PRESS RELEASE

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CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2013 THIRD QUARTER RESULTS

CALGARY, ALBERTA – NOVEMBER 7, 2013 – FOR IMMEDIATE RELEASE

Commenting on third quarter results, Steve Laut, President of Canadian Natural stated, "We achieved excellent results this quarter both operationally and financially, which demonstrates our ability to execute on our strategy to deliver premium value and defined growth. Our experienced team, together with our strong and diverse asset base, continues to maximize shareholder value in the near-, mid- and long-term. As a result of this continued strength in the Company’s results and successful execution to date on the Horizon project expansion, the Company’s Board of Directors have increased, commencing with Q4/13, the quarterly dividend to $0.20 per share, an increase of 60% over the previous quarterly dividend, to $0.80 per share per year.

Operationally, it was a successful quarter, with record quarterly production of approximately 703,000 barrels of oil equivalent per day, driven by record liquids production of approximately 509,000 barrels per day. Primary heavy crude oil achieved its eleventh consecutive record quarterly production with volumes of approximately 140,500 barrels of crude oil per day. Additionally, we achieved record Pelican Lake crude oil production, demonstrating the strength of our innovative polymer flood technology in this reservoir.

We achieved many milestones this quarter as we continue to execute on our strategy of focusing on projects which maximize returns to our shareholders. Horizon had strong and reliable production averaging approximately 112,000 barrels of high quality synthetic crude oil per day, with September 2013 production of approximately 117,000 barrels per day. The construction of Horizon Phase 2/3 is physically 30% complete and we are well on our way to deliver a project which provides significant value to our shareholders, without production decline, for decades. Thermal in situ oil sands production was robust at 109,000 barrels of crude oil per day. Our Kirby South SAGD project achieved first steam injection in September, ahead of schedule and on budget. The Septimus plant expansion was completed during the third quarter and is operating at capacity with over 12,200 barrels per day of liquids production and 125 MMcf per day of natural gas production.

The continued prudent development of our assets enables us to generate substantial and growing cash flow which can be allocated to resource development, sustainable dividends, share purchases, opportunistic acquisitions, and debt repayment.”

Canadian Natural’s Chief Financial Officer, Corey Bieber, continued, “Our record cash flow this quarter of approximately $2.45 billion was due to the strong performance of all assets and the robust crude oil price environment. As expected, Canadian Natural achieved strong price realizations with the tightening of both heavy oil differentials and Brent-WTI differentials in the third quarter of 2013. This cash flow generation enables us to effectively manage our balance sheet while maximizing shareholder value and delivering premium value and defined growth.”

QUARTERLY HIGHLIGHTS

($ Millions, except per common share amounts)	Three Months Ended **Sep 30 2013**	Three Months Ended Jun 30 2013	Three Months Ended Sep 30 2012	Nine Months Ended **Sep 30 2013**	Nine Months Ended Sep 30 2012
Net earnings	**$ 1,168**	$ 476	$ 360	**$ 1,857**	$ 1,540
Per common share – basic	**$ 1.07**	$ 0.44	$ 0.33	**$ 1.70**	$ 1.40
– diluted	**$ 1.07**	$ 0.44	$ 0.33	**$ 1.70**	$ 1.40
Adjusted net earnings from operations (1)	**$ 1,009**	$ 462	$ 353	**$ 1,872**	$ 1,259
Per common share – basic	**$ 0.93**	$ 0.42	$ 0.33	**$ 1.72**	$ 1.15
– diluted	**$ 0.93**	$ 0.42	$ 0.32	**$ 1.72**	$ 1.14
Cash flow from operations (2)	**$ 2,454**	$ 1,670	$ 1,431	**$ 5,695**	$ 4,465
Per common share – basic	**$ 2.26**	$ 1.53	$ 1.31	**$ 5.23**	$ 4.07
– diluted	**$ 2.26**	$ 1.53	$ 1.30	**$ 5.22**	$ 4.06
Capital expenditures, net of dispositions	**$ 1,655**	$ 1,792	$ 1,621	**$ 5,183**	$ 4,541
Daily production, before royalties					
Natural gas (MMcf/d)	**1,163**	1,122	1,191	**1,145**	1,248
Crude oil and NGLs (bbl/d)	**509,182**	436,363	469,168	**478,308**	445,140
Equivalent production (BOE/d) (3)	**702,938**	623,315	667,616	**669,170**	653,220

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

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

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

- Canadian Natural generated record quarterly cash flow from operations of approximately $2.45 billion in Q3/13, an increase of 71% compared to approximately $1.43 billion in Q3/12 and an increase of 47% compared to approximately $1.67 billion in Q2/13. The record quarterly cash flow was as a result of higher crude oil and NGLs and synthetic crude oil ("SCO") netbacks combined with record quarterly liquids production as a result of a high level of activity on heavy crude oil assets, strong Pelican Lake crude oil production, strong thermal in situ oil sands ("thermal in situ") and Horizon Oil Sands ("Horizon") production volumes and the successful expansion of the Septimus plant.
- Adjusted net earnings from operations in Q3/13 were $1,009 million, an increase of 186% from $353 million in Q3/12 and an increase of 118% from $462 million in Q2/13. Changes in adjusted net earnings primarily reflect the changes in cash flow from operations.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.20 per share payable on January 1, 2014, representing a 60% increase over the previous quarterly dividend. This is the fourteenth consecutive year of dividend increases since the Company first paid a dividend in 2001 and a compound annual growth rate of 31% from 2009 when Horizon first commenced production. This dividend reflects the continued strong operational results of the Company and the successful execution to date on the Horizon Phase 2/3 development, both in terms of construction accomplished and cost performance to date and the amount of future contracts that have been awarded. To date, over two-thirds of Horizon project costs have been completed or have moved to the contracting stage.

- Record total production for Q3/13 averaged 702,938 barrels of oil equivalent per day ("BOE/d"). Production volumes exceeded Q3/12 and Q2/13 levels by 5% and 13% respectively, primarily as a result of strong liquids growth across all assets. The quarterly highlights include higher volumes at Horizon as the Company achieved safe, steady and reliable production. Additionally, production volumes increased as a result of a high level of activity on primary heavy crude oil assets, strong Pelican Lake performance, growth in light crude oil and NGLs production and the cyclic nature of thermal in situ, contributing to record liquids production and record total BOE/d production.
- In Q3/13, primary heavy crude oil operations achieved record quarterly production of approximately 140,500 barrels per day ("bbl/d"), the Company's eleventh consecutive quarter of record primary heavy crude oil production. Primary heavy crude oil production increased 10% and 3% from Q3/12 and Q2/13, respectively, due to strong results from the Company's drilling program.
- In Q3/13, Pelican Lake operations achieved record quarterly production volumes of greater than 45,500 bbl/d, 9% higher than Q2/13 volumes. Production has increased, as expected, subsequent to the completion of an oil battery in Q2/13 which alleviated production constraints. This is the third consecutive quarter of production increases, which reflects Canadian Natural's continued success in implementing polymer flooding technology.
- First steam injection was achieved at Kirby South in September 2013, ahead of the originally targeted steam-in date of November 2013. Kirby South, a 100% owned and operated steam assisted gravity drainage ("SAGD") project, was completed on budget, at a cost of approximately $30,000 per flowing barrel. Steam is currently being circulated in 28 well pairs on 4 pads to initiate the SAGD processes. The well response at Kirby South is performing as expected and production is targeted to grow to 40,000 bbl/d in Q4/14. All evaporators, steam generators and oil treating vessels are in service and the first shipment of crude oil produced from commissioning activities was delivered on November 4, 2013.
- Operating performance at Horizon has been strong since the Company executed its first major turnaround in May 2013. Horizon SCO production for Q3/13 was approximately 112,000 bbl/d, with September 2013 production at approximately 117,000 bbl/d. Canadian Natural expects production reliability at Horizon with Q4/13 production volumes currently targeted to average between 110,000 bbl/d and 115,000 bbl/d.
- At Septimus, the Company's liquids rich natural gas Montney play, the plant expansion was completed in early Q3/13. During the first week of September 2013, the newly expanded gas plant reached its production capacity of 125 MMcf/d and approximately 12,200 bbl/d of liquids with the completion of new wells. The liquids rich production at Septimus contains high value condensate and NGLs, which significantly contributes to the favorable economics and revenue generation by the Septimus field.
- In Q3/13, Canadian Natural completed the acquisition of Barrick Energy Inc. for approximately $173 million. 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 added approximately 4,200 bbl/d of light crude oil and NGLs and 4 MMcf/d of natural gas production. These assets have been integrated into the Company's operations and optimization opportunities are underway.
- During the third quarter of 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for net cash consideration of US$255 million, including a recovery of US$14 million of past incurred costs, resulting in an after-tax gain on sale of exploration and evaluation property of $166 million. Further, in the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US$450 million for a commercial crude oil discovery and US$120 million for a commercial natural gas discovery. Long lead equipment has been ordered and the operator is targeting to drill the first exploration well in 2014.
- In Q3/13, 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.
- As expected, heavy oil differentials narrowed during the third quarter, resulting in favorable price realizations for the Company. The WCS heavy oil differential ("WCS differential") as a percent of WTI averaged 16% in Q3/13 compared to 24% in Q3/12 and 20% in Q2/13. The narrowing during this quarter reflects normal seasonality as heavy oil demand increases. Q4/13 indications are wider as a result of market volatility due to infrastructure turnarounds and normal seasonal variation.
- As expected, the Dated Brent to WTI differential narrowed to US$4.53/bbl in Q3/13 compared to US$17.38/bbl in Q3/12 and US$8.21/bbl in Q2/13. Overall pricing relative to Dated Brent pricing for Canadian Natural's North American crude oil production improved in Q3/13 as a result.

- Year to date, Canadian Natural has purchased for cancellation 9,255,500 common shares at a weighted average price of $31.13 per common share.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

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

OPERATIONS REVIEW

Drilling activity (number of wells)

	Nine Months Ended Sep 30			
	2013		2012	
	Gross	**Net**	Gross	Net
Crude oil	**824**	**793**	952	909
Natural gas	**44**	**33**	37	32
Dry	**18**	**17**	14	14
Subtotal	**886**	**843**	1,003	955
Stratigraphic test / service wells	**331**	**330**	612	611
Total	**1,217**	**1,173**	1,615	1,566
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			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Crude oil and NGLs production (bbl/d)	**256,329**	241,402	231,292	**244,849**	226,254
Net wells targeting crude oil	**294**	136	328	**701**	800
Net successful wells drilled	**287**	131	322	**685**	786
Success rate	**98%**	96%	98%	**98%**	98%

- North America crude oil and NGLs operations achieved record quarterly production of 256,329 bbl/d in Q3/13, an increase of 11% and 6% from Q3/12 and Q2/13 levels respectively.
- Canadian Natural drilled 253 net primary heavy crude oil wells in Q3/13. 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 Q3/13 primary heavy crude oil operations achieved record production volumes of approximately 140,500 bbl/d, resulting in the eleventh consecutive quarter of record primary heavy crude oil production volumes. The Company is targeting to drill an additional 252 net primary heavy crude oil wells in Q4/13.
- Woodenhouse achieved record production volumes during Q3/13 averaging approximately 16,000 bbl/d, representing an increase of 19% from Q2/13 levels of approximately 13,500 bbl/d. Subsequent to Q3/13, on October 17, 2013, fuel gas supply to the Woodenhouse operation was interrupted as a result of a third party pipeline issue. Production volumes have been temporarily affected and the Company has acquired an alternative fuel source to substantially mitigate the disruption. Woodenhouse is expected to return to full production rates when the third party restores fuel gas supply.

- Pelican Lake achieved record quarterly crude oil production of approximately 45,500 bbl/d in Q3/13, a 12% increase from Q3/12 and a 9% increase from Q2/13. This is the third consecutive quarter of production increases, which reflects Canadian Natural's continued success in implementing polymer flooding technology. Eleven net horizontal production wells were drilled during the quarter and an additional 8 net horizontal production wells are targeted to be drilled in Q4/13. Operating costs have continued to decline to approximately $9.45/bbl as production increases and optimization strategies are implemented.
- North America light crude oil and NGLs achieved record quarterly production of approximately 70,300 bbl/d in Q3/13. Production increased 10% from Q2/13, largely as a result of the Barrick acquisition and increased NGLs production associated with the Septimus project expansion. The Company drilled 30 net light crude oil wells in Q3/13 and targets to drill 33 additional net wells in Q4/13. 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.

Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Bitumen production (bbl/d)	**109,200**	90,051	101,603	**102,715**	92,130
Net wells targeting bitumen	**47**	27	43	**107**	123
Net successful wells drilled	**47**	27	43	**107**	123
Success rate	**100%**	100%	100%	**100%**	100%

- Q3/13 thermal in situ production volumes increased to more than 109,000 bbl/d due to the timing of steaming and production cycles.
- During Q2/13, bitumen emulsion was discovered at surface at 4 separate locations in the Company's Primrose development area, 3 at Primrose East and 1 at Primrose South. Canadian Natural continues to work with Alberta Environment and Sustainable Resource Development ("AESRD") on an effective and efficient clean-up. Cleanup of the 3 Primrose East sites is essentially complete and the Primrose South site cleanup is expected to be completed in 2014.
- Canadian Natural continues to work with the Alberta Energy Regulator ("AER") on the causation review of the bitumen emulsion seepage. Canadian Natural believes the cause of the bitumen emulsion seepage is mechanical failures of wellbores in the vicinity of the 4 impacted locations. The Company has reviewed all the wellbores in the vicinity of each seepage and has prioritized further work to confirm the mechanical failure, pending regulatory approval for surface access.
- The Company's near term steaming plan at Primrose has been modified as a result of the seepages, with steaming being reduced in certain areas until the causation review with the AER is complete. Canadian Natural believes that reserves recovered from the Primrose area over its life cycle will be substantially unchanged.
- First steam injection was achieved at Kirby South in September 2013, ahead of the originally targeted steam-in date of November 2013. Kirby South, a 100% owned and operated steam assisted gravity drainage ("SAGD") project, was completed on budget, at a cost of approximately $30,000 per flowing barrel. Steam is currently being circulated in 28 well pairs on 4 pads to initiate the SAGD processes. The well response at Kirby South is performing as expected and production is targeted to grow to 40,000 bbl/d in Q4/14. All evaporators, steam generators and oil treating vessels are in service and the first shipment of crude oil produced from commissioning activities was delivered on November 4, 2013.
- Detailed engineering is progressing for Kirby North Phase 1. As of September 30, 2013, the engineering portion was approximately 80% complete. Site preparation for the project is underway and will continue into Q4/13. The project is targeted for Board sanctioning in Q2/14.
- Kirby South and Kirby North Phase 1 will contribute to a staged expansion plan for the greater Kirby area. The Company targets to increase Kirby area production volumes, over time, to approximately 140,000 bbl/d. Canadian Natural's current overall thermal in situ development plan targets to increase facility capacity from current levels of approximately 170,000 bbl/d to approximately 510,000 bbl/d in staged increments over the next 15 years.
- Planned drilling activity for Q4/13 includes 35 net thermal in situ wells, excluding strat and service wells.

Natural Gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Natural gas production (MMcf/d)	**1,136**	1,092	1,169	**1,118**	1,226
Net wells targeting natural gas	**10**	8	9	**34**	32
Net successful wells drilled	**10**	8	9	**33**	32
Success rate	**100%**	100%	100%	**97%**	100%

- During Q3/13, North America natural gas production averaged 1,136 MMcf/d, representing a 4% increase from Q2/13 levels and a 3% decrease from Q3/12 levels. The decrease in production levels year over year was due to natural production declines, reflecting Canadian Natural's strategic decision to allocate capital to higher return crude oil projects. The increase in production from last quarter was driven by Septimus production and also as a result of the resumption in production after planned maintenance and turnarounds in Q2/13.
- At Septimus, the Company's liquids rich natural gas Montney play, the plant expansion was completed during Q3/13. During the first week of September 2013, the newly expanded gas plant reached its production capacity of 125 MMcf/d and approximately 12,200 bbl/d of liquids with the completion of new wells. During Q3/13, Canadian Natural drilled 7 net wells at Septimus and the company targets to drill 6 additional net wells in Q4/13, which, when completed, will maximize the utilization of the plant capacity in 2014.
- 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 explore options 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. The data room opened in Q3/13 and presentations to interested parties are underway and tracking to plan.

International Exploration and Production

	Three Months Ended			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Crude oil production (bbl/d)					
North Sea	**15,522**	18,901	19,502	**17,720**	20,054
Offshore Africa	**16,172**	18,055	17,566	**16,780**	19,618
Natural gas production (MMcf/d)					
North Sea	**4**	4	2	**3**	2
Offshore Africa	**23**	26	20	**24**	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 31,700 bbl/d during the quarter, a 14% decline from Q2/13, primarily due to planned maintenance and turnaround activities undertaken at Tiffany and Ninian South. Crude oil production volumes declined 14% from Q3/12 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 September 2012, the UK government announced the implementation of the Brownfield Allowance ("BFA"), which allows for a property development allowance on qualifying preapproved field developments. This allowance partially mitigates the impact of previous tax increases. To date Canadian Natural has received approval for two BFAs. The Tiffany field BFA resulted in a two well infill drilling program, which achieved first oil in May 2013. The most recent BFA was awarded for the Company's Ninian Field development plan, which includes four new production wells, four injectors and two well upgrades. Drilling is targeted to commence in Q4/13.

- Canadian Natural is in the process of obtaining a drilling rig to undertake the light crude oil infill drilling program at Espoir, Côte d'Ivoire. The development of Espoir is now targeted to commence in the second half of 2014 with a 10 well drilling program. This program is targeted to add 5,900 BOE/d of net production when complete.
- Development plans for Baobab are underway with a 7 well drilling program targeting to commence in 2015. This program is targeted to add 11,000 BOE/d of net production.
- Earlier in 2013 Canadian Natural announced the acquisition of two prospective blocks in Côte d'Ivoire which are prospective for deepwater channel/fan structures similar to Jubilee crude oil discoveries in Ghana and plays elsewhere in offshore Africa.
  - Block CI-12 is located approximately 35 km west of the Canadian Natural's current production at Espoir and Baobab and Canadian Natural operates with a 60% working interest. The Company plans to commence a new 3D seismic acquisition in Q4/13. Potential exploration drilling is targeted for 2015.
  - Block CI-514 is operated by Total and Canadian Natural has a 36% working interest. A seismic program has been completed and a drilling rig has been contracted to commence drilling in the first half of 2014.
- During the third quarter of 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for net cash consideration of US$255 million, including a recovery of US$14 million of past incurred costs, resulting in an after-tax gain on sale of exploration and evaluation property of $166 million. Further, in the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US$450 million for a commercial crude oil discovery and US$120 million for a commercial natural gas discovery. Long lead equipment has been ordered and the operator is targeting to drill the first exploration well in 2014.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Synthetic crude oil production (bbl/d)	**111,959**	67,954	99,205	**96,244**	87,084

- During Q3/13, SCO production averaged approximately 112,000 bbl/d at Horizon Oil Sands, up 65% from the previous quarter as the completion of the Company's first major maintenance turnaround occurred in May 2013. Horizon SCO production averaged approximately 117,000 bbl/d in September 2013. Subsequent to Q3/13, October production was approximately 105,600 bbl/d of SCO. October production volumes were affected by third party pipeline issues, which limited the supply of fuel gas to the Horizon site for three days, including the ramp down and ramp up of facilities. Q4/13 production guidance is targeted to range from 110,000 bbl/d to 115,000 bbl/d.
- Canadian Natural achieved several key milestones in Q3/13 as the Company continues to deliver on its strategy to transition to a longer life, low decline asset base which provides significant and growing free cash flow. Canadian Natural's staged expansion to 250,000 bbl/d of SCO production capacity continues to progress on track and below sanctioned costs.
- An update to the staged Phase 2/3 physical completion of expansion at the end of Q3/13 is as follows:
  - Overall Horizon Phase 2/3 expansion is 30% physically complete.
  - Reliability – Tranche 2 is 91% physically complete and approximately 5% under budget. This phase will increase performance, overall production reliability and the Gas Recovery Unit will recover additional light oil barrels in 2014.
  - Directive 74 includes technological investment and research into tailings management. This project remains on track and is physically 22% complete.
  - Phase 2A is a coker expansion which will utilize pre-invested infrastructure and equipment to expand the Coker Plant and alleviate the current bottleneck. The expansion is 70% physically complete with current progress tracking ahead of schedule. The coker tie-in was originally scheduled to be completed in mid-2015, however, due to strong construction performance and the early completion of the coker installation, the Company has accelerated the tie-in to September 2014. An increase in Horizon production capacity of approximately 12,000 bbl/d is targeted to occur subsequent to the completion of the coker tie-in.

- Phase 2B is 20% physically complete. This phase expands the capacity of major components such as gas/oil hydrotreatment, froth treatment and the hydrogen plant. This phase is targeted to add another 45,000 bbl/d of production capacity in 2016.
- Phase 3 is on track and on schedule. This phase is 19% physically complete, and includes the addition of supplementary extraction trains. This phase is targeted to increase production capacity by 80,000 bbl/d in 2017 and will result in additional reliability, redundancy and significant operating cost savings.
- The projects currently under construction continue to trend at or below cost estimates.

▪ Horizon expansion progress has been very good with physical completion of 30% to date compared with only 28% of estimated costs incurred or $3.9 billon. Total project capital budgeted for the Horizon Phase 2/3 expansion in 2013 is approximately $2 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.

▪ To ensure greater cost certainty, Canadian Natural has negotiated over half of committed capital as lump sum contracts and is in the contract negotiation stage for two-thirds of targeted project capital. To date, Canadian Natural is running 10% below our original cost estimates.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 105.82**	$ 94.23	$ 92.19	**$ 98.17**	$ 96.20
WCS blend differential from WTI (%) (2)	**16%**	20%	24%	**23%**	23%
SCO price (US$/bbl)	**$ 109.97**	$ 99.10	$ 90.84	**$ 101.49**	$ 92.82
Condensate benchmark pricing (US$/bbl)	**$ 103.83**	$ 101.50	$ 96.09	**$ 104.16**	$ 101.85
Average realized pricing before risk management (C$/bbl) (3)	**$ 89.24**	$ 75.10	$ 69.72	**$ 75.32**	$ 74.60
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.68**	$ 3.41	$ 2.08	**$ 3.00**	$ 2.07
Average realized pricing before risk management (C$/Mcf)	**$ 3.15**	$ 4.05	$ 2.54	**$ 3.56**	$ 2.48

(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					
July	$ 104.70	14%	$ 5.98	$ 3.25	$ 1.60
August	$ 106.54	15%	$ 3.20	$ 4.71	$ (2.78)
September	$ 106.24	21%	$ 3.24	$ 5.66	$ (4.88)
October	$ 100.55	26%	$ (2.44)	$ 8.49	$ (1.92)
November*	$ 96.46	32%	$ (10.70)	$ 12.42	$ (6.41)

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

- As expected, heavy oil differentials narrowed during the third quarter, resulting in favorable price realizations for the Company. The WCS differential averaged 16% in Q3/13 compared to 24% in Q3/12 and 20% in Q2/13. The differential narrowed during Q3/13 compared to Q2/13 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. Q4/13 indications are wider as a result of market volatility due to infrastructure turnarounds and normal seasonal variation.
- Canadian Natural contributed over 166,000 bbl/d of its heavy crude oil blends to the WCS blend in Q3/13. The Company remains the largest contributor to the WCS blend, accounting for over 61% of the total blend this quarter.
- The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During Q3/13, condensate price to WTI narrowed to US$1.99/bbl discount compared to US$7.27/bbl premium in Q2/13 reflecting normal seasonality.
- As expected, the Dated Brent to WTI differential narrowed to US$4.53/bbl in Q3/13 compared to US$17.38/bbl in Q3/12 and US$8.21/bbl in Q2/13, 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.
- SCO pricing averaged US$109.97/bbl for the Q3/13, an increase of 21% from US$90.84/bbl from Q3/12, and an increase of 11% from US$99.10/bbl from Q2/13. The increase in SCO pricing from the previous periods was primarily due to the increase in benchmark pricing. Q4/13 indications are wider largely as a result of pipeline apportionments.

NORTH WEST REDWATER UPGRADING AND REFINING

During Q3/13 the North West Redwater refinery engineering progressed and preliminary earthwork continued. The North West Redwater team is working toward a final cost control estimate, with the final report targeted for November 15, 2013. At present, Canadian Natural has invested $307 million into the partnership, accounted for using the equity method. The partnership has incurred to date $477 million in debt, of which 25% is attributable to Canadian Natural under a 30 year fee-for-service tolling agreement. The North West Redwater refinery, upon construction, will strengthen the Company's position by providing a competitive return on investment and by adding 50,000 bbl/d of bitumen conversion capacity in Alberta which will help reduce pricing volatility in all Western Canadian heavy crude oil.

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 appropriate financial resources for the near-, mid- and long-term.

- The Company's strategy is to maintain a diverse portfolio balanced across various commodity types. The Company achieved production of 702,938 BOE/d for Q3/13 with approximately 97% of production located in G8 countries.
- Canadian Natural has a strong balance sheet with debt to book capitalization of 27% and debt to EBITDA of 1.1x at September 30, 2013.
- Canadian Natural maintains significant financial stability and liquidity represented by approximately $2.9 billion of available credit under its bank credit facilities, net of commercial paper issued as at September 30, 2013.

- 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. As at November 5, 2013, 317,000 bbl/d of currently forecasted Q4/13 crude oil volumes and approximately 184,000 bbl/d of 2014 crude oil volumes were 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 Q4/13, and approximately 175,000 bbl/d of crude oil volumes in 2014 with floors of US$75.00 and US$80.00. 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
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 9,255,500 common shares at a weighted average price of $31.13 per common share.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.20 per share payable on January 1, 2014, an increase of 60% over the previous quarterly dividend. This is the fourteenth consecutive year of dividend increases since the Company first paid a dividend in 2001, with a compound annual growth rate of 24% since that time, and a compound annual growth rate of 31% from 2009 when Horizon first commenced production.

OUTLOOK

For 2013, original annual production guidance was 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. Q4/13 production guidance before royalties is forecast to average between 474,000 and 513,000 bbl/d of crude oil and NGLs and between 1,195 and 1,205 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 nine months ended September 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 September 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 and adjusted depreciation, depletion and amortization are included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

A Barrel of Oil Equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and 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 nine months ended September 30, 2013 in relation to the comparable periods in 2012 and the second 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 November 5, 2013.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Product sales	**$ 5,284**	$ 4,230	$ 3,978	**$ 13,615**	$ 12,136
Net earnings	**$ 1,168**	$ 476	$ 360	**$ 1,857**	$ 1,540
Per common share – basic	**$ 1.07**	$ 0.44	$ 0.33	**$ 1.70**	$ 1.40
– diluted	**$ 1.07**	$ 0.44	$ 0.33	**$ 1.70**	$ 1.40
Adjusted net earnings from operations (1)	**$ 1,009**	$ 462	$ 353	**$ 1,872**	$ 1,259
Per common share – basic	**$ 0.93**	$ 0.42	$ 0.33	**$ 1.72**	$ 1.15
– diluted	**$ 0.93**	$ 0.42	$ 0.32	**$ 1.72**	$ 1.14
Cash flow from operations (2)	**$ 2,454**	$ 1,670	$ 1,431	**$ 5,695**	$ 4,465
Per common share – basic	**$ 2.26**	$ 1.53	$ 1.31	**$ 5.23**	$ 4.07
– diluted	**$ 2.26**	$ 1.53	$ 1.30	**$ 5.22**	$ 4.06
Capital expenditures, net of dispositions	**$ 1,655**	$ 1,792	$ 1,621	**$ 5,183**	$ 4,541

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

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

Adjusted Net Earnings from Operations

	Three Months Ended			*Nine Months Ended*	
($ millions)	***Sep 30 2013***	*Jun 30 2013*	*Sep 30 2012*	***Sep 30 2013***	*Sep 30 2012*
Net earnings as reported	***$ 1,168***	*$ 476*	*$ 360*	***$ 1,857***	*$ 1,540*
Share-based compensation, net of tax (1)	***48***	*(49)*	*49*	***70***	*(173)*
Unrealized risk management loss (gain), net of tax (2)	***99***	*(92)*	*22*	***58***	*(41)*
Unrealized foreign exchange (gain) loss, net of tax (3)	***(75)***	*112*	*(136)*	***115***	*(125)*
Realized foreign exchange gain on repayment of US dollar debt securities (4)	***–***	*–*	*–*	***(12)***	*–*
Gain on corporate acquisition/disposition of properties, net of tax (5)	***(231)***	*–*	*–*	***(231)***	*–*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (6)	***–***	*15*	*58*	***15***	*58*
Adjusted net earnings from operations	***$ 1,009***	*$ 462*	*$ 353*	***$ 1,872***	*$ 1,259*

(1) The Company's employee stock option plan provides for a cash payment option. Accordingly, the fair value of the outstanding vested options is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings or are capitalized to Oil Sands Mining and Upgrading construction costs.

(2) Derivative financial instruments are recorded at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.

(3) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, partially offset by the impact of cross currency swaps, and are recognized in net earnings.

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

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

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

Cash Flow from Operations

	Three Months Ended			Nine Months Ended	
($ millions)	***Sep 30 2013***	*Jun 30 2013*	*Sep 30 2012*	***Sep 30 2013***	*Sep 30 2012*
Net earnings	***$ 1,168***	*$ 476*	*$ 360*	***$ 1,857***	*$ 1,540*
Non-cash items:					
Depletion, depreciation and amortization	***1,258***	*1,172*	*1,056*	***3,572***	*3,115*
Share-based compensation	***48***	*(49)*	*49*	***70***	*(173)*
Asset retirement obligation accretion	***41***	*42*	*38*	***125***	*113*
Unrealized risk management loss (gain)	***121***	*(114)*	*34*	***69***	*(50)*
Unrealized foreign exchange (gain) loss	***(75)***	*112*	*(136)*	***115***	*(125)*
Realized foreign exchange gain on repayment of US dollar debt securities	***–***	*–*	*–*	***(12)***	*–*
Equity loss from jointly controlled entity	***1***	*–*	*1*	***3***	*6*
Deferred income tax expense	***123***	*31*	*29*	***127***	*39*
Gain on corporate acquisition/disposition of properties	***(289)***	*–*	*–*	***(289)***	*–*
Current income tax on disposition of properties	***58***	*–*	*–*	***58***	*–*
Cash flow from operations	***$ 2,454***	*$ 1,670*	*$ 1,431*	***$ 5,695***	*$ 4,465*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the nine months ended September 30, 2013 were $1,857 million compared with $1,540 million for the nine months ended September 30, 2012. Net earnings for the nine months ended September 30, 2013 included net after-tax expenses of $15 million compared with net after-tax income of $281 million for the nine months ended September 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, the gain on corporate acquisition/disposition of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the nine months ended September 30, 2013 were $1,872 million compared with $1,259 million for the nine months ended September 30, 2012.

Net earnings for the third quarter of 2013 were $1,168 million compared with $360 million for the third quarter of 2012 and $476 million for the second quarter of 2013. Net earnings for the third quarter of 2013 included net after-tax income of $159 million compared with $7 million for the third quarter of 2012 and $14 million for the second quarter of 2013 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the gain on corporate acquisition/disposition of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the third quarter of 2013 were $1,009 million compared with $353 million for the third quarter of 2012 and $462 million for the second quarter of 2013.

The increase in adjusted net earnings for the nine months ended September 30, 2013 from the comparable period in 2012 was primarily due to:

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

partially offset by:

- lower natural gas sales volumes; and
- higher depletion, depreciation and amortization expense.

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

- higher crude oil and NGLs and SCO sales volumes in the North America and Oil Sands Mining and Upgrading segments;
- higher realized SCO prices;
- higher crude oil and NGLs netbacks;
- higher natural gas netbacks;
- lower realized risk management losses; and
- the impact of a weaker Canadian dollar;

partially offset by:

- lower natural gas sales volumes; and
- higher depletion, depreciation and amortization expense.

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

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

partially offset by:

- lower natural gas netbacks; and
- higher depletion, depreciation and amortization expense.

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 nine months ended September 30, 2013 was $5,695 million compared with $4,465 million for the nine months ended September 30, 2012. Cash flow from operations for the third quarter of 2013 was $2,454 million compared with $1,431 million for the third quarter of 2012 and $1,670 million for the second 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 nine months ended September 30, 2013 increased 2% to 669,170 BOE/d from 653,220 BOE/d for the nine months ended September 30, 2012. Total production before royalties for the third quarter of 2013 increased 5% to 702,938 BOE/d from 667,616 BOE/d for the third quarter of 2012, and increased 13% from 623,315 BOE/d for the second 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)		**Sep 30 2013**		Jun 30 2013		Mar 31 2013		Dec 31 2012
Product sales	**$**	**5,284**	$	4,230	$	4,101	$	4,059
Net earnings	**$**	**1,168**	$	476	$	213	$	352
Net earnings per common share								
– basic	**$**	**1.07**	$	0.44	$	0.19	$	0.32
– diluted	**$**	**1.07**	$	0.44	$	0.19	$	0.32

($ millions, except per common share amounts)		Sep 30 2012		Jun 30 2012		Mar 31 2012		Dec 31 2011
Product sales	$	3,978	$	4,187	$	3,971	$	4,788
Net earnings	$	360	$	753	$	427	$	832
Net earnings per common share								
– basic	$	0.33	$	0.68	$	0.39	$	0.76
– diluted	$	0.33	$	0.68	$	0.39	$	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.
- **Gains on corporate acquisition/disposition of properties** – Fluctuations due to the recognition of gains on corporate acquisitions/dispositions in the third quarter of 2013.

BUSINESS ENVIRONMENT

	Three Months Ended						Nine Months Ended			
		Sep 30 2013		Jun 30 2013		Sep 30 2012		**Sep 30 2013**		Sep 30 2012
WTI benchmark price (US$/bbl)	**$**	**105.82**	$	94.23	$	92.19	**$**	**98.17**	$	96.20
Dated Brent benchmark price (US$/bbl)	**$**	**110.35**	$	102.44	$	109.57	**$**	**108.40**	$	112.07
WCS blend differential from WTI (US$/bbl)	**$**	**17.42**	$	19.10	$	21.78	**$**	**22.72**	$	22.03
WCS blend differential from WTI (%)		**16%**		20%		24%		**23%**		23%
SCO price (US$/bbl)	**$**	**109.97**	$	99.10	$	90.84	**$**	**101.49**	$	92.82
Condensate benchmark price (US$/bbl)	**$**	**103.83**	$	101.50	$	96.09	**$**	**104.16**	$	101.85
NYMEX benchmark price (US$/MMBtu)	**$**	**3.60**	$	4.09	$	2.82	**$**	**3.68**	$	2.62
AECO benchmark price (C$/GJ)	**$**	**2.68**	$	3.41	$	2.08	**$**	**3.00**	$	2.07
US/Canadian dollar average exchange rate (US$)	**$**	**0.9629**	$	0.9774	$	1.0047	**$**	**0.9770**	$	0.9977

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$98.17 per bbl for the nine months ended September 30, 2013, an increase of 2% from US$96.20 per bbl for the nine months ended September 30, 2012. WTI averaged US$105.82 per bbl for the third quarter of 2013, an increase of 15% from US$92.19 per bbl for the third quarter of 2012, and an increase of 12% from US$94.23 per bbl for the second quarter of 2013.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Dated Brent ("Brent") pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$108.40 per bbl for the nine months ended September 30, 2013, a decrease of 3% from US$112.07 per bbl for the nine months ended September 30, 2012. Brent averaged US$110.35 per bbl for the third quarter of 2013, an increase of 1% from US$109.57 per bbl for the third quarter of 2012, and an increase of 8% from US$102.44 per bbl for the second quarter of 2013.

WTI and Brent pricing were reflective of the political instability in the Middle East, creating volatility in the crude oil price. The Brent differential from WTI tightened for the three and nine months ended September 30, 2013 from the comparable periods due to a two-year low inventory level at Cushing of approximately 33 million barrels at September 30, 2013, reflecting a continued debottlenecking of logistical constraints from Cushing to the US Gulf Coast.

The WCS Heavy Differential averaged 23% for the nine months ended September 30, 2013 and was comparable with the nine months ended September 30, 2012. The WCS Heavy Differential averaged 16% for the third quarter of 2013 compared with 24% for the third quarter of 2012, and 20% for the second quarter of 2013. The WCS Heavy Differential tightened in the third quarter of 2013 from the comparable periods as a result of increased seasonal heavy oil demand as well as higher refinery utilization rates. The WCS Heavy Differential per barrel widened in October 2013 to average US$26.34 per bbl and in November 2013 to average US$31.31 per bbl. To partially mitigate its exposure to widening heavy crude oil differentials, as at September 30, 2013, the Company has entered into physical crude oil sales contracts with weighted average fixed WCS differentials as follows: 17,000 bbl/d in the fourth quarter of 2013 at US$21.49 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 per bbl.

The SCO price averaged US$101.49 per bbl for the nine months ended September 30, 2013, an increase of 9% from US$92.82 per bbl for the nine months ended September 30, 2012. The SCO price averaged US$109.97 per bbl for the third quarter of 2013, an increase of 21% from US$90.84 per bbl for the third quarter of 2012, and an increase of 11% from US$99.10 per bbl for the second quarter of 2013. The increase in SCO pricing for the three and nine months ended September 30, 2013 from the comparable periods was primarily due to the increase in benchmark pricing.

The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During the third quarter of 2013, the condensate price differential from 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$3.68 per MMBtu for the nine months ended September 30, 2013, an increase of 40% from US$2.62 per MMBtu for the nine months ended September 30, 2012. NYMEX natural gas prices averaged US$3.60 per MMBtu for the third quarter of 2013, an increase of 28% from US$2.82 per MMBtu for the third quarter of 2012, and a decrease of 12% from US$4.09 per MMBtu for the second quarter of 2013.

AECO natural gas prices for the nine months ended September 30, 2013 averaged $3.00 per GJ, an increase of 45% from $2.07 per GJ for the nine months ended September 30, 2012. AECO natural gas prices for the third quarter of 2013 averaged $2.68 per GJ, an increase of 29% from $2.08 per GJ for the third quarter of 2012, and a decrease of 21% from $3.41 per GJ for the second quarter of 2013.

During the third quarter of 2013, natural gas prices continued to recover from the low pricing levels in 2012. Natural gas prices increased for the three and nine months ended September 30, 2013 from the comparable periods in 2012 due to a return to normal natural gas storage levels. Natural gas prices decreased for the third quarter of 2013 from the second quarter of 2013 due to continued strong US supply and reduced weather related natural gas demand. AECO natural gas prices declined more than NYMEX in the third quarter due to changes in third party short-term tolling arrangements which resulted in higher costs to move natural gas to Eastern markets.

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. During the third quarter of 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 originating at Hardisty, Alberta with delivery points in Quebec City, Quebec and Saint John, New Brunswick. This pipeline is subject to regulatory approval.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**365,529**	331,453	332,895	**347,564**	318,384
North America – Oil Sands Mining and Upgrading	**111,959**	67,954	99,205	**96,244**	87,084
North Sea	**15,522**	18,901	19,502	**17,720**	20,054
Offshore Africa	**16,172**	18,055	17,566	**16,780**	19,618
	509,182	436,363	469,168	**478,308**	445,140
Natural gas (MMcf/d)					
North America	**1,136**	1,092	1,169	**1,118**	1,226
North Sea	**4**	4	2	**3**	2
Offshore Africa	**23**	26	20	**24**	20
	1,163	1,122	1,191	**1,145**	1,248
Total barrels of oil equivalent (BOE/d)	**702,938**	623,315	667,616	**669,170**	653,220
Product mix					
Light and medium crude oil and NGLs	**14%**	16%	15%	**15%**	16%
Pelican Lake heavy crude oil	**6%**	7%	6%	**6%**	6%
Primary heavy crude oil	**20%**	22%	19%	**21%**	19%
Bitumen (thermal oil)	**16%**	14%	15%	**15%**	14%
Synthetic crude oil	**16%**	11%	15%	**14%**	13%
Natural gas	**28%**	30%	30%	**29%**	32%
Percentage of product sales (1) (2) (excluding midstream revenue)					
Crude oil and NGLs	**93%**	88%	92%	**90%**	92%
Natural gas	**7%**	12%	8%	**10%**	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			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**299,194**	274,850	261,655	**288,046**	262,561
North America – Oil Sands Mining and Upgrading	**104,627**	65,077	95,704	**91,304**	83,004
North Sea	**15,481**	18,839	19,441	**17,664**	20,000
Offshore Africa	**11,998**	14,974	11,662	**13,519**	14,726
	431,300	373,740	388,462	**410,533**	380,291
Natural gas (MMcf/d)					
North America	**1,109**	1,016	1,159	**1,072**	1,218
North Sea	**4**	4	2	**3**	2
Offshore Africa	**18**	22	16	**20**	17
	1,131	1,042	1,177	**1,095**	1,237
Total barrels of oil equivalent (BOE/d)	**619,800**	547,330	584,577	**592,983**	586,337

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 nine months ended September 30, 2013 increased 7% to 478,308 bbl/d from 445,140 bbl/d for the nine months ended September 30, 2012. Crude oil and NGLs production for the third quarter of 2013 increased 9% to 509,182 bbl/d from 469,168 bbl/d for the third quarter of 2012 and increased 17% from 436,363 bbl/d for the second quarter of 2013. The increase in production for the three and nine months ended September 30, 2013 from the comparable periods was primarily due to strong Horizon production, the impact of a strong heavy crude oil drilling program, and increased production from the Company's cyclic thermal operations. Crude oil and NGLs production in the third quarter of 2013 was within the Company's previously issued guidance of 506,000 to 529,000 bbl/d.

Natural gas production for the nine months ended September 30, 2013 decreased 8% to 1,145 MMcf/d from 1,248 MMcf/d for the nine months ended September 30, 2012. Natural gas production for the third quarter of 2013 decreased 2% to 1,163 MMcf/d from 1,191 MMcf/d for the third quarter of 2012 and increased 4% from 1,122 MMcf/d for the second quarter of 2013. The decrease in natural gas production for the three and nine months ended September 30, 2013 from the comparable periods in 2012 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. The increase in natural gas production for the third quarter of 2013 from the second quarter of 2013 was primarily a result of the completion of the Septimus plant facility expansion earlier than originally forecasted. Natural gas production in the third quarter of 2013 exceeded the Company's previously issued guidance of 1,135 to 1,155 MMcf/d.

For 2013, original annual production guidance was 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. Fourth quarter 2013 production guidance is targeted to average between 474,000 and 513,000 bbl/d of crude oil and NGLs and between 1,195 and 1,205 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the nine months ended September 30, 2013 increased 9% to average 347,564 bbl/d from 318,384 bbl/d for the nine months ended September 30, 2012. For the third quarter of 2013, crude oil and NGLs production increased 10% to average 365,529 bbl/d compared with 332,895 bbl/d for the third quarter of 2012 and increased 10% from 331,453 bbl/d for the second quarter of 2013. The increase in crude oil and NGLs production for the three and nine months ended September 30, 2013 from the comparable periods was primarily due to the impact of a strong heavy crude oil drilling program and the cyclic nature of the Company's thermal operations. Third quarter 2013 production of crude oil and NGLs was within the Company's previously issued guidance of 365,000 to 380,000 bbl/d. Fourth quarter 2013 production guidance is targeted to average between 332,000 and 362,000 bbl/d for crude oil and NGLs.

Natural gas production for the nine months ended September 30, 2013 decreased 9% to 1,118 MMcf/d compared with 1,226 MMcf/d for the nine months ended September 30, 2012. Natural gas production decreased 3% to 1,136 MMcf/d for the third quarter of 2013 compared with 1,169 MMcf/d in the third quarter of 2012 and increased 4% from 1,092 MMcf/d for the second quarter of 2013. The decrease in natural gas production for the three and nine months ended September 30, 2013 from the comparable periods in 2012 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. The increase in natural gas production for the third quarter of 2013 from the second quarter of 2013 was primarily a result of the completion of the Septimus plant facility expansion earlier than originally forecasted.

North America – Oil Sands Mining and Upgrading

Production averaged 96,244 bbl/d for the nine months ended September 30, 2013 compared with 87,084 bbl/d for the nine months ended September 30, 2012. For the third quarter of 2013, SCO production averaged 111,959 bbl/d compared with 99,205 bbl/d for the third quarter of 2012 and 67,954 bbl/d for the second quarter of 2013. Production increased for the three and nine months ended September 30, 2013 from the comparable periods, reflecting a continued focus on reliable and efficient operations, and the impact of the successful completion of Horizon's planned maintenance turnaround in May 2013. Production of SCO was within the Company's previously issued guidance of 110,000 to 115,000 bbl/d for the third quarter of 2013. Fourth quarter 2013 production guidance is targeted to average between 110,000 and 115,000 bbl/d.

North Sea

North Sea crude oil production for the nine months ended September 30, 2013 decreased 12% to 17,720 bbl/d from 20,054 bbl/d for the nine months ended September 30, 2012. Third quarter 2013 North Sea crude oil production decreased 20% to 15,522 bbl/d compared with 19,502 bbl/d for the third quarter of 2012, and decreased 18% from 18,901 bbl/d for the second quarter of 2013. The decrease in production for the three and nine months ended September 30, 2013 from the comparable periods 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. In addition, during the third quarter of 2013, the Company completed two planned turnarounds of 28 days and 30 days on the Tiffany and Ninian South platforms, respectively.

The Company received approval for the Brownfield Allowance for the Tiffany field in January 2013 and as a result, during the second quarter of 2013 the Company completed one injection well conversion and drilled one production well which came on at Tiffany, with production of approximately 1,500 bbl/d, exceeding original forecasted volumes.

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. 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. The financial impact to operations has been mitigated through receipt of business interruption insurance proceeds.

Offshore Africa

Offshore Africa crude oil production decreased 14% to 16,780 bbl/d for the nine months ended September 30, 2013 from 19,618 bbl/d for the nine months ended September 30, 2012. Third quarter 2013 crude oil production averaged 16,172 bbl/d, decreasing 8% from 17,566 bbl/d for the third quarter of 2012 and decreasing 10% from 18,055 bbl/d for the second quarter of 2013. The decrease in production volumes for the three and nine months ended September 30, 2013 from the comparable periods was due to natural field declines.

International Guidance

The Company's North Sea and Offshore Africa third quarter 2013 crude oil and NGLs production was within the Company's previously issued guidance of 31,000 to 34,000 bbl/d. Fourth quarter 2013 production guidance is targeted to average between 32,000 and 36,000 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)	**Sep 30 2013**	Jun 30 2013	Dec 31 2012
North America – Exploration and Production	**499,490**	691,583	643,758
North America – Oil Sands Mining and Upgrading (SCO)	**1,172,723**	1,061,417	993,627
North Sea	**533,155**	583,227	77,018
Offshore Africa	**1,858,081**	811,742	1,036,509
	4,063,449	3,147,969	2,750,912

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Crude oil and NGLs ($/bbl) (1)					
Sales price (2) (3)	**$ 89.24**	$ 75.10	$ 69.72	**$ 75.32**	$ 74.60
Transportation	**2.38**	2.32	2.13	**2.36**	2.17
Realized sales price, net of transportation	**86.86**	72.78	67.59	**72.96**	72.43
Royalties	**15.20**	11.60	12.08	**11.92**	11.44
Production expense	**15.90**	16.51	15.79	**16.64**	16.40
Netback	**$ 55.76**	$ 44.67	$ 39.72	**$ 44.40**	$ 44.59
Natural gas ($/Mcf) (1)					
Sales price (2) (3)	**$ 3.15**	$ 4.05	$ 2.54	**$ 3.56**	$ 2.48
Transportation	**0.27**	0.29	0.26	**0.28**	0.26
Realized sales price, net of transportation	**2.88**	3.76	2.28	**3.28**	2.22
Royalties	**0.10**	0.28	0.05	**0.17**	0.05
Production expense	**1.38**	1.41	1.30	**1.44**	1.27
Netback	**$ 1.40**	$ 2.07	$ 0.93	**$ 1.67**	$ 0.90
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2) (3)	**$ 67.09**	$ 58.49	$ 51.07	**$ 57.97**	$ 53.15
Transportation	**2.18**	2.18	1.99	**2.19**	2.00
Realized sales price, net of transportation	**64.91**	56.31	49.08	**55.78**	51.15
Royalties	**10.35**	8.29	7.94	**8.26**	7.37
Production expense	**13.36**	13.81	12.97	**13.96**	13.15
Netback	**$ 41.20**	$ 34.21	$ 28.17	**$ 33.56**	$ 30.63

(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			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Crude oil and NGLs ($/bbl) (1) (2) (3)					
North America	**$ 87.62**	$ 71.81	$ 65.99	**$ 72.18**	$ 69.89
North Sea	**$ 117.30**	$ 104.47	$ 108.04	**$ 111.84**	$ 112.69
Offshore Africa	**$ 119.48**	$ 107.71	$ 112.59	**$ 111.73**	$ 115.19
Company average	**$ 89.24**	$ 75.10	$ 69.72	**$ 75.32**	$ 74.60
Natural gas ($/Mcf) (1) (2) (3)					
North America	**$ 3.00**	$ 3.90	$ 2.41	**$ 3.41**	$ 2.35
North Sea	**$ 6.12**	$ 7.03	$ 5.90	**$ 6.14**	$ 5.42
Offshore Africa	**$ 10.47**	$ 10.02	$ 10.09	**$ 10.24**	$ 10.29
Company average	**$ 3.15**	$ 4.05	$ 2.54	**$ 3.56**	$ 2.48
Company average ($/BOE) (1) (2) (3)	**$ 67.09**	$ 58.49	$ 51.07	**$ 57.97**	$ 53.15

(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 increased 3% to average $72.18 per bbl for the nine months ended September 30, 2013 from $69.89 per bbl for the nine months ended September 30, 2012. North America realized crude oil prices averaged $87.62 per bbl for the third quarter of 2013, an increase of 33% compared with $65.99 per bbl for the third quarter of 2012 and an increase of 22% compared with $71.81 per bbl for the second quarter of 2013. The increase in realized crude oil prices for the three and nine months ended September 30, 2013 from the comparable periods was due to higher WTI benchmark pricing and the impact of a weaker Canadian dollar relative to the US dollar, partially offset by lower NGLs pricing. In addition to these factors, the increase in realized crude oil prices for the three months ended September 30, 2013 from the comparable periods also reflected the impact of tightening WCS Heavy Differentials. The Company continues to focus on its crude oil blending marketing strategy and in the third quarter of 2013 contributed approximately 166,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 45% to average $3.41 per Mcf for the nine months ended September 30, 2013 from $2.35 per Mcf for the nine months ended September 30, 2012. North America realized natural gas prices increased 24% to average $3.00 per Mcf for the third quarter of 2013 compared with $2.41 per Mcf in the third quarter of 2012, and decreased 23% compared with $3.90 per Mcf for the second quarter of 2013. The increase in realized natural gas prices for the three and nine months ended September 30, 2013 from the comparable periods in 2012 was primarily due to a return to normal gas storage levels. The decrease in realized natural gas prices for the third quarter of 2013 from the second quarter of 2013 was primarily due to continued strong US supply and reduced weather related gas demand as well as changes in third party short-term tolling arrangements.

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

(Quarterly Average)	**Sep 30 2013**	Jun 30 2013	Sep 30 2012
Wellhead Price (1) (2) (3)			
Light and medium crude oil and NGLs ($/bbl)	**$ 83.10**	$ 78.15	$ 68.80
Pelican Lake heavy crude oil ($/bbl)	**$ 90.32**	$ 75.17	$ 66.18
Primary heavy crude oil ($/bbl)	**$ 89.76**	$ 71.75	$ 63.79
Bitumen (thermal oil) ($/bbl)	**$ 86.68**	$ 65.99	$ 66.97
Natural gas ($/Mcf)	**$ 3.00**	$ 3.90	$ 2.41

(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 averaged $111.84 per bbl for the nine months ended September 30, 2013 and were comparable with $112.69 per bbl for the nine months ended September 30, 2012. Realized crude oil prices increased 9% to average $117.30 per bbl for the third quarter of 2013 from $108.04 per bbl for the third quarter of 2012, and increased 12% from $104.47 per bbl for the second quarter of 2013. The fluctuations in realized crude oil prices for the three and nine months ended September 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 3% to average $111.73 per bbl for the nine months ended September 30, 2013 from $115.19 per bbl for the nine months ended September 30, 2012. Realized crude oil prices increased 6% to average $119.48 per bbl for the third quarter of 2013 from $112.59 per bbl for the third quarter of 2012, and increased 11% from $107.71 per bbl for the second quarter of 2013. The fluctuations in realized crude oil prices for the three and nine months ended September 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			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 15.65**	$ 11.81	$ 11.65	**$ 12.15**	$ 11.22
North Sea	**$ 0.31**	$ 0.34	$ 0.33	**$ 0.35**	$ 0.30
Offshore Africa	**$ 30.83**	$ 18.38	$ 37.84	**$ 19.55**	$ 28.20
Company average	**$ 15.20**	$ 11.60	$ 12.08	**$ 11.92**	$ 11.44
Natural gas ($/Mcf) [(1)]					
North America	**$ 0.06**	$ 0.25	$ 0.02	**$ 0.13**	$ 0.02
Offshore Africa	**$ 2.06**	$ 1.68	$ 1.89	**$ 1.77**	$ 1.78
Company average	**$ 0.10**	$ 0.28	$ 0.05	**$ 0.17**	$ 0.05
Company average ($/BOE) [(1)]	**$ 10.35**	$ 8.29	$ 7.94	**$ 8.26**	$ 7.37

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

North America

North America crude oil and natural gas royalties for the nine months ended September 30, 2013 compared with the nine months ended September 30, 2012 reflected movements in benchmark commodity prices and the fluctuations of the WCS Heavy Differential.

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

Natural gas royalties averaged approximately 2% of product sales for the third quarter of 2013 compared with 1% for the third quarter of 2012 and 7% for the second quarter of 2013. The fluctuations in natural gas royalty rates compared with the comparable periods reflected movements in realized natural gas prices. Natural gas royalties are anticipated to average 4% to 5% 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 24% for the third quarter of 2013 compared with 32% for the third quarter of 2012 and 17% for the second quarter of 2013. The fluctuation in royalties from the comparable periods was due to adjustments to royalties on liftings.

Offshore Africa royalty rates are anticipated to average 15% to 16% of product sales for 2013.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 13.04**	$ 14.83	$ 12.52	**$ 14.12**	$ 13.63
North Sea	**$ 78.66**	$ 47.85	$ 60.94	**$ 66.55**	$ 53.25
Offshore Africa	**$ 25.13**	$ 17.98	$ 38.34	**$ 22.23**	$ 23.40
Company average	**$ 15.90**	$ 16.51	$ 15.79	**$ 16.64**	$ 16.40
Natural gas ($/Mcf) [(1)]					
North America	**$ 1.33**	$ 1.38	$ 1.28	**$ 1.41**	$ 1.25
North Sea	**$ 5.79**	$ 3.53	$ 3.44	**$ 4.57**	$ 3.78
Offshore Africa	**$ 2.82**	$ 2.34	$ 2.37	**$ 2.46**	$ 1.97
Company average	**$ 1.38**	$ 1.41	$ 1.30	**$ 1.44**	$ 1.27
Company average ($/BOE) [(1)]	**$ 13.36**	$ 13.81	$ 12.97	**$ 13.96**	$ 13.15

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

North America

North America crude oil and NGLs production expense for the nine months ended September 30, 2013 increased 4% to $14.12 per bbl from $13.63 per bbl for the nine months ended September 30, 2012. North America crude oil and NGLs production expense for the third quarter of 2013 increased 4% to $13.04 per bbl from $12.52 per bbl for the third quarter of 2012 and decreased 12% from $14.83 per bbl for the second quarter of 2013. The increase in production expense for the three and nine months ended September 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 decrease in production expense for the third quarter of 2013 from the second quarter of 2013 was primarily a result of the cyclic nature of thermal production. 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 nine months ended September 30, 2013 increased 13% to $1.41 per Mcf from $1.25 per Mcf for the nine months ended September 30, 2012. North America natural gas production expense for the third quarter of 2013 increased 4% to $1.33 per Mcf from $1.28 per Mcf for the third quarter of 2012 and decreased 4% from $1.38 per Mcf for the second quarter of 2013. Natural gas production expense increased for the three and nine months ended September 30, 2013 from the comparable periods in 2012 primarily due to lower production volumes related to the strategic reduction in natural gas activity. Natural gas production expense decreased for the third quarter of 2013 from the second quarter of 2013 due to increased production from the completion of the Septimus plant facility expansion earlier than originally forecasted. 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 nine months ended September 30, 2013 increased 25% to $66.55 per bbl from $53.25 per bbl for the nine months ended September 30, 2012. North Sea crude oil production expense for the third quarter of 2013 increased 29% to $78.66 per bbl from $60.94 per bbl for the third quarter of 2012 and increased 64% from $47.85 per bbl for the second quarter of 2013. Production expense increased on a per barrel basis for the three and nine months ended September 30, 2013 from the comparable periods due to production declines on relatively fixed costs. The increase for the third quarter of 2013 from the second quarter of 2013 was due to turnaround activities at both Tiffany and Ninian South platforms. North Sea crude oil production expense remains unchanged from the previously issued guidance of $62.00 to $66.00 per bbl for 2013, reflecting natural declines on a relatively fixed cost structure.

Offshore Africa

Offshore Africa crude oil production expense for the nine months ended September 30, 2013 decreased 5% to $22.23 per bbl from $23.40 per bbl for the nine months ended September 30, 2012. Offshore Africa crude oil production expense for the third quarter of 2013 averaged $25.13 per bbl, a decrease of 34% from $38.34 per bbl for the third quarter of 2012, and an increase of 40% from $17.98 per bbl for the second quarter of 2013. Production expense fluctuated for the three and nine months ended September 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 $27.00 to $30.00 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			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Expense ($ millions)	**$ 1,089**	$ 1,009	$ 931	**$ 3,121**	$ 2,777
$/BOE (1)	**$ 20.33**	$ 19.97	$ 18.00	**$ 20.10**	$ 17.96

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

Depletion, depreciation and amortization expense increased for the three and nine months ended September 30, 2013 from the comparable periods due to higher sales volumes in North America associated with heavy oil drilling and higher overall future development costs.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Expense ($ millions)	**$ 32**	$ 33	$ 30	**$ 99**	$ 89
$/BOE (1)	**$ 0.61**	$ 0.65	$ 0.59	**$ 0.64**	$ 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 reliable and efficient operations. During the third quarter of 2013, subsequent to the successful completion of the planned maintenance turnaround in May 2013, the Company recognized strong operating performance leading to production of 111,959 bbl/d, which was within stated guidance.

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

($/bbl) [1]	Three Months Ended Sep 30 2013	Jun 30 2013	Sep 30 2012	Nine Months Ended Sep 30 2013	Sep 30 2012
SCO sales price [2]	**$ 114.19**	$ 99.63	$ 89.13	**$ 104.07**	$ 91.15
Bitumen value for royalty purposes [3]	**$ 82.78**	$ 61.08	$ 57.40	**$ 69.38**	$ 60.53
Bitumen royalties [4]	**$ 6.82**	$ 4.41	$ 3.45	**$ 5.13**	$ 4.52
Transportation	**$ 1.52**	$ 1.72	$ 1.73	**$ 1.59**	$ 1.76

(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 $104.07 per bbl for the nine months ended September 30, 2013, an increase of 14% compared with $91.15 per bbl for nine months ended September 30, 2012. Realized SCO sales prices averaged $114.19 per bbl for the third quarter of 2013, an increase of 28% compared with $89.13 per bbl for the third quarter of 2012 and an increase of 15% compared with $99.63 per bbl for the second 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 Sep 30 2013	Jun 30 2013	Sep 30 2012	Nine Months Ended Sep 30 2013	Sep 30 2012
Cash production costs	**$ 407**	$ 394	$ 398	**$ 1,178**	$ 1,132
Less: costs incurred during the period of turnaround/suspension of production	**–**	(104)	–	**(104)**	(154)
Adjusted cash production costs	**$ 407**	$ 290	$ 398	**$ 1,074**	$ 978
Adjusted cash production costs, excluding natural gas costs	**$ 380**	$ 268	$ 373	**$ 997**	$ 912
Adjusted natural gas costs	**27**	22	25	**77**	66
Adjusted cash production costs	**$ 407**	$ 290	$ 398	**$ 1,074**	$ 978

($/bbl) [1]	Three Months Ended Sep 30 2013	Jun 30 2013	Sep 30 2012	Nine Months Ended Sep 30 2013	Sep 30 2012
Adjusted cash production costs, excluding natural gas costs	**$ 37.27**	$ 41.53	$ 40.03	**$ 38.21**	$ 38.05
Adjusted natural gas costs	**2.63**	3.41	2.66	**2.95**	2.75
Adjusted cash production costs	**$ 39.90**	$ 44.94	$ 42.69	**$ 41.16**	$ 40.80
Sales (bbl/d) [2]	**110,750**	70,950	101,263	**95,588**	87,569

(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 $41.16 per bbl for the nine months ended September 30, 2013, and were comparable with $40.80 per bbl for the nine months ended September 30, 2012. Adjusted cash production costs for the third quarter of 2013 averaged $39.90 per bbl, a decrease of 7% compared with $42.69 per bbl for the third quarter of 2012 and a decrease of 11% compared with $44.94 per bbl for the second quarter of 2013 primarily due to the impact of higher production volumes on a relatively fixed cost structure. Cash production costs are anticipated to average $42.50 to $44.50 per bbl for 2013.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2013**	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Depletion, depreciation and amortization	**$ 167**	$ 161	$ 124	**$ 445**	$ 333
Less: depreciation incurred during the period of turnaround/suspension of production	**–**	(79)	–	**(79)**	(6)
Adjusted depletion, depreciation and amortization	**$ 167**	$ 82	$ 124	**$ 366**	$ 327
$/bbl (1)	**$ 16.40**	$ 12.70	$ 13.31	**$ 14.02**	$ 13.63

(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 and minor asset derecognitions.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2013**	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Expense	**$ 9**	$ 9	$ 8	**$ 26**	$ 24
$/bbl (1)	**$ 0.83**	$ 1.32	$ 0.85	**$ 0.98**	$ 0.99

(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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2013**	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Revenue	**$ 28**	$ 29	$ 24	**$ 84**	$ 67
Production expense	**9**	9	7	**26**	21
Midstream cash flow	**19**	20	17	**58**	46
Depreciation	**2**	2	1	**6**	5
Equity loss from jointly controlled entity	**1**	–	1	**3**	6
Segment earnings before taxes	**$ 16**	$ 18	$ 15	**$ 49**	$ 35

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 **Sep 30 2013**	Jun 30 2013	Sep 30 2012	Nine Months Ended **Sep 30 2013**	Sep 30 2012
Expense	**$ 82**	$ 81	$ 64	**$ 242**	$ 206
$/BOE [1]	**$ 1.28**	$ 1.43	$ 1.05	**$ 1.33**	$ 1.15

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

Administration expense for the three and nine months ended September 30, 2013 increased from the comparable periods in 2012 primarily due to higher staffing related costs and general corporate costs.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended **Sep 30 2013**	Jun 30 2013	Sep 30 2012	Nine Months Ended **Sep 30 2013**	Sep 30 2012
Expense (recovery)	**$ 48**	$ (49)	$ 49	**$ 70**	$ (173)

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 $70 million share-based compensation expense for the nine months ended September 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 nine months ended September 30, 2013, the Company capitalized $13 million in respect of share-based compensation expense to Oil Sands Mining and Upgrading (September 30, 2012 – $9 million recovery).

For the nine months ended September 30, 2013, the Company paid $2 million for stock options surrendered for cash settlement (September 30, 2012 – $7 million).

INTEREST AND OTHER FINANCING COSTS

($ millions, except per BOE amounts)	Three Months Ended **Sep 30 2013**	Jun 30 2013	Sep 30 2012	Nine Months Ended **Sep 30 2013**	Sep 30 2012
Expense, gross	**$ 116**	$ 112	$ 119	**$ 341**	$ 347
Less: capitalized interest	**46**	40	27	**122**	66
Expense, net	**$ 70**	$ 72	$ 92	**$ 219**	$ 281
$/BOE [1]	**$ 1.10**	$ 1.26	$ 1.51	**$ 1.21**	$ 1.57
Average effective interest rate	**4.3%**	4.3%	4.9%	**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 nine months ended September 30, 2013 decreased compared with 2012 due to lower variable interest rates and lower average fixed-rate US dollar debt levels, partially offset by the impact of a weaker Canadian dollar on US dollar denominated debt interest. Gross interest and other financing costs for the third quarter of 2013 increased from the second quarter of 2013 due to higher Canadian denominated debt levels and the impact of a weaker Canadian dollar on US dollar denominated debt interest. Capitalized interest of $122 million for the nine months ended September 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 nine months ended September 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. In addition, the Company's average effective interest rate for the nine months ended September 30, 2013 decreased from the comparative period in 2012 primarily due to an increase in the utilization of the lower cost US commercial paper program that was implemented in March 2013.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2013**	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Crude oil and NGLs financial instruments	**$ 39**	$ –	$ 18	**$ 39**	$ 46
Foreign currency contracts	**(17)**	(19)	119	**(119)**	124
Realized loss (gain)	**22**	(19)	137	**(80)**	170
Crude oil and NGLs financial instruments	**57**	(54)	58	**27**	(26)
Natural gas financial instruments	**8**	–	–	**8**	–
Foreign currency contracts	**56**	(60)	(24)	**34**	(24)
Unrealized loss (gain)	**121**	(114)	34	**69**	(50)
Net loss (gain)	**$ 143**	$ (133)	$ 171	**$ (11)**	$ 120

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

The Company recorded a net unrealized loss of $69 million ($58 million after-tax) on its risk management activities for the nine months ended September 30, 2013, including an unrealized loss of $121 million ($99 million after-tax) for the third quarter of 2013 (June 30, 2013 – unrealized gain of $114 million; $92 million after-tax; September 30, 2012 – unrealized loss of $34 million; $22 million after-tax).

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2013**	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Net realized loss (gain)	**$ 12**	$ 1	$ 21	**$ (19)**	$ 18
Net unrealized (gain) loss [(1)]	**(75)**	112	(136)	**115**	(125)
Net (gain) loss	**$ (63)**	$ 113	$ (115)	**$ 96**	$ (107)

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

The net realized foreign exchange gain for the nine months ended September 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 nine months ended September 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 September 30, 2013 – unrealized loss of $55 million, June 30, 2013 – unrealized gain of $86 million, September 30, 2012 – unrealized loss of $85 million; nine months ended September 30, 2013 – unrealized gain of $80 million; September 30, 2012 – unrealized loss of $80 million). The US/Canadian dollar exchange rate ended the third quarter of 2013 at US$0.9723 (June 30, 2013 – US$0.9513; December 31, 2012 – US$1.0051; September 30, 2012 – US$1.0166).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Sep 30 2013	Jun 30 2013	Sep 30 2012	Nine Months Ended Sep 30 2013	Sep 30 2012
North America [1]	**$ 178**	$ 111	$ 61	**$ 411**	$ 298
North Sea	**–**	25	22	**18**	86
Offshore Africa [2]	**76**	36	50	**147**	150
PRT (recovery) expense – North Sea	**(15)**	(33)	(19)	**(61)**	13
Other taxes	**8**	6	–	**18**	11
Current income tax expense	**247**	145	114	**533**	558
Deferred income tax expense	**159**	44	23	**199**	34
Deferred PRT (recovery) expense – North Sea	**(36)**	(13)	6	**(72)**	5
Deferred income tax expense	**123**	31	29	**127**	39
	370	176	143	**660**	597
Income tax rate and other legislative changes	**–**	(15)	(58)	**(15)**	(58)
	$ 370	$ 161	$ 85	**$ 645**	$ 539
Effective income tax rate on adjusted net earnings from operations [3]	**27.2%**	27.9%	23.8%	**27.6%**	28.5%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.
(2) Includes current income taxes relating to disposition of properties.
(3) Excludes the impact of current and deferred PRT expense and other current income tax expense.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's results of operations, financial position or liquidity.

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 $660 million in Canada and $40 million to $60 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended **Sep 30 2013**	 Jun 30 2013	 Sep 30 2012	Nine Months Ended **Sep 30 2013**	 Sep 30 2012
Exploration and Evaluation					
Net (proceeds) expenditures [2] [3]	**$ (238)**	$ 10	$ 59	**$ (151)**	$ 299
Property, Plant and Equipment					
Net property acquisitions [2]	**174**	–	23	**185**	68
Well drilling, completion and equipping	**566**	419	485	**1,540**	1,336
Production and related facilities	**431**	466	533	**1,434**	1,483
Capitalized interest and other [4]	**29**	29	28	**86**	88
Net expenditures	**1,200**	914	1,069	**3,245**	2,975
Total Exploration and Production	**962**	924	1,128	**3,094**	3,274
Oil Sands Mining and Upgrading					
Horizon Phases 2/3 construction costs	**550**	555	354	**1,460**	892
Sustaining capital	**41**	158	41	**250**	129
Turnaround costs	**1**	80	11	**98**	16
Capitalized interest and other [4]	**41**	22	24	**101**	32
Total Oil Sands Mining and Upgrading	**633**	815	430	**1,909**	1,069
Midstream	**3**	4	5	**12**	10
Abandonments [5]	**44**	37	48	**136**	163
Head office	**13**	12	10	**32**	25
Total net capital expenditures	**$ 1,655**	$ 1,792	$ 1,621	**$ 5,183**	$ 4,541
By segment					
North America [2]	**$ 1,106**	$ 826	$ 1,029	**$ 3,025**	$ 3,040
North Sea	**92**	62	79	**239**	199
Offshore Africa [3]	**(236)**	36	20	**(170)**	35
Oil Sands Mining and Upgrading	**633**	815	430	**1,909**	1,069
Midstream	**3**	4	5	**12**	10
Abandonments [5]	**44**	37	48	**136**	163
Head office	**13**	12	10	**32**	25
Total	**$ 1,655**	$ 1,792	$ 1,621	**$ 5,183**	$ 4,541

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

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

Net capital expenditures for the nine months ended September 30, 2013 were $5,183 million compared with $4,541 million for the nine months ended September 30, 2012. Net capital expenditures for the third quarter of 2013 were $1,655 million compared with $1,621 million for the third quarter of 2012 and $1,792 million for the second quarter of 2013.

The fluctuations in capital expenditures for the three and nine months ended September 30, 2013 from the comparable periods was primarily due to the ramp up of Horizon site construction activity, increased well drilling and completions spending, and the acquisition of Barrick Energy Inc. in the third quarter of 2013, partially offset by the disposition of a 50% working interest in Block 11B/12B in South Africa and the substantial completion of Kirby South site construction. In addition, fluctuations in capital expenditures were impacted by seasonality as well as the Horizon turnaround completed in the second quarter of 2013.

During the third quarter of 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for net cash consideration of US$255 million, including a recovery of US$14 million of past incurred costs, resulting in an after-tax gain on sale of exploration and evaluation property of $166 million. Further, in the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US$450 million for a commercial crude oil discovery and US$120 million for a commercial natural gas discovery. Long lead equipment has been ordered and the operator is targeting to drill the first exploration well in 2014.

Drilling Activity (number of wells)

	Three Months Ended			Nine Months Ended	
	Sep 30 2013	Jun 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Net successful natural gas wells	**10**	8	9	**33**	32
Net successful crude oil wells (1)	**334**	159	365	**793**	909
Dry wells	**7**	5	6	**17**	14
Stratigraphic test / service wells	**9**	16	22	**330**	611
Total	**360**	188	402	**1,173**	1,566
Success rate (excluding stratigraphic test / service wells)	**98%**	97%	99%	**98%**	99%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 59% of the total capital expenditures for the nine months ended September 30, 2013 compared with approximately 71% for the nine months ended September 30, 2012.

During the third quarter of 2013, the Company targeted 10 net natural gas wells, including 7 wells in Northeast British Columbia, 2 wells in Northwest Alberta and 1 well in Northern Plains. The Company also targeted 341 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 253 primary heavy crude oil wells, 11 Pelican Lake heavy crude oil wells, and 47 bitumen (thermal oil) wells were drilled. Another 30 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall Primrose thermal production for the third quarter of 2013 averaged approximately 109,000 bbl/d compared with approximately 102,000 bbl/d for the third quarter of 2012 and approximately 90,000 bbl/d for the second quarter of 2013. Production volumes were in line with expectations due to the cyclic nature of thermal production at Primrose.

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 causation review and remediation plans. The Company's near term steaming plan at the Primrose field has been modified, with steaming being restricted in certain areas until the causation review with the regulators is complete.

The next planned phase of the Company's in situ Oil Sands assets expansion is the Kirby South Project. Site construction is complete and first steam injection was achieved on September 16, 2013.

Development of the tertiary recovery conversion projects at Pelican Lake continued and 11 horizontal wells were drilled during the third quarter of 2013. Pelican Lake production averaged approximately 45,500 bbl/d for the third quarter of 2013 compared with 41,000 bbl/d for the third quarter of 2012 and 42,000 bbl/d for the second 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. Production for the third quarter of 2013 increased from comparable periods, with further ramp up of production anticipated in early 2014.

For the fourth quarter of 2013, the Company's overall planned drilling activity in North America is expected to be 293 net crude oil wells, 35 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 third 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. The financial impact to operations has been mitigated through receipt of business interruption insurance proceeds.

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 a Brownfield Allowance for the Tiffany field in January 2013. During the second quarter of 2013, the Company completed one injection well conversion and drilled one 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 drilling will commence in the fourth quarter of 2013.

The Company currently plans to decommission the Murchison platform in the North Sea commencing in the first quarter of 2014 and estimates the decommissioning efforts will continue for approximately 5 years. In October 2013 the Company entered into a Decommissioning Relief Deed ("DRD") with the UK Government. The DRD was introduced in July 2013 and is a contractual mechanism whereby the UK Government guarantees tax relief on future abandonment expenditures.

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 operational and safety issues with the drilling contractor, the drilling rig has been de-mobilized. The Company is assessing the opportunity to commence drilling in the latter half of 2014 at Espoir and is seeking an alternative rig to carry out the planned drilling activity.

Exploration activities continue to progress in both Côte d'Ivoire and South Africa with Block CI-514 and South Africa targeted to commence drilling in 2014.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Sep 30 2013**	Jun 30 2013	Dec 31 2012	Sep 30 2012
Working capital deficit [1]	**$ 969**	$ 948	$ 1,264	$ (1,002)
Long-term debt [2] [3]	**$ 9,393**	$ 10,033	$ 8,736	$ 8,416
Share capital	**$ 3,765**	$ 3,736	$ 3,709	$ 3,691
Retained earnings	**21,720**	20,748	20,516	20,383
Accumulated other comprehensive income	**67**	67	58	46
Shareholders' equity	**$ 25,552**	$ 24,551	$ 24,283	$ 24,120
Debt to book capitalization [3] [4]	**27%**	29%	26%	26%
Debt to market capitalization [3] [5]	**21%**	24%	22%	20%
After-tax return on average common shareholders' equity [6]	**9%**	6%	8%	10%
After-tax return on average capital employed [3] [7]	**7%**	5%	7%	8%

(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 September 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 annual MD&A for the year ended December 31, 2012. 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 September 30, 2013, the Company had in place unsecured bank credit facilities of $4,725 million, of which approximately $2,900 million, net of commercial paper issuances of $514 million, was available.

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. 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.

Subsequent to September 30, 2013, the Company filed base shelf prospectuses that allow for the issue of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until December 2015. If issued, these securities will bear interest as determined at the date of issuance.

Long-term debt was $9,393 million at September 30, 2013, resulting in a debt to book capitalization ratio of 27% (June 30, 2013 – 29%; December 31, 2012 – 26%; September 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 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 September 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 November 5, 2013, 317,000 bbl/d of currently forecasted fourth quarter 2013 crude oil volumes and approximately 184,000 bbl/d of 2014 crude oil volumes were hedged using price collars and physical crude oil sales contracts with fixed WCS differentials. An additional 500 MMBtu/d of 2014 natural gas volumes were hedged using AECO basis swaps. Further details related to the Company's commodity related derivative financial instruments outstanding at September 30, 2013 are discussed in note 13 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at September 30, 2013, there were 1,085,933,000 common shares outstanding (September 30, 2012 – 1,095,134,000 common shares) and 67,062,000 stock options outstanding. As at November 4, 2013, the Company had 1,085,908,000 common shares outstanding and 66,425,000 stock options outstanding.

On November 5, 2013, the Company's Board of Directors approved an increase in the annual dividend to $0.80 per common share (previous annual dividend rate of $0.50 per common share), beginning with the dividend payable on January 1, 2014 at $0.20 per common share. This represents a 60% increase from the previous quarterly dividend, reflecting the stability of the Company's cash flow and providing a return to shareholders. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

In April 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 nine months ended September 30, 2013, the Company purchased 8,835,500 common shares at a weighted average price of $31.05 per common share, for a total cost of $274 million. Retained earnings were reduced by $244 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2013, the Company purchased 420,000 common shares at a weighted average price of $32.70 per common share for a total cost of $14 million.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at September 30, 2013:

($ millions)	Remaining 2013	2014	2015	2016	2017	Thereafter
Product transportation and pipeline	$ 84	$ 287	$ 272	$ 197	$ 176	$ 1,288
Offshore equipment operating leases	$ 32	$ 125	$ 108	$ 78	$ 59	$ 69
Long-term debt (1)	$ 514	$ 874	$ 400	$ 984	$ 1,616	$ 5,063
Interest and other financing costs (2)	$ 90	$ 427	$ 392	$ 374	$ 312	$ 3,941
Office leases	$ 8	$ 35	$ 42	$ 43	$ 46	$ 375
Other	$ 55	$ 176	$ 140	$ 61	$ 1	$ 2

(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 September 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 nine months ended September 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	Sep 30 2013	Dec 31 2012
ASSETS			
Current assets			
Cash and cash equivalents		$ **18**	$ 37
Accounts receivable		**1,727**	1,197
Inventory		**697**	554
Prepaids and other		**202**	126
		2,644	1,914
Exploration and evaluation assets	3	**2,617**	2,611
Property, plant and equipment	4	**45,814**	44,028
Other long-term assets	5	**351**	427
		$ **51,426**	$ 48,980
LIABILITIES			
Current liabilities			
Accounts payable		$ **557**	$ 465
Accrued liabilities		**2,479**	2,273
Current income tax liabilities		**320**	285
Current portion of long-term debt	6	**514**	798
Current portion of other long-term liabilities	7	**257**	155
		4,127	3,976
Long-term debt	6	**8,879**	7,938
Other long-term liabilities	7	**4,611**	4,609
Deferred income tax liabilities		**8,257**	8,174
		25,874	24,697
SHAREHOLDERS' EQUITY			
Share capital	9	**3,765**	3,709
Retained earnings		**21,720**	20,516
Accumulated other comprehensive income	10	**67**	58
		25,552	24,283
		$ **51,426**	$ 48,980

Commitments and contingencies (note 14).

Approved by the Board of Directors on November 5, 2013

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Sep 30 2013	Three Months Ended Sep 30 2012	Nine Months Ended Sep 30 2013	Nine Months Ended Sep 30 2012
Product sales		**$ 5,284**	$ 3,978	**$ 13,615**	$ 12,136
Less: royalties		**(625)**	(442)	**(1,417)**	(1,247)
Revenue		**4,659**	3,536	**12,198**	10,889
Expenses					
Production		**1,130**	1,071	**3,361**	3,177
Transportation and blending		**700**	606	**2,293**	2,014
Depletion, depreciation and amortization	4	**1,258**	1,056	**3,572**	3,115
Administration		**82**	64	**242**	206
Share-based compensation	7	**48**	49	**70**	(173)
Asset retirement obligation accretion	7	**41**	38	**125**	113
Interest and other financing costs		**70**	92	**219**	281
Risk management activities	13	**143**	171	**(11)**	120
Foreign exchange (gain) loss		**(63)**	(115)	**96**	(107)
Gain on corporate acquisition/disposition of properties	3,4	**(289)**	–	**(289)**	–
Equity loss from jointly controlled entity	5	**1**	1	**3**	6
		3,121	3,033	**9,681**	8,752
Earnings before taxes		**1,538**	503	**2,517**	2,137
Current income tax expense	8	**247**	114	**533**	558
Deferred income tax expense	8	**123**	29	**127**	39
Net earnings		**$ 1,168**	$ 360	**$ 1,857**	$ 1,540
Net earnings per common share					
Basic	12	**$ 1.07**	$ 0.33	**$ 1.70**	$ 1.40
Diluted	12	**$ 1.07**	$ 0.33	**$ 1.70**	$ 1.40

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2013	Three Months Ended Sep 30 2012	Nine Months Ended Sep 30 2013	Nine Months Ended Sep 30 2012
Net earnings	**$ 1,168**	$ 360	**$ 1,857**	$ 1,540
Items that may be reclassified subsequently to net earnings				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized (loss) income during the period, net of taxes of $nil million (2012 – $3 million) – three months ended; $3 million (2012 – $2 million) – nine months ended	**(1)**	(20)	**21**	14
Reclassification to net earnings, net of taxes of $nil (2012 – $nil) – three months ended; $nil (2012 – $nil) – nine months ended	**1**	(3)	**(1)**	(4)
	–	(23)	**20**	10
Foreign currency translation adjustment				
Translation of net investment	**–**	10	**(11)**	10
Other comprehensive income (loss), net of taxes	**–**	(13)	**9**	20
Comprehensive income	**$ 1,168**	$ 347	**$ 1,866**	$ 1,560

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Nine Months Ended **Sep 30 2013**	Sep 30 2012
Share capital	9		
Balance – beginning of period		**$ 3,709**	$ 3,507
Issued upon exercise of stock options		**65**	164
Previously recognized liability on stock options exercised for common shares		**21**	43
Purchase of common shares under Normal Course Issuer Bid		**(30)**	(23)
Balance – end of period		**3,765**	3,691
Retained earnings			
Balance – beginning of period		**20,516**	19,365
Net earnings		**1,857**	1,540
Purchase of common shares under Normal Course Issuer Bid	9	**(244)**	(177)
Dividends on common shares	9	**(409)**	(345)
Balance – end of period		**21,720**	20,383
Accumulated other comprehensive income	10		
Balance – beginning of period		**58**	26
Other comprehensive income, net of taxes		**9**	20
Balance – end of period		**67**	46
Shareholders' equity		**$ 25,552**	$ 24,120

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Sep 30 2013	Three Months Ended Sep 30 2012	Nine Months Ended Sep 30 2013	Nine Months Ended Sep 30 2012
Operating activities					
Net earnings		**$ 1,168**	$ 360	**$ 1,857**	$ 1,540
Non-cash items					
Depletion, depreciation and amortization		**1,258**	1,056	**3,572**	3,115
Share-based compensation		**48**	49	**70**	(173)
Asset retirement obligation accretion		**41**	38	**125**	113
Unrealized risk management loss (gain)		**121**	34	**69**	(50)
Unrealized foreign exchange (gain) loss		**(75)**	(136)	**115**	(125)
Realized foreign exchange gain on repayment of US dollar debt securities		**–**	–	**(12)**	–
Equity loss from jointly controlled entity		**1**	1	**3**	6
Deferred income tax expense		**123**	29	**127**	39
Gain on corporate acquisition/disposition of properties		**(289)**	–	**(289)**	–
Current income tax on disposition of properties		**58**	–	**58**	–
Other		**17**	7	**73**	47
Abandonment expenditures		**(44)**	(48)	**(136)**	(163)
Net change in non-cash working capital		**(294)**	132	**(596)**	245
		2,133	1,522	**5,036**	4,594
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net		**(500)**	139	**751**	(420)
Issue of medium-term notes, net	6	**–**	–	**98**	498
Repayment of US dollar debt securities		**–**	–	**(398)**	–
Issue of common shares on exercise of stock options		**26**	24	**65**	164
Purchase of common shares under Normal Course Issuer Bid		**(67)**	(63)	**(274)**	(200)
Dividends on common shares		**(136)**	(115)	**(387)**	(329)
Net change in non-cash working capital		**(6)**	(13)	**(17)**	(29)
		(683)	(28)	**(162)**	(316)
Investing activities					
Net proceeds (expenditures) on exploration and evaluation assets		**238**	(59)	**151**	(299)
Net expenditures on property, plant and equipment		**(1,849)**	(1,514)	**(5,198)**	(4,079)
Current income tax on disposition of properties		**(58)**	–	**(58)**	–
Investment in other long-term assets		**–**	–	**–**	2
Net change in non-cash working capital		**220**	90	**212**	85
		(1,449)	(1,483)	**(4,893)**	(4,291)
Increase (decrease) in cash and cash equivalents		**1**	11	**(19)**	(13)
Cash and cash equivalents – beginning of period		**17**	10	**37**	34
Cash and cash equivalents – end of period		**$ 18**	$ 21	**$ 18**	$ 21
Interest paid		**$ 126**	$ 134	**$ 365**	$ 360
Income taxes paid		**$ 30**	$ 99	**$ 314**	$ 534

(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	**97**	**–**	**15**	**–**	**112**
Transfers to property, plant and equipment	**(67)**	**–**	**–**	**–**	**(67)**
Disposals	**–**	**–**	**(39)**	**–**	**(39)**
At September 30, 2013	**$ 2,594**	**$ –**	**$ 23**	**$ –**	**$ 2,617**

During the third quarter of 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for net cash consideration of US$255 million, including a recovery of US$14 million of past incurred costs, resulting in a pre-tax gain on sale of exploration and evaluation property of $224 million ($166 million after-tax). Further, in the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US$450 million for a commercial crude oil discovery and US$120 million for a commercial natural gas discovery.

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	**2,962**	**239**	**78**	**1,909**	**12**	**32**	**5,232**
Transfers from E&E assets	**67**	**–**	**–**	**–**	**–**	**–**	**67**
Disposals/derecognitions	**(160)**	**–**	**–**	**(357)**	**–**	**–**	**(517)**
Foreign exchange adjustments and other	**–**	**156**	**104**	**–**	**–**	**–**	**260**
At September 30, 2013	**$ 53,193**	**$ 4,969**	**$ 3,227**	**$ 18,515**	**$ 324**	**$ 302**	**$ 80,530**
Accumulated depletion and depreciation							
At December 31, 2012	$ 24,991	$ 2,709	$ 2,273	$ 1,202	$ 103	$ 182	$ 31,460
Expense	**2,650**	**365**	**90**	**445**	**6**	**16**	**3,572**
Disposals/derecognitions	**(160)**	**–**	**–**	**(357)**	**–**	**–**	**(517)**
Foreign exchange adjustments and other	**(3)**	**107**	**100**	**(3)**	**–**	**–**	**201**
At September 30, 2013	**$ 27,478**	**$ 3,181**	**$ 2,463**	**$ 1,287**	**$ 109**	**$ 198**	**$ 34,716**
Net book value							
– at September 30, 2013	**$ 25,715**	**$ 1,788**	**$ 764**	**$ 17,228**	**$ 215**	**$ 104**	**$ 45,814**
– at December 31, 2012	$ 25,333	$ 1,865	$ 772	$ 15,761	$ 209	$ 88	$ 44,028

Horizon project costs not subject to depletion	
At September 30, 2013	**$ 3,579**
At December 31, 2012	$ 2,066

The Company has capitalized additional costs to date of $1,432 million (December 31, 2012 – $1,021 million) related to the development of the Kirby Thermal Oil Sands Project which are not subject to depletion.

During the nine months ended September 30, 2013, the Company acquired a number of producing crude oil and natural gas assets in the North American and North Sea Exploration and Production segments, including properties from the acquisition of Barrick Energy Inc. effective July 31, 2013, for total cash consideration of $191 million (year ended December 31, 2012 – $144 million). These transactions were accounted for using the acquisition method of accounting. In connection with these acquisitions, the Company assumed associated asset retirement obligations of $41 million (year ended December 31, 2012 – $12 million) and recognized net deferred tax assets of $75 million related to temporary differences in the carrying amount of the acquired properties and their tax bases. No debt obligations were assumed. The Company recognized after-tax gains of $65 million on these acquisitions. The above amounts are estimates and may be subject to change based on the receipt of new information.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. For the nine months ended September 30, 2013, pre-tax interest of $122 million (September 30, 2012 – $66 million) was capitalized to property, plant and equipment using a capitalization rate of 4.4% (September 30, 2012 – 4.8%).

5. OTHER LONG-TERM ASSETS

	Sep 30 2013	Dec 31 2012
Investment in North West Redwater Partnership	**$ 307**	$ 310
Other	**44**	117
	$ 351	$ 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 September 30, 2013, Redwater had interim borrowings of $477 million under credit facilities totaling $1,200 million, which mature no later than December 2017. These facilities are collateralized 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 rata 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

	Sep 30 2013	Dec 31 2012
Canadian dollar denominated debt		
Bank credit facilities	**$ 1,212**	$ 971
Medium-term notes	**1,400**	1,300
	2,612	2,271
US dollar denominated debt		
Commercial paper (September 30, 2013 – US$500 million; December 31, 2012 – US$nil)	**514**	–
US dollar debt securities (September 30, 2013 – US$6,150 million; December 31, 2012 – US$6,550 million)	**6,325**	6,517
Less: original issue discount on US dollar debt securities (1)	**(19)**	(20)
	6,820	6,497
Fair value impact of interest rate swaps on US dollar debt securities (2)	**12**	19
	6,832	6,516
Long-term debt before transaction costs	**9,444**	8,787
Less: transaction costs (1) (3)	**(51)**	(51)
	9,393	8,736
Less: current portion of commercial paper	**514**	–
current portion of other long-term debt (1)	**–**	798
	$ 8,879	$ 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 $12 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 September 30, 2013, the Company had in place unsecured bank credit facilities of $4,725 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 September 30, 2013, was 1.9% (September 30, 2012 – 2.0%), and on long-term debt outstanding for the nine months ended September 30, 2013 was 4.4% (September 30, 2012 – 4.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $555 million, including a $70 million financial guarantee related to Horizon and $373 million of letters of credit related to North Sea operations, were outstanding at September 30, 2013. Subsequent to September 30, 2013, the financial guarantee related to Horizon was reduced to $65 million.

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.

Subsequent to September 30, 2013, the Company filed a base shelf prospectus that allows for the issue of up to $3,000 million of medium-term notes in Canada, which expires in December 2015. If issued, these securities will bear interest as determined at the date of issuance.

US Dollar Debt Securities

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

Subsequent to September 30, 2013, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States, which expires in December 2015. If issued, these securities will bear interest as determined at the date of issuance.

7. OTHER LONG-TERM LIABILITIES

	Sep 30 2013	Dec 31 2012
Asset retirement obligations	**$ 4,358**	$ 4,266
Share-based compensation	**214**	154
Risk management (note 13)	**225**	257
Other	**71**	87
	4,868	4,764
Less: current portion	**257**	155
	$ 4,611	$ 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:

	Sep 30 2013	Dec 31 2012
Balance – beginning of period	**$ 4,266**	$ 3,577
Liabilities incurred	**45**	51
Liabilities acquired	**41**	12
Liabilities settled	**(136)**	(204)
Asset retirement obligation accretion	**125**	151
Revision of estimates	**(27)**	384
Change in discount rate	**–**	315
Foreign exchange	**44**	(20)
Balance – end of period	**$ 4,358**	$ 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.

	Sep 30 2013	Dec 31 2012
Balance – beginning of period	**$ 154**	$ 432
Share-based compensation expense (recovery)	**70**	(214)
Cash payment for stock options surrendered	**(2)**	(7)
Transferred to common shares	**(21)**	(45)
Capitalized to (recovered from) Oil Sands Mining and Upgrading	**13**	(12)
Balance – end of period	**214**	154
Less: current portion	**154**	129
	$ 60	$ 25

8. INCOME TAXES

The provision for income tax is as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Current corporate income tax – North America	**$ 178**	$ 61	**$ 411**	$ 298
Current corporate income tax – North Sea	**–**	22	**18**	86
Current corporate income tax – Offshore Africa	**76**	50	**147**	150
Current PRT [1] (recovery) expense – North Sea	**(15)**	(19)	**(61)**	13
Other taxes	**8**	–	**18**	11
Current income tax expense	**247**	114	**533**	558
Deferred corporate income tax expense	**159**	23	**199**	34
Deferred PRT [1] (recovery) expense – North Sea	**(36)**	6	**(72)**	5
Deferred income tax expense	**123**	29	**127**	39
Income tax expense	**$ 370**	$ 143	**$ 660**	$ 597

(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.

	Nine Months Ended Sep 30, 2013	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,092,072**	**$ 3,709**
Issued upon exercise of stock options	**2,697**	**65**
Previously recognized liability on stock options exercised for common shares	**–**	**21**
Purchase of common shares under Normal Course Issuer Bid	**(8,836)**	**(30)**
Balance – end of period	**1,085,933**	**$ 3,765**

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 November 5, 2013, the Board of Directors set the regular quarterly dividend at $0.20 per common share, an increase from the previous quarterly dividend of $0.125 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 nine months ended September 30, 2013, the Company purchased 8,835,500 common shares at a weighted average price of $31.05 per common share, for a total cost of $274 million. Retained earnings were reduced by $244 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2013, the Company purchased 420,000 common shares at a weighted average price of $32.70 per common share for a total cost of $14 million.

Stock Options

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

	Nine Months Ended Sep 30, 2013		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**73,747**	**$**	**34.13**
Granted	**8,218**	**$**	**30.19**
Surrendered for cash settlement	**(229)**	**$**	**23.69**
Exercised for common shares	**(2,697)**	**$**	**24.17**
Forfeited	**(11,977)**	**$**	**35.03**
Outstanding – end of period	**67,062**	**$**	**33.90**
Exercisable – end of period	**20,023**	**$**	**34.64**

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:

		Sep 30 2013		Sep 30 2012
Derivative financial instruments designated as cash flow hedges	**$**	**106**	$	72
Foreign currency translation adjustment		**(39)**		(26)
	$	**67**	$	46

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 September 30, 2013, the ratio was within the target range at 27%.

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

	Sep 30 2013	Dec 31 2012
Long-term debt (1)	**$ 9,393**	$ 8,736
Total shareholders' equity	**$ 25,552**	$ 24,283
Debt to book capitalization	**27%**	26%

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

12. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
	Sep 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Weighted average common shares outstanding – basic (thousands of shares)	**1,086,813**	1,095,267	**1,089,495**	1,098,145
Effect of dilutive stock options (thousands of shares)	**1,847**	1,856	**1,899**	2,725
Weighted average common shares outstanding – diluted (thousands of shares)	**1,088,660**	1,097,123	**1,091,394**	1,100,870
Net earnings	**$ 1,168**	$ 360	**$ 1,857**	$ 1,540
Net earnings per common share – basic	**$ 1.07**	$ 0.33	**$ 1.70**	$ 1.40
– diluted	**$ 1.07**	$ 0.33	**$ 1.70**	$ 1.40

13. FINANCIAL INSTRUMENTS

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

	Sep 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	**$ 1,727**	**$ –**	**$ –**	**$ –**	**$ 1,727**
Accounts payable	**–**	**–**	**–**	**(557)**	**(557)**
Accrued liabilities	**–**	**–**	**–**	**(2,479)**	**(2,479)**
Other long-term liabilities	**–**	**(70)**	**(155)**	**(62)**	**(287)**
Long-term debt [(1)]	**–**	**–**	**–**	**(9,393)**	**(9,393)**
	$ 1,727	**$ (70)**	**$ (155)**	**$ (12,491)**	**$ (10,989)**

	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:

	Sep 30, 2013		
	Carrying amount	**Fair value**	
Asset (liability) (1)		**Level 1**	**Level 2**
Other long-term liabilities	**$ (225)**	**$ –**	**$ (225)**
Fixed rate long-term debt (2) (3) (4)	**(7,667)**	**(8,424)**	**–**
	$ (7,892)	**$ (8,424)**	**$ (225)**

	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 $12 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 financial instruments held and a reconciliation to the Company's consolidated balance sheets.

Asset (liability)	**Sep 30, 2013**	Dec 31, 2012
Derivatives held for trading		
Crude oil price collars	**$ (44)**	$ (16)
Foreign currency forward contracts	**(18)**	20
Natural gas AECO basis swaps	**(8)**	–
Cash flow hedges		
Foreign currency forward contracts	**(2)**	–
Cross currency swaps	**(153)**	(261)
	$ (225)	$ (257)
Included within:		
Current portion of other long-term liabilities	**$ (81)**	$ (4)
Other long-term liabilities	**(144)**	(253)
	$ (225)	$ (257)

For the nine months ended September 30, 2013 the Company recognized a gain of $4 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, interest rate and foreign currency 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 liability were recognized in the financial statements as follows:

Asset (liability)	**Sep 30, 2013**	Dec 31, 2012
Balance – beginning of period	**$ (257)**	$ (274)
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	**(69)**	42
Foreign exchange	**78**	(53)
Other comprehensive income	**23**	28
Balance – end of period	**(225)**	(257)
Less: current portion	**(81)**	(4)
	$ (144)	$ (253)

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2013	Sep 30 2012	**Sep 30 2013**	Sep 30 2012
Net realized risk management loss (gain)	**$ 22**	$ 137	**$ (80)**	$ 170
Net unrealized risk management loss (gain)	**121**	34	**69**	(50)
	$ 143	$ 171	**$ (11)**	$ 120

Financial Risk Factors

a) Market risk

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

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At September 30, 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	Oct 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$135.59	Brent
	Oct 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$132.18	Brent
	Jan 2014	–	Jun 2014	50,000 bbl/d	US$80.00	–	US$123.09	Brent
	Jan 2014	–	Dec 2014	50,000 bbl/d	US$75.00	–	US$121.57	Brent
	Jan 2014	–	Dec 2014	50,000 bbl/d	US$80.00	–	US$120.17	Brent
	Oct 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$97.73	WTI
	Oct 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$110.34	WTI
	Oct 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$111.05	WTI
	Oct 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$118.26	WTI
	Jan 2014	–	Dec 2014	50,000 bbl/d	US$75.00	–	US$105.54	WTI

	Remaining term			Volume	Weighted average price	Index
Natural gas						
AECO basis swaps	Apr 2014	–	Oct 2014	500 MMBtu/d	US$0.50	AECO/NYMEX

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 September 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 September 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	Oct 2013	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Oct 2013	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Oct 2013	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Oct 2013	–	Mar 2038	US$550	1.170	6.25%	5.76%

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

In addition to the cross currency swap contracts noted above, at September 30, 2013, the Company had US$2,213 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$500 million designated as cash flow hedges.

b) Credit risk

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

Counterparty credit risk management

The Company’s accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At September 30, 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 September 30, 2013, the Company had no net risk management assets 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	$	557	$	–	$	–	$	–
Accrued liabilities	$	2,479	$	–	$	–	$	–
Risk management	$	81	$	42	$	76	$	26
Other long-term liabilities	$	22	$	40	$	–	$	–
Long-term debt (1)	$	514	$	1,274	$	3,012	$	4,651

(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	$	84	$	287	$	272	$	197	$	176	$	1,288
Offshore equipment operating leases	$	32	$	125	$	108	$	78	$	59	$	69
Office leases	$	8	$	35	$	42	$	43	$	46	$	375
Other	$	55	$	176	$	140	$	61	$	1	$	2

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

(millions of Canadian dollars, unaudited)	Exploration and Production															
	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2013	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012
Segmented product sales	**3,829**	2,786	**9,826**	8,601	**212**	198	**576**	713	**75**	158	**489**	615	**4,116**	3,142	**10,891**	9,929
Less: royalties	**(536)**	(359)	**(1,196)**	(991)	**(1)**	(1)	**(2)**	(2)	**(18)**	(50)	**(85)**	(146)	**(555)**	(410)	**(1,283)**	(1,139)
Segmented revenue	**3,293**	2,427	**8,630**	7,610	**211**	197	**574**	711	**57**	108	**404**	469	**3,561**	2,732	**9,608**	8,790
Segmented expenses																
Production	**580**	521	**1,773**	1,608	**120**	98	**297**	302	**17**	51	**100**	124	**717**	670	**2,170**	2,034
Transportation and blending	**702**	602	**2,292**	2,000	**1**	2	**4**	8	**–**	–	**1**	1	**703**	604	**2,297**	2,009
Depletion, depreciation and amortization	**937**	839	**2,663**	2,448	**142**	63	**368**	222	**10**	29	**90**	107	**1,089**	931	**3,121**	2,777
Asset retirement obligation accretion	**23**	22	**69**	64	**9**	6	**26**	20	**–**	2	**4**	5	**32**	30	**99**	89
Realized risk management activities	**22**	137	**(80)**	170	**–**	–	**–**	–	**–**	–	**–**	–	**22**	137	**(80)**	170
Gain on corporate acquisition/disposition of properties	**(65)**	–	**(65)**	–	**–**	–	**–**	–	**(224)**	–	**(224)**	–	**(289)**	–	**(289)**	–
Equity loss from jointly controlled entity	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Total segmented expenses	**2,199**	2,121	**6,652**	6,290	**272**	169	**695**	552	**(197)**	82	**(29)**	237	**2,274**	2,372	**7,318**	7,079
Segmented earnings (loss) before the following	**1,094**	306	**1,978**	1,320	**(61)**	28	**(121)**	159	**254**	26	**433**	232	**1,287**	360	**2,290**	1,711
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing costs																
Unrealized risk management activities																
Foreign exchange (gain) loss																
Total non-segmented expenses																
Earnings before taxes																
Current income tax expense																
Deferred income tax expense																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter-segment elimination and other				Total			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2013	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012
Segmented product sales	**1,164**	831	**2,716**	2,196	**28**	24	**84**	67	**(24)**	(19)	**(76)**	(56)	**5,284**	3,978	**13,615**	12,136
Less: royalties	**(70)**	(32)	**(134)**	(108)	**–**	–	**–**	–	**–**	–	**–**	–	**(625)**	(442)	**(1,417)**	(1,247)
Segmented revenue	**1,094**	799	**2,582**	2,088	**28**	24	**84**	67	**(24)**	(19)	**(76)**	(56)	**4,659**	3,536	**12,198**	10,889
Segmented expenses																
Production	**407**	398	**1,178**	1,132	**9**	7	**26**	21	**(3)**	(4)	**(13)**	(10)	**1,130**	1,071	**3,361**	3,177
Transportation and blending	**15**	16	**48**	46	**–**	–	**–**	–	**(18)**	(14)	**(52)**	(41)	**700**	606	**2,293**	2,014
Depletion, depreciation and amortization	**167**	124	**445**	333	**2**	1	**6**	5	**–**	–	**–**	–	**1,258**	1,056	**3,572**	3,115
Asset retirement obligation accretion	**9**	8	**26**	24	**–**	–	**–**	–	**–**	–	**–**	–	**41**	38	**125**	113
Realized risk management activities	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**22**	137	**(80)**	170
Gain on corporate acquisition/disposition of properties	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(289)**	–	**(289)**	–
Equity loss from jointly controlled entity	**–**	–	**–**	–	**1**	1	**3**	6	**–**	–	**–**	–	**1**	1	**3**	6
Total segmented expenses	**598**	546	**1,697**	1,535	**12**	9	**35**	32	**(21)**	(18)	**(65)**	(51)	**2,863**	2,909	**8,985**	8,595
Segmented earnings (loss) before the following	**496**	253	**885**	553	**16**	15	**49**	35	**(3)**	(1)	**(11)**	(5)	**1,796**	627	**3,213**	2,294
Non-segmented expenses																
Administration													**82**	64	**242**	206
Share-based compensation													**48**	49	**70**	(173)
Interest and other financing costs													**70**	92	**219**	281
Unrealized risk management activities													**121**	34	**69**	(50)
Foreign exchange (gain) loss													**(63)**	(115)	**96**	(107)
Total non-segmented expenses													**258**	124	**696**	157
Earnings before taxes													**1,538**	503	**2,517**	2,137
Current income tax expense													**247**	114	**533**	558
Deferred income tax expense													**123**	29	**127**	39
Net earnings													**1,168**	360	**1,857**	1,540

Capital Expenditures [(1)]

	Nine Months Ended					
	Sep 30, 2013			Sep 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	**$ 97**	**$ (67)**	**$ 30**	$ 294	$ (114)	$ 180
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa [(3)]	**(24)**	**–**	**(24)**	5	–	5
	$ 73	**$ (67)**	**$ 6**	$ 299	$ (114)	$ 185
Property, plant and equipment						
Exploration and Production						
North America	**$ 2,928**	**$ (59)**	**$ 2,869**	$ 2,746	$ 71	$ 2,817
North Sea	**239**	**–**	**239**	199	(33)	166
Offshore Africa	**78**	**–**	**78**	30	(6)	24
	3,245	**(59)**	**3,186**	2,975	32	3,007
Oil Sands Mining and Upgrading [(4)]	**1,909**	**(357)**	**1,552**	1,069	34	1,103
Midstream	**12**	**–**	**12**	10	–	10
Head office	**32**	**–**	**32**	25	–	25
	$ 5,198	**$ (416)**	**$ 4,782**	$ 4,079	$ 66	$ 4,145

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

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

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

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

Segmented Assets

	Total Assets	
	Sep 30 2013	Dec 31 2012
Exploration and Production		
North America	**$ 29,633**	$ 29,012
North Sea	**2,047**	1,993
Offshore Africa	**918**	924
Other	**47**	36
Oil Sands Mining and Upgrading	**18,012**	16,291
Midstream	**666**	636
Head office	**103**	88
	$ 51,426	$ 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 November 2013. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended September 30, 2013:

Interest coverage (times)	
Net earnings (1)	7.5x
Cash flow from operations (2)	18.1x

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

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

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Thursday, November 7, 2013. The North American conference call number is 1-866-225-2055 and the outside North American conference call number is 001-416-340-8410. Please call in about 10 minutes before the starting time in order to be patched into the call.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time, Thursday, November 14, 2013. To access the rebroadcast in North America, dial 1-800-408-3053. Those outside of North America, dial 001-905-694-9451. The pass code to use is 6854115.

WEBCAST

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

For further information, please contact:

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