign exchange adjustments	**–**	**–**	**2**	**–**	**2**
At June 30, 2013	**$ 2,599**	**$ –**	**$ 56**	**$ –**	**$ 2,655**

4. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2012	$ 50,324	$ 4,574	$ 3,045	$ 16,963	$ 312	$ 270	$ 75,488
Additions	**1,846**	**147**	**59**	**1,276**	**9**	**19**	**3,356**
Transfers from E&E assets	**45**	**–**	**–**	**–**	**–**	**–**	**45**
Disposals/derecognitions	**(100)**	**–**	**–**	**(317)**	**–**	**–**	**(417)**
Foreign exchange adjustments and other	**–**	**267**	**176**	**–**	**–**	**–**	**443**
At June 30, 2013	**$ 52,115**	**$ 4,988**	**$ 3,280**	**$ 17,922**	**$ 321**	**$ 289**	**$ 78,915**
Accumulated depletion and depreciation							
At December 31, 2012	$ 24,991	$ 2,709	$ 2,273	$ 1,202	$ 103	$ 182	$ 31,460
Expense	**1,718**	**224**	**80**	**278**	**4**	**10**	**2,314**
Disposals/derecognitions	**(100)**	**–**	**–**	**(317)**	**–**	**–**	**(417)**
Foreign exchange adjustments and other	**–**	**173**	**134**	**–**	**–**	**–**	**307**
At June 30, 2013	**$ 26,609**	**$ 3,106**	**$ 2,487**	**$ 1,163**	**$ 107**	**$ 192**	**$ 33,664**
Net book value							
– at June 30, 2013	**$ 25,506**	**$ 1,882**	**$ 793**	**$ 16,759**	**$ 214**	**$ 97**	**$ 45,251**
– at December 31, 2012	$ 25,333	$ 1,865	$ 772	$ 15,761	$ 209	$ 88	$ 44,028

Horizon project costs not subject to depletion	
At June 30, 2013	**$ 3,022**
At December 31, 2012	$ 2,066

In addition, the Company has capitalized costs to date of $1,320 million (December 31, 2012 – $1,021 million) related to the development of the Kirby Thermal Oil Sands Project which are not subject to depletion.

The Company acquired a number of producing crude oil and natural gas assets in the North American and North Sea Exploration and Production segments for total cash consideration of $11 million during the six months ended June 30, 2013 (year ended December 31, 2012 – $144 million), net of associated asset retirement obligations of $10 million (year ended December 31, 2012 – $12 million). Interests in jointly controlled assets were acquired with full tax basis. No working capital or debt obligations were assumed.

Subsequent to June 30, 2013, the Company acquired all of the issued and outstanding common shares of Barrick Energy Inc. ("BEI") for total cash consideration of approximately $173 million. BEI's assets include working interests in producing crude oil and natural gas properties and undeveloped land. Due to the timing of the close of the acquisition, the purchase accounting and related disclosures have not been finalized.

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 construction is substantially complete. For the six months ended June 30, 2013, pre-tax interest of $76 million (June 30, 2012 – $39 million) was capitalized to property, plant and equipment using a capitalization rate of 4.4% (June 30, 2012 – 4.8%).

5. OTHER LONG-TERM ASSETS

	Jun 30 2013	Dec 31 2012
Investment in North West Redwater Partnership	$ 308	$ 310
Risk management (note 13)	35	–
Other	61	117
	404	427
Less: current portion	35	–
	$ 369	$ 427

Other long-term assets include an investment in the 50% owned Redwater. The investment is accounted for using the equity method. Redwater 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, an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement. During 2012, the Project received board sanction from Redwater and its partners.

As at June 30, 2013, Redwater had interim borrowings of $353 million under credit facilities totaling $600 million which mature no later than December 2017. These facilities are secured by a floating charge on the assets of Redwater with a mandatory repayment required from future financing proceeds. At maturity, under its processing agreement, the Company would be obligated to pay its 25% pro rate share of any shortfall.

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

6. LONG-TERM DEBT

	Jun 30 2013	Dec 31 2012
Canadian dollar denominated debt		
Bank credit facilities	$ 1,963	$ 971
Medium-term notes	1,400	1,300
	3,363	2,271
US dollar denominated debt		
Commercial paper (June 30, 2013 – US$250 million; December 31, 2012 – US$nil)	263	–
US dollar debt securities (June 30, 2013 – US$6,150 million; December 31, 2012 – US$6,550 million)	6,465	6,517
Less: original issue discount on US dollar debt securities (1)	(19)	(20)
	6,709	6,497
Fair value impact of interest rate swaps on US dollar debt securities (2)	14	19
	6,723	6,516
Long-term debt before transaction costs	10,086	8,787
Less: transaction costs (1) (3)	(53)	(51)
	10,033	8,736
Less: current portion of commercial paper	263	–
current portion of other long-term debt (1)	–	798
	$ 9,770	$ 7,938

(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% unsecured notes due December 2014 was adjusted by $14 million (December 31, 2012 – $19 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, 2013, the Company had in place unsecured bank credit facilities of $4,724 million, comprised of:

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

During the second quarter of 2013, the $3,000 million revolving syndicated credit facility was extended to June 2017. Each of the $3,000 million and $1,500 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 established a US commercial paper program in the first quarter of 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.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at June 30, 2013, was 2.1% (June 30, 2012 – 1.9%), and on long-term debt outstanding for the six months ended June 30, 2013 was 4.4% (June 30, 2012 – 4.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $560 million, including a $77 million financial guarantee related to Horizon and $358 million of letters of credit related to North Sea operations, were outstanding at June 30, 2013.

Medium-Term Notes

During the first quarter of 2013, the Company repaid $400 million of 4.50% medium-term notes.

During the second quarter of 2013, the Company issued $500 million of 2.89% medium-term notes due August 2020. Proceeds from the securities issued were used to repay bank indebtedness and for general corporate purposes. 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 November 2013. If issued, these securities will bear interest as determined at the date of issuance.

US Dollar Debt Securities

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

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 November 2013. If issued, these securities will bear interest as determined at the date of issuance.

7. OTHER LONG-TERM LIABILITIES

	Jun 30 2013	Dec 31 2012
Asset retirement obligations	**$ 4,340**	$ 4,266
Share-based compensation	**169**	154
Risk management (note 13)	**80**	257
Other	**77**	87
	4,666	4,764
Less: current portion	**153**	155
	$ 4,513	$ 4,609

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.3% (December 31, 2012 – 4.3%). A reconciliation of the discounted asset retirement obligations is as follows:

	Jun 30 2013	Dec 31 2012
Balance – beginning of period	**$ 4,266**	$ 3,577
Liabilities incurred	**27**	51
Liabilities acquired	**10**	12
Liabilities settled	**(92)**	(204)
Asset retirement obligation accretion	**84**	151
Revision of estimates	**(27)**	384
Change in discount rate	**–**	315
Foreign exchange	**72**	(20)
Balance – end of period	**$ 4,340**	$ 4,266

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 2013	Dec 31 2012
Balance – beginning of period	**$ 154**	$ 432
Share-based compensation expense (recovery)	**22**	(214)
Cash payment for stock options surrendered	**(1)**	(7)
Transferred to common shares	**(11)**	(45)
Capitalized to (recovered from) Oil Sands Mining and Upgrading	**5**	(12)
Balance – end of period	**169**	154
Less: current portion	**131**	129
	$ 38	$ 25

8. INCOME TAXES

The provision for income tax is as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Current corporate income tax – North America	**$ 111**	$ 124	**$ 233**	$ 237
Current corporate income tax – North Sea	**25**	19	**18**	64
Current corporate income tax – Offshore Africa	**36**	64	**71**	100
Current PRT [(1)] (recovery) expense – North Sea	**(33)**	1	**(46)**	32
Other taxes	**6**	5	**10**	11
Current income tax expense	**145**	213	**286**	444
Deferred corporate income tax expense	**44**	59	**40**	11
Deferred PRT [(1)] (recovery) expense – North Sea	**(13)**	3	**(36)**	(1)
Deferred income tax expense	**31**	62	**4**	10
Income tax expense	**$ 176**	$ 275	**$ 290**	$ 454

(1) Petroleum Revenue Tax.

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.

9. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued common shares	Six Months Ended Jun 30, 2013 **Number of shares** (thousands)		**Amount**
Balance – beginning of period	**1,092,072**	**$**	**3,709**
Issued upon exercise of stock options	**1,605**		**39**
Previously recognized liability on stock options exercised for common shares	**–**		**11**
Purchase of common shares under Normal Course Issuer Bid	**(6,708)**		**(23)**
Balance – end of period	**1,086,969**	**$**	**3,736**

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 6, 2013, the Board of Directors set the regular quarterly dividend at $0.125 per common share (2012 – $0.105 per common share).

Normal Course Issuer Bid

In April 2013, 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 2013 and ending April 2014, up to 54,635,116 common shares. The Company's Normal Course Issuer Bid announced in 2012 expired April 2013.

For the six months ended June 30, 2013, the Company purchased 6,707,500 common shares at a weighted average price of $30.86 per common share, for a total cost of $207 million. Retained earnings were reduced by $184 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2013, the Company purchased 230,000 common shares at a weighted average price of $30.98 per common share for a total cost of $7 million.

Stock Options

The following table summarizes information relating to stock options outstanding at June 30, 2013:

	Six Months Ended Jun 30, 2013 **Stock options** (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**73,747**	**$**	**34.13**
Granted	**5,809**	**$**	**29.82**
Surrendered for cash settlement	**(133)**	**$**	**23.52**
Exercised for common shares	**(1,605)**	**$**	**24.86**
Forfeited	**(10,355)**	**$**	**35.08**
Outstanding – end of period	**67,463**	**$**	**33.84**
Exercisable – end of period	**21,106**	**$**	**34.13**

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.

10. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

		Jun 30 2013		Jun 30 2012
Derivative financial instruments designated as cash flow hedges	**$**	**106**	$	95
Foreign currency translation adjustment		**(39)**		(36)
	$	**67**	$	59

11. 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, 2013, the ratio was within the target range at 29%.

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 2013		Dec 31 2012
Long-term debt [(1)]	$	**10,033**	$	8,736
Total shareholders' equity	$	**24,551**	$	24,283
Debt to book capitalization		**29%**		26%

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

12. NET EARNINGS PER COMMON SHARE

	Three Months Ended				Six Months Ended			
		Jun 30 2013		Jun 30 2012		**Jun 30 2013**		Jun 30 2012
Weighted average common shares outstanding – basic (thousands of shares)		**1,089,302**		1,099,046		**1,090,858**		1,099,600
Effect of dilutive stock options (thousands of shares)		**1,719**		2,055		**1,896**		3,131
Weighted average common shares outstanding – diluted (thousands of shares)		**1,091,021**		1,101,101		**1,092,754**		1,102,731
Net earnings	**$**	**476**	$	753	**$**	**689**	$	1,180
Net earnings per common share – basic	**$**	**0.44**	$	0.68	**$**	**0.63**	$	1.07
– diluted	**$**	**0.44**	$	0.68	**$**	**0.63**	$	1.07

13. FINANCIAL INSTRUMENTS

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

	Jun 30, 2013				
Asset (liability)	**Loans and receivables at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 1,614**	**$ –**	**$ –**	**$ –**	**$ 1,614**
Other long-term assets	**–**	**32**	**3**	**–**	**35**
Accounts payable	**–**	**–**	**–**	**(667)**	**(667)**
Accrued liabilities	**–**	**–**	**–**	**(2,451)**	**(2,451)**
Other long-term liabilities	**–**	**20**	**(100)**	**(68)**	**(148)**
Long-term debt [(1)]	**–**	**–**	**–**	**(10,033)**	**(10,033)**
	$ 1,614	**$ 52**	**$ (97)**	**$ (13,219)**	**$ (11,650)**

	Dec 31, 2012				
Asset (liability)	Loans and receivables at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 1,197	$ –	$ –	$ –	$ 1,197
Accounts payable	–	–	–	(465)	(465)
Accrued liabilities	–	–	–	(2,273)	(2,273)
Other long-term liabilities	–	4	(261)	(79)	(336)
Long-term debt [(1)]	–	–	–	(8,736)	(8,736)
	$ 1,197	$ 4	$ (261)	$ (11,553)	$ (10,613)

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

	Jun 30, 2013		
	Carrying amount	**Fair value**	
Asset (liability) [1]		**Level 1**	**Level 2**
Other long-term assets	**$ 35**	**$ –**	**$ 35**
Other long-term liabilities	**(80)**	**–**	**(80)**
Fixed rate long-term debt [2] [3] [4]	**(7,807)**	**(8,591)**	**–**
	$ (7,852)	**$ (8,591)**	**$ (45)**

	Dec 31, 2012		
	Carrying amount	Fair value	
Asset (liability) [1]		Level 1	Level 2
Other long-term liabilities	$ (257)	$ –	$ (257)
Fixed rate long-term debt [2] [3] [4]	(7,765)	(9,118)	–
	$ (8,022)	$ (9,118)	$ (257)

(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% unsecured notes due December 2014 was adjusted by $14 million (December 31, 2012 – $19 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.

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

Asset (liability)	**Jun 30, 2013**	Dec 31, 2012
Derivatives held for trading		
Crude oil price collars	**$ 14**	$ (16)
Foreign currency forward contracts	**38**	20
Cash flow hedges		
Foreign currency forward contracts	**2**	–
Cross currency swaps	**(99)**	(261)
	$ (45)	$ (257)
Included within:		
Current portion of other long-term assets (liabilities)	**$ 35**	$ (4)
Other long-term liabilities	**(80)**	(253)
	$ (45)	$ (257)

For the six months ended June 30, 2013 the Company recognized a gain of $3 million (December 31, 2012 – gain of $1 million) related to ineffectiveness arising from cash flow hedges.

Risk Management

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. 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 market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. 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.

The changes in estimated fair values of derivative financial instruments included in the risk management asset (liability) were recognized in the financial statements as follows:

Asset (liability)	**Six Months Ended Jun 30, 2013**	Year Ended Dec 31, 2012
Balance – beginning of period	**$ (257)**	$ (274)
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	**52**	42
Foreign exchange	**137**	(53)
Other comprehensive income	**23**	28
Balance – end of period	**(45)**	(257)
Less: current portion	**35**	(4)
	$ (80)	$ (253)

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

	Three Months Ended		Six Months Ended	
	Jun 30 2013	Jun 30 2012	**Jun 30 2013**	Jun 30 2012
Net realized risk management (gain) loss	**$ (19)**	$ (61)	**$ (102)**	$ 33
Net unrealized risk management gain	**(114)**	(144)	**(52)**	(84)
	$ (133)	$ (205)	**$ (154)**	$ (51)

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, 2013, 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 [1]	Jul 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$135.59	Brent
	Jul 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$132.18	Brent
	Jan 2014	–	Dec 2014	50,000 bbl/d	US$75.00	–	US$121.57	Brent
	Jul 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$97.73	WTI
	Jul 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$110.34	WTI
	Jul 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$111.05	WTI
	Jan 2014	–	Dec 2014	50,000 bbl/d	US$75.00	–	US$105.54	WTI

(1) Subsequent to June 30, 2013, the Company entered into an additional 50,000 bbl/d of US$80.00 – US$118.26 WTI collars for the period August to December 2013 and an additional 50,000 bbl/d of US$80.00 – US$120.17 Brent collars for the period January to December 2014.

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. The 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, 2013, 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 in its subsidiaries 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 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, 2013, 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 2013	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Jul 2013	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Jul 2013	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Jul 2013	–	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments designated as hedges at June 30, 2013, were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at June 30, 2013, the Company had US$2,643 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$250 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, 2013, 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, 2013, the Company had net risk management assets of $29 million with specific counterparties related to derivative financial instruments (December 31, 2012 – $18 million).

c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

The maturity dates for financial liabilities are as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 667	$ –	$ –	$ –
Accrued liabilities	$ 2,451	$ –	$ –	$ –
Risk management	$ –	$ 9	$ 53	$ 18
Other long-term liabilities	$ 22	$ 46	$ –	$ –
Long-term debt (1)	$ 263	$ 1,294	$ 3,802	$ 4,732

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

14. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	Remaining 2013	2014	2015	2016	2017	Thereafter
Product transportation and pipeline	$ 117	$ 225	$ 209	$ 138	$ 118	$ 795
Offshore equipment operating leases	$ 65	$ 128	$ 110	$ 80	$ 60	$ 71
Office leases	$ 16	$ 34	$ 32	$ 33	$ 35	$ 262
Other	$ 97	$ 99	$ 86	$ 15	$ 2	$ 6

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 a 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.

15. 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	
	2013	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012
Segmented product sales	**3,189**	2,757	**5,997**	5,815	**187**	236	**364**	515	**206**	240	**414**	457	**3,582**	3,233	**6,775**	6,787
Less: royalties	**(384)**	(244)	**(660)**	(632)	**–**	–	**(1)**	(1)	**(34)**	(62)	**(67)**	(96)	**(418)**	(306)	**(728)**	(729)
Segmented revenue	**2,805**	2,513	**5,337**	5,183	**187**	236	**363**	514	**172**	178	**347**	361	**3,164**	2,927	**6,047**	6,058
Segmented expenses																
Production	**588**	505	**1,193**	1,087	**75**	119	**177**	204	**36**	51	**83**	73	**699**	675	**1,453**	1,364
Transportation and blending	**735**	683	**1,590**	1,398	**1**	3	**3**	6	**1**	1	**1**	1	**737**	687	**1,594**	1,405
Depletion, depreciation and amortization	**855**	811	**1,726**	1,609	**114**	75	**226**	159	**40**	50	**80**	78	**1,009**	936	**2,032**	1,846
Asset retirement obligation accretion	**23**	21	**46**	42	**8**	7	**17**	14	**2**	2	**4**	3	**33**	30	**67**	59
Realized risk management activities	**(19)**	(61)	**(102)**	33	**–**	–	**–**	–	**–**	–	**–**	–	**(19)**	(61)	**(102)**	33
Equity loss from jointly controlled entity	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Total segmented expenses	**2,182**	1,959	**4,453**	4,169	**198**	204	**423**	383	**79**	104	**168**	155	**2,459**	2,267	**5,044**	4,707
Segmented earnings (loss) before the following	**623**	554	**884**	1,014	**(11)**	32	**(60)**	131	**93**	74	**179**	206	**705**	660	**1,003**	1,351
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing costs																
Unrealized risk management activities																
Foreign exchange 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	
	2013	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012
Segmented product sales	**643**	951	**1,552**	1,365	**29**	22	**56**	43	**(24)**	(19)	**(52)**	(37)	**4,230**	4,187	**8,331**	8,158
Less: royalties	**(28)**	(55)	**(64)**	(76)	**–**	–	**–**	–	**–**	–	**–**	–	**(446)**	(361)	**(792)**	(805)
Segmented revenue	**615**	896	**1,488**	1,289	**29**	22	**56**	43	**(24)**	(19)	**(52)**	(37)	**3,784**	3,826	**7,539**	7,353
Segmented expenses																
Production	**394**	388	**771**	734	**9**	7	**17**	14	**(6)**	(2)	**(10)**	(6)	**1,096**	1,068	**2,231**	2,106
Transportation and blending	**18**	18	**33**	30	**–**	–	**–**	–	**(17)**	(14)	**(34)**	(27)	**738**	691	**1,593**	1,408
Depletion, depreciation and amortization	**161**	146	**278**	209	**2**	2	**4**	4	**–**	–	**–**	–	**1,172**	1,084	**2,314**	2,059
Asset retirement obligation accretion	**9**	8	**17**	16	**–**	–	**–**	–	**–**	–	**–**	–	**42**	38	**84**	75
Realized risk management activities	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(19)**	(61)	**(102)**	33
Equity loss from jointly controlled entity	**–**	–	**–**	–	**–**	5	**2**	5	**–**	–	**–**	–	**–**	5	**2**	5
Total segmented expenses	**582**	560	**1,099**	989	**11**	14	**23**	23	**(23)**	(16)	**(44)**	(33)	**3,029**	2,825	**6,122**	5,686
Segmented earnings (loss) before the following	**33**	336	**389**	300	**18**	8	**33**	20	**(1)**	(3)	**(8)**	(4)	**755**	1,001	**1,417**	1,667
Non-segmented expenses																
Administration													**81**	77	**160**	142
Share-based compensation													**(49)**	(115)	**22**	(222)
Interest and other financing costs													**72**	93	**149**	189
Unrealized risk management activities													**(114)**	(144)	**(52)**	(84)
Foreign exchange loss													**113**	62	**159**	8
Total non-segmented expenses													**103**	(27)	**438**	33
Earnings before taxes													**652**	1,028	**979**	1,634
Current income tax expense													**145**	213	**286**	444
Deferred income tax expense													**31**	62	**4**	10
Net earnings													**476**	753	**689**	1,180

Capital Expenditures [(1)]

	Six Months Ended					
	Jun 30, 2013			Jun 30, 2012		
	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	**$ 80**	**$ (45)**	**$ 35**	$ 239	$ (76)	$ 163
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa	**7**	**–**	**7**	1	–	1
	$ 87	**$ (45)**	**$ 42**	$ 240	$ (76)	$ 164
Property, plant and equipment						
Exploration and Production						
North America	**$ 1,839**	**$ (48)**	**$ 1,791**	$ 1,772	$ 59	$ 1,831
North Sea	**147**	**–**	**147**	120	(36)	84
Offshore Africa	**59**	**–**	**59**	14	(6)	8
	2,045	**(48)**	**1,997**	1,906	17	1,923
Oil Sands Mining and Upgrading [(3)]	**1,276**	**(317)**	**959**	639	35	674
Midstream	**9**	**–**	**9**	5	–	5
Head office	**19**	**–**	**19**	15	–	15
	$ 3,349	**$ (365)**	**$ 2,984**	$ 2,565	$ 52	$ 2,617

(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 2013	Dec 31 2012
Exploration and Production		
North America	**$ 29,515**	$ 29,012
North Sea	**2,094**	1,993
Offshore Africa	**1,016**	924
Other	**29**	36
Oil Sands Mining and Upgrading	**17,408**	16,291
Midstream	**651**	636
Head office	**97**	88
	$ 50,810	$ 48,980

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated October 2011. 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, 2013:

Interest coverage (times)	
Net earnings [(1)]	5.1x
Cash flow from operations [(2)]	15.6x

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

(2) Cash flow from operations plus current income taxes and interest expense excluding current PRT expense and other taxes; divided by the sum of interest expense and capitalized interest.

Corporate Information

Board of Directors

Catherine M. Best, FCA, ICD.D
N. Murray Edwards
Timothy W. Faithfull
Honourable Gary A. Filmon, P.C., O.C., O.M.
Christopher L. Fong
Ambassador Gordon D. Giffin
Wilfred A. Gobert
Steve W. Laut
Keith A.J. MacPhail
Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C.
Dr. Eldon R. Smith, O.C., M.D.
David A. Tuer

Officers

N. Murray Edwards
Chairman of the Board

Steve W. Laut
President

Tim S. McKay
Executive Vice-President & Chief Operating Officer

Douglas A. Proll
Executive Vice-President

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

Mary-Jo E. Case
Senior Vice-President, Land & Human Resources

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Senior Vice-President, Marketing

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

Peter J. Janson
Senior Vice-President, Horizon Operations

Terry J. Jocksch
Senior Vice-President, Thermal

Allen M. Knight
Senior Vice-President, International & Corporate Development

Bill R. Peterson
Senior Vice-President, Production, Drilling & Completions

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

Lyle G. Stevens
Senior Vice-President, Exploitation

Jeff W. Wilson
Senior Vice-President, Exploration

Randall S. Davis
Vice-President, Finance & Accounting

Bruce E. McGrath
Corporate Secretary

International Operations

CNR International (U.K.) Limited

Aberdeen, Scotland

James A. Edens
Vice-President & Managing Director International

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

Barry Duncan
Vice-President, Finance, International

David M. Haywood
Vice-President, Operations, International

Andrew M. McBoyle
Vice-President, Exploitation, International

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

Stock Listing

Toronto Stock Exchange
Trading Symbol – CNQ

New York Stock Exchange
Trading Symbol – CNQ

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

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