Press Release

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES
2012 THIRD QUARTER RESULTS
CALGARY, ALBERTA – NOVEMBER 8, 2012 – FOR IMMEDIATE RELEASE

Commenting on third quarter results, Canadian Natural's Vice-Chairman John Langille stated, "During the first nine months of 2012 we effectively executed a balanced capital budget. Our large proved plus probable reserve base (7.5 billion barrels of oil equivalent) delivered $4.5 billion of cash flow ensuring we maintain a strong balance sheet with debt to book capitalization at 26% and debt to EBITDA of 1.1 times. This strong financial position supports our ability to drive effective capital allocation, efficiently control costs and continue implementing our successful strategy.

As part of our successful strategy we have sanctioned the North West Redwater refinery project. This project strengthens our position by not only providing a competitive return on investment but also by adding 50,000 bbl/d of heavy crude oil conversion capacity in Alberta which will help reduce volatility in pricing all Western Canadian heavy crude oil."

Steve Laut, President of Canadian Natural continued, "We had a solid operating quarter and we met or exceeded production guidance in all areas of the business. The Company achieved strong production volumes, up 9% from the third quarter of last year, due to our successful heavy and light crude oil drilling programs and our oil sands operations, both thermal in situ and Horizon mining. This is impressive considering the Company deferred an additional $230 million of capital this quarter, over and above the $680 million that was previously deferred, totalling $910 million of reduced capital expenditures since mid-2012.

During the third quarter, we made substantial progress in driving our mid and long term potential assets forward. The Horizon expansion is making solid progress and tracking below cost estimates. At Pelican Lake, we continue to roll out our leading edge polymer flood and are seeing strong production response. We achieved 67% construction completion at Kirby South Phase 1 and target first steam in late 2013.

Additionally the Company has added 31,570 net acres of thermal in situ lands contiguous to our Kirby land holdings. The additional lands contain significant SAGD resource potential within the McMurray reservoir creating long term value for the Company. It is expected that these lands will increase overall production capacity at our thermal in situ operations that currently is targeted to add 500,000 barrels per day of bitumen over the next fifteen years.

Canadian Natural is in an excellent position. We have a proven strategy that works, and are focused on effective and efficient operations in all areas. Our vast resource base, strong technical expertise, and financial resources will facilitate our ability to significantly grow cash flow and maximize returns for our shareholders."

QUARTERLY HIGHLIGHTS

($ Millions, except per common share amounts)	Three Months Ended **Sep 30 2012**	Three Months Ended Jun 30 2012	Three Months Ended Sep 30 2011	Nine Months Ended **Sep 30 2012**	Nine Months Ended Sep 30 2011
Net earnings	**$ 360**	$ 753	$ 836	**$ 1,540**	$ 1,811
Per common share – basic	**$ 0.33**	$ 0.68	$ 0.76	**$ 1.40**	$ 1.65
– diluted	**$ 0.33**	$ 0.68	$ 0.76	**$ 1.40**	$ 1.64
Adjusted net earnings from operations (1)	**$ 353**	$ 606	$ 719	**$ 1,259**	$ 1,568
Per common share – basic	**$ 0.33**	$ 0.55	$ 0.65	**$ 1.15**	$ 1.43
– diluted	**$ 0.32**	$ 0.55	$ 0.65	**$ 1.14**	$ 1.42
Cash flow from operations (2)	**$ 1,431**	$ 1,754	$ 1,767	**$ 4,465**	$ 4,389
Per common share – basic	**$ 1.31**	$ 1.60	$ 1.62	**$ 4.07**	$ 4.01
– diluted	**$ 1.30**	$ 1.59	$ 1.60	**$ 4.06**	$ 3.98
Capital expenditures, net of dispositions	**$ 1,621**	$ 1,324	$ 1,406	**$ 4,541**	$ 4,505
Daily production, before royalties					
Natural gas (MMcf/d)	**1,191**	1,255	1,252	**1,248**	1,249
Crude oil and NGLs (bbl/d)	**469,168**	470,523	403,900	**445,140**	370,439
Equivalent production (BOE/d) (3)	**667,616**	679,607	612,575	**653,220**	578,618

(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.

- During Q3/12, the Company achieved quarterly production of 667,616 BOE/d, representing an increase of 9% over Q3/11, and met or exceeded production guidance in all areas of the business.
- The Company's total crude oil and NGLs production during Q3/12 was 469,168 bbl/d, representing an increase of 16% over Q3/11 and comparable to Q2/12. The increase from Q3/11 was primarily due to a strong primary heavy crude oil drilling program, the timing of production cycles in bitumen ("thermal in situ"), and safe, steady and reliable operations at Horizon. Q3/12 production volumes remained consistent with Q2/12 volumes and were primarily driven by increased heavy crude oil production, increased Pelican Lake crude oil production and increased thermal in situ production offset by lower synthetic crude oil ("SCO") production.
- During Q3/12, total natural gas production for the Company was 1,191 MMcf/d representing a decrease of 5% from both Q3/11 and Q2/12 levels. The decrease in production from Q3/11 and Q2/12 was primarily a result of natural declines and 40 MMcf/d of cumulative shut-in natural gas volumes reflecting the Company's strategic decision to allocate capital to higher return crude oil projects due to low natural gas prices.
- Canadian Natural generated quarterly cash flow of $1.43 billion, compared to $1.77 billion in Q3/11 and $1.75 billion in Q2/12. Cash flow decreased from Q3/11 primarily resulting from lower crude oil and NGLs and natural gas netbacks and lower SCO pricing partially offset by higher crude oil and SCO sales volumes. The decrease in cash flow from Q2/12 was primarily due to lower SCO sales volumes and lower crude oil and NGLs netbacks. These factors, along with the impact of a stronger Canadian dollar and non-operational realized risk management losses were partially offset by higher crude oil sales volumes in North America and higher natural gas prices.

- Adjusted net earnings from operations for the quarter were $353 million, compared with adjusted net earnings of $719 million in Q3/11 and $606 million in Q2/12. Changes in adjusted net earnings reflect the changes in cash flow from operations.
- The Company reduced targeted 2012 capital spending by an additional $230 million in the quarter, resulting in total capital spending reductions of $910 million or 12%, compared to the updated capital budget announced in May 2012. At the same time, the mid-point of total BOE production volume guidance has decreased only 1% for 2012. This illustrates the strength of the Company’s asset base and ability to maintain capital flexibility while allocating capital to the highest return projects.
- Operating highlights for Q3/12 include the following with further details included in the Operations Review sections.
    - Primary heavy crude oil operations achieved production volumes that totaled over 128,000 bbl/d, resulting in the seventh consecutive quarter of record production. Production increased by 26% compared with Q3/11.
    - North America light crude oil and NGLs quarterly production increased 15% from Q3/11.
    - Reservoir performance at Pelican Lake continues to be positive as production volumes of approximately 41,000 bbl/d in Q3/12 were achieved, an increase of 8% over Q3/11 volumes.
    - In Q3/12, thermal in situ production grew 8% from the previous quarter to approximately 102,000 bbl/d.
    - Kirby South Phase 1 is progressing ahead of plan. All major equipment and modules have been delivered and installed on site with overall construction progress ahead of schedule.
    - In Q3/12, solid production volumes were achieved at Horizon Oil Sands (“Horizon”), exceeding 99,200 bbl/d.
    - Canadian Natural’s staged expansion to 250,000 bbl/d of SCO production capacity at Horizon continues to progress on track.
- Subsequent to Q3/12, North West Redwater Partnership and its owners (50% Canadian Natural) completed the sanctioning process for the construction of a 50,000 bbl/d bitumen refinery. Simultaneously, the feedstock providers (Canadian Natural for 12,500 bbl/d and Alberta Petroleum Marketing Commission for 37,500 bbl/d) approved the target toll amounts and have now committed to the 30 year tolling agreement.
- To date in 2012, Canadian Natural has purchased 7,825,200 common shares for cancellation at a weighted average price of $29.22 per common share.
- Declared a quarterly cash dividend on common shares of $0.105 per common share payable January 1, 2013.
- Canadian Natural will release its 2013 budget details on Tuesday, December 4, 2012. The Company will provide forward looking information on its 2013 operating year.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

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

OPERATIONS REVIEW

Drilling activity (number of wells)

	Nine Months Ended Sep 30			
	2012		2011	
	Gross	**Net**	Gross	Net
Crude oil	**952**	**909**	816	773
Natural gas	**37**	**32**	68	56
Dry	**14**	**14**	32	31
Subtotal	**1,003**	**955**	916	860
Stratigraphic test / service wells	**612**	**611**	547	545
Total	**1,615**	**1,566**	1,463	1,405
Success rate (excluding stratigraphic test / service wells)		**99%**		96%

North America Exploration and Production

North America crude oil and NGLs

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Crude oil and NGLs production (bbl/d)	**332,895**	316,483	304,671	**318,384**	296,892
Net wells targeting crude oil	**371**	268	327	**923**	802
Net successful wells drilled	**365**	266	317	**909**	773
Success rate	**98%**	99%	97%	**98%**	96%

- Production averaged 332,895 bbl/d in Q3/12 representing an increase of 9% from Q3/11 and an increase of 5% from Q2/12. The increase in production from Q3/11 was a result of a successful primary heavy crude oil drilling program and the timing of thermal in situ production cycles. The increase in production from Q2/12 was a result of strong heavy crude oil production, increased Pelican Lake volumes and the continuing ramp up of thermal in situ production as pads re-entered the production cycle.
- Primary heavy crude oil currently provides the highest return on capital projects in Canadian Natural's portfolio. Primary heavy crude oil operations achieved production volumes that totaled over 128,000 bbl/d, resulting in the seventh consecutive quarter of record production. Production increased by 26% and 5% compared with Q3/11 and Q2/12 levels respectively, primarily due to a successful drilling program and strong production results from Woodenhouse, a new non-traditional primary heavy crude oil area located 75 kilometers north of Pelican Lake.

  - The production profiles at Woodenhouse have been better than anticipated. In October 2012, production averaged 9,300 bbl/d and exit rate production for 2012 is targeted at approximately 12,600 bbl/d. In 2012, 71 wells have been drilled at Woodenhouse and the Company targets to drill 15 additional wells by year-end.
  - Canadian Natural targets to drill 241 net primary heavy crude oil wells (including Woodenhouse) in Q4/12 for a targeted record of 901 total net wells in 2012, 93 more net wells than the original budget. The Company has further increased its targeted annual production guidance by 5% to an increase of 22% over 2011 production volumes.
  - Canadian Natural continues to demonstrate efficient and effective operations in primary heavy crude oil. Low quarterly operating costs of $14.27/bbl were achieved in Q3/12 and continue to result in high netbacks and high value production contributing to the Company's significant cash flow.
- North America light crude oil and NGLs quarterly production increased 15% from Q3/11 as a result of a successful light oil drilling program and increased production from Septimus. North America light crude oil and NGLs is a significant part of Canadian Natural's balanced portfolio, averaging approximately 62,600 bbl/d in the quarter.
- Reservoir performance at Pelican Lake continues to be positive as production volumes of approximately 41,000 bbl/d in Q3/12 were achieved, an increase of 8% over Q3/11 volumes.
  - The Company achieved over 37,000 bbl/d in Q2/12, approximately 41,000 bbl/d in Q3/12 and exit rates for 2012 are targeted to be approximately 43,000 bbl/d, a 16% increase from Q2/12 production volumes.
  - Construction of the 25,000 bbl/d battery expansion is targeted to be on stream by Q2/13 and will support production growth to over 60,000 bbl/d targeted by 2015/16.
  - Pelican Lake continues to achieve low quarterly operating costs at $10.69/bbl in Q3/12, which result in high netbacks and high value production contributing to the Company's significant cash flow.
  - Ultimate recovery from this world class pool is targeted to be 561 million barrels (363 million barrels of proved plus probable reserves and 198 million barrels of best estimate contingent resources) of additional crude oil through a disciplined multi-year expansion plan.
- Canadian Natural's robust portfolio of thermal in situ projects is a significant part of the Company's defined plan to transition to a longer-life, more sustainable asset base with the ability to generate significant shareholder value for decades to come. The Company targets to grow thermal in situ production to approximately 500,000 bbl/d of capacity by delivering projects that will add 40,000 bbl/d of production every two to three years.
  - In Q3/12, thermal in situ production grew 8% from the previous quarter to approximately 102,000 bbl/d.
    - The Company achieved over 94,000 bbl/d in Q2/12, approximately 102,000 bbl/d in Q3/12 and exit rates for 2012 are targeted to be approximately 119,500 bbl/d, a 27% increase from Q2/12 production volumes.
    - Total quarterly operating costs, including energy costs, for the quarter were $8.84/bbl in Q3/12, which is industry leading for thermal in situ and demonstrates the Company's commitment to operational excellence. As a result, the Company achieves high netbacks and high volume production contributing to the Company's significant cash flow.
  - Kirby South Phase 1 is progressing ahead of plan. All major equipment and modules have been delivered and installed on site with overall construction progress ahead of schedule. An update to the project at the end of Q3/12 is as follows:
    - Overall project is 67% complete.
    - Module assembly is 96% complete.
    - Overall construction is 58% complete.
    - Drilling is 73% complete. Drilling on the fourth of seven pads was completed in Q3/12 and the fifth pad was rig released in early Q4/12.
    - First steam-in is targeted for late 2013 and production is targeted to ramp up to 40,000 bbl/d in 2014.

- Over the past twelve months and through 3 separate transactions, 31,570 net acres of additional leases adjacent to Canadian Natural's Kirby In Situ Oil Sands Expansion Project ("Kirby Project") were acquired, adding best estimate contingent resources of 340 million barrels of bitumen. The Company is in the early stages of integrating the acquired lands into the development plan and is expecting to increase production capacity for future phases in Kirby North and Kirby South beyond current estimates. The Company expects to gain significant capital and operating synergies within the Kirby Project, which will create the potential to drive exploitation opportunities similar to those seen at Primrose over the last decade.
- On Kirby North Phase 1, engineering design specifications are complete and the transition to detailed engineering is now in progress. Critical long lead items have been ordered and the central plant site has been cleared. First steam-in is targeted for early 2016.
- At Grouse, engineering is on track. The design basis memorandum engineering is complete and the transition to engineering design specifications is now in progress. First steam-in is targeted for late 2017.

▪ For Q4/12, the Company plans to drill 42 net thermal in situ wells and 302 net crude oil wells, excluding strat test and service wells.

▪ North America crude oil and NGLs quarterly operating costs decreased to $12.52/bbl in Q3/12 from $13.10/bbl in Q2/12. The decrease was primarily due to reduced primary heavy crude oil operating costs as a result of strategic capital investments made during the first half of 2012 and the timing of thermal in situ production cycles.

North America natural gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Natural gas production (MMcf/d)	**1,169**	1,230	1,226	**1,226**	1,223
Net wells targeting natural gas	**9**	4	21	**32**	57
Net successful wells drilled	**9**	4	21	**32**	56
Success rate	**100%**	100%	100%	**100%**	98%

▪ North America natural gas production for the quarter averaged 1,169 MMcf/d representing a decrease of 5% from both Q3/11 and Q2/12 production levels. The decrease in production levels was a result of natural declines and 40 MMcf/d of cumulative shut-in natural gas volumes reflecting the Company's strategic decision to allocate capital to higher return crude oil projects.

▪ The Company reduced capital spending on natural gas by an additional $45 million in the quarter, resulting in total capital spending reductions of $345 million or 42% for 2012 compared to the original capital budget while the mid-point of production volume guidance decreased 6% in 2012 compared to the original capital budget. This illustrates the strength of the Company's asset base and ability to maintain capital flexibility and allocate capital to the highest return projects.

▪ North America natural gas quarterly operating costs increased to $1.28/Mcf in Q3/12 from $1.13/Mcf in Q2/12 as a result of reduced volumes, seasonal maintenance activity, increased property taxes and lease rentals.

▪ Canadian Natural is the second largest natural gas producer in Canada and has an extensive land base where it demonstrates efficient and effective operations. The Company's vast land base of both conventional and unconventional natural gas assets and ownership of infrastructure favorably positions the Company to increase drilling activity and production volumes once gas prices strengthen. Canadian Natural's significant unconventional assets include approximately 1,044,000 net acres in the Montney and approximately 500,000 net acres in the Duvernay.

International Exploration and Production

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Crude oil production (bbl/d)					
North Sea	**19,502**	17,619	26,350	**20,054**	31,077
Offshore Africa	**17,566**	20,598	22,525	**19,618**	23,105
Natural gas production (MMcf/d)					
North Sea	**2**	2	5	**2**	7
Offshore Africa	**20**	23	21	**20**	19
Net wells targeting crude oil	**–**	–	–	**–**	0.9
Net successful wells drilled	**–**	–	–	**–**	0.9
Success rate	**–**	–	–	**–**	100%

- North Sea crude oil production averaged 19,502 bbl/d during Q3/12 representing a decrease of 26% compared with Q3/11 and an increase of 11% compared with Q2/12. The decrease from Q3/11 was primarily due to suspended operations at Banff/Kyle, planned maintenance on a third-party operated pipeline, and planned maintenance turnarounds at the Ninian platforms that commenced late in Q3/12. The increase from Q2/12 was primarily due to partial recovery of production volumes following the unplanned shutdown of the Ninian platforms in Q2/12 as a result of a third-party pipeline outage.
- Production in Offshore Africa averaged 17,566 bbl/d during Q3/12 representing a decrease of 22% compared with Q3/11 and a decrease of 15% compared with Q2/12. The decrease from Q3/11 and Q2/12 production volumes was primarily due to natural declines and a planned 9 day turnaround at Baobab. A planned 15 day turnaround at Espoir is scheduled in Q4/12.
- Canadian Natural's eight well infill drilling program at the Espoir Field is progressing. The drilling rig has arrived in Côte d'Ivoire and preparations are currently being undertaken to commence drilling. The Company targets first oil in Q2/13 ramping up to production of 6,500 BOE/d at the completion of the Espoir drilling program, offsetting natural declines. The cost of this program is targeted at $24,000 per flowing BOE.
- Conversion of the license of the Company's 100% working interest block in South Africa has been completed and all regulatory requirements to drill a well are complete. Targeted drilling windows are from Q4/13 to Q1/14 and from Q4/14 to Q1/15.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Synthetic crude oil production (bbl/d)	**99,205**	115,823	50,354	**87,084**	19,365

- Horizon continued to demonstrate solid operational performance in the quarter. Production averaged 99,205 bbl/d, representing a 97% increase from Q3/11 and a 14% decrease from Q2/12. The increase from Q3/11 was due to improved steady operations at Horizon, and the decrease from Q2/12 resulted from the Company's decision to operate at restricted rates for a portion of Q3/12 to ensure safe, steady and reliable operations in anticipation of the proactive planned maintenance that was completed in Q4/12.
- Previously planned maintenance at Horizon originally scheduled to occur in late Q3/12 was shifted into Q4/12 (October) to optimize the benefit of the outage and address potential risks associated with the winter season. The planned outage, scheduled for twelve days in the month of October, was completed on schedule and on cost. Production was returned to 115,000 bbl/d and then temporarily reduced to proactively allow tank volumes and overall performance to reach optimal levels not yet achieved following the ramp up. The decision to temporarily reduce production reflects the Company's commitment to increasing overall reliability going forward. Horizon production guidance for 2012 has been reduced to range from 87,000 bbl/d to 89,000 bbl/d. However, overall long term production volumes are expected to increase because of these proactive actions.
- The Company's focus on operational discipline and proactive maintenance activities will, over time, deliver increasing levels of reliability resulting in more effective and efficient operations, and lower operating costs at the plant. In Q3/12 quarterly operating costs averaged $42.69/bbl, which were primarily a result of lower production volumes and one-time costs.

- Canadian Natural's staged expansion to 250,000 bbl/d of SCO production capacity continues to progress on track. An update to the expansion at the end of Q3/12 is as follows:
  - Overall Horizon expansion is 15% complete.
  - Reliability – Tranche 2 is 84% complete.
  - Directive 74 and Technology are 14% complete.
  - Phase 2A is 39% complete.
  - Phase 2B is 6% complete.
  - Phase 3 is 6% complete.
  - Thus far, four lump sum contracts have been awarded and projects currently under construction are trending at or below cost estimates.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 92.19**	$ 93.50	$ 89.81	**$ 96.20**	$ 95.52
WCS blend differential from WTI (%) (2)	**24%**	24%	20%	**23%**	20%
SCO price (US$/bbl)	**$ 90.84**	$ 89.54	$ 100.64	**$ 92.82**	$ 103.86
Average realized pricing before risk management (C$/bbl) (3)	**$ 67.59**	$ 69.99	$ 73.80	**$ 72.43**	$ 74.77
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.08**	$ 1.74	$ 3.53	**$ 2.07**	$ 3.55
Average realized pricing before risk management (C$/Mcf)	**$ 2.28**	$ 1.90	$ 3.76	**$ 2.22**	$ 3.81

(1) West Texas Intermediate ("WTI").
(2) Western Canadian Select ("WCS").
(3) Excludes SCO.

- The WCS heavy crude oil differential as a percent of WTI was seasonally normal, averaging 24% in Q3/12, and in line with the Company's long term expectations and well below historical averages. The WCS heavy differential remained unchanged from Q2/12. The Company anticipates continued volatility in the differential in Q4/12 and narrowing of the differential thereafter as additional conversion and pipeline capacity come on stream.
- For December 2012, heavy crude oil currently trades at a US$6.00 premium (7% premium) to WTI on the US Gulf Coast ("USGC") and at a US$30.00 discount (35% discount) at Hardisty reflecting the logistical constraints at Cushing, which are currently being debottlenecked.
  - Canadian Natural ships approximately 20,000 bbl/d of heavy crude oil via a combination of pipelines to USGC markets and receives Mayan based pricing for these barrels.
  - Approximately 10,000 bbl/d of heavy crude oil is railed to USGC markets and receives significantly higher netbacks than the traditional heavy crude oil markets.
  - This highlights the strong demand for Gulf Coast refiners to use heavy crude oil blends as feedstock, and the value to Canadian producers reaching the Gulf Coast.
- During Q3/12, Canadian Natural contributed 155,000 bbl/d of its heavy crude oil stream to the WCS blend. The Company is the largest contributor of the WCS blend, accounting for 55%.
- Natural gas pricing remains weak as compared to previous year pricing. In response, Canadian production has declined while US production remains steady through 2012. AECO benchmark natural gas prices strengthened in Q3/12 compared with Q2/12 due to increased demand from the power generation sector and increased seasonal demand.

NORTH WEST REDWATER UPGRADING AND REFINING

Subsequent to Q3/12, North West Redwater Partnership and its owners (50% Canadian Natural) completed the sanctioning process for the construction of a 50,000 bbl/d bitumen refinery. Simultaneously, the feedstock providers (Canadian Natural for 12,500 bbl/d and Alberta Petroleum Marketing Commission for 37,500 bbl/d) approved the target toll amounts and have now committed to the 30 year tolling agreement. Canadian Natural will earn a return on the project of 10% on its equity investment, and additional margin on any excess capacity available over design capacity. Based on sanction capital for the project, the majority of equity has already been contributed to the partnership. Target commencement of deliveries is mid-2016.

The North West Redwater refinery project strengthens the Company's position by not only providing a competitive return on investment but by also adding 50,000 bbl/d of bitumen conversion capacity in Alberta which will help reduce volatility in pricing all Western Canadian heavy crude oil. There is potential to further expand the downstream capacity of the North West Redwater refinery project from its 50,000 bbl/d of bitumen facility capacity in Phase 1 to 150,000 bbl/d of bitumen facility capacity.

FINANCIAL REVIEW

The financial position of Canadian Natural remains strong as the Company continues to implement proven strategies and focuses on disciplined capital allocation. Canadian Natural's cash flow generation, credit facilities, diverse asset base and related capital expenditure programs, and commodity hedging policy all support a flexible financial position and provide the right financial resources for the near, mid and long term.

- The Company's strategy is to maintain a diverse portfolio balanced across various commodity types. The Company achieved production of 667,616 BOE/d for the quarter with over 97% of production located in G8 countries.
- Canadian Natural has a strong balance sheet with debt to book capitalization of 26% and debt to EBITDA of 1.1x. At September 30, 2012, long-term debt amounted to $8.4 billion compared with $8.6 billion at December 31, 2011.
- Canadian Natural maintains significant financial stability and liquidity represented by approximately $4.26 billion in available unused bank lines at the end of the quarter.
- The Company's commodity hedging program protects investment returns, ensures ongoing balance sheet strength and supports the Company's cash flow for its capital expenditures programs. The Company has hedged approximately 60% of the remaining crude oil volumes forecasted for 2012, 150,000 bbl/d of crude oil volumes for the first half of 2013, and 100,000 bbl/d of crude oil volumes for the second half of 2013 through a combination of puts and collars.
- To date in 2012, Canadian Natural has purchased 7,825,200 common shares for cancellation at a weighted average price of $29.22 per common share.
- Declared a quarterly cash dividend on common shares of $0.105 per common share payable January 1, 2013.

OUTLOOK

The Company forecasts 2012 production levels before royalties to average between 1,222 and 1,229 MMcf/d of natural gas and between 452,000 and 460,000 bbl/d of crude oil and NGLs. Q4/12 production guidance before royalties is forecast to average between 1,145 and 1,165 MMcf/d of natural gas and between 467,000 and 495,000 bbl/d of crude oil and NGLs. 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" 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 and costs, 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, Pelican Lake, the Kirby Thermal Oil Sands Project, 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 and natural gas 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 natural gas liquids ("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, 2012 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2011.

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, 2012 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board. Unless otherwise stated, 2010 comparative figures have been restated in accordance with IFRS issued as at December 31, 2011. This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, and cash production costs. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The derivation of cash production costs is included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

A Barrel of Oil Equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel 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 transportation and 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, 2012 in relation to the comparable periods in 2011 and the second quarter of 2012. The accompanying tables form an integral part of this MD&A. This MD&A is dated November 6, 2012. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2011, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Product sales	**$ 3,978**	$ 4,187	$ 3,690	**$ 12,136**	$ 10,719
Net earnings	**$ 360**	$ 753	$ 836	**$ 1,540**	$ 1,811
Per common share – basic	**$ 0.33**	$ 0.68	$ 0.76	**$ 1.40**	$ 1.65
– diluted	**$ 0.33**	$ 0.68	$ 0.76	**$ 1.40**	$ 1.64
Adjusted net earnings from operations (1)	**$ 353**	$ 606	$ 719	**$ 1,259**	$ 1,568
Per common share – basic	**$ 0.33**	$ 0.55	$ 0.65	**$ 1.15**	$ 1.43
– diluted	**$ 0.32**	$ 0.55	$ 0.65	**$ 1.14**	$ 1.42
Cash flow from operations (2)	**$ 1,431**	$ 1,754	$ 1,767	**$ 4,465**	$ 4,389
Per common share – basic	**$ 1.31**	$ 1.60	$ 1.62	**$ 4.07**	$ 4.01
– diluted	**$ 1.30**	$ 1.59	$ 1.60	**$ 4.06**	$ 3.98
Capital expenditures, net of dispositions	**$ 1,621**	$ 1,324	$ 1,406	**$ 4,541**	$ 4,505

(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" presented below lists 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" presented lists 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 2012***	*Jun 30 2012*	*Sep 30 2011*	***Sep 30 2012***	*Sep 30 2011*
Net earnings as reported	***$ 360***	*$ 753*	*$ 836*	***$ 1,540***	*$ 1,811*
Share-based compensation, net of tax (1)	***49***	*(115)*	*(249)*	***(173)***	*(309)*
Unrealized risk management loss (gain), net of tax (2)	***22***	*(103)*	*(97)*	***(41)***	*(145)*
Unrealized foreign exchange (gain) loss, net of tax (3)	***(136)***	*71*	*454*	***(125)***	*332*
Realized foreign exchange gain on repayment of US dollar debt securities (4)	***–***	*–*	*(225)*	***–***	*(225)*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (5)	***58***	*–*	*–*	***58***	*104*
Adjusted net earnings from operations	***$ 353***	*$ 606*	*$ 719*	***$ 1,259***	*$ 1,568*

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

(2) Derivative financial instruments are recorded at fair value on the balance sheets, with changes in 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 third quarter of 2011, the Company repaid US$400 million of US dollar debt securities bearing interest at 6.7%.

(5) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted. During the third quarter of 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax rate relief on decommissioning expenditures to 50%, resulting in an increase in the Company's deferred income tax liability of $58 million. During the first quarter of 2011, the UK government enacted an increase to the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. The Company's deferred income tax liability was increased by $104 million with respect to this tax rate change.

Cash Flow from Operations

	Three Months Ended			Nine Months Ended	
($ millions)	***Sep 30 2012***	*Jun 30 2012*	*Sep 30 2011*	***Sep 30 2012***	*Sep 30 2011*
Net earnings	***$ 360***	*$ 753*	*$ 836*	***$ 1,540***	*$ 1,811*
Non-cash items:					
Depletion, depreciation and amortization	***1,056***	*1,084*	*887*	***3,115***	*2,606*
Share-based compensation	***49***	*(115)*	*(249)*	***(173)***	*(309)*
Asset retirement obligation accretion	***38***	*38*	*33*	***113***	*97*
Unrealized risk management loss (gain)	***34***	*(144)*	*(122)*	***(50)***	*(186)*
Unrealized foreign exchange (gain) loss	***(136)***	*71*	*454*	***(125)***	*332*
Realized foreign exchange gain on repayment of US dollar debt securities	***–***	*–*	*(225)*	***–***	*(225)*
Equity loss from jointly controlled entity	***1***	*5*	*–*	***6***	*–*
Deferred income tax expense	***29***	*62*	*153*	***39***	*263*
Horizon asset impairment provision	***–***	*–*	*–*	***–***	*396*
Insurance recovery – property damage	***–***	*–*	*–*	***–***	*(396)*
Cash flow from operations	***$ 1,431***	*$ 1,754*	*$ 1,767*	***$ 4,465***	*$ 4,389*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the nine months ended September 30, 2012 amounted to $1,540 million compared with $1,811 million for the nine months ended September 30, 2011. Net earnings for the nine months ended September 30, 2012 included net after-tax income of $281 million compared with net after-tax income of $243 million for the nine months ended September 30, 2011 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of a realized foreign exchange gain on repayment of long-term debt and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the nine months ended September 30, 2012 were $1,259 million compared with $1,568 million for the nine months ended September 30, 2011.

Net earnings for the third quarter of 2012 were $360 million compared with $836 million for the third quarter of 2011 and $753 million for the second quarter of 2012. Net earnings for the third quarter of 2012 included net after-tax income of $7 million compared with $117 million for the third quarter of 2011 and $147 million for the second quarter of 2012 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of a realized foreign exchange gain on repayment of long-term debt and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the third quarter of 2012 were $353 million compared with $719 million for the third quarter of 2011 and $606 million for the second quarter of 2012.

The decrease in adjusted net earnings for the three and nine months ended September 30, 2012 from the comparable periods in 2011 was primarily due to:

- lower crude oil and NGLs and natural gas netbacks;
- lower realized synthetic crude oil (“SCO”) prices;
- higher depletion, depreciation and amortization expense; and
- realized risk management losses;

partially offset by:

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

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

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower crude oil and NGLs netbacks;
- the impact of a stronger Canadian dollar; and
- realized risk management losses;

partially offset by:

- higher crude oil sales volumes in the North America segment; and
- lower 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, 2012 was $4,465 million compared with $4,389 million for the nine months ended September 30, 2011. Cash flow from operations for the third quarter of 2012 was $1,431 million compared with $1,767 million for the third quarter of 2011 and $1,754 million for the second quarter of 2012. The fluctuations in cash flow from operations from the comparable periods was primarily due to the factors noted above relating to the decrease in adjusted net earnings, excluding depletion, depreciation and amortization expense.

Total production before royalties for the nine months ended September 30, 2012 increased 13% to 653,220 BOE/d from 578,618 BOE/d for the nine months ended September 30, 2011. Total production before royalties for the third quarter of 2012 increased 9% to 667,616 BOE/d from 612,575 BOE/d for the third quarter of 2011, and decreased 2% from 679,607 BOE/d for the second quarter of 2012. Production for the third quarter of 2012 was within the Company's previously issued guidance.

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 2012**		Jun 30 2012		Mar 31 2012		Dec 31 2011
Product sales	**$**	**3,978**	$	4,187	$	3,971	$	4,788
Net earnings (loss)	**$**	**360**	$	753	$	427	$	832
Net earnings (loss) per common share								
– basic	**$**	**0.33**	$	0.68	$	0.39	$	0.76
– diluted	**$**	**0.33**	$	0.68	$	0.39	$	0.76

($ millions, except per common share amounts)		Sep 30 2011		Jun 30 2011		Mar 31 2011		Dec 31 2010
Product sales	$	3,690	$	3,727	$	3,302	$	3,787
Net earnings (loss)	$	836	$	929	$	46	$	(309)
Net earnings (loss) per common share								
– basic	$	0.76	$	0.85	$	0.04	$	(0.28)
– diluted	$	0.76	$	0.84	$	0.04	$	(0.28)

Volatility in the quarterly net earnings (loss) 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 (“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 oil drilling program, and the impact of the suspension and 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, and payout of the Baobab field in May 2011.
- **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 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 that had higher operating costs per Mcf than the Company’s existing properties, and the suspension and recommencement of production at Horizon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes, proved reserves, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company’s proved undeveloped reserves, the impact of the suspension and recommencement of production at Horizon and the impact of impairments at the Olowi field in offshore Gabon.
- **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 recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense include statutory tax rate and other legislative changes substantively enacted in the various periods.

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
WTI benchmark price (US$/bbl)	**$ 92.19**	$ 93.50	$ 89.81	**$ 96.20**	$ 95.52
Dated Brent benchmark price (US$/bbl)	**$ 109.57**	$ 108.21	$ 113.46	**$ 112.07**	$ 111.96
WCS blend differential from WTI (US$/bbl)	**$ 21.78**	$ 22.83	$ 17.66	**$ 22.03**	$ 19.32
WCS blend differential from WTI (%)	**24%**	24%	20%	**23%**	20%
SCO price (US$/bbl)	**$ 90.84**	$ 89.54	$ 100.64	**$ 92.82**	$ 103.86
Condensate benchmark price (US$/bbl)	**$ 96.09**	$ 99.49	$ 101.73	**$ 101.85**	$ 104.27
NYMEX benchmark price (US$/MMBtu)	**$ 2.82**	$ 2.26	$ 4.19	**$ 2.62**	$ 4.23
AECO benchmark price (C$/GJ)	**$ 2.08**	$ 1.74	$ 3.53	**$ 2.07**	$ 3.55
US/Canadian dollar average exchange rate (US$)	**$ 1.0047**	$ 0.9897	$ 1.0197	**$ 0.9977**	$ 1.0224

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$96.20 per bbl for the nine months ended September 30, 2012 and was comparable with the nine months ended September 30, 2011. WTI averaged US$92.19 per bbl for the third quarter of 2012, an increase of 3% from US$89.81 per bbl for the third quarter of 2011 and was comparable with the second quarter of 2012. WTI pricing was reflective of the political instability in the Middle East with growing tensions between Israel and Iran creating instability in the crude price; partially offset by declining optimism in the United States economy, the European debt crisis, and lower than expected growth in Asian demand.

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$112.07 per bbl for the nine months ended September 30, 2012 and was comparable with the nine months ended September 30, 2011. Brent averaged US$109.57 per bbl for the third quarter of 2012, a decrease of 3% compared with US$113.46 per bbl for the third quarter of 2011 and was comparable with the second quarter of 2012. The higher Brent pricing relative to WTI was due to logistical constraints and high inventory levels of crude oil at Cushing. The differential is expected to narrow with the expansion of the Seaway pipeline in the first quarter of 2013.

The WCS Heavy Differential averaged 23% for the nine months ended September 30, 2012 compared with 20% for the nine months ended September 30, 2011. The WCS Heavy Differential averaged 24% for the second and third quarters of 2012 compared with 20% in the third quarter of 2011. The WCS Heavy Differential widened from the comparable periods in 2011 as a result of planned and unplanned maintenance at key refineries accessible by Canadian crude oil.

The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During the third quarter of 2012, condensate prices continued to trade at a premium to WTI, similar to prior periods, 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$2.62 per MMBtu for the nine months ended September 30, 2012, a decrease of 38% from US$4.23 per MMBtu for the nine months ended September 30, 2011. NYMEX natural gas prices averaged US$2.82 per MMBtu for the third quarter of 2012, a decrease of 33% from US$4.19 per MMBtu for the third quarter of 2011, and an increase of 25% from US$2.26 per MMBtu for the second quarter of 2012.

AECO natural gas prices for the nine months ended September 30, 2012 averaged $2.07 per GJ, a decrease of 42% from $3.55 per GJ for the nine months ended September 30, 2011. AECO natural gas prices for the third quarter of 2012 averaged $2.08 per GJ, a decrease of 41% from $3.53 per GJ for the third quarter of 2011, and an increase of 20% from $1.74 per GJ for the second quarter of 2012.

During the third quarter of 2012, natural gas prices continued to be weak. While Canadian production has declined in response to low prices, US production has held steady during 2012. The AECO natural gas price has increased from the second quarter of 2012 as a result of a shift to higher utilization of gas fired electric generators supported by the low natural gas prices, and higher weather related gas demand resulting from warmer than normal summer temperatures.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**332,895**	316,483	304,671	**318,384**	296,892
North America – Oil Sands Mining and Upgrading	**99,205**	115,823	50,354	**87,084**	19,365
North Sea	**19,502**	17,619	26,350	**20,054**	31,077
Offshore Africa	**17,566**	20,598	22,525	**19,618**	23,105
	469,168	470,523	403,900	**445,140**	370,439
Natural gas (MMcf/d)					
North America	**1,169**	1,230	1,226	**1,226**	1,223
North Sea	**2**	2	5	**2**	7
Offshore Africa	**20**	23	21	**20**	19
	1,191	1,255	1,252	**1,248**	1,249
Total barrels of oil equivalent (BOE/d)	**667,616**	679,607	612,575	**653,220**	578,618
Product mix					
Light and medium crude oil and NGLs	**15%**	15%	17%	**16%**	19%
Pelican Lake heavy crude oil	**6%**	5%	6%	**6%**	6%
Primary heavy crude oil	**19%**	18%	17%	**19%**	18%
Bitumen (thermal oil)	**15%**	14%	18%	**14%**	18%
Synthetic crude oil	**15%**	17%	8%	**13%**	3%
Natural gas	**30%**	31%	34%	**32%**	36%
Percentage of product sales (1) (excluding midstream revenue)					
Crude oil and NGLs	**92%**	93%	85%	**92%**	85%
Natural gas	**8%**	7%	15%	**8%**	15%

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**261,655**	272,089	251,909	**262,561**	243,202
North America – Oil Sands Mining and Upgrading	**95,704**	109,569	48,509	**83,004**	18,648
North Sea	**19,441**	17,578	26,284	**20,000**	31,000
Offshore Africa	**11,662**	15,051	18,452	**14,726**	20,936
	388,462	414,287	345,154	**380,291**	313,786
Natural gas (MMcf/d)					
North America	**1,159**	1,218	1,189	**1,218**	1,177
North Sea	**2**	2	5	**2**	7
Offshore Africa	**16**	19	17	**17**	16
	1,177	1,239	1,211	**1,237**	1,200
Total barrels of oil equivalent (BOE/d)	**584,577**	620,700	546,861	**586,337**	513,839

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, Pelican Lake heavy crude oil, primary heavy crude oil, bitumen (thermal oil) and SCO.

Crude oil and NGLs production for the nine months ended September 30, 2012 increased 20% to 445,140 bbl/d from 370,439 bbl/d for the nine months ended September 30, 2011. Crude oil and NGLs production for the third quarter of 2012 increased 16% to 469,168 bbl/d from 403,900 bbl/d for the third quarter of 2011 and was comparable with the second quarter of 2012. The increase in production from the comparable periods in 2011 was primarily related to increased production at Horizon, the impact of a strong heavy crude oil drilling program, and the cyclic nature of the Company's thermal operations. Crude oil and NGLs production in the third quarter of 2012 was within the Company's previously issued guidance of 451,000 to 480,000 bbl/d.

Natural gas production for the nine months ended September 30, 2012 averaged 1,248 MMcf/d and was comparable with the nine months ended September 30, 2011. Natural gas production for the third quarter of 2012 decreased by 5% to 1,191 MMcf/d from 1,252 MMcf/d from the third quarter of 2011 and decreased by 5% from 1,255 MMcf/d for the second quarter of 2012. The decrease in natural gas production for the third quarter of 2012 from the comparable periods was primarily a result of expected production declines due to the allocation of capital to higher return crude oil projects, which continue to result in a strategic reduction of natural gas drilling activity. The Company shut in approximately 20 MMcf/d of natural gas production in 2012 and overall has shut in approximately 40 MMcf/d due to the decrease in natural gas prices. Natural gas production in the third quarter of 2012 slightly exceeded the Company's previously issued guidance of 1,170 to 1,190 MMcf/d.

For 2012, annual production guidance is targeted to average between 452,000 and 460,000 bbl/d of crude oil and NGLs and between 1,222 and 1,229 MMcf/d of natural gas. Fourth quarter 2012 production guidance is targeted to average between 467,000 and 495,000 bbl/d of crude oil and NGLs and between 1,145 and 1,165 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the nine months ended September 30, 2012 increased 7% to average 318,384 bbl/d from 296,892 bbl/d for the nine months ended September 30, 2011. For the third quarter of 2012, crude oil and NGLs production increased 9% to average 332,895 bbl/d compared with 304,671 bbl/d for the third quarter of 2011 and increased 5% from 316,483 bbl/d for the second quarter of 2012. Increases in crude oil and NGLs production from comparable periods were primarily due to the impact of a strong heavy crude oil drilling program and the cyclic nature of the Company's thermal operations. Production of crude oil and NGLs was at the upper end of the Company's previously issued guidance of 322,000 bbl/d to 335,000 bbl/d for the third quarter of 2012. Fourth quarter 2012 production guidance is targeted to average between 350,000 and 365,000 bbl/d of crude oil and NGLs.

Natural gas production for the nine months ended September 30, 2012 averaged 1,226 MMcf/d and was comparable with the nine months ended September 30, 2011. Natural gas production decreased 5% to 1,169 MMcf/d for the third quarter of 2012 compared with 1,226 MMcf/d in the third quarter of 2011 and 1,230 MMcf/d in the second quarter of 2012. Natural gas production for the third quarter of 2012 decreased from the comparable periods primarily as a result of expected production declines due to the allocation of capital to higher return crude oil projects, which continue to result in a strategic reduction of natural gas drilling activity. The Company has reduced its drilling activities and shut in approximately 40 MMcf/d of natural gas production due to the decline in natural gas prices.

North America – Oil Sands Mining and Upgrading

Production averaged 87,084 bbl/d for the nine months ended September 30, 2012 compared with 19,365 bbl/d for the nine months ended September 30, 2011. For the third quarter of 2012, SCO production averaged 99,205 bbl/d compared with 50,354 bbl/d for the third quarter of 2011 and 115,823 bbl/d for the second quarter of 2012. Production for the three and nine months ended September 30, 2012 increased from the comparable periods in 2011 as production volumes in 2011 reflected the suspension of production due to the coker fire incident. Third quarter production in 2012 decreased from the second quarter as the Company operated at restricted rates for a portion of the third quarter to ensure safe, steady, reliable operations in anticipation of the proactive planned 12 day outage in the fourth quarter. Production of SCO remained within the Company's previously issued guidance of 95,000 to 105,000 bbl/d for the third quarter of 2012.

Subsequent to September 30, 2012 the Company completed the 12 day planned maintenance outage followed by a return to full production. Full year production guidance for 2012 has been revised to 87,000 bbl/d to 89,000 bbl/d.

North Sea

North Sea crude oil production for the nine months ended September 30, 2012 decreased 35% to 20,054 bbl/d from 31,077 bbl/d for the nine months ended September 30, 2011. For the third quarter of 2012, North Sea crude oil production decreased 26% to 19,502 bbl/d from 26,350 bbl/d for the third quarter of 2011, and increased 11% from 17,619 bbl/d for the second quarter of 2012. The decrease in production volumes for the three and nine months ended September 30, 2012 from the comparable periods in 2011 was primarily due to temporary shut ins of the third-party operated pipeline to Sullom Voe for unplanned maintenance, which caused all Ninian and associated fields to be shut in, planned turnaround activity, the suspension of production at Banff/Kyle, and natural field declines due to curtailment of development activities in the North Sea as a result of corporate tax increases that were enacted in 2011. The increase in production volumes for the third quarter of 2012 from the second quarter of 2012 was due to the temporary reinstatement of the third-party operated pipeline to Sullom Voe, which was subsequently shut in again in late September 2012, and the timing of planned turnaround activity. 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 and appropriate shut-down procedures were activated. The FPSO and associated floating storage unit have subsequently been removed from the field. The extent of the damage, including associated costs and related property damage, are not expected to be significant. The timing of returning to the field is currently being assessed.

Offshore Africa

Offshore Africa crude oil production decreased 15% to 19,618 bbl/d for the nine months ended September 30, 2012 from 23,105 bbl/d for the nine months ended September 30, 2011. Third quarter crude oil production averaged 17,566 bbl/d, decreasing 22% from 22,525 bbl/d for the third quarter of 2011 and decreasing 15% from 20,598 bbl/d in the second quarter of 2012. The decrease in production volumes from the comparable periods was due to natural field declines and the shut in of approximately 1,500 bbl/d of production at the Olowi field, Gabon as a result of a second failure in the midwater arch. The Company is currently assessing the operability of the midwater arch.

International Guidance

The Company's North Sea and Offshore Africa third quarter 2012 crude oil and NGLs production was within the Company's previously issued guidance of 34,000 to 40,000 bbl/d. Fourth quarter 2012 production guidance is targeted to average between 32,000 and 38,000 bbl/d of crude oil.

Crude Oil Inventory Volumes

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

(bbl)	**Sep 30 2012**	Jun 30 2012	Dec 31 2011
North America – Exploration and Production	**656,340**	587,765	557,475
North America – Oil Sands Mining and Upgrading (SCO)	**888,442**	1,077,734	1,021,236
North Sea	**150,269**	–	286,633
Offshore Africa	**1,058,992**	678,540	527,312
	2,754,043	2,344,039	2,392,656

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 67.59**	$ 69.99	$ 73.80	**$ 72.43**	$ 74.77
Royalties	**12.08**	9.18	11.52	**11.44**	11.19
Production expense	**15.79**	16.66	16.42	**16.40**	15.37
Netback	**$ 39.72**	$ 44.15	$ 45.86	**$ 44.59**	$ 48.21
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 2.28**	$ 1.90	$ 3.76	**$ 2.22**	$ 3.81
Royalties	**0.05**	0.05	0.17	**0.05**	0.18
Production expense	**1.30**	1.15	1.15	**1.27**	1.15
Netback	**$ 0.93**	$ 0.70	$ 2.44	**$ 0.90**	$ 2.48
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 49.08**	$ 49.17	$ 55.19	**$ 51.15**	$ 55.76
Royalties	**7.94**	5.93	7.59	**7.37**	7.43
Production expense	**12.97**	13.06	12.83	**13.15**	12.18
Netback	**$ 28.17**	$ 30.18	$ 34.77	**$ 30.63**	$ 36.15

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

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 63.73**	$ 65.10	$ 67.81	**$ 67.54**	$ 69.21
North Sea	**$ 106.68**	$ 108.22	$ 109.28	**$ 111.38**	$ 108.18
Offshore Africa	**$ 112.59**	$ 106.30	$ 114.44	**$ 115.19**	$ 106.93
Company average	**$ 67.59**	$ 69.99	$ 73.80	**$ 72.43**	$ 74.77
Natural gas ($/Mcf) (1) (2)					
North America	**$ 2.15**	$ 1.73	$ 3.67	**$ 2.09**	$ 3.73
North Sea	**$ 3.65**	$ 3.98	$ 3.26	**$ 3.93**	$ 4.05
Offshore Africa	**$ 9.95**	$ 10.54	$ 9.38	**$ 10.15**	$ 8.46
Company average	**$ 2.28**	$ 1.90	$ 3.76	**$ 2.22**	$ 3.81
Company average ($/BOE) (1) (2)	**$ 49.08**	$ 49.17	$ 55.19	**$ 51.15**	$ 55.76

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

North America

North America realized crude oil prices decreased 2% to average $67.54 per bbl for the nine months ended September 30, 2012 from $69.21 per bbl for the nine months ended September 30, 2011. North America realized crude oil prices averaged $63.73 per bbl for the third quarter of 2012, a decrease of 6% compared with $67.81 per bbl for the third quarter of 2011 and a decrease of 2% compared with $65.10 per bbl for the second quarter of 2012. The decrease in prices for the three and nine months ended September 30, 2012 from the comparable periods in 2011 was primarily a result of the widening of the WCS Heavy Differential; partially offset by the fluctuations in the Canadian dollar relative to the US dollar. The Company continues to focus on its crude oil blending marketing strategy, and in the third quarter of 2012 contributed approximately 155,000 bbl/d of heavy crude oil blends to the WCS stream.

In the first quarter of 2011, the Company announced that it had entered into a partnership agreement with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of a bitumen upgrader and refinery ("the Project") near Redwater, Alberta. In addition, the partnership has entered into processing agreements that target to process bitumen for the Company and the Government of Alberta under a 30 year fee-for-service tolling agreement under the Bitumen Royalty In Kind initiative. Subsequent to September 30, 2012, the Project was sanctioned by the Board of Directors of each partner of the North West Redwater Partnership ("Redwater"), and the associated target toll amounts were agreed to by Redwater, the Company and the Government of Alberta.

North America realized natural gas prices decreased 44% to average $2.09 per Mcf for the nine months ended September 30, 2012 from $3.73 per Mcf for the nine months ended September 30, 2011. North America realized natural gas prices decreased 41% to average $2.15 per Mcf for the third quarter of 2012 compared with $3.67 per Mcf in the third quarter of 2011, and increased 24% compared with $1.73 per Mcf for the second quarter of 2012. The decrease in natural gas prices for the three and nine months ended September 30, 2012 from the comparable periods in 2011 was primarily due to lower NYMEX and AECO benchmark pricing related to the impact of strong supply from US shale projects. The increase in natural gas prices for the third quarter of 2012 from the second quarter of 2012 was primarily due to higher NYMEX and AECO benchmark pricing related to a shift to higher utilization of gas fired electric generators and higher weather related gas demand resulting from warmer than normal summer temperatures.

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

(Quarterly Average)	**Sep 30 2012**	Jun 30 2012	Sep 30 2011
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 67.33**	$ 69.75	$ 78.54
Pelican Lake heavy crude oil ($/bbl)	**$ 63.03**	$ 63.07	$ 66.33
Primary heavy crude oil ($/bbl)	**$ 61.54**	$ 63.69	$ 65.08
Bitumen (thermal oil) ($/bbl)	**$ 64.56**	$ 64.65	$ 65.31
Natural gas ($/Mcf)	**$ 2.15**	$ 1.73	$ 3.67

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

North Sea

North Sea realized crude oil prices increased 3% to average $111.38 per bbl for the nine months ended September 30, 2012 from $108.18 per bbl for the nine months ended September 30, 2011. Realized crude oil prices averaged $106.68 per bbl for the third quarter of 2012, a decrease of 2% from $109.28 per bbl for the third quarter of 2011, and a decrease 1% from $108.22 per bbl for the second quarter of 2012. The fluctuations in realized crude oil prices in the North Sea from the comparable periods were primarily the result of fluctuations in Brent benchmark pricing and the Canadian dollar, and the timing of liftings.

Offshore Africa

Offshore Africa realized crude oil prices increased 8% to average $115.19 per bbl for the nine months ended September 30, 2012 from $106.93 per bbl for the nine months ended September 30, 2011. Realized crude oil prices decreased 2% to average $112.59 per bbl for the third quarter of 2012 from $114.44 per bbl for the third quarter of 2011, and increased 6% from $106.30 per bbl for the second quarter of 2012. The fluctuations in realized crude oil prices in Offshore Africa from the comparable periods were primarily the result of fluctuations in Brent benchmark pricing and the Canadian dollar, and the timing of liftings.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 11.65**	$ 8.33	$ 11.78	**$ 11.22**	$ 12.31
North Sea	**$ 0.33**	$ 0.26	$ 0.27	**$ 0.30**	$ 0.27
Offshore Africa	**$ 37.84**	$ 28.63	$ 20.69	**$ 28.20**	$ 11.02
Company average	**$ 12.08**	$ 9.18	$ 11.52	**$ 11.44**	$ 11.19
Natural gas ($/Mcf) [1]					
North America	**$ 0.02**	$ 0.02	$ 0.15	**$ 0.02**	$ 0.17
Offshore Africa	**$ 1.89**	$ 1.86	$ 1.90	**$ 1.78**	$ 1.33
Company average	**$ 0.05**	$ 0.05	$ 0.17	**$ 0.05**	$ 0.18
Company average ($/BOE) [1]	**$ 7.94**	$ 5.93	$ 7.59	**$ 7.37**	$ 7.43

(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, 2012 compared with the nine months ended September 30, 2011 reflected benchmark commodity prices.

Crude oil and NGLs royalties averaged approximately 18% of product sales for the third quarter of 2012 compared with 17% for the third quarter of 2011 and 13% for the second quarter of 2012. The increase in royalties from the second quarter of 2012 was the result of fluctuating pricing related to production from Oil Sands Royalty projects. Crude oil and NGLs royalties per bbl are anticipated to average 16% to 18% of product sales for 2012.

Natural gas royalties averaged approximately 1% of product sales for the second and third quarters of 2012 compared with 4% for the third quarter of 2011. The decrease in natural gas royalty rates from the third quarter of 2011 was due to lower realized natural gas prices. Natural gas royalties are anticipated to average 1% to 2% of product sales for 2012.

Offshore Africa

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital costs, the status of payouts, and the timing of liftings from each field.

Royalty rates as a percentage of product sales averaged approximately 32% for the third quarter of 2012 compared with 18% for the third quarter of 2011 and 26% for the second quarter of 2012. The increase in royalty rates from the comparable periods was due to higher crude oil prices during the year, adjustments to royalties on liftings, and the payout of the Baobab field in May 2011.

Offshore Africa royalty rates are anticipated to average 23% to 28% of product sales for 2012.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 12.52**	$ 13.10	$ 13.38	**$ 13.63**	$ 12.84
North Sea	**$ 60.94**	$ 68.32	$ 49.72	**$ 53.25**	$ 37.26
Offshore Africa	**$ 38.34**	$ 22.94	$ 19.91	**$ 23.40**	$ 19.99
Company average	**$ 15.79**	$ 16.66	$ 16.42	**$ 16.40**	$ 15.37
Natural gas ($/Mcf) [1]					
North America	**$ 1.28**	$ 1.13	$ 1.13	**$ 1.25**	$ 1.13
North Sea	**$ 3.44**	$ 3.89	$ 2.68	**$ 3.78**	$ 2.64
Offshore Africa	**$ 2.37**	$ 1.78	$ 2.16	**$ 1.97**	$ 1.86
Company average	**$ 1.30**	$ 1.15	$ 1.15	**$ 1.27**	$ 1.15
Company average ($/BOE) [1]	**$ 12.97**	$ 13.06	$ 12.83	**$ 13.15**	$ 12.18

(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, 2012 increased 6% to $13.63 per bbl from $12.84 per bbl for the nine months ended September 30, 2011. North America crude oil and NGLs production expense for the third quarter of 2012 decreased 6% to $12.52 per bbl from $13.38 per bbl for the third quarter of 2011 and decreased 4% from $13.10 per bbl for the second quarter of 2012. The increase in production expense for the nine months ended September 30, 2012 from the comparable period in 2011 was a result of higher overall service costs relating to heavy crude oil production. The decrease in production expense for the three months ended September 30, 2012 from the comparable period in 2011 was a result of the timing of thermal steam cycles and lower servicing costs in Pelican and light oil areas. The decrease in production expense from the second quarter of 2012 was a result of lower primary heavy oil costs and the timing of thermal steam cycles. North America crude oil and NGLs production expense is anticipated to average $12.75 to $13.25 per bbl for 2012.

North America natural gas production expense for the nine months ended September 30, 2012 increased 11% to $1.25 per Mcf from $1.13 per Mcf for the nine months ended September 30, 2011. North America natural gas production expense for the third quarter of 2012 increased 13% to $1.28 per Mcf from $1.13 per Mcf for the comparable periods. Natural gas production expense for the three and nine months ended September 30, 2012 increased from the comparable periods in 2011 due to the impact of shut-in production and lower production volumes related to the curtailment of capital expenditures related to gas activity. Natural gas production expense increased in the third quarter of 2012 compared to the second quarter of 2012 due to seasonal maintenance activity. North America natural gas production expense is anticipated to average $1.22 to $1.26 per Mcf for 2012.

North Sea

North Sea crude oil production expense for the nine months ended September 30, 2012 increased 43% to $53.25 per bbl from $37.26 per bbl for the nine months ended September 30, 2011. North Sea crude oil production expense for the third quarter of 2012 increased 23% to $60.94 per bbl from $49.72 per bbl for the third quarter of 2011, and decreased 11% from $68.32 per bbl for the second quarter of 2012. Production expense increased on a per barrel basis for the three and nine months ended September 30, 2012 from the comparable periods in 2011 due to the impact of production declines on relatively fixed costs, temporary shut ins of the third-party operated pipeline to Sullom Voe, and higher maintenance costs related to turnaround activity completed during the quarter. Production expense decreased for the third quarter of 2012 from the second quarter of 2012 due to higher production volumes on relatively fixed costs. North Sea crude oil production expense is anticipated to average $52.00 to $53.00 per bbl for 2012.

Offshore Africa

Offshore Africa crude oil production expense increased 17% to $23.40 per bbl from $19.99 per bbl for the nine months ended September 30, 2012. Offshore Africa crude oil production expense for the third quarter of 2012 averaged $38.34 per bbl, an increase of 93% compared with $19.91 per bbl for the third quarter of 2011 and an increase of 67% compared with $22.94 per bbl for the second quarter of 2012. Production expense for the three and nine months ended September 30, 2012 fluctuated from the comparable periods as a result of the timing of liftings from various fields, which have different cost structures. Annual Offshore Africa crude oil production expense is anticipated to average $24.50 to $25.50 per bbl for 2012.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Expense ($ millions)	**$ 931**	$ 936	$ 809	**$ 2,777**	$ 2,468
$/BOE (1)	**$ 18.00**	$ 18.13	$ 15.96	**$ 17.96**	$ 16.29

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

Depletion, depreciation and amortization expense increased for the nine months ended September 30, 2012 compared with 2011 due to higher production volumes in North America associated with heavy oil drilling and the impact of higher future development costs.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Expense ($ millions)	**$ 30**	$ 30	$ 28	**$ 89**	$ 82
$/BOE (1)	**$ 0.59**	$ 0.59	$ 0.54	**$ 0.58**	$ 0.54

(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

On March 13, 2012 the Company successfully and safely completed the unplanned maintenance on the fractionating unit in the primary upgrading facility. The positive impact of the third ore preparation plant ("OPP") and continued emphasis on safe, steady and reliable operations resulted in production of 99,205 bbl/d of SCO in the third quarter of 2012, within the Company's previously issued guidance of 95,000 to 105,000 bbl/d of SCO.

PRODUCT PRICES AND ROYALTIES – OIL SANDS MINING AND UPGRADING

($/bbl) [1]	Three Months Ended **Sep 30 2012**	 Jun 30 2012	 Sep 30 2011	Nine Months Ended **Sep 30 2012**	 Sep 30 2011
SCO sales price [2]	**$ 87.40**	$ 88.11	$ 96.19	**$ 89.39**	$ 92.45
Bitumen value for royalty purposes [3]	**$ 57.40**	$ 59.83	$ 56.54	**$ 60.53**	$ 59.18
Bitumen royalties [4]	**$ 3.45**	$ 5.20	$ 3.48	**$ 4.52**	$ 3.60

(1) Amounts expressed on a per unit basis are based on sales volumes excluding the period during suspension of production.
(2) Net of transportation.
(3) Calculated as the simple average of the monthly 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 $89.39 per bbl for the nine months ended September 30, 2012, a decrease of 3% compared to $92.45 per bbl for the nine months ended September 30, 2011. Realized SCO sales prices averaged $87.40 per bbl for the third quarter of 2012, a decrease of 9% compared with $96.19 per bbl for the third quarter of 2011 and a decrease of 1% compared with $88.11 per bbl for the second quarter of 2012, reflecting benchmark pricing.

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 2012**	 Jun 30 2012	 Sep 30 2011	Nine Months Ended **Sep 30 2012**	 Sep 30 2011
Cash production costs	**$ 398**	$ 388	$ 306	**$ 1,132**	$ 783
Less: costs incurred during the period of suspension of production	**–**	–	(151)	**(154)**	(581)
Adjusted cash production costs	**$ 398**	$ 388	$ 155	**$ 978**	$ 202
Adjusted cash production costs, excluding natural gas costs	**$ 373**	$ 362	$ 144	**$ 912**	$ 186
Adjusted natural gas costs	**25**	26	11	**66**	16
Adjusted cash production costs	**$ 398**	$ 388	$ 155	**$ 978**	$ 202

($/bbl) [1]	Three Months Ended **Sep 30 2012**	 Jun 30 2012	 Sep 30 2011	Nine Months Ended **Sep 30 2012**	 Sep 30 2011
Adjusted cash production costs, excluding natural gas costs	**$ 40.03**	$ 34.45	$ 33.13	**$ 38.05**	$ 34.70
Adjusted natural gas costs	**2.66**	2.53	2.72	**2.75**	3.02
Adjusted cash production costs	**$ 42.69**	$ 36.98	$ 35.85	**$ 40.80**	$ 37.72
Sales (bbl/d)	**101,263**	115,552	47,218	**87,569**	19,663

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

Adjusted cash production costs averaged $40.80 per bbl for the nine months ended September 30, 2012, an increase of 8% compared with $37.72 per bbl for the nine months ended September 30, 2011. Adjusted cash production costs for the third quarter of 2012 averaged $42.69 per bbl, an increase of 15% compared with $36.98 per bbl for the second quarter of 2012, primarily due to reduced production levels. Horizon operated at restricted rates for a portion of the third quarter of 2012 to ensure safe, steady, reliable operations in anticipation of the 12 day proactive planned maintenance outage in the fourth quarter of 2012.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2012**	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Depletion, depreciation and amortization	**$ 124**	$ 146	$ 77	**$ 333**	$ 133
Less: depreciation incurred during the period of suspension of production	**–**	–	(21)	**(6)**	(64)
Adjusted depletion, depreciation and amortization	**$ 124**	$ 146	$ 56	**$ 327**	$ 69
$/bbl (1)	**$ 13.31**	$ 13.84	$ 13.00	**$ 13.63**	$ 12.88

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

Depletion, depreciation and amortization expense for the three and nine months ended September 30, 2012 increased from the comparable periods in 2011 primarily due to higher sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2012**	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Expense	**$ 8**	$ 8	$ 5	**$ 24**	$ 15
$/bbl (1)	**$ 0.85**	$ 0.76	$ 1.14	**$ 0.99**	$ 2.77

(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 2012**	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Revenue	**$ 24**	$ 22	$ 23	**$ 67**	$ 66
Production expense	**7**	7	7	**21**	19
Midstream cash flow	**17**	15	16	**46**	47
Depreciation	**1**	2	1	**5**	5
Segment earnings before taxes	**$ 16**	$ 13	$ 15	**$ 41**	$ 42

Midstream operating results were consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2012**	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Expense	**$ 64**	$ 77	$ 65	**$ 206**	$ 188
$/BOE (1)	**$ 1.05**	$ 1.24	$ 1.17	**$ 1.15**	$ 1.20

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

Administration expense for the nine months ended September 30, 2012 increased from the comparable period primarily due to higher staffing related costs and general corporate costs. Administration expense for the third quarter of 2012 decreased from the second quarter of 2012 due to increased overhead recoveries associated with the capital programs.

SHARE-BASED COMPENSATION

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2012**	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Expense (recovery)	**$ 49**	$ (115)	$ (249)	**$ (173)**	$ (309)

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 $173 million share-based compensation recovery for the nine months ended September 30, 2012, primarily as a result of remeasurement of the fair value of outstanding stock options at the end of the period related to a decrease in the Company's share price, offset by 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, 2012, a $9 million recovery was recognized in respect of capitalized share-based compensation to Oil Sands Mining and Upgrading (September 30, 2011 – $19 million recovery).

For the nine months ended September 30, 2012, the Company paid $7 million for stock options surrendered for cash settlement (September 30, 2011 – $12 million).

INTEREST AND OTHER FINANCING COSTS

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2012**	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Expense, gross	**$ 119**	$ 114	$ 113	**$ 347**	$ 330
Less: capitalized interest	**27**	21	16	**66**	40
Expense, net	**$ 92**	$ 93	$ 97	**$ 281**	$ 290
$/BOE (1)	**$ 1.51**	$ 1.50	$ 1.75	**$ 1.57**	$ 1.85
Average effective interest rate	**4.9%**	4.8%	4.6%	**4.8%**	4.7%

(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, 2012 increased compared with 2011 due to higher average US dollar debt levels, higher variable interest rates, and the impact of a weaker Canadian dollar on US dollar denominated debt; partially offset by lower Canadian dollar denominated debt levels. Gross interest and other financing costs for the third quarter of 2012 increased from the second quarter of 2012 due to higher variable interest rates; partially offset by the impact of a stronger Canadian dollar on US dollar denominated debt. Capitalized interest of $66 million for the nine months ended September 30, 2012 related to Horizon Phase 2/3 expansions and the Kirby Project.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2012**	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Crude oil and NGLs financial instruments	**$ 18**	$ 19	$ 26	**$ 46**	$ 90
Foreign currency contracts and interest rate swaps	**119**	(80)	(49)	**124**	(9)
Realized loss (gain)	**$ 137**	$ (61)	$ (23)	**$ 170**	$ 81
Crude oil and NGLs financial instruments	**$ 58**	$ (180)	$ (71)	**$ (26)**	$ (139)
Foreign currency contracts and interest rate swaps	**(24)**	36	(51)	**(24)**	(47)
Unrealized loss (gain)	**$ 34**	$ (144)	$ (122)	**$ (50)**	$ (186)
Net loss (gain)	**$ 171**	$ (205)	$ (145)	**$ 120**	$ (105)

Complete details related to outstanding derivative financial instruments at September 30, 2012 are disclosed in note 13 to the Company's unaudited interim consolidated financial statements.

The Company recorded a net unrealized gain of $50 million ($41 million after-tax) on its risk management activities for the nine months ended September 30, 2012, including an unrealized loss of $34 million ($22 million after-tax) for the third quarter of 2012 (June 30, 2012 – unrealized gain of $144 million; $103 million after-tax; September 30, 2011 – unrealized gain of $122 million; $97 million after-tax), primarily due to changes in crude oil forward pricing and the fluctuations of unrealized gains and losses related to crude oil and foreign currency contracts.

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2012**	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Net realized loss (gain)	**$ 21**	$ (9)	$ (243)	**$ 18**	$ (225)
Net unrealized (gain) loss (1)	**(136)**	71	454	**(125)**	332
Net (gain) loss	**$ (115)**	$ 62	$ 211	**$ (107)**	$ 107

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

The net realized foreign exchange loss for the nine months ended September 30, 2012 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for the nine months ended September 30, 2012 was primarily related to the strengthening of the Canadian dollar with respect to US dollar debt. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (three months ended September 30, 2012 – unrealized loss of $85 million; June 30, 2012 – unrealized gain of $47 million; September 30, 2011 – unrealized gain of $150 million; nine months ended September 30, 2012 – unrealized loss of $80 million; September 30, 2011 – unrealized gain of $84 million). The Canadian dollar ended the third quarter at US$1.0166 (June 30, 2012 – US$0.9813; September 30, 2011 – US$0.9626).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Sep 30 2012	Three Months Ended Jun 30 2012	Three Months Ended Sep 30 2011	Nine Months Ended Sep 30 2012	Nine Months Ended Sep 30 2011
North America [1]	**$ 61**	$ 124	$ 26	**$ 298**	$ 196
North Sea	**22**	19	45	**86**	161
Offshore Africa	**50**	64	46	**150**	90
PRT (recovery) expense – North Sea	**(19)**	1	42	**13**	96
Other taxes	**–**	5	6	**11**	18
Current income tax	**114**	213	165	**558**	561
Deferred income tax expense	**23**	59	157	**34**	255
Deferred PRT expense (recovery) – North Sea	**6**	3	(4)	**5**	8
Deferred income tax expense	**29**	62	153	**39**	263
	143	275	318	**597**	824
Income tax rate and other legislative changes	**(58)**	–	–	**(58)**	(104)
	$ 85	$ 275	$ 318	**$ 539**	$ 720
Effective income tax rate on adjusted net earnings from operations [2]	**23.8%**	27.1%	25.7%	**28.5%**	26.2%

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

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

During 2011, the Canadian federal government enacted legislation to implement several taxation changes. These changes include a requirement that, beginning in 2012, partnership income must be included in the taxable income of each corporate partner based on the tax year of the partner, rather than the fiscal year of the partnership. The legislation includes a five-year transition provision and has no impact on net earnings.

During the first quarter of 2011, the UK government enacted an increase to the supplementary income tax rate charged on profits from UK North Sea crude oil and natural gas production, increasing the combined corporate and supplementary income tax rate from 50% to 62%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $104 million as at March 31, 2011.

During the third quarter of 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax relief on decommissioning expenditures to 50%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $58 million.

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

For 2012, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $440 million to $480 million in Canada and $300 million to $350 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Sep 30 2012	Jun 30 2012	Sep 30 2011	Nine Months Ended Sep 30 2012	Sep 30 2011
Exploration and Evaluation					
Net expenditures	**$ 59**	$ 32	$ 85	**$ 299**	$ 200
Property, Plant and Equipment					
Net property acquisitions	**23**	7	127	**68**	616
Well drilling, completion and equipping	**485**	352	437	**1,336**	1,293
Production and related facilities	**533**	445	415	**1,483**	1,210
Capitalized interest and other [2]	**28**	30	28	**88**	78
Net expenditures	**1,069**	834	1,007	**2,975**	3,197
Total Exploration and Production	**1,128**	866	1,092	**3,274**	3,397
Oil Sands Mining and Upgrading					
Horizon Phases 2/3 construction costs	**354**	346	126	**892**	331
Sustaining capital	**41**	51	52	**129**	126
Turnaround costs	**11**	3	–	**16**	79
Capitalized interest and other [2]	**24**	5	(3)	**32**	15
Total Oil Sands Mining and Upgrading	**430**	405	175	**1,069**	551
Horizon coker rebuild and collateral damage costs [3]	**–**	–	80	**–**	389
Midstream	**5**	4	1	**10**	5
Abandonments [4]	**48**	39	54	**163**	147
Head office	**10**	10	4	**25**	16
Total net capital expenditures	**$ 1,621**	$ 1,324	$ 1,406	**$ 4,541**	$ 4,505
By segment					
North America	**$ 1,029**	$ 788	$ 1,045	**$ 3,040**	$ 3,190
North Sea	**79**	66	46	**199**	156
Offshore Africa	**20**	12	1	**35**	51
Oil Sands Mining and Upgrading	**430**	405	255	**1,069**	940
Midstream	**5**	4	1	**10**	5
Abandonments [4]	**48**	39	54	**163**	147
Head office	**10**	10	4	**25**	16
Total	**$ 1,621**	$ 1,324	$ 1,406	**$ 4,541**	$ 4,505

(1) The net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.

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

(3) During 2011, the Company recognized $393 million of property damage insurance recoveries (see note 7 to the interim consolidated financial statements), offsetting the costs incurred related to the coker rebuild and collateral damage costs.

(4) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

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

Net capital expenditures for the nine months ended September 30, 2012 were $4,541 million, comparable with $4,505 million for the nine months ended September 30, 2011. Net capital expenditures for the third quarter of 2012 were $1,621 million compared with $1,406 million for the third quarter of 2011 and $1,324 million for the second quarter of 2012.

Excluding the Horizon coker rebuild and collateral damage costs incurred in 2011, the increase in capital expenditures for the three and nine months ended September 30, 2012 from 2011 was primarily due to the ramp up of Horizon field construction activity, partially offset by lower net property acquisition costs. The increase in capital expenditures for the three months ended September 30, 2012 from the second quarter of 2012 was primarily due to an increase in well drilling and completion activities related to the primary heavy oil drilling program.

Drilling Activity (number of wells)

	Three Months Ended			Nine Months Ended	
	Sep 30 2012	Jun 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Net successful natural gas wells	**9**	4	21	**32**	56
Net successful crude oil wells (1)	**365**	266	317	**909**	773
Dry wells	**6**	2	10	**14**	31
Stratigraphic test / service wells	**22**	5	25	**611**	545
Total	**402**	277	373	**1,566**	1,405
Success rate (excluding stratigraphic test / service wells)	**99%**	99%	97%	**99%**	96%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 71% of the total capital expenditures for the nine months ended September 30, 2012 compared with approximately 74% for the nine months ended September 30, 2011.

During the third quarter of 2012, the Company targeted 9 net natural gas wells, including 2 wells in Northeast British Columbia and 7 wells in Northwest Alberta. The Company also targeted 371 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 267 primary heavy crude oil wells, 20 Pelican Lake heavy crude oil wells, 1 light crude oil well and 43 bitumen (thermal oil) wells were drilled. Another 40 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall Primrose thermal production for the third quarter of 2012 averaged approximately 102,000 bbl/d compared with approximately 110,000 bbl/d for the third quarter of 2011 and approximately 94,000 bbl/d for the second quarter of 2012. Production volumes were in line with expectations due to the cyclic nature of thermal production at Primrose. As part of the phased expansion of its in situ Oil Sands assets, the Company is continuing to develop its Primrose thermal projects. Additional pad drilling was completed and drilled on budget, with these wells coming on production in 2013.

The next planned phase of the Company's in situ Oil Sands assets expansion is the Kirby South Phase 1 Project. As at September 30, 2012, the overall project was 67% complete, drilling was completed on the fourth of seven pads and first steam is targeted for 2013. The Company has acquired approximately 49 sections (12,630 hectares) of additional Oil Sands rights immediately adjacent to the Kirby in situ Oil Sands expansion project.

Development of the tertiary recovery conversion projects at Pelican Lake continued and 20 horizontal wells were drilled during the quarter. Pelican Lake production averaged approximately 41,000 bbl/d for the third quarter of 2012 compared with 38,000 bbl/d for the third quarter of 2011 and 37,000 bbl/d for the second quarter of 2012.

For the fourth quarter of 2012, the Company's overall planned drilling activity in North America is expected to be 302 net crude oil wells, 42 net bitumen wells and 3 net natural gas wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the third quarter of 2012 was focused on the field construction of the gas recovery unit, sulphur recovery unit, butane treatment unit, coker expansion, and extraction trains 3 and 4, along with engineering related to the hydrogen 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. All personnel on board the FPSO were safe and accounted for. The extent of the damage, including associated costs and related property damage, are not expected to be significant. The timing of returning to the field is currently being assessed.

In March 2011, the UK government enacted an increase to the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. As a result of the increase in the corporate income tax rate, the Company's development activities in the North Sea were reduced. The Company is continuing to high grade all North Sea prospects for potential development opportunities in 2012 and future years.

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 is currently assessing the impact of this initiative on its future capital programs.

Offshore Africa

During the fourth quarter of 2011, the Company sanctioned an 8 well drilling program at the Espoir field in Côte d'Ivoire. Preparations are ongoing, targeting commencement of drilling operations in the fourth quarter of 2012. At the Olowi field in Gabon, approximately 1,500 bbl/d of production was shut in due to a second failure in the midwater arch. The Company is currently assessing the operability of the midwater arch.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	Sep 30 2012	Jun 30 2012	Dec 31 2011	Sep 30 2011
Working capital (deficit) (1)	**$ (1,002)**	$ (732)	$ (894)	$ (213)
Long-term debt (2) (3)	**$ 8,416**	$ 8,522	$ 8,571	$ 9,327
Share capital	**$ 3,691**	$ 3,670	$ 3,507	$ 3,431
Retained earnings	**20,383**	20,193	19,365	18,642
Accumulated other comprehensive income	**46**	59	26	71
Shareholders' equity	**$ 24,120**	$ 23,922	$ 22,898	$ 22,144
Debt to book capitalization (3) (4)	**26%**	26%	27%	30%
Debt to market capitalization (3) (5)	**20%**	22%	17%	22%
After-tax return on average common shareholders' equity (6)	**10%**	12%	12%	7%
After-tax return on average capital employed (3) (7)	**8%**	10%	10%	6%

(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, 2012, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's December 31, 2011 annual MD&A. In addition, the Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon maintaining an investment grade debt rating and the condition of capital and credit markets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy. At September 30, 2012, the Company had $4,261 million of available credit under its bank credit facilities.

Over the next 12 months, the Company has maturities of long-term debt aggregating $1,138 million (US$350 million due October 2012, $400 million due January 2013 and US$400 million due February 2013). It is the Company's intention to retire this indebtedness utilizing cash flow from operations generated in excess of capital expenditures and available bank credit facilities as necessary, while maintaining the ongoing dividend program. On a pro forma basis, reflecting the retirement of this indebtedness, the available credit under its bank credit facilities at September 30, 2012 would amount to $3,123 million.

During the second quarter of 2012, the $1,500 million revolving syndicated credit facility was extended to June 2016. Additionally, the Company issued $500 million of 3.05% medium-term notes due June 2019. Proceeds from the securities issued were used to repay bank indebtedness and for general corporate purposes. After issuing these securities, the Company has $2,500 million remaining on its outstanding $3,000 million base shelf prospectus that allows for the issue of medium-term notes in Canada, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance.

The Company has US$2,000 million remaining on its outstanding US$3,000 million base shelf prospectus that allows for the issue of US dollar debt securities in the United States, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance. Subsequent to September 30, 2012, US$350 million of US dollar denominated debt securities bearing interest at 5.45% were repaid.

Long-term debt was $8,416 million at September 30, 2012, resulting in a debt to book capitalization ratio of 26% (June 30, 2012 – 26%; September 30, 2011 – 30%). This ratio is below the 35% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. The Company has hedged a portion of its crude oil production for 2012 and 2013 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, 2012 are discussed in note 5 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedging policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures 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 6, 2012, approximately 60% of currently forecasted fourth quarter 2012 crude oil volumes were hedged using collars and puts. Further details related to the Company's commodity related derivative financial instruments outstanding at September 30, 2012 are discussed in note 13 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at September 30, 2012, there were 1,095,134,000 common shares outstanding and 66,029,000 stock options outstanding. As at November 5, 2012, the Company had 1,094,484,000 common shares outstanding and 65,435,000 stock options outstanding.

During the second quarter of 2012, the Company amended its Articles by special resolution of the Shareholders, changing the designation of its Class 1 preferred shares to "Preferred Shares" which may be issuable in series. If issued, the number of shares in each series, and the designation, rights, privileges, restrictions and conditions attached to the shares will be determined by the Board of Directors of the Company.

On March 6, 2012, the Company's Board of Directors approved an increase in the annual dividend to be paid by the Company to $0.42 per common share for 2012. The increase represents an approximately 17% increase from 2011, recognizing the stability of the Company's cash flow and providing a return to shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

In April 2012, 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 9, 2012 and ending April 8, 2013, up to 55,027,447 common shares.

On March 31, 2011, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the TSX and the NYSE, during the twelve month period commencing April 6, 2011 and ending April 5, 2012, up to 27,406,131 common shares of the Company.

As at September 30, 2012, 6,876,200 common shares (June 30, 2012 – 4,621,600 common shares; March 31, 2012 – 692,200 common shares) had been purchased for cancellation at a weighted average price of $29.10 per common share (June 30, 2012 – $29.63 per common share; March 31, 2012 – $33.11 per common share), for a total cost of $200 million (June 30, 2012 – $137 million; March 31, 2012 – $23 million). Subsequent to September 30, 2012, the Company purchased 949,000 common shares at a weighted average price of $30.18 per common share for a total cost of $29 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. As at September 30, 2012, no entities were consolidated under the Standing Interpretations Committee ("SIC") 12, "Consolidation – Special Purpose Entities". The following table summarizes the Company's commitments as at September 30, 2012:

($ millions)	Remaining 2012	2013	2014	2015	2016	Thereafter
Product transportation and pipeline	$ 58	$ 213	$ 204	$ 192	$ 126	$ 889
Offshore equipment operating leases and offshore drilling	$ 43	$ 153	$ 120	$ 103	$ 75	$ 121
Long-term debt (1)	$ 344	$ 794	$ 836	$ 437	$ 589	$ 5,468
Interest and other financing costs (2)	$ 103	$ 397	$ 377	$ 343	$ 329	$ 3,997
Office leases	$ 8	$ 32	$ 35	$ 33	$ 34	$ 309
Other	$ 76	$ 169	$ 95	$ 42	$ 10	$ 8

(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, 2012.

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.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

For the impact of new accounting standards, refer to the MD&A and the audited consolidated financial statements for the year ended December 31, 2011.

CRITICAL ACCOUNTING ESTIMATES AND CHANGE IN ACCOUNTING POLICIES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements 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 accounting policies is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2011.

Consolidated Balance Sheets

As at (millions of Canadian dollars, unaudited)	Note	Sep 30 2012	Dec 31 2011
ASSETS			
Current assets			
Cash and cash equivalents		**$ 21**	$ 34
Accounts receivable		**1,365**	2,077
Inventory		**570**	550
Prepaids and other		**191**	120
		2,147	2,781
Exploration and evaluation assets	2	**2,660**	2,475
Property, plant and equipment	3	**42,724**	41,631
Other long-term assets	4	**338**	391
		$ 47,869	$ 47,278
LIABILITIES			
Current liabilities			
Accounts payable		**$ 525**	$ 526
Accrued liabilities		**2,218**	2,347
Current income tax liabilities		**232**	347
Current portion of long-term debt	5	**1,138**	359
Current portion of other long-term liabilities	6	**174**	455
		4,287	4,034
Long-term debt	5	**7,278**	8,212
Other long-term liabilities	6	**3,954**	3,913
Deferred income tax liabilities		**8,230**	8,221
		23,749	24,380
SHAREHOLDERS' EQUITY			
Share capital	9	**3,691**	3,507
Retained earnings		**20,383**	19,365
Accumulated other comprehensive income	10	**46**	26
		24,120	22,898
		$ 47,869	$ 47,278

Commitments and contingencies (note 14).

Approved by the Board of Directors on November 6, 2012

Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Sep 30 2012	Three Months Ended Sep 30 2011	Nine Months Ended Sep 30 2012	Nine Months Ended Sep 30 2011
Product sales		**$ 3,978**	$ 3,690	**$ 12,136**	$ 10,719
Less: royalties		**(442)**	(400)	**(1,247)**	(1,145)
Revenue		**3,536**	3,290	**10,889**	9,574
Expenses					
Production		**1,071**	959	**3,177**	2,637
Transportation and blending		**606**	459	**2,014**	1,745
Depletion, depreciation and amortization	3	**1,056**	887	**3,115**	2,606
Administration		**64**	65	**206**	188
Share-based compensation	6	**49**	(249)	**(173)**	(309)
Asset retirement obligation accretion	6	**38**	33	**113**	97
Interest and other financing costs		**92**	97	**281**	290
Risk management activities	13	**171**	(145)	**120**	(105)
Foreign exchange (gain) loss		**(115)**	211	**(107)**	107
Horizon asset impairment provision	7	**–**	–	**–**	396
Insurance recovery – property damage	7	**–**	–	**–**	(396)
Insurance recovery – business interruption	7	**–**	(181)	**–**	(317)
Equity loss from jointly controlled entity	4	**1**	–	**6**	–
		3,033	2,136	**8,752**	6,939
Earnings before taxes		**503**	1,154	**2,137**	2,635
Current income tax expense	8	**114**	165	**558**	561
Deferred income tax expense	8	**29**	153	**39**	263
Net earnings		**$ 360**	$ 836	**$ 1,540**	$ 1,811
Net earnings per common share					
Basic	12	**$ 0.33**	$ 0.76	**$ 1.40**	$ 1.65
Diluted	12	**$ 0.33**	$ 0.76	**$ 1.40**	$ 1.64

Consolidated Statements of Comprehensive Income

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2012	Three Months Ended Sep 30 2011	Nine Months Ended Sep 30 2012	Nine Months Ended Sep 30 2011
Net earnings	**$ 360**	$ 836	**$ 1,540**	$ 1,811
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized (loss) income during the period, net of taxes of $3 million (2011 – $6 million) – three months ended; $2 million (2011 – $5 million) – nine months ended	**(20)**	46	**14**	44
Reclassification to net earnings, net of taxes of $nil (2011 – $4 million) – three months ended; $nil (2011 – $13 million) – nine months ended	**(3)**	12	**(4)**	41
	(23)	58	**10**	85
Foreign currency translation adjustment				
Translation of net investment	**10**	(25)	**10**	(23)
Other comprehensive (loss) income, net of taxes	**(13)**	33	**20**	62
Comprehensive income	**$ 347**	$ 869	**$ 1,560**	$ 1,873

Consolidated Statements of Changes in Equity

(millions of Canadian dollars, unaudited)	Note	Nine Months Ended **Sep 30 2012**	Sep 30 2011
Share capital	9		
Balance – beginning of period		**$ 3,507**	$ 3,147
Issued upon exercise of stock options		**164**	192
Previously recognized liability on stock options exercised for common shares		**43**	100
Purchase of common shares under Normal Course Issuer Bid		**(23)**	(8)
Balance – end of period		**3,691**	3,431
Retained earnings			
Balance – beginning of period		**19,365**	17,212
Net earnings		**1,540**	1,811
Purchase of common shares under Normal Course Issuer Bid	9	**(177)**	(84)
Dividends on common shares	9	**(345)**	(297)
Balance – end of period		**20,383**	18,642
Accumulated other comprehensive income	10		
Balance – beginning of period		**26**	9
Other comprehensive income, net of taxes		**20**	62
Balance – end of period		**46**	71
Shareholders' equity		**$ 24,120**	$ 22,144

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Sep 30 2012**	Three Months Ended Sep 30 2011	Nine Months Ended **Sep 30 2012**	Nine Months Ended Sep 30 2011
Operating activities					
Net earnings		**$ 360**	$ 836	**$ 1,540**	$ 1,811
Non-cash items					
Depletion, depreciation and amortization		**1,056**	887	**3,115**	2,606
Share-based compensation		**49**	(249)	**(173)**	(309)
Asset retirement obligation accretion		**38**	33	**113**	97
Unrealized risk management loss (gain)		**34**	(122)	**(50)**	(186)
Unrealized foreign exchange (gain) loss		**(136)**	454	**(125)**	332
Realized foreign exchange gain on repayment of US dollar debt securities		**–**	(225)	**–**	(225)
Equity loss from jointly controlled entity	4	**1**	–	**6**	–
Deferred income tax expense		**29**	153	**39**	263
Horizon asset impairment provision	7	**–**	–	**–**	396
Insurance recovery – property damage	7	**–**	–	**–**	(396)
Other		**7**	9	**47**	(9)
Abandonment expenditures		**(48)**	(54)	**(163)**	(147)
Net change in non-cash working capital		**132**	(469)	**245**	(303)
		1,522	1,253	**4,594**	3,930
Financing activities					
Issue (repayment) of bank credit facilities, net		**139**	652	**(420)**	985
Repayment of US dollar debt securities		**–**	(390)	**–**	(390)
Issue of medium-term notes, net		**–**	–	**498**	–
Issue of common shares on exercise of stock options		**24**	11	**164**	192
Purchase of common shares under Normal Course Issuer Bid		**(63)**	(92)	**(200)**	(92)
Dividends on common shares		**(115)**	(99)	**(329)**	(279)
Net change in non-cash working capital		**(13)**	(5)	**(29)**	(10)
		(28)	77	**(316)**	406
Investing activities					
Expenditures on exploration and evaluation assets and property, plant and equipment		**(1,573)**	(1,352)	**(4,378)**	(4,358)
Investment in other long-term assets		**–**	–	**2**	(346)
Net change in non-cash working capital		**90**	34	**85**	364
		(1,483)	(1,318)	**(4,291)**	(4,340)
Increase (decrease) in cash and cash equivalents		**11**	12	**(13)**	(4)
Cash and cash equivalents – beginning of period		**10**	6	**34**	22
Cash and cash equivalents – end of period		**$ 21**	$ 18	**$ 21**	$ 18
Interest paid		**$ 134**	$ 151	**$ 360**	$ 376
Income taxes paid		**$ 99**	$ 141	**$ 534**	$ 516

Notes to the Consolidated Financial Statements

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

1. ACCOUNTING POLICIES

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

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

Within Western Canada, the Company maintains certain midstream activities that include pipeline operations and an electricity co-generation system.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2500, 855-2 Street S.W., Calgary, Alberta.

These interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, 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, 2011. 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, 2011.

2. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2011	$ 2,442	$ –	$ 33	$ –	$ 2,475
Additions	**294**	**–**	**5**	**–**	**299**
Transfers to property, plant and equipment	**(114)**	**–**	**–**	**–**	**(114)**
At September 30, 2012	**$ 2,622**	**$ –**	**$ 38**	**$ –**	**$ 2,660**

3. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2011	$ 46,120	$ 4,147	$ 3,044	$ 15,211	$ 298	$ 234	$ 69,054
Additions	**2,787**	**205**	**32**	**1,108**	**10**	**25**	**4,167**
Transfers from E&E assets	**114**	**–**	**–**	**–**	**–**	**–**	**114**
Disposals/ derecognitions	**(84)**	**(39)**	**(8)**	**(5)**	**–**	**–**	**(136)**
Foreign exchange adjustments and other	**–**	**(139)**	**(101)**	**–**	**–**	**–**	**(240)**
At September 30, 2012	**$ 48,937**	**$ 4,174**	**$ 2,967**	**$ 16,314**	**$ 308**	**$ 259**	**$ 72,959**
Accumulated depletion and depreciation							
At December 31, 2011	$ 21,721	$ 2,512	$ 2,152	$ 776	$ 96	$ 166	$ 27,423
Expense	**2,438**	**220**	**107**	**333**	**5**	**12**	**3,115**
Disposals/ derecognitions	**(84)**	**(39)**	**(6)**	**(5)**	**–**	**–**	**(134)**
Foreign exchange adjustments and other	**–**	**(86)**	**(62)**	**(21)**	**–**	**–**	**(169)**
At September 30, 2012	**$ 24,075**	**$ 2,607**	**$ 2,191**	**$ 1,083**	**$ 101**	**$ 178**	**$ 30,235**
Net book value							
– at September 30, 2012	**$ 24,862**	**$ 1,567**	**$ 776**	**$ 15,231**	**$ 207**	**$ 81**	**$ 42,724**
– at December 31, 2011	$ 24,399	$ 1,635	$ 892	$ 14,435	$ 202	$ 68	$ 41,631

Development projects not subject to depletion	
At September 30, 2012	**$ 1,669**
At December 31, 2011	$ 1,443

The Company acquired a number of producing crude oil and natural gas assets in the North America Exploration and Production segment for total cash consideration of $67 million during the nine months ended September 30, 2012 (year ended December 31, 2011 – $1,012 million), net of associated asset retirement obligations of $4 million (year ended December 31, 2011 – $79 million). Interests in jointly controlled assets were acquired with full tax basis. No working capital or debt obligations were assumed.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once construction is substantially complete. For the nine months ended September 30, 2012, pre-tax interest of $66 million was capitalized to property, plant and equipment (September 30, 2011 – $40 million) using a capitalization rate of 4.8% (September 30, 2011 – 4.7%).

4. OTHER LONG-TERM ASSETS

	Sep 30 2012	Dec 31 2011
Investment in North West Redwater Partnership	**$ 313**	$ 321
Other	**25**	70
	$ 338	$ 391

Other long-term assets include an investment in the 50% owned North West Redwater Partnership ("Redwater"). The investment is accounted for using the equity method. Redwater has committed to construct and operate a bitumen upgrader and refinery (the "Project") under processing agreements that target to process bitumen for the Company and the Government of Alberta under a 30 year fee-for-service tolling agreement. Subsequent to September 30, 2012, the Project was sanctioned by the Board of Directors of each partner of Redwater, and the associated target toll amounts were agreed to by Redwater, the Company and the Government of Alberta.

5. LONG-TERM DEBT

	Sep 30 2012	Dec 31 2011
Canadian dollar denominated debt		
Bank credit facilities	**$ 380**	$ 796
Medium-term notes	**1,300**	800
	1,680	1,596
US dollar denominated debt		
US dollar debt securities (US$6,900 million)	**6,788**	7,017
Less: original issue discount on US dollar debt securities (1)	**(21)**	(21)
	6,767	6,996
Fair value impact of interest rate swaps on US dollar debt securities (2)	**21**	31
	6,788	7,027
Long-term debt before transaction costs	**8,468**	8,623
Less: transaction costs (1) (3)	**(52)**	(52)
	8,416	8,571
Less: current portion (1) (2) (4)	**1,138**	359
	$ 7,278	$ 8,212

(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 amounts of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 were adjusted by $21 million (December 31, 2011 – $31 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.

(4) Subsequent to September 30, 2012, US$350 million of US dollar denominated debt securities bearing interest at 5.45% were repaid.

Bank Credit Facilities

As at September 30, 2012, the Company had in place unsecured bank credit facilities of $4,724 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $3,000 million maturing June 2015;
- 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 2012, the $1,500 million revolving syndicated credit facility was extended to June 2016. 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's weighted average interest rate on bank credit facilities outstanding as at September 30, 2012, was 2.0% (September 30, 2011 – 2.3%), and on long-term debt outstanding for the nine months ended September 30, 2012 was 4.8% (September 30, 2011 – 4.7%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $561 million, including $95 million related to Horizon and $271 million related to North Sea operations, were outstanding at September 30, 2012. During the third quarter of 2012, the Company issued a financial guarantee for $100 million supporting a revolving credit facility in the 50% owned North West Redwater Partnership.

Subsequent to September 30, 2012, the financial guarantee related to Horizon was reduced to $87 million and the financial guarantee related to Redwater was increased by $25 million to $125 million.

Medium-Term Notes

During the second quarter of 2012, the Company issued $500 million of 3.05% medium-term unsecured notes due June 2019. After issuing these securities, the Company has $2,500 million remaining on its outstanding $3,000 million base shelf prospectus that allows for the issue of medium-term notes in Canada, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance.

US Dollar Debt Securities

The Company has US$2,000 million remaining on its outstanding US$3,000 million base shelf prospectus that allows for the issue of US dollar debt securities in the United States, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance.

6. OTHER LONG-TERM LIABILITIES

	Sep 30 2012	Dec 31 2011
Asset retirement obligations	**$ 3,544**	$ 3,577
Share-based compensation	**200**	432
Risk management (note 13)	**292**	274
Other	**92**	85
	4,128	4,368
Less: current portion	**174**	455
	$ 3,954	$ 3,913

Asset retirement obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.6% (December 31, 2011 – 4.6%). A reconciliation of the discounted asset retirement obligations is as follows:

	Sep 30 2012	Dec 31 2011
Balance – beginning of period	**$ 3,577**	$ 2,624
Liabilities incurred	**37**	12
Liabilities acquired	**4**	79
Liabilities settled	**(163)**	(213)
Asset retirement obligation accretion	**113**	130
Revision of estimates	**5**	924
Foreign exchange	**(29)**	21
Balance – end of period	**$ 3,544**	$ 3,577

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 2012	Dec 31 2011
Balance – beginning of period	**$ 432**	$ 663
Share-based compensation recovery	**(173)**	(102)
Cash payment for stock options surrendered	**(7)**	(14)
Transferred to common shares	**(43)**	(115)
Capitalized to (recovered from) Oil Sands Mining and Upgrading	**(9)**	–
Balance – end of period	**200**	432
Less: current portion	**143**	384
	$ 57	$ 48

7. HORIZON ASSET IMPAIRMENT PROVISION AND INSURANCE RECOVERY

In 2011, the Company recognized an asset impairment provision in the Oil Sands Mining and Upgrading segment of $396 million, net of accumulated depletion and amortization, related to the property damage resulting from a fire in the Horizon primary upgrading coking plant. The Company also recorded final property damage insurance recoveries of $393 million and business interruption insurance recoveries of $333 million in 2011. In the first quarter of 2012, upon final settlement of its insurance claims, all outstanding insurance proceeds were collected.

8. INCOME TAXES

The provision for income tax is as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Current corporate income tax – North America	**$ 61**	$ 26	**$ 298**	$ 196
Current corporate income tax – North Sea	**22**	45	**86**	161
Current corporate income tax – Offshore Africa	**50**	46	**150**	90
Current PRT [1] (recovery) expense – North Sea	**(19)**	42	**13**	96
Other taxes	**–**	6	**11**	18
Current income tax expense	**114**	165	**558**	561
Deferred corporate income tax expense	**23**	157	**34**	255
Deferred PRT [1] expense (recovery) – North Sea	**6**	(4)	**5**	8
Deferred income tax expense	**29**	153	**39**	263
Income tax expense	**$ 143**	$ 318	**$ 597**	$ 824

(1) Petroleum Revenue Tax.

During 2011, the Canadian federal government enacted legislation to implement several taxation changes. These changes include a requirement that, beginning in 2012, partnership income must be included in the taxable income of each corporate partner based on the tax year of the partner, rather than the fiscal year of the partnership. The legislation includes a five-year transition provision and has no impact on net earnings.

During the first quarter of 2011, the UK government enacted an increase to the supplementary income tax rate charged on profits from UK North Sea crude oil and natural gas production, increasing the combined corporate and supplementary income tax rate from 50% to 62%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $104 million as at March 31, 2011.

During the third quarter of 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax relief on decommissioning expenditures to 50%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $58 million.

9. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Nine Months Ended Sep 30, 2012	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,096,460**	**$ 3,507**
Issued upon exercise of stock options	**5,550**	**164**
Previously recognized liability on stock options exercised for common shares	**–**	**43**
Purchase of common shares under Normal Course Issuer Bid	**(6,876)**	**(23)**
Balance – end of period	**1,095,134**	**$ 3,691**

Preferred Shares

During the second quarter of 2012, the Company amended its Articles by special resolution of the Shareholders, changing the designation of its Class 1 preferred shares to “Preferred Shares” which may be issuable in series. If issued, the number of shares in each series, and the designation, rights, privileges, restrictions and conditions attached to the shares will be determined by the Board of Directors of the Company.

Dividend Policy

On March 6, 2012, the Board of Directors set the regular quarterly dividend at $0.105 per common share (2011 – $0.09 per common share). The Company has paid regular quarterly dividends in January, April, July, and October of each year since 2001. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

Normal Course Issuer Bid

The Company’s Normal Course Issuer Bid announced in 2011 expired April 5, 2012. In April 2012, 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 9, 2012 and ending April 8, 2013, up to 55,027,447 common shares.

For the nine months ended September 30, 2012, the Company purchased 6,876,200 common shares at a weighted average price of $29.10 per common share, for a total cost of $200 million. Retained earnings were reduced by $177 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2012, the Company purchased 949,000 common shares at a weighted average price of $30.18 per common share for a total cost of $29 million.

Stock Options

The following table summarizes information relating to stock options outstanding at September 30, 2012:

	Nine Months Ended Sep 30, 2012	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of period	**73,486**	**$ 34.85**
Granted	**4,949**	**$ 31.80**
Surrendered for cash settlement	**(853)**	**$ 30.17**
Exercised for common shares	**(5,550)**	**$ 29.52**
Forfeited	**(6,003)**	**$ 36.92**
Outstanding – end of period	**66,029**	**$ 34.94**
Exercisable – end of period	**21,090**	**$ 32.93**

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 2012	Sep 30 2011
Derivative financial instruments designated as cash flow hedges	**$ 72**	$ 118
Foreign currency translation adjustment	**(26)**	(47)
	$ 46	$ 71

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 35% 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, 2012, the ratio was below the target range at 26%.

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 2012	Dec 31 2011
Long-term debt [1]	**$ 8,416**	$ 8,571
Total shareholders' equity	**$ 24,120**	$ 22,898
Debt to book capitalization	**26%**	27%

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

12. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
	Sep 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Weighted average common shares outstanding – basic (thousands of shares)	**1,095,267**	1,096,750	**1,098,145**	1,095,753
Effect of dilutive stock options (thousands of shares)	**1,856**	4,673	**2,725**	8,103
Weighted average common shares outstanding – diluted (thousands of shares)	**1,097,123**	1,101,423	**1,100,870**	1,103,856
Net earnings	**$ 360**	$ 836	**$ 1,540**	$ 1,811
Net earnings per common share – basic	**$ 0.33**	$ 0.76	**$ 1.40**	$ 1.65
– diluted	**$ 0.33**	$ 0.76	**$ 1.40**	$ 1.64

13. FINANCIAL INSTRUMENTS

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

	Sep 30, 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	**$ 1,365**	**$ –**	**$ –**	**$ –**	**$ 1,365**
Accounts payable	**–**	**–**	**–**	**(525)**	**(525)**
Accrued liabilities	**–**	**–**	**–**	**(2,218)**	**(2,218)**
Other long-term liabilities	**–**	**12**	**(304)**	**(85)**	**(377)**
Long-term debt [1]	**–**	**–**	**–**	**(8,416)**	**(8,416)**
	$ 1,365	**$ 12**	**$ (304)**	**$ (11,244)**	**$ (10,171)**

	Dec 31, 2011				
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	$ 2,077	$ –	$ –	$ –	$ 2,077
Accounts payable	–	–	–	(526)	(526)
Accrued liabilities	–	–	–	(2,347)	(2,347)
Other long-term liabilities	–	(38)	(236)	(75)	(349)
Long-term debt [1]	–	–	–	(8,571)	(8,571)
	$ 2,077	$ (38)	$ (236)	$ (11,519)	$ (9,716)

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

The carrying amount 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, 2012		
	Carrying amount	**Fair value**	
Asset (liability) [(1)]		**Level 1**	**Level 2**
Other long-term liabilities	**$ (292)**	**$ –**	**$ (292)**
Fixed rate long-term debt [(2) (3) (4)]	**(8,036)**	**(9,466)**	**–**
	$ (8,328)	**$ (9,466)**	**$ (292)**

	Dec 31, 2011		
	Carrying amount	Fair value	
Asset (liability) [(1)]		Level 1	Level 2
Other long-term liabilities	$ (274)	$ –	$ (274)
Fixed rate long-term debt [(2) (3) (4)]	(7,775)	(9,120)	–
	$ (8,049)	$ (9,120)	$ (274)

(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 amounts of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $21 million (December 31, 2011 – $31 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 long-term debt.

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

Asset (liability)	**Sep 30, 2012**	Dec 31, 2011
Derivatives held for trading		
Crude oil price collars	**$ 26**	$ (13)
Crude oil put options, net of put premium financing obligations	**(13)**	–
Foreign currency forward contracts	**(1)**	(25)
Cash flow hedges		
Cross currency swaps	**(304)**	(236)
	$ (292)	$ (274)
Included within:		
Current portion of other long-term liabilities	**$ (7)**	$ (43)
Other long-term liabilities	**(285)**	(231)
	$ (292)	$ (274)

Ineffectiveness arising from cash flow hedges recognized in net earnings for the nine months ended September 30, 2012 resulted in no gain or loss (December 31, 2011 – loss of $2 million).

Risk Management

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

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

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

Asset (liability)	**Nine Months Ended Sep 30, 2012**	Year Ended Dec 31, 2011
Balance – beginning of period	**$ (274)**	$ (485)
Net cost of outstanding put options	**18**	–
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	**50**	128
Foreign exchange	**(80)**	42
Other comprehensive income	**12**	41
	(274)	(274)
Add: put premium financing obligations (1)	**(18)**	–
Balance – end of period	**(292)**	(274)
Less: current portion	**(7)**	(43)
	$ (285)	$ (231)

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

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2012	Sep 30 2011	**Sep 30 2012**	Sep 30 2011
Net realized risk management loss (gain)	**$ 137**	$ (23)	**$ 170**	$ 81
Net unrealized risk management loss (gain)	**34**	(122)	**(50)**	(186)
	$ 171	$ (145)	**$ 120**	$ (105)

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, 2012, the Company had the following derivative financial instruments outstanding to manage its commodity price risks:

Sales contracts

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars	Oct 2012	–	Dec 2012	50,000 bbl/d	US$80.00	–	US$134.87	Brent
	Oct 2012	–	Dec 2012	50,000 bbl/d	US$80.00	–	US$136.06	Brent
	Oct 2012	–	Dec 2012	50,000 bbl/d	US$80.00	–	US$113.62	WTI
	Oct 2012	–	Jun 2013	50,000 bbl/d	US$80.00	–	US$145.07	Brent
	Jan 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$110.34	WTI
	Jan 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$135.59	Brent
Crude oil puts	Oct 2012	–	Dec 2012	100,000 bbl/d			US$80.00	WTI

During the fourth quarter of 2012, US$19 million of put option costs will be settled.

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. 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, 2012, 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 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 long-term debt 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, 2012, 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 2012	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Oct 2012	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Oct 2012	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Oct 2012	–	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments designated as hedges at September 30, 2012, were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at September 30, 2012, the Company had US$2,881 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less.

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, 2012, 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, 2012, the Company had net risk management assets of $10 million with specific counterparties related to derivative financial instruments (December 31, 2011 – $nil).

c) Liquidity Risk

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

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, 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	$ 525	$ –	$ –	$ –
Accrued liabilities	$ 2,218	$ –	$ –	$ –
Risk management	$ 7	$ 45	$ 142	$ 98
Other long-term liabilities	$ 24	$ 23	$ 38	$ –
Long-term debt (1)	$ 1,138	$ –	$ 2,944	$ 4,386

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

14. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	Remaining 2012	2013	2014	2015	2016	Thereafter
Product transportation and pipeline	$ 58	$ 213	$ 204	$ 192	$ 126	$ 889
Offshore equipment operating leases and offshore drilling	$ 43	$ 153	$ 120	$ 103	$ 75	$ 121
Office leases	$ 8	$ 32	$ 35	$ 33	$ 34	$ 309
Other	$ 76	$ 169	$ 95	$ 42	$ 10	$ 8

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	
	2012	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011
Segmented product sales	**2,786**	2,730	**8,601**	8,643	**198**	276	**713**	907	**158**	250	**615**	638	**3,142**	3,256	**9,929**	10,188
Less: royalties	**(359)**	(339)	**(991)**	(1,056)	**(1)**	–	**(2)**	(2)	**(50)**	(46)	**(146)**	(68)	**(410)**	(385)	**(1,139)**	(1,126)
Segmented revenue	**2,427**	2,391	**7,610**	7,587	**197**	276	**711**	905	**108**	204	**469**	570	**2,732**	2,871	**8,790**	9,062
Segmented expenses																
Production	**521**	493	**1,608**	1,417	**98**	114	**302**	309	**51**	45	**124**	120	**670**	652	**2,034**	1,846
Transportation and blending	**602**	454	**2,000**	1,726	**2**	3	**8**	10	**–**	1	**1**	1	**604**	458	**2,009**	1,737
Depletion, depreciation and amortization	**839**	714	**2,448**	2,114	**63**	51	**222**	184	**29**	44	**107**	170	**931**	809	**2,777**	2,468
Asset retirement obligation accretion	**22**	18	**64**	53	**6**	8	**20**	24	**2**	2	**5**	5	**30**	28	**89**	82
Realized risk management activities	**137**	(23)	**170**	81	**–**	–	**–**	–	**–**	–	**–**	–	**137**	(23)	**170**	81
Horizon asset impairment provision	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Insurance recovery – property damage (note 7)	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Insurance recovery – business interruption (note 7)	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Equity loss from jointly controlled entity	**1**	–	**6**	–	**–**	–	**–**	–	**–**	–	**–**	–	**1**	–	**6**	–
Total segmented expenses	**2,122**	1,656	**6,296**	5,391	**169**	176	**552**	527	**82**	92	**237**	296	**2,373**	1,924	**7,085**	6,214
Segmented earnings (loss) before the following	**305**	735	**1,314**	2,196	**28**	100	**159**	378	**26**	112	**232**	274	**359**	947	**1,705**	2,848
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	
	2012	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011
Segmented product sales	**831**	427	**2,196**	516	**24**	23	**67**	66	**(19)**	(16)	**(56)**	(51)	**3,978**	3,690	**12,136**	10,719
Less: royalties	**(32)**	(15)	**(108)**	(19)	**–**	–	**–**	–	**–**	–	**–**	–	**(442)**	(400)	**(1,247)**	(1,145)
Segmented revenue	**799**	412	**2,088**	497	**24**	23	**67**	66	**(19)**	(16)	**(56)**	(51)	**3,536**	3,290	**10,889**	9,574
Segmented expenses																
Production	**398**	306	**1,132**	783	**7**	7	**21**	19	**(4)**	(6)	**(10)**	(11)	**1,071**	959	**3,177**	2,637
Transportation and blending	**16**	15	**46**	46	**–**	–	**–**	–	**(14)**	(14)	**(41)**	(38)	**606**	459	**2,014**	1,745
Depletion, depreciation and amortization	**124**	77	**333**	133	**1**	1	**5**	5	**–**	–	**–**	–	**1,056**	887	**3,115**	2,606
Asset retirement obligation accretion	**8**	5	**24**	15	**–**	–	**–**	–	**–**	–	**–**	–	**38**	33	**113**	97
Realized risk management activities	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**137**	(23)	**170**	81
Horizon asset impairment provision	**–**	–	**–**	396	**–**	–	**–**	–	**–**	–	**–**	–	–	–	–	396
Insurance recovery – property damage (note 7)	**–**	–	**–**	(396)	**–**	–	**–**	–	**–**	–	**–**	–	–	–	–	(396)
Insurance recovery – business interruption (note 7)	**–**	(181)	**–**	(317)	**–**	–	**–**	–	**–**	–	**–**	–	–	(181)	–	(317)
Equity loss from jointly controlled entity	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**1**	–	**6**	–
Total segmented expenses	**546**	222	**1,535**	660	**8**	8	**26**	24	**(18)**	(20)	**(51)**	(49)	**2,909**	2,134	**8,595**	6,849
Segmented earnings (loss) before the following	**253**	190	**553**	(163)	**16**	15	**41**	42	**(1)**	4	**(5)**	(2)	**627**	1,156	**2,294**	2,725
Non-segmented expenses																
Administration													**64**	65	**206**	188
Share-based compensation													**49**	(249)	**(173)**	(309)
Interest and other financing costs													**92**	97	**281**	290
Unrealized risk management activities													**34**	(122)	**(50)**	(186)
Foreign exchange (gain) loss													**(115)**	211	**(107)**	107
Total non-segmented expenses													**124**	2	**157**	90
Earnings before taxes													**503**	1,154	**2,137**	2,635
Current income tax expense													**114**	165	**558**	561
Deferred income tax expense													**29**	153	**39**	263
Net earnings													**360**	836	**1,540**	1,811

Capital Expenditures [1]

	Nine Months Ended					
	Sep 30, 2012			Sep 30, 2011		
	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	**$ 294**	**$ (114)**	**$ 180**	$ 199	$ (225)	$ (26)
North Sea	**–**	**–**	**–**	–	(4)	(4)
Offshore Africa	**5**	**–**	**5**	1	–	1
	$ 299	**$ (114)**	**$ 185**	$ 200	$ (229)	$ (29)
Property, plant and equipment						
Exploration and Production						
North America	**$ 2,746**	**$ 71**	**$ 2,817**	$ 2,991	$ 255	$ 3,246
North Sea	**199**	**(33)**	**166**	156	4	160
Offshore Africa	**30**	**(6)**	**24**	50	(29)	21
	2,975	**32**	**3,007**	3,197	230	3,427
Oil Sands Mining and Upgrading [3] [4]	**1,069**	**34**	**1,103**	940	(406)	534
Midstream	**10**	**–**	**10**	5	–	5
Head office	**25**	**–**	**25**	16	–	16
	$ 4,079	**$ 66**	**$ 4,145**	$ 4,158	$ (176)	$ 3,982

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

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

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

(4) During the first quarter of 2011, the Company derecognized certain property, plant and equipment related to the coker fire at Horizon in the amount of $411 million. This amount was included in non cash and fair value changes.

Segmented Assets

	Total Assets	
	Sep 30 2012	Dec 31 2011
Exploration and Production		
North America	**$ 29,028**	$ 28,554
North Sea	**1,652**	1,809
Offshore Africa	**898**	1,070
Other	**44**	23
Oil Sands Mining and Upgrading	**15,825**	15,433
Midstream	**341**	321
Head office	**81**	68
	$ 47,869	$ 47,278

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated October 2011. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended September 30, 2012:

Interest coverage (times)	
Net earnings (1)	8.3x
Cash flow from operations (2)	17.3x

(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 8, 2012. The North American conference call number is 1-800-952-6845 and the outside North American conference call number is 001-416-695-7848. 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 15, 2012. 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.

2013 BUDGET DETAILS

Canadian Natural will release its 2013 budget details on Tuesday, December 4, 2012. The news release will provide forward looking information on the Company's 2013 operating year.

A conference call and webcast, which will include presentation slides, will be held on the same day at 9:00 am MT (11:00 am ET). Presentation slides will be available shortly before the conference call. Conference call information and presentation can be accessed on the homepage of Canadian Natural's website at: www.cnrl.com under Upcoming Events and News.

For further information, please contact:

CANADIAN NATURAL RESOURCES LIMITED

2500, 855 - 2nd Street S.W.

Calgary, Alberta

T2P 4J8

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

JOHN G. LANGILLE
Vice-Chairman

STEVE W. LAUT
President

COREY B. BIEBER
Vice-President,
Finance & Investor Relations

Trading Symbol - CNQ
Toronto Stock Exchange
New York Stock Exchange